New Zealand Hydrogen Scenarios

Report to MBIE

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Definitions

ABS	American Bureau of Shipping
B100	100 percent biofuel
B20	20 percent biofuel blend
BAU	Business as usual
BE	Battey electric
BEB	Battery electric buses
BEV	Battery electric vehicle
CCC	Climate Change Commission
CCS	Carbon Capture and Storage
Class NB	Goods vehicle that has a gross vehicle mass exceeding 3.5 tonnes but not exceeding 12 tonnes
Class NC	Goods vehicle that has a gross vehicle mass exceeding 12 tonnes
CO_2-e	Carbon dioxide equivalent
DAC	Direct air capture
DRI	Direct reduced iron
EAF	Electric arc furnace
EOR	Enhanced oil recovery
EU	Europe
ETS	Emissions Trading Scheme
FCEB	Fuel cell electric bus
FCEV	Hydrogen fuel cell vehicle
GHG	Greenhouse Gas
H2	Hydrogen
HFC	Hydrogen fuel cell
ICE	Internal combustion engine
IPPU	Industrial Processes and Produce Use
IRENA	International Renewable Energy Agency
kg	Kilograms
kt	Kilotonnes
LCFS	Low carbon fuel standard
LCOE	levelised cost of electricity
LOHC	Liquid organic hydrogen carriers

MCH	Methyl Cyclo Hexane
MMT	Million metric ton
MOU	Memorandum of Understanding
Mt	Metric tons
MW	Megawatt
MWh	Megawatt hour
NDC	Nationally Determined Contribution
NZ$	New Zealand Dollar
NZU	New Zealand Unit Types
P2G	Power-to-gas
PEM	Polymer electrolyte membrane electrolysis
PJ	Petajoule
POAL	Ports of Auckland Limited
PtL	Power to liquid
RE	Renewable energy
SAF	Sustainable Aviation Fuel
SOFC	Solid oxide fuel cell
TWh	Terawatt hour
TOL	Toluene
TPA	Tonnes per annum
US	United States
US$	United States Dollar
UNFCCC	United Nations Framework Convention on Climate Change
WACC	Weighted average cost of capital
ZEV	Zero-emissions vehicle

Executive summary

The New Zealand Government (the government) wants to develop hydrogen scenarios for New Zealand, following the development of the 2019 Hydrogen Green Paper 'A vision for hydrogen in New Zealand' and a hydrogen demand, supply and international trade model built by Castalia in 2020 (the Castalia-MBIE 2020 Hydrogen Model). The scenarios will inform a Hydrogen Roadmap for New Zealand.

New Zealand green hydrogen may account for around 8 percent of total energy demand by 2050

Hydrogen technologies and green hydrogen as an energy carrier could help the government achieve its greenhouse gas (GHG) emissions reduction targets.[1] As variable renewable electricity sources such as solar and wind increase as a share of generation capacity, the electricity system will need to become more flexible. Green hydrogen is a flexible renewable energy (RE) carrier, which can be used in a wide range of applications, such as transport, energy and electricity system services, and industry. It can also be exported to assist overseas decarbonisation efforts.[2] It can reduce emissions in high emitting and difficult to decarbonise sectors. Hydrogen could also offer a strategic opportunity for New Zealand to become less reliant on fossil fuel imports for key sectors, particularly transport, which creates future resilience against fuel security risks. It is not without its challenges, however. There are competing technologies which could offer lower cost emissions reductions.

This report explores possible use cases of green hydrogen under a business-as-usual (BAU) in 2050 pathway, and also looks at New Zealand's possible hydrogen economy in 2050 under specific intervention scenarios. Our BAU scenario modelling suggests that around 8 percent of New Zealand's energy demand could be met by green hydrogen as an energy vector in 2050. It is possible that this demand will increase over time as hydrogen technologies become more developed. Table 0.1 details New Zealand's estimated hydrogen demand in 2050 under a BAU scenario, compared to other countries' estimates. Those other estimates include lower-cost blue, brown and grey hydrogen, whereas our New Zealand analysis only includes green hydrogen.[3]

Table 0.1: New Zealand's BAU hydrogen demand in 2050 compared to other estimates

Region	Total hydrogen demand 2050 (MMT)	Sources of hydrogen	Share of total energy demand in 2050 (%)	Key use cases	Source
New Zealand	0.34	Green	8 (BAU) (Excluding uncertain use cases)	Transport (heavy trucks, coach buses, and speciality vehicles)	Castalia Analysis

1 In this report we only analyse green hydrogen.

2 Throughout this report we have considered export as a sector.

3 This estimate is in line with other studies, because:

- Other studies include blue and grey hydrogen (our study is green only)
- Other studies include uncertain use cases (our estimate includes likely use cases only)
- Other studies include synthetic fuels and natural gas replacement for heating (New Zealand has better opportunities to electrify).

World	1,370	Green, Blue	15—24 (Strong policy)	Space and water heating, peaking power, industry, and transport	BNEF
US	63	Green, Blue, Gray	14 (Ambitious)	Transport, industry, buildings, and refining	McKinsey
Canada	20	Green, Blue, Gray	30	Transport, synthetic fuel, natural gas replacement, grey crude production feedstock, and other industrial uses	Zen
EU	68.2	Green, Blue, Gray	24 (Ambitious)	Power generation, transport, heating for buildings, and industry	McKinsey

Other countries have ambitious hydrogen strategies and interventions

New Zealand's hydrogen policy is not as advanced as other developed countries. Australia has developed a hydrogen strategy and committed significant sums to projects. Europe, Canada and the US governments and the private sector have likewise committed significant sums toward the development of a hydrogen economy.

Hydrogen in New Zealand can be used in four sectors

We identified four sectors in New Zealand where hydrogen technology and applications of hydrogen as an energy carrier could be used: transport, energy and electricity system services, industry, and exports.

Hydrogen in the transport sector

Hydrogen use is most likely in heavy-duty vehicles like trucks, some buses and in speciality vehicles. Hydrogen fuel cell (HFC) vehicles have a high gravimetric energy density, fast refuelling time, and a long driving range compared with alternatives. Battery electric (BE) vehicles are the main competing zero-emission technology, and biofuel is the main competing low carbon fuel source.

Hydrogen is likely to be used in aviation applications; however it is not clear whether hydrogen will be combusted, in a hybrid HFC-combustion aircraft or used as an input to Synthetic-Sustainable Aviation Fuel (SAF).

Marine applications using hydrogen are possible for small vessels and some larger vessels using HFCs, or as a fuel (including via green ammonia) in combustion engines for deep-sea and larger fleets. BE vessels are the main competing technology, and advanced biofuels is the main competing fuel source.

Rail may utilise HFC trains in applications that require long-range, high-power demands, low service frequency, and fast refuelling times. Hybrid HFC-BE trains may also be utilised. Like marine, green ammonia is also being considered for rail applications. The electrification of railway lines is the main competing technology, while biofuel is the main competing fuel source.

Hydrogen for energy and electricity system services

Hydrogen could have different uses for energy and electricity systems services. In theory hydrogen could be used as electricity storage over various time horizons and for generation could help improve the resilience of the electricity system. Hydrogen produced during periods of low electricity demand could be stored and used to support intra-day and inter-seasonal security of supply.

Electric batteries are likely to be more viable for daily peak demand requirements, whereas hydrogen storage may become more viable for longer duration storage, and where multiple uses for hydrogen are possible.

Electrolysers that would normally produce hydrogen provide an option for rapid demand response option in electricity systems. These could better utilise existing electricity generating resource by making more supply available without increasing the required capacity on the grid.

Hydrogen in industry

There is currently only limited scope to replace industrial feedstocks with hydrogen. Fertiliser production may utilise hydrogen as a feedstock if costs come down and technological processes improve. Hydrogen could also be used in steel production as a feedstock, however, the technology to do this at scale is still in development. At this stage, steel production using hydrogen feedstock is the only zero-emission alternative to traditional steelmaking. In the future, carbon capture and storage (CCS) may be a viable way to reduce, but probably not eliminate, emissions from the traditional steelmaking process. Finding a CCS site in New Zealand that is geologically suitable and passes environmental and social standards is also likely to be difficult. Therefore, if emissions are to be eliminated from steelmaking, hydrogen is likely to play a significant role.

High-temperature process heat could use hydrogen as a combusted heat source. Electricity and biomass are effective heat sources, but only for low and medium-temperature process heat. Domestic and commercial combustion may utilise hydrogen as a combusted heat source for heating and cooking. Hydrogen use in this application is likely to be small, due to electricity and biogas as strong competing energy sources for heat pumps and stoves.

Hydrogen to support decarbonisation in export markets

Hydrogen produced in New Zealand could help meet global demand, particularly in countries like Japan, Korea, and Singapore. New Zealand's abundant RE sources mean that hydrogen could be cost-competitive. Other countries with low-cost energy sources will compete with New Zealand in the global market.

BAU pathway for hydrogen uptake has demand from around 2030

Under a BAU pathway, we expect hydrogen uptake in heavy vehicles and for hydrogen technology to support the electricity system and produce hydrogen for export from around 2030. The BAU pathway assumes that New Zealand policy is generally supportive of hydrogen technology, without specific interventions, and the cost of carbon steadily rises over the 30-year period. The modelling assumptions are detailed in Section 4.

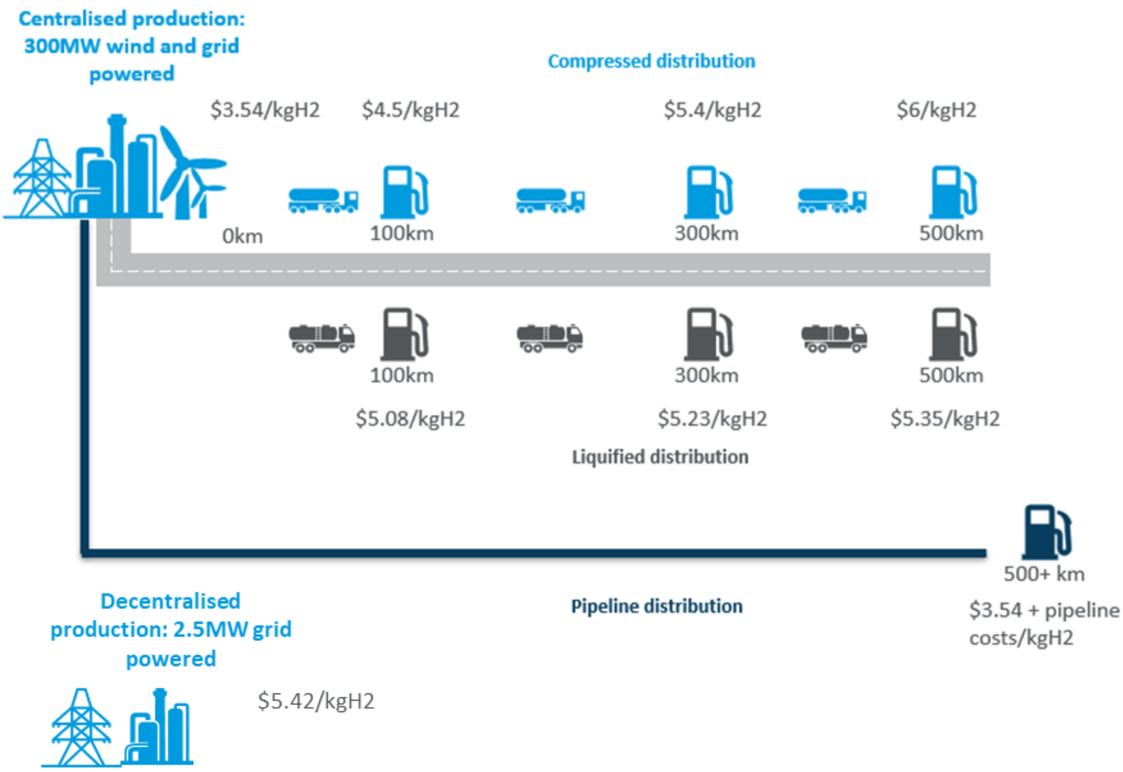
Production pathways depend on plant utilisation, electricity costs and distance from market

New Zealand's domestic delivered hydrogen costs are comparable to global forecast benchmarks. The advantages of scale production can be outweighed by distance from the point of use.

Production of hydrogen could be a combination of both centralised production and distribution and decentralised production and distribution, depending on electricity costs and distance from users

Delivered hydrogen costs in New Zealand will depend on production and distribution costs. Cost competitiveness of centralised versus decentralised production is broadly comparable. Figure 0.1 illustrates the difference in delivered hydrogen prices in the BAU scenario. While large-scale centralised bulk production costs are lower (US$3.54/kg) compared to smaller-scale decentralised production (US$5.42/kg), once delivery cost as either compressed gas or liquid are considered, the cost of at the point of use is very similar. Distribution via pipelines is likely to be cost-competitive, but costs are difficult to estimate.

Figure 0.1: Illustration of centralised vs decentralised production in 2035 under BAU (US$)

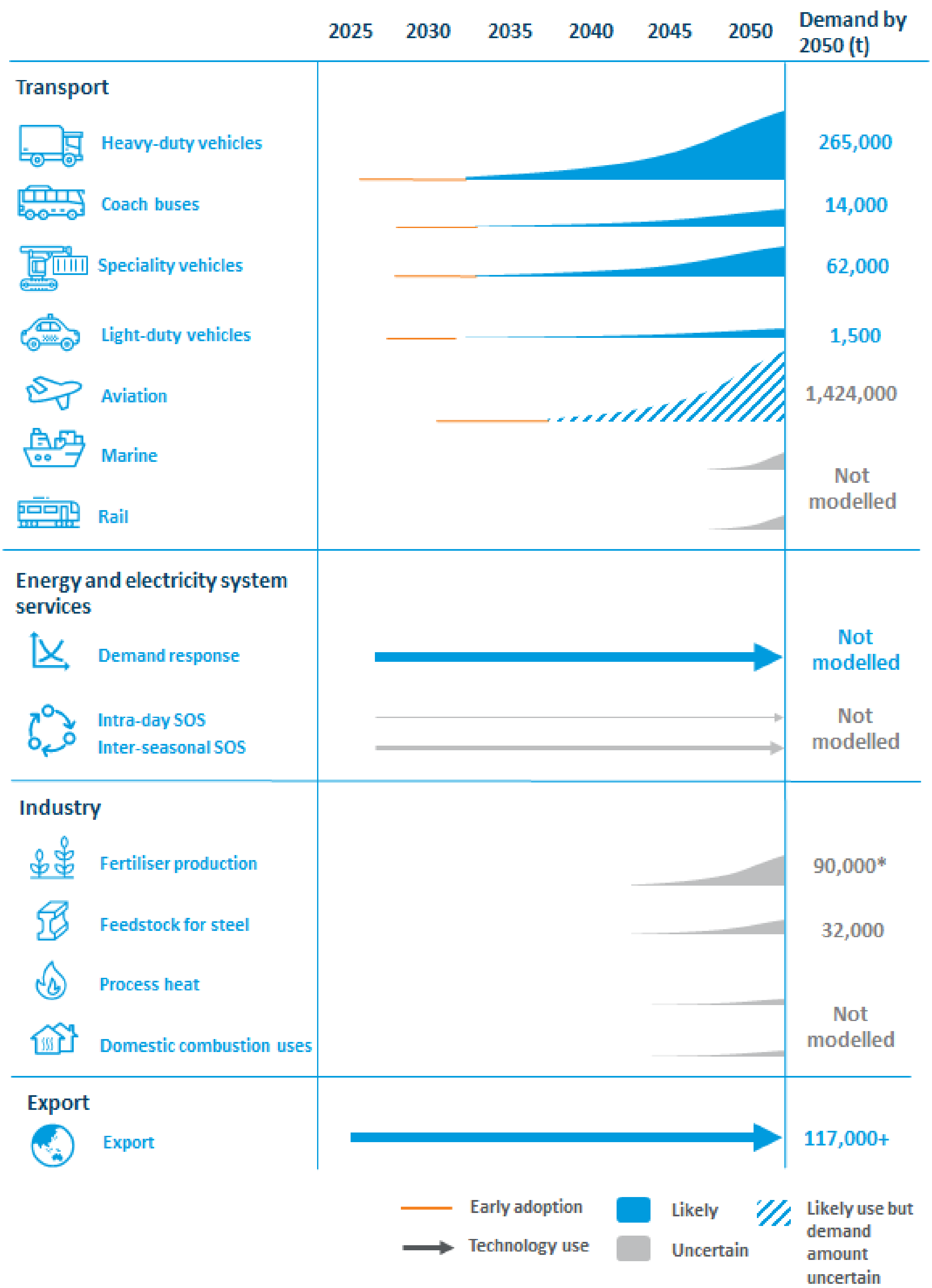


Demand depends on relative competitiveness of hydrogen technologies and uses

Figure 0.2 illustrates the tipping point and uptake timeframes for each use case and an assessment of the likelihood of development. It also shows the approximate hydrogen demand by 2050 in the base case. We then go into this modelling in more detail below. It is important to note that our modelling is highly sensitive to technological developments.

We did not carry out detailed modelling for marine use cases because HFC technology is in the early stages of development and relative costs of HFCs and competing low-carbon solutions are not clear. For rail, the use of HFC trains in New Zealand will depend on the cost of electrifying remaining sectors of the network. We also did not model process heat and domestic combustion uses of hydrogen. Direct electrification is lower cost for many applications. It is not clear if hydrogen would be lower cost that other energy sources or carriers for combustion use cases.

Figure 0.2: Illustration of hydrogen uptake in BAU scenario

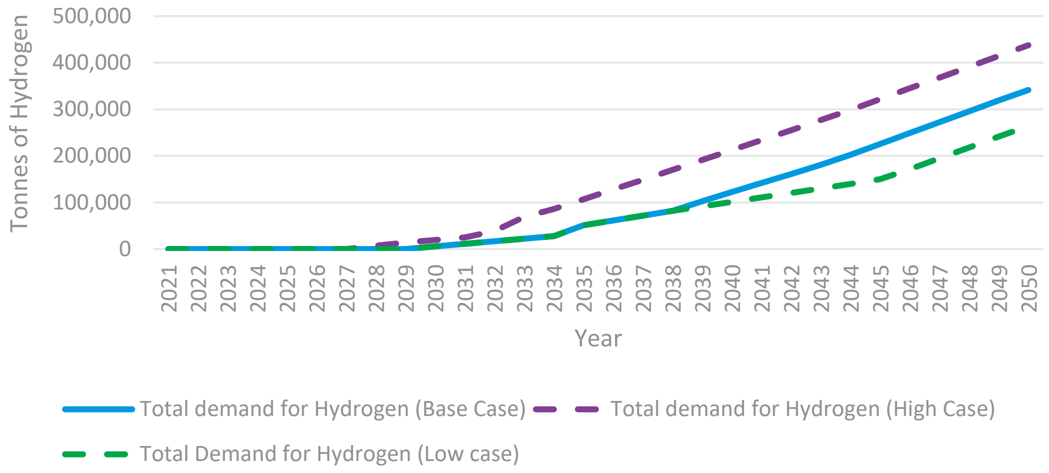


Note: Figures are rounded.
**For fertilizer production, around 1 percent of annual demand will be produced in the short-term using green hydrogen from wind-powered hydrogen production at Kapuni.*

Heavy vehicles, coach buses, and speciality vehicles will drive demand in the transport sector

The transport sector is likely to be the largest source of demand of hydrogen in New Zealand. Demand will come from heavy trucks, coach buses and speciality vehicles. Figure 0.3 shows estimated demand in a base, high and low case.

Figure 0.3: Demand for hydrogen in transport applications in New Zealand



Heavy vehicle demand is the largest source of estimated demand, that is not dependent on the emergence of new technologies. We estimate the tipping point for demand for hydrogen in heavy vehicles to start around 2030. There will be demand for high frequency users and specific use cases prior to this. This will grow to around 265,000 tonnes by 2050.

The tipping point for demand for hydrogen in coach buses in the average use case is expected to emerge around the 2040s, when total cost of ownership for particular routes falls below equivalent BEBs and diesel alternatives. Some use cases are expected to be economic before this. Estimated demand for hydrogen will grow to around 14,3004 tonnes by 2050.

The tipping point for demand for hydrogen in specialty vehicles is expected to start in the mid-2030s. This will grow to around 62,500 tonnes by 2050.

Our modelling shows that once the capital costs of HFC-EV light-duty vehicles and BEVs reach parity, the total cost of ownership is comparable. This will justify using or switching to HFC-EV light-duty vehicles for some users who have high travel demand and when EV charging time is a constraint. Our modelling suggests that total demand for hydrogen for light-duty commercial use is approximately 1,449 tonnes by 2050.

Demand in aviation is likely to occur. However, it is unclear which technologies will become dominant, and how much demand there will be. Some demand may also emerge in marine and rail. The tipping point for demand in these three applications is highly uncertain because the technologies that could decarbonise the sectors are in development.

Demand response would play a role in the electricity sector

Hydrogen technology is likely to support the electricity system as a demand response option. Hydrogen production can be ramped up and down quickly and can follow electrical load flexibly. Demand response is a key feature of the business model for the Southern Green Hydrogen opportunity in Southland.

Hydrogen technologies may be a viable means to overcome inter-seasonal security of supply, but are unlikely to provide intra-day security of supply. Hydrogen storage (such as via natural gas pipeline or in a geological formation) may be viable for long duration storage to mitigate dry year risk. Biomass and pumped hydro may be more economic. It is not clear which long-term storage technologies are most suitable in New Zealand. Hydrogen technologies are unlikely to provide intra-day security of supply due to viable alternatives, such as electric batteries. Hydrogen storage may also be viable for some defined applications where multiple uses for hydrogen are possible, for example when hydrogen is used for vehicle fuel and in a fuel cell.

Industrial demand for hydrogen will be small during the transition and there may be demand in steel making

Hydrogen may have some relatively small-scale uses, but industrial demand will probably not drive hydrogen production decisions. Hydrogen could be used in steelmaking, but demand will be modest relative to transport use. If the steel mill can convert its entire production process, potential demand for hydrogen in steelmaking would be between 30-35 kilo tonnes per year. Although this demand for hydrogen is relatively low compared to other use cases such as transport, the emissions reduction impact is still significant.

New Zealand exports appear to be globally competitive

New Zealand-produced hydrogen is likely to be in the range of cost-competitiveness with key trading partner countries. The Southern Green Hydrogen proposal in Southland could utilise an existing transmission line, and significant capacity (up to 800 MW) from the Manapouri power station at a high utilisation rate. This compares favourably to overseas production options.

Interventions could bring forward hydrogen uptake or preserve infrastructure options

> The interventions examined in this section are not current government policy. They are indicative policies that Castalia has identified that the government may or may not choose to investigate further at a later date.

Overall, typical policy interventions would not make a significant difference to hydrogen uptake in the model. This is because subsidies (or tariffs) on capital equipment or inputs have a relatively modest impact on the total cost of ownership.

However, there may be strategic opportunities that fall outside of the modelling approach in this report. For example, hydrogen for aviation is still in early stages of development, but New Zealand has some advantage as a test-case country.

Interventions could reduce costs of hydrogen technologies relative to competition

Interventions such as subsidies, tariffs, or taxes on vehicles and mandates for vehicle types could reduce capital cost of hydrogen technologies relative to other technologies. These interventions will support demand. Subsidies for fertiliser and steel production using hydrogen could support demand.

Our modelling suggests that changing the price of diesel fuel would also have little impact on the timing of uptake of hydrogen vehicles. Our modelling also suggests that the change in demand for hydrogen is very small from a 20 percent increase in tax on diesel vehicles. This is because the additional cost of tariff increase is spread over the vehicle’s useful life. A 10 percent increase in tariffs has no impact on overall demand for hydrogen in the transport sector.

Interventions that support production could change timing of uptake

Support for scale production, production subsidies, emissions taxes or emissions trading scheme (ETS) prices, and low carbon fuel standards (LCFS) could reduce the cost of hydrogen fuel relative to other technologies, energy sources, or energy carriers. Use of these interventions could accelerate the pace of uptake. Large-scale research and development support in New Zealand is unlikely to impact global capital costs or the global industry. While pure science and support for research and development should continue, domestic interventions in these matters are unlikely to materially change uptake.

Our modelling suggests that large subsidies for the capex cost of building a plant (25-45 percent subsidy) would have only a modest impact on timing of hydrogen demand. Subsidies on plant capex have a larger impact after 2040 compared to base case. This is because hydrogen trucks below 12,000 kgs become viable earlier due to the cheaper cost of producing hydrogen.

Interventions that preserve infrastructure options

There may be future uses for existing infrastructure to provide services in the hydrogen economy. Infrastructure includes:

- Gas pipeline infrastructure
- Storage and distribution facilities
- Electricity generation infrastructure.

Preserving this infrastructure may provide options that avoid additional sunk costs or enable wider range of decarbonisation technologies. A range of interventions could be used to preserve the infrastructure.

Interventions that reduce import path dependency

Imported hydrogen may be lower cost than domestically produced hydrogen before scale production and a domestic supply chain is built. This could lead to a path dependency where it is not economic to build a competing domestic supply chain. Interventions could lower domestic production cost.

Strategic and long-term support

New Zealand's advantages are in its sunk investments in infrastructure and its strategic advantages in certain sectors. Other countries are undertaking significant investment in hydrogen technology and projects where governments have identified a particular strategic advantage. New Zealand policy is probably best targeted at particular niches where the country already has an advantage relative to other countries, which are spending significant sums. For example, the Australian government has recognised a strategic advantage in developing brown or blue hydrogen from natural gas and the future possibilities of switching to producing green hydrogen from solar PV. Northern hemisphere countries are investing heavily in industrial uses, hydrogen to replace natural gas for heating, and in heavy transport.

New Zealand policymakers could explore supporting longer-term and strategic support for particular niches. For instance, New Zealand seems to have an advantage in the aviation sector. Air New Zealand and Airbus have a strategic joint initiative where the companies will cooperate on understanding how to integrate hydrogen aircraft in a commercial network. If hydrogen technology advances to a stage where hydrogen can meet the energy demand for New Zealand's forecast aviation demand, then aviation would be the largest source of hydrogen demand (1.4 million tonnes, about four times the land transport demand). Hydrogen aviation technology is not yet available, so no policy interventions should yet be considered. However, the government should ensure that as it emerges, the regulations and wider policy environment supports the sector's development.

1 Introduction

The purpose of this report is to analyse the sectors and technologies for likely hydrogen demand and understand the supply potential for hydrogen in New Zealand. This report outlines our understanding of how the hydrogen economy could develop in New Zealand under a BAU scenario to 2050. It analyses four sectors and use cases for hydrogen within those sectors. This analysis enables us to develop scenarios of varying interventions that could change the pace of hydrogen uptake, preserve infrastructure options, or reduce the likelihood of import path dependency.

In this report, we only analyse green hydrogen. Green hydrogen is produced via water electrolysis using, almost exclusively, electricity from RE sources. Approximately 84 percent of New Zealand's grid electricity is RE[4], but the government's policy objective is to transition to 90 percent RE by 2025 and to increase the penetration of RE beyond this.

The report is structured as follows:

- Section 2 sets out the New Zealand and international policy context
- Section 3 shows how hydrogen can contribute to the government's net zero 2050 goal in three sectors, plus exports to support decarbonisation elsewhere
- Section 4 sets out the BAU pathways to the hydrogen economy under:
  - Pathways for the production costs for supply of hydrogen
  - Pathways for the demand for hydrogen in the four sectors[5]
- Section 5 outlines the intervention scenarios to the hydrogen economy in terms of:
  - Interventions that change the pace of uptake
  - Interventions that preserve infrastructure options
  - Interventions that reduce the likelihood of import path dependency.

The following appendices are also included:

- Appendix A: Breakdown of total hydrogen demand in New Zealand across sectors and use cases
- Appendix B: List of stakeholders that have been engaged to date for this project

4 https://www.nzte.govt.nz/page/renewable-energy

5 Throughout this report we have considered export as a sector.

2 New Zealand and international policy context

New Zealand's green hydrogen scenarios need to be seen in the context of the government's policies and aims for decarbonisation. The government has set a net zero emissions target for 2050. Other countries have also incorporated hydrogen into their energy policy framework. We briefly summarise these here.

2.1 New Zealand's GHG emissions profile and commitments

This section summarises the policy context of New Zealand's GHG emissions profile and commitments to reduce emissions.

The New Zealand Government (the government) set a target of net zero emissions by 2050 in the Climate Change Response (Zero Carbon) Amendment Act 2019 (the Act).[6] The 2050 targets are designed to achieve a domestic low-emission transition across a range of sectors, including transport, electricity production, and industry. The Act updated New Zealand's First Nationally Determined Contribution (NDC) (first submitted in 2016 and updated in 2020), which initially targeted reducing the country's GHG emissions to 30 percent below 2005 levels by 2030[7] to comply with New Zealand's obligations under the Paris Agreement.

In 2019, the government also set a target of 100 percent RE generation by 2035.[8] Key RE sources for New Zealand are solar, hydro, and geothermal, and green hydrogen is a key RE carrier. New Zealand is expected to use a portfolio of RE options with varying applications. New Zealand's gross annual GHG emissions were 82.3 Mt CO_2-e in 2019.[9] Table 2.1 details New Zealand's gross emissions sources by sector (and some key sub-sectors). The emissions cited in this report use New Zealand's gross emissions, detailed in New Zealand's Greenhouse Gas Inventory, submitted to the United Nations Framework Convention on Climate Change (UNFCCC) in April 2021.

The CCC predicts that, under current policies, gross long-lived emissions would fall to approximately 45 Mt CO_2-e by 2030, and continue to fall to around 33 Mt CO_2-e in 2050. Net emissions would also reduce, largely through increased carbon removals, with 1.1 million hectares of new forest to be planted by 2050.

6 Climate Change Response (Zero Carbon) Amendment Act 2019 is available at: https://www.legislation.govt.nz/act/public/2019/0061/latest/LMS183736.html

7 New Zealand's First NDC is available at: https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/New%20Zealand%20First/New%20Zealand%20first%20NDC.pdf

8 https://www.beehive.govt.nz/release/nz-embracing-renewable-electricity-future

9 https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf, p.79

Table 2.1: Emissions in New Zealand (as of 2019)

Sector	Amount of GHG emissions (kt CO_2-e)	Percent of gross GHG emissions (%)
Agriculture	39,617.1	48
Energy	34,263.1	42
▪ **Transport**	16,207.6	
▪ Public electricity and heat production	4,181.3	
Industrial Processes and Product Use (IPPU)	5,115.9	6
▪ **Chemical industry**	209.5	
▪ **Metal industry**	2,325.2	
Waste	3,316.9	4
Land Use, Land-Use Change and Forestry (LULUCF)	*-27,425.1*	*-33*
Total gross emissions	**82,317.9**	**100**
Total net emissions	**54,892.8**	

Note: The LULUCF sector is not a part of gross emissions, and is included here as a negative value

2.2 International hydrogen policy context

Hydrogen is emerging as an important priority for decarbonising energy in many other economies. Reducing the cost of green hydrogen (US$/kg) is the key factor affecting the increased role of hydrogen. Many developed countries are providing strong policy support. Our review shows that national strategies and roadmaps expect total demand for hydrogen of around 15-30 percent of total energy demand in those countries or areas by 2050. Overall, more than 228 hydrogen projects valued at US$300 billion up to 2030 have been announced.[10]

In the United States, , the Department of Energy recently announced US$52.5 million to fund 31 projects to advance next-generation clean hydrogen technologies and support its Hydrogen Energy Earthshot Initiative. Canada has several projects including the Hydrogen Locomotive Program, New Edmonton Blue Hydrogen Hub, and Alberta Zero Emissions Hydrogen Transit with investments over a US$1 billion. In the European Union, projects with a value of approximately US$17 billion have been committed. Australia's government has committed AU$ 1.4 billion dollars in building a hydrogen industry and projects are being developed in several states, notably in Queensland where Woodside Petroleum will invest more than AU$ 746 million to build a hydrogen/ammonia plant. [11] Table 2.2 compares New Zealand's strategy with other countries, and some proposed projects.

[10] https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021.pdf

[11] https://www.reuters.com/business/energy/woodside-invest-over-a1-bln-hydrogen-ammonia-plant-w-australia-2021-10-25/

Table 2.2: New Zealand's BAU hydrogen demand in 2050 compared to other estimates

Region	International hydrogen policy developments[12]	Total hydrogen demand 2050 (MMT)	Sources of hydrogen	Share of total energy demand in 2050 (%)	Key use cases	Source
New Zealand	A vision for Hydrogen in New Zealand released September 2019; MBIE-Castalia 2020 Hydrogen Model; Hydrogen Scenarios (this document)	0.34	Green	8 (BAU) (Excluding uncertain use cases)	Transport (heavy trucks, coach buses, and speciality vehicles)	Castalia Analysis
World		1,370	Green, Blue	15—24 (Strong policy, Ambitious)	Space and water heating, peaking power, industry, and transport	BNEF
US	Department of Energy Hydrogen Program Plan released November 2020	63	Green, Blue, Gray	14 (Ambitious)	Transport, industry, buildings, and refining	McKinsey
Canada	Hydrogen Strategy for Canada released December 2020	20	Green, Blue, Gray	30	Transport, synthetic fuel, natural gas replacement, grey crude production feedstock, and other industrial uses	Zen
EU	European Commission – A Hydrogen Strategy for a Climate-Neutral Europe released July 2020	68.2	Green, Blue, Gray	24 (Ambitious)	Power generation, transport, heating for buildings, and industry	McKinsey
Australia	Australia's national hydrogen strategy released November 2019	19.8	Green	20 (Best case scenario[13])	Steelmaking, ammonia production, oil refining, light and heavy transport, heating, power generation and shipping	Deloitte[14]

[12] https://research.csiro.au/hyresource/international-hydrogen-policy-developments-an-update/

[13] Hydrogen Energy Demand Growth Prediction and Assessment (2021–2050) Using a System Thinking and System Dynamics Approach (Yusaf et.al, 2022)

[14] https://www2.deloitte.com/content/dam/Deloitte/au/Documents/future-of-cities/deloitte-au-australian-global-hydrogen-demand-growth-scenario-analysis-091219.pdf

3 Hydrogen use cases in 2050

This section describes the use cases of hydrogen in New Zealand, given the government's objectives for reducing GHG emissions. We describe the role that hydrogen technologies and hydrogen as an energy carrier could play in decarbonising key sectors in New Zealand, outline competing technologies, and discuss the key determinants for hydrogen uptake.

There are four main sectors in New Zealand's economy where hydrogen can play a key decarbonisation role; domestic use in transport, energy and electricity system services, industry, and overseas decarbonisation efforts through export trade.

Below we discuss possible uses of hydrogen by 2050 using the following structure:

- The role of hydrogen technologies and hydrogen as an energy carrier in four sectors: transport, energy and electricity system services, industry, and exports
- The competing technologies and energy sources to produce hydrogen
- The factors that will determine whether hydrogen is a cost-competitive energy carrier and the technology is viable.

3.1 Transport

Hydrogen technologies and hydrogen as an energy carrier can significantly reduce emissions from the transport sector by replacing fossil fuels. The government's 2050 emissions targets require significant adoption of hydrogen in the transport sector. Hydrogen is useful for decarbonising the transport sector because it is a RE carrier with a high gravimetric energy density required for transportation. Hydrogen has the highest energy content per mass of all chemical fuels at between 120.2–141 MJ/kg.[15]

Emissions from transport were 16,207.6 kilo tonnes (kt) CO_2-e in 2019, which accounted for 19.7 percent of total gross GHG emissions in New Zealand.[16] New Zealand imported over 306 petajoules (PJ) of oil in 2020, of which 207 PJ (27.5 percent) was for domestic transport.[17] Under current policies, transport emissions are predicted to be 7,800 kt CO2-e in 2050.[18] Figure 3.1 details total emissions in the transport sector and by sub-sector in 2019.

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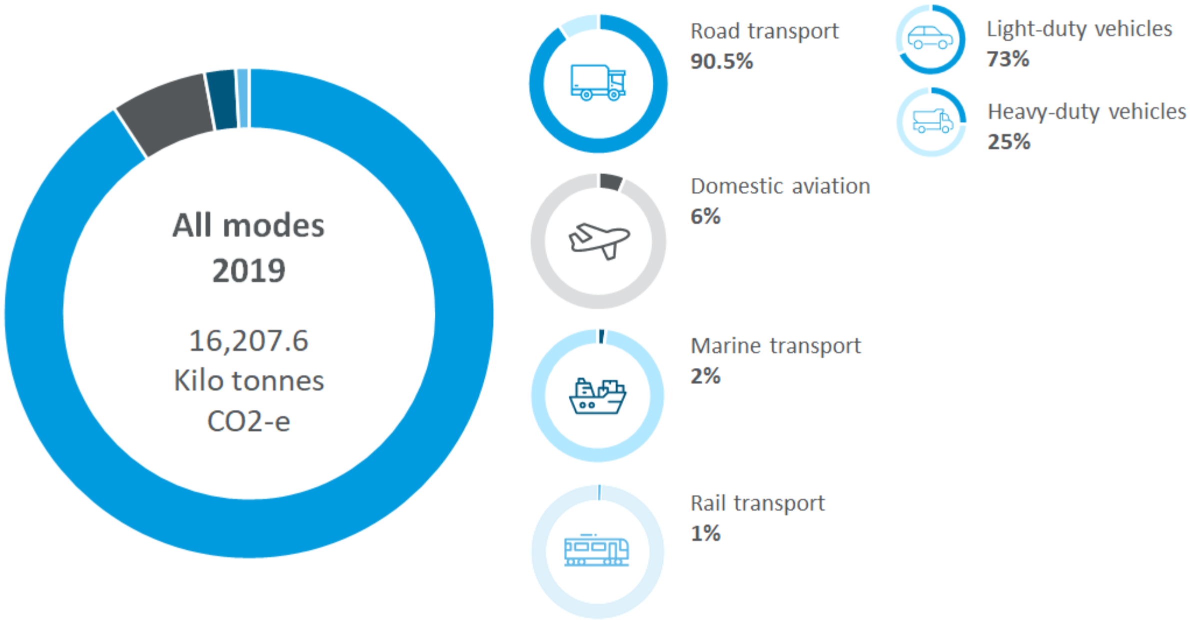
15 https://absinfo.eagle.org/acton/attachment/16130/f-bd25832f-8a70-4cc9-b75f-3aadf5d5f259/1/-/-/-/-/hydrogen-as-marine-fuel-whitepaper-21111.pdf

16 Time series emissions data 1990 to 2019 from New Zealand's Greenhouse Gas Inventory published in 2021. Figures are rounded to 1 decimal place. Available at: https://environment.govt.nz/publications/new-zealands-greenhouse-gas-inventory-1990-2019/

17 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/oil-statistics/

18 https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf

Figure 3.1: GHG emissions in New Zealand's transport sector in 2019



Source: Ministry of the Environment, New Zealand's Greenhouse Gas Inventory, 2021 and Ministry of Transport, Green Freight Strategic Working Paper, 2020

3.1.1 Heavy-duty vehicles

Hydrogen fuel cell (HFC-EVs) heavy vehicles could play an important role in reducing emissions by replacing fossil fuel in heavy-duty vehicles. Emissions from heavy-duty vehicles[19] accounted for 25 percent of total road transport emissions in 2019, and are predicted to account for 42 percent of total road transport emissions in 2050 under current policies.[20] Table 3.1 details New Zealand's heavy-duty vehicle profile.

The uptake of HFC-EV heavy vehicles will depend on vehicle capital cost and the relative energy costs of other technologies or availability of low-emissions alternative fuels.

Table 3.1: New Zealand's heavy-duty vehicle profile (as of 2017)

	Medium truck (under 10 tonnes)	Heavy truck (over 10 tonnes)
Number	77,000	70,000
Billions of kilometres (km) travelled	0.873	2.19

[19] A heavy vehicle has a gross vehicle mass (GVM) of more than 3,500 kilograms. There are two classes of heavy vehicle:

- Medium goods vehicle (class NB)—a goods vehicle that has a gross vehicle mass exceeding 3.5 tonnes but not exceeding 12 tonnes, and
- Heavy goods vehicle (class NC)—a goods vehicle that has a gross vehicle mass exceeding 12 tonnes.

https://www.nzta.govt.nz/vehicles/vehicle-types/heavy-trucks/

[20] https://www.transport.govt.nz//assets/Uploads/Paper/Green-Freight-Strategic-Working-Paper_FINAL-May-2020.pdf, p.17

	Medium truck (under 10 tonnes)	Heavy truck (over 10 tonnes)
Grams of Co2-e per km	530	1,420
kt CO2-e	463	3,115

Source: Adaptation from Ministry of Transport, Green Freight Strategic Working Paper (2020)

HFC-EV heavy vehicles can play a key role in the future transport sector

HFC-EVs could play an important role in decarbonising heavy vehicles, such as freight trucks, semi-trucks, tractor-trailers, and other off-roading vehicles. Compared with other fuels, HFC-EVs have high energy density, fast refuelling time (10-20 minutes) with a longer driving range on a single tank (1,200 km)[21], and are more fuel-efficient on undulating terrain.

HFC-EVs are likely to be the most viable option for class NC heavy-duty vehicles (vehicles exceeding 12 tonnes), as well as the heavier vehicles in class NB.[22] Vehicles on the lighter end of class NB may have viable battery electric vehicle (BEV) options. HFC-EVs are currently commercially available from companies including Hyzon Motors[23] and Hyundai[24], and are being trialled by other companies such as Toyota.[25] The application of the technology is currently limited but is expected to grow in the near term.

BE heavy vehicles are the major competing technology and biofuel is a competing fuel source

BE heavy vehicles are the main competing technology to HFC-EVs for heavy vehicles. BEV heavy vehicles currently have more efficient energy use than HFC-EV heavy vehicles, requiring roughly one-third as much input. BE heavy vehicles are commercially available from companies including Daimler and Chanje.[26] However, heavy trucks are difficult to convert to BE if the range and recharging time needs to match that of diesel trucks[27]. In addition, batteries are heavy, which impacts payload and economics and takes up space that could otherwise be reserved for freight.

Biofuel[28] is a competing fuel source to hydrogen as an energy carrier. Conventional biofuel blends as high as 20 percent (B20) can be used in some large trucks and coach buses. Conventional biofuel blends above B20 tend to require engine modification.

[21] https://www.transportenvironment.org/discover/comparing-hydrogen-and-battery-electric-trucks/

[22] Class NB is a goods vehicle that has a gross vehicle mass exceeding 3.5 tonnes but not exceeding 12 tonnes, and class NC is a goods vehicle that has a gross vehicle mass exceeding 12 tonnes.

[23] https://hyzonmotors.com/vehicle/

[24] https://www.hyundai.news/eu/brand/hyundai-xcient-fuel-cell-heads-to-europe-for-commercial-use/

Hyundai aims to have an HFC-EV in every part of its vehicle range by 2028 and state that HFC-EVs for heavy vehicles are a gateway to other applications. Source: personal communication with hydrogen stakeholders.

[25] https://global.toyota/en/newsroom/corporate/34009225.html

[26] https://www.greenbiz.com/article/8-electric-truck-and-van-companies-watch-2020

[27] Fueling the Future of Mobility (Deloitte China and Ballard), Fuel Cells and Hydrogen Applications for Regions and Cities Vol.2 (Roland Berger, 2017).

[28] Biofuels are fuels made from renewable biomass, such as plant material. The most common biofuel is ethanol, which is a petrol substitute, and biodiesel, which is a diesel substitute. https://www.mbie.govt.nz/dmsdocument/15020-increasing-the-use-of-biofuels-in-transport-consultation-paper-on-the-sustainable-biofuels-mandate-pdf

Advanced biofuels can be produced from a wider range of feedstock and present opportunities to overcome the limitations of conventional biofuels. For example, some advanced biofuels are 'drop-in fuels', meaning they can be used in existing vehicles and fuel infrastructure without modifications.[29] 100 percent biofuels (B100) are being developed and can be applied in heavy transport applications. Major truck manufacturing companies like Scania are now producing truck engines capable of running on B100.[30] Trials using B100 in buses and heavy trucks have been successful.[31]

Biofuels have the advantage of enabling decarbonisation of the current vehicle fleet, rather than replacing vehicles before or after the end of their useful life. Biofuels are likely to play a short-term role in reducing emissions from heavy vehicles until the current fleet is replaced.

Potential demand for biofuel for heavy-duty vehicles has been estimated at 4 percent of liquid fuel demand in 2050.[32] This demand means that biofuel could be cost competitive with hydrogen in 2050. The supply of biofuel in New Zealand is likely to be limited unless imported or second or third generation biofuels are developed and utilised. While supply remains limited, it is uncertain whether transport or process heat will be the key user.

Vehicle capital cost and competitiveness of other technologies will be key determinants for HFC-EV heavy vehicle uptake

The CCC predicts that of the trucks imported in 2030, 42 percent of medium trucks and 18 percent of heavy trucks would be an EV and/or HFC-EV. By 2035, this is expected to increase to 95 percent and 73 percent, respectively.[33] HFC-EVs are likely to be the most viable option for class NC heavy-duty vehicles (vehicles exceeding 12 tonnes), as well as the heavier vehicles in class NB.[34] Vehicles that are on the lighter end of class NB may have viable BE options.

The uptake of HFC-EV heavy vehicles is dependent on a range of factors:

- Technological development of electric battery and storage technologies for the heaviest of vehicles, including longer range and faster charging time
- Capital cost of HFC-EVs heavy vehicles compared with BE heavy vehicles
- The cost of hydrogen fuel relative to electricity and biofuel
- Availability of biofuels for transport
- Access to refuelling and recharging infrastructure and time required to refuel or recharge

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29 https://www.mbie.govt.nz/dmsdocument/15020-increasing-the-use-of-biofuels-in-transport-consultation-paper-on-the-sustainable-biofuels-mandate-pdf

30 https://www.mbie.govt.nz/dmsdocument/15020-increasing-the-use-of-biofuels-in-transport-consultation-paper-on-the-sustainable-biofuels-mandate-pdf; https://www.truckinginfo.com/10146888/running-on-100-biodiesel-yeah-thats-happening

31 https://www.biofuel-express.com/en/biodiesel/

32 https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf, p. 110.

33 https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf, p.107

34 Class NB is a goods vehicle that has a gross vehicle mass exceeding 3.5 tonnes but not exceeding 12 tonnes, and class NC is a goods vehicle that has a gross vehicle mass exceeding 12 tonnes.

- Available supply of HFC-EV and BE heavy vehicles.[35]

3.1.2 Coach buses

Fuel Cell Electric Buses (FCEBs) could reduce emissions from passenger transport by replacing fossil fuel powered buses. New Zealand had 11,500 coach buses in 2019[36], the majority of which are powered by diesel.[37] Emissions from buses accounted for approximately 2 percent of total road transport emissions in 2019, and are predicted to account for approximately 5 percent of total road transport emissions in 2050 under current policies[38] The CCC expects the use of public transport to grow from around 3.5 percent in 2019 to 7.7 in 2030. The uptake of this technology will depend on the cost-effectiveness of FCEBs and the competitiveness of other technologies.

FCEBs can play a key role in bus travel from remote locations and in some metro applications

FCEBs can play an important role in decarbonising buses because they can match the performance of conventional fossil fuel buses. FCEBs also have high fuel economy, fast refuelling times (10 minutes), and have a longer driving range on a single tank than other low-carbon alternatives.[39] FCEBs are commercially available today, and more than 2,000 are currently operating globally.[40]

Castalia modelling shows that FCEBs are likely to be most viable in New Zealand on long-haul and remote routes and metro routes with high power requirements because they are long and/or undulating.[41] For example, RealNZ, a tourism operator in New Zealand, is focussing on operating FCEBs and developing refuelling infrastructure for its lower South Island operations.[42] FCEBs also have performance advantages over BEBs in extreme heat or cold, which may be relevant for some parts of New Zealand.

Castalia analysis of certain bus routes in and around Auckland suggests that a FCEB has a lower cost compared to BEB for long and/or undulating routes. There is a trade-off between the lower energy costs but charging downtime for BEBs, and the higher energy costs but superior range and operating capacity for FCEBs.[43] FCEBs may also be used for metro routes, depending on cost competitiveness with BEBs. Auckland Transport will begin using an FCEB between Howick and Britomart and may expand its FCEB fleet depending on how costs compare to diesel and BEBs.[44] Industrial gas manufacturer BOC is supplying hydrogen to the Ports of Auckland Limited (POAL) transport refuelling demonstration project at its Glenbrook site, and is urging the government to commit to a fleet of FCEBs.[45]

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35 Stakeholders suggested that there is more demand for HFC-EV heavy vehicles than there is supply, and New Zealand is unlikely to be a top priority country for supply without Government support or intervention. Source: Personal communication with hydrogen stakeholders.

36 Used for public transport or tourism.

37 https://www.transport.govt.nz/statistics-and-insights/fleet-statistics/vehicle-fleet/

38 https://www.transport.govt.nz//assets/Uploads/Paper/Green-Freight-Strategic-Working-Paper_FINAL-May-2020.pdf p.17

39 http://www.chfca.ca/fuel-cell-electric-buses-fcebs/

40 http://www.chfca.ca/fuel-cell-electric-buses-fcebs/

41 Castalia analysis.

42 https://www.nzhydrogen.org/nz-hydrogen-projects

43 Castalia analysis.

44 https://at.govt.nz/about-us/news-events/new-zealand-s-first-hydrogen-fuel-cell-bus-unveiled/

45 Energy News, BOC seeks green H2 transport launchpad, 1 October 2021.

BEBs compete with FCEBs on metro bus routes

BEBs are the main competing technology to FCEBs. BEBs perform similarly to fossil fuel buses and, in some cases, are already more cost-effective on a total cost of ownership basis than fossil fuel buses. The CCC expects a rapid switch to BEBs in the next ten years. BEBs are most viable for replacing diesel buses on metro routes, where high power requirements are not required. BEBs are commercially available and have been adopted globally, predominantly for metro routes, with approximately 500,000 BEBs in operation.[46] Metro buses are being electrified in New Zealand. Auckland Transport launched its fully electric bus fleet in January 2021 (the AirportLink) and launched Waiheke's electric bus fleet at the end of 2020.[47]

Despite uptake, BEBs have a shorter range than FCEBs and diesel buses, and require charging downtime. Using BEBs change the logistics of operating a bus fleet. BEBs will also necessitate significant electrical infrastructure (for example, multiple MW depending on the size of the depot), which can be cost-prohibitive. These factors can skew the total cost of ownership depending on the fleet and individual use case. Some bus transport providers may require flexibility that FCEBs offer, which BEBs do not have. Transport providers may use a combination of FCEBs and BEBs.

Cost-effectiveness and competitiveness of other technologies will be key determinants for FCEB uptake

FCEBs will likely replace fossil fuel buses taking long, remote, and undulating routes and will possibly make up a part of a zero-emissions metro bus fleet (along with BEBs). The uptake of FCEBs in these specific applications is dependent on a range of factors:

- Technological development of electric battery and storage technologies for buses, including longer range and faster charging time
- The capital cost of vehicles and infrastructure and cost-effectiveness over the lifetime of an FCEB compared with a BEB
- Access to refuelling and recharging infrastructure and time required to refuel or recharge
- The cost of hydrogen fuel relative to electricity.

3.1.3 Speciality vehicles

HFC-EVs could play an important role in reducing emissions from speciality vehicles requiring high energy density and continuous power for long periods, such as excavation vehicles used in mining operations, large forklifts, cranes, straddle carriers at ports and other large off-road vehicles.

High emitting sectors such as mining and ports use specialty vehicles. HFC-EVs can support high emitting sectors to reduce overall emissions and decrease abatement costs. There are approximately 6,900 speciality vehicles in New Zealand.[48] Speciality vehicles use approximately 275 million litres of diesel per year.[49] The mining and quarrying sector uses 82 million litres of

[46] https://about.bnef.com/electric-vehicle-outlook/?sf122680186=1

[47] https://at.govt.nz/about-us/news-events/new-zealand-s-first-hydrogen-fuel-cell-bus-unveiled/

[48] Castalia analysis.

[49] Castalia analysis, supported by EECA data. Available at: https://www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/Off-road-liquid-fuel-insights.pdf

diesel per year.[50] The building and construction sector uses approximately 193 million litres of diesel per year[51] CCC modelling suggests that meeting the 2050 targets will require abatement costs of NZ$150 per tonne of emissions in 2035 and NZ$250 per tonne of emissions in 2050. The uptake of this technology will depend on vehicle capital cost and availability and competitiveness of other technologies.

HFC-EV speciality vehicles can play key role in the decarbonising speciality vehicles

HFC-EVs speciality vehicles could play an important role in reducing emissions from speciality vehicles such as excavation vehicles, rubbish trucks, forklifts, straddle carriers, and cranes. HFC-EVs speciality vehicles are useful in locations where hydrogen can be produced and vehicles refuelled at sites such as mines and ports. HFC-EV excavation vehicles can replace diesel power reliance for above ground and underground mining vehicles. The vehicles are currently in prototype and will likely be available for purchase from 2023 onwards.[52] Hydrogen-diesel combustion excavation vehicles are also being explored as an alternative pathway to create the demand for HFC-EV excavation vehicles and other industrial vehicles.

HFC-EV forklifts are commercially available, with more than 25,000 units (of varying classes) in operation globally. HFC-EV forklift technology is developing rapidly to improve run-time and performance to match or exceed internal combustion engine (ICE) forklifts, which is expected to increase use of technology. HFC-EV forklifts are expected to be competitive over BE alternatives in big distribution centres running multi shifts. HFC-EV forklifts have relatively fast refuelling time (approximately three minutes) and longer run time than BE alternatives. HFC-EV forklifts, therefore, do not require operators to replace batteries during a shift, which is often required for BE alternatives.[53] The operation of HFC-EVs forklifts is also not affected by diminishing battery charge. HFC-EVs remove the requirement of extra recharging infrastructure and battery swapping processes.

HFC-EV cranes are also being developed and will be particularly important for reducing emissions from hard to abate machinery. For example, an HFC-EV rail crane is deployed at China's Qingdao port[54] and POAL is developing a hydrogen fuel production plan, which includes the use of HFC-EV forklifts and cranes.[55] HFC-EV straddle carriers are also being developed.[56]

HFCs can also provide stationary energy supply at high emitting locations

HFCs may also be used as stationary energy supply at high-emitting locations, such as at ports for docked ships, or at airports for backup power. Docked ships contribute to emissions by running diesel power for essential systems while at berth. HFCs can replace on-board diesel generators, or auxiliary or main engines. Sandia National Laboratories found that HFCs may be

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50 Diesel in this sector is predominantly used by dump trucks, loaders, specialist drilling equipment, and processing and crushing equipment.

51 Diesel in this sector is predominantly used by excavation equipment such as diggers, scrapers, and bulldozers, as well as heavy trucks over 3.5 tonnes, and utes, and light-duty vehicles.

52 https://www.constructionequipment.com/hyundai-develop-hydrogen-powered-eqpt

53 Personal communication with industry stakeholders.

54 https://fuelcellsworks.com/news/worlds-first-hydrogen-powered-5g-port-put-into-service/

55 https://www.stuff.co.nz/auckland/109042288/ports-of-auckland-plans-hydrogen-fuel-plant-to-power-forklifts-and-cars

56 https://www.worldcargonews.com/news/news/new-straddle-carrier-from-zpmc-68000

technically feasible and commercially attractive for docked ships.[57] Airports can also utilise HFCs for backup power communications networks and computer systems and other applications such as runway lighting and automatic walkways. HFCs may be used for stationary energy supply and backup power when hydrogen is also used elsewhere on site.

BE speciality vehicles are the major competing technology and biofuel is a competing energy source to HFC-EVs speciality vehicles

BE speciality vehicles are the major competing technology to HFC-EV speciality vehicles. BE excavation vehicles are being developed, and commercial production is expected to begin from 2023.[58] BE forklifts are commercially available and are widely used, particularly for indoor purposes. The largest BE forklift has approximately 12,000 pounds of lifting power.[59]

Advancements in technology have enabled BE forklifts to compete with ICE forklifts, while also having lower operation and maintenance costs. BE forklifts also have lower infrastructure costs than HFC equivalents because they can be charged via a facilities' existing electricity supply rather than requiring new infrastructure. BE cranes have also been developed[60]; however, the size and lifting power of the cranes may be limited by battery technology. Hybrid BE-diesel straddle carriers are also being used.[61]

Biofuel is a competing energy source to HFC-EVs speciality vehicles. B20 can be used in speciality vehicles to reduce emissions. This approach may be used to decarbonise the existing speciality vehicle fleet rather than replacing vehicles before the end of their useful life. Biofuels may play a short-term role in reducing emissions from speciality vehicles until the current fleet is replaced by low-emissions vehicles like HFC-EV and BE speciality vehicles.

Plug-in electricity and batteries are the key competing technologies to HFCs for stationary energy supply

Plug-in electricity supply is the key competing technology to HFCs for stationary energy supply at high emitting locations. Shore-side plug-in capabilities provide electricity to vessels while at berth using power from the grid or locally generated renewable power. This requires retrofitting charging facilities on existing vessels. POAL has undertaken several feasibility studies for shore-side power at their cruise berths and container terminal.[62] Airports can also utilise batteries for backup power for a range of applications. These applications can utilise batteries while retaining existing equipment.

Vehicle capital cost and competitiveness of other technologies will be key determinants for HFC-EV speciality vehicle uptake

The uptake of HFC-EV speciality vehicles is dependent on a range of factors:

- Technological development of electric battery and storage technologies for the heaviest of speciality vehicles and for stationary energy supply
- The capital cost of HFC-EVs compared with BEVs speciality vehicles

57 https://phys.org/news/2013-06-power-seaports-job-hydrogen-fuel.html

58 https://www.greencarcongress.com/2021/01/20210126-proterra.html

59 https://www.toyotaforklift.com/blog/advantages-of-lithium-batteries-for-electric-forklifts; https://www.toyotaforklift.com/lifts/electric-motor-rider-forklifts/large-electric-forklift

60 https://www.equipmentjournal.com/construction-equipment/liebherr-develops-the-worlds-first-battery-powered-crawler-cranes/; https://www.maeda-minicranes.com/products/battery-cranes/

61 https://hhla.de/en/company/news/detail-view/the-worlds-most-advanced-hybrid-straddle-carrier

62 Personal communication with POAL.

- The cost of hydrogen fuel relative to electricity and biofuel
- Access to refuelling infrastructure and the ability to produce hydrogen at mining and port locations
- Access to large transmission infrastructure capable of charging BE fleets
- Time required to refuel or recharge
- The available supply of HFC-EVs speciality vehicles.

3.1.4 Light-duty vehicles

HFC-EV light-duty vehicles could play an important role in reducing emissions from light-duty vehicles by replacing fossil fuel vehicles.[63] Emissions from light-duty vehicles accounted for 73 percent of total road transport emissions in 2019, and are predicted to account for 52 percent of total road transport emissions in 2050 under current policies.[64] The CCC predicts that:

- EVs (including BEV and/or HFC-EV) will make up at least 50 percent of total light-vehicle imports by 2029, increasing to 100 percent by 2035
- 46 percent of all light vehicle travel would be in an EV (including BEV and/or HFC-EV) and 36 percent of light-duty vehicles on our roads would be electric by 2035.[65]

The uptake of HFC-EV light-duty vehicles will depend on vehicle capital cost and the comparative cost of hydrogen and electricity.

Some uptake of HFC-EV light-duty vehicles is likely, particularly for high-frequency users

HFC-EV light-duty vehicles are commercially available today and there are more than 30,000 vehicles globally deployed. HFC-EV light-duty vehicles have a faster refuelling time and can have a long driving range on a single tank compared with BEV alternatives and some ICEs.

Two HFC-EV light-duty vehicle models are currently commercially available.[66] They are currently produced in small volumes and the capital costs remain more expensive than ICE and BEV equivalents.

HFC-EV light-duty vehicles in New Zealand are most attractive in frequent use cases. For example, downtime to charge for fleet operators can be costly and inconvenient.[67] The recharge time for BEVs means the vehicles are out of service for longer than with the relatively faster hydrogen refuelling time. Along with frequent users, HFC-EV light-duty vehicles could also be attractive for:

- Drivers living in remote or rural locations where BEVs are less convenient due to longer recharging times, shorter driving range, and because charging is difficult

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[63] Light-duty vehicles are vehicles that eight up to 3.5 tonnes, and include household light-duty vehicles, commercial light-duty vehicles, and vehicles shares and taxis.

https://www.nzta.govt.nz/vehicles/vehicle-types/heavy-trucks/

[64] https://www.transport.govt.nz//assets/Uploads/Paper/Green-Freight-Strategic-Working-Paper_FINAL-May-2020.pdf, p.17

[65] https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf, p.107

[66] Toyota Mirai and the Hyundai Nexo.

[67] Such as taxis, couriers, and ride sharing services.

- Drivers in urban centres where a higher proportion of households live in multi-unit residential buildings, where charging infrastructure might not be available. HFC-EVs are therefore more convenient to refuel than charging a BEV.

BEVs are the major competing technology

BEVs are the key competing technology to HFC-EVs for light-duty vehicles, and already widely used in New Zealand and globally. Although the capital cost of BEVs is higher than most ICE equivalents, capital costs are reducing rapidly due to continued reductions in lithium-ion battery costs and rapidly increasing global production. Subsidies for BEVs and low emissions vehicles have been available since 2021. This subsidy has already increased the BEV fleet and is likely to incentivise additional fleet growth. BEV fleet growth is high in most developed country markets in 2021. As the charging infrastructure develops, these trends will make the uptake of light vehicle HFC-EVs more difficult, and service and technical support is established.

Vehicle capital costs and the comparative cost of hydrogen and electricity will be key determinants for HFC-EV light vehicle uptake

It is unlikely that HFC-EVs will be the dominant light vehicle in the New Zealand market because:

- There is a small market for people living in multi-unit residential buildings, and, where there is, electricity could be easily supplied
- Electricity is already supplied to remote households and there is a small market of light-duty vehicles travelling long distances from remote locations
- BEVs are readily available and are already capturing the light vehicle market.

Instead, HFC-EVs will likely be used by a relatively small proportion of light vehicle users with heavy use patterns or particular range requirements. The uptake will depend on the availability of hydrogen for other technologies (such as heavy vehicles). We expect some companies to utilise HFC-EV (and BEVs) to electrify light-duty vehicles for commercial fleets. The uptake of HFC-EVs in these specific applications is dependent on a range of factors:

- The capital cost and cost-effectiveness of HFC-EVs compared with BEBs
- Access to refuelling infrastructure
- The cost of hydrogen fuel relative to biofuels
- The cost of hydrogen fuel relative to electricity.

3.1.5 Aviation transport

Hydrogen could play a role in decarbonising aviation. Hydrogen can be used as a feedstock for SAF, or as a fuel for HFC aircraft, hydrogen combustion engines, or hybrid combustion-HFC aircraft. Aviation is a particularly hard to abate sector because aviation requires high power output and energy-dense fuels, which is largely provided by fossil fuels due to lack of viable alternatives. Hydrogen is useful for aviation because of its high gravimetric energy density.

Domestic aviation contributed 1,024 kt CO_2-e in 2019, equivalent to 6 percent of total transport emissions.[68] International aviation contributed 3,856 kt CO_2-e in 2019.[69] Emissions from international aviation are not currently part of the 2050 targets in New Zealand. The CCC is reviewing whether the 2050 targets should include international aviation.

The uptake of hydrogen in the aviation sector will depend on hydrogen infrastructure developments, hydrogen technology developments, and price of Synthetic-SAF compared to fossil fuel.

Aviation hydrogen is developing, and uptake will depend on many factors

Hydrogen can play a role in decarbonising aviation through Synthetic-SAF, HFC aircraft, hydrogen combustion engines, and hybrid combustion-HFC aircraft.

Hydrogen as a feedstock can be used in the production of Synthetic-SAF,[70] also called Power-to-liquid (PtL) fuels.[71] SAFs have similar properties to conventional jet fuel but with a smaller carbon footprint due to use of low-carbon feedstock during production. Synthetic-SAF is a ‘drop in’ fuel that can be used by current aircraft.[72] Air New Zealand considers SAF the only option currently available for decarbonising long-haul air travel; hydrogen combustion engines and HFC aircraft will unlikely be used for long-haul flights due to storage limitations.[73]

Air New Zealand has been part of a Sustainable Aviation Fuel Consortium for the past five years in partnership with Z Energy and other stakeholders.[74] This consortium developed a roadmap for SAF to 2050, which shows that there is a viable pathway to develop a SAF industry in New Zealand.[75] Air New Zealand and MBIE recently signed a memorandum of understanding (MOU) to run a request for proposal process inviting industry leaders to demonstrate the feasibility of operating a SAF plant at a commercial scale.[76]

HFCs can also replace conventional aircraft propulsion systems. Electricity is produced from hydrogen and oxygen inputs to power an electric motor that in turn drives a propeller or ducted fan. HFC aircraft require the redesign of almost all the components of the aircraft. Several publicly known HFC propulsion aircraft are currently in development. For example, Airbus unveiled three HFC propulsion aircraft concepts in September 2020, including a 100-seat hydrogen-powered aircraft, that it says could enter service by 2035.[77] One HFC aircraft has

68 Time series emissions data 1990 to 2019 from New Zealand's Greenhouse Gas Inventory published in 2021. Figures are rounded to 1 decimal place. Available at: https://environment.govt.nz/publications/new-zealands-greenhouse-gas-inventory-1990-2019/

69 MBIE GHG emissions statistics. Available online at: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/new-zealand-energy-sector-greenhouse-gas-emissions/

70 Synthetic SAF’s are liquid fuels produced from hydrogen and captured carbon dioxide, using sustainable electricity as the principal power source. https://www.airbus.com/newsroom/news/en/2021/07/Power-to-Liquids.html

71 https://www.airbus.com/newsroom/news/en/2021/07/Power-to-Liquids.html

72 https://royalsociety.org/-/media/policy/projects/synthetic-fuels/synthetic-fuels-briefing.pdf

73 Personal communication with Air New Zealand.

Hydrogen has low volumetric density, meaning a lot of hydrogen must be stored. Storage is an issue on aircrafts. https://absinfo.eagle.org/acton/attachment/16130/f-bd25832f-8a70-4cc9-b75f-3aadf5d5f259/1/-/-/-/-/hydrogen-as-marine-fuel-whitepaper-21111.pdf

74 https://www.airnewzealand.co.nz/press-release-2021-airnz-backs-governments-biofuels-mandate

75 https://www.scoop.co.nz/stories/BU2110/S00017/z-signals-intent-to-participate-in-the-rfp-process-for-sustainable-aviation-fuel-production-in-new-zealand.htm

76 https://transporttalk.co.nz/news/z-energy-backs-proposal-for-sustainable-aviation-fuel-industry-in-nz

77 https://www.airbus.com/innovation/zero-emission/hydrogen/zeroe.html

already flown using hydrogen fuel, while the others remain at lower technology readiness levels.[78] Hydrogen-electric aircraft companies are also developing aircraft powertrains. None have been built yet, but commercial commitments have been made to develop 19-seat and 50-seat aircraft by the late 2020s, and 100-seat aircraft by the early 2030s.[79]

Hydrogen can generate thrust through the combustion of hydrogen in a modified jet engine. Hydrogen combustion aircraft would release no emissions during operation. The propulsion system for hydrogen combustion is similar to conventional aircraft, therefore current aircraft could be redesigned or retrofitted to accommodate technology (rather than total redesign required for HFC propulsion aircraft).[80] However, no direct hydrogen combustion aircraft has yet been developed despite feasibility studies in the past.[81] Research also suggests that hydrogen combustion in traditional aircraft is less efficient than HFC propulsion aircraft because HFC aircraft can carry 20-40 percent less fuel.[82]

Airships could utilise combusted hydrogen in more effective ways than traditional aircraft. Hydrogen is used as a lifting gas, which removes the need for engine power. Some airship designs are also looking at integrating solar PV to drive propellers (hybrid airships). Airships save significant energy compared with aircraft because airships do not need to produce lift. Given their fuel efficiency, airships could be utilised for long-distance and long-duration operations and are being explored for passenger and freight transport, and space exploration.[83] However, the flammability and toxicity of hydrogen have resulted in regulations that prevent the use of hydrogen as a lifting gas. Regulatory changes would be required to increase demand for airships.

New Zealand’s large proportion of short-range domestic routes, combined with a large share of RE, is considered favourable for the uptake of hydrogen technologies (HFC, combustion, or hybrid combustion-HFC) for the domestic network. At this stage, airships do not appear to be a key technology to decarbonise New Zealand’s aviation sector. Air New Zealand considers that 75 percent of domestic fuel usage is likely to be replaced by HFC or combustion aircraft in future. Air New Zealand estimates that an HFC aircraft carrying 50-100 people could operate New Zealand’s main domestic trunk routes by 2035. Ideally, Air New Zealand would have a demonstration project by 2030. Longer haul routes, such as from New Zealand to Australia and to Pacific Islands are expected from 2050.[84] In September 2021, Air New Zealand and Airbus announced a joint initiative to investigate how hydrogen-powered aircraft could assist the national airline with reaching its goal of net zero emissions by 2050.[85] This initiative could be a key driving factor for hydrogen use in the aviation sector and could have flow-on effects on other sectors.

78 https://www.rolandberger.com/en/Insights/Publications/Hydrogen-A-future-fuel-for-aviation.html

79 https://techcrunch.com/2021/04/14/zeroavias-hydrogen-fuel-cell-plane-ambitions-clouded-by-technical-challenges/

80 https://www.rolandberger.com/en/Insights/Publications/Hydrogen-A-future-fuel-for-aviation.html, p.19

81 https://www.rolandberger.com/en/Insights/Publications/Hydrogen-A-future-fuel-for-aviation.html, p.17

82 https://www.rolandberger.com/en/Insights/Publications/Hydrogen-A-future-fuel-for-aviation.html, p.18

83 https://www.pv-magazine.com/2021/10/13/time-to-re-envision-the-zeppelin-this-time-as-a-hydrogen-transportation-method/

84 Personal communication with Air New Zealand.

85 https://www.airnewzealand.co.nz/press-release-2021-airnz-and-airbus-to-research-future-of-hydrogen-powered-aircraft#:~:text=Air%20New%20Zealand%20and%20aircraft,net%20zero%20emissions%20by%202050.&text=This%20research%20will%20help%20to,work%20to%20decarbonise%20the%20airline.%22

BE aircraft are the main competing technology, and bio-SAF is the key competing fuel source

BE aircraft that seat up to 9-10 people are in the market already. BE aircraft technology is developing quickly and is expected to be commercially available around 2025, before hydrogen alternatives.[86] Sounds Air plans to take passengers on short-haul small BE aircraft with 19 passenger capacity from 2026. This application is supported by global fuel company Shell, which sees BE aircraft as applicable on very short-haul routes.[87] Air New Zealand is considering BE aircraft for short domestic flights of less than 400 km. Air New Zealand estimates that approximately 25 percent of fuel consumed for the domestic network could be viable for BE flights over the medium-term.[88]

BE aircraft technology has limitations due to battery weight and size, making medium and long-haul travel challenging. In addition, BE aircraft require battery replacement every 1-2 years. Air New Zealand considers hydrogen-powered aircraft as competitive against BE aircraft, once infrastructure costs and other factors are considered. Further research and technological development is required to determine how competitive hydrogen-powered aircrafts are against BE alternatives.[89]

Bio-SAF is the key competing fuel source to hydrogen. The technology behind Bio-SAF is more developed than Synthetic-SAF, so current productions costs are considerably lower. However, it is expected that towards 2050, Synthetic-SAF using hydrogen as a feedstock will be cheaper and produced in larger volumes than bio-SAF, as hydrogen costs decrease and technology develops.[90] Air New Zealand predicts that Bio-SAF (biomass feedstock) will be used before 2040, which could then be replaced with Synthetic-SAF (hydrogen feedstock) beyond 2040.[91]

Hydrogen infrastructure developments, hydrogen technology developments, and price of Synthetic-SAF compared to fossil fuel and bio-SAF will be key determinants for the uptake of hydrogen in the aviation sector

SAFs (either Synthetic-SAF or Bio-SAF) are likely the only non-fossil fuel solution for long-haul flights, while HFC, hydrogen combustion, and hybrid aircraft could provide short and medium-haul flights. Small BE aircraft are expected for short-haul routes. The uptake of hydrogen in these applications is dependent on a range of factors, including:

- Hydrogen infrastructure developments
  - Production of Synthetic-SAF remains constrained by the availability of low-emission hydrogen from renewable electricity and the associated costs

[86] Personal communication with Air New Zealand.

[87] Shell Report. Available online at: https://www.shell.com/promos/energy-and-innovation/v1/decarbonising-aviation-cleared-for-take-off/_jcr_content.stream/1632757263451/e4f516f8d0b02333f1459e60dc4ff7fd1650f51c/decarbonising-aviation-industry-report.pdf

[88] https://transporttalk.co.nz/news/hydrogen-powered-planes-studied-for-nz; and personal communication with Air New Zealand.

[89] Personal communication with Air New Zealand.

[90] https://www.shell.com/promos/energy-and-innovation/v1/decarbonising-aviation-cleared-for-take-off/_jcr_content.stream/1632757263451/e4f516f8d0b02333f1459e60dc4ff7fd1650f51c/decarbonising-aviation-industry-report.pdf

[91] Personal communication with Air New Zealand.

  - Uptake will require the development of large-scale transport and infrastructure solutions required to supply airports with the necessary quantities of hydrogen needed to fuel aircraft[92]
- Technology developments to meet safety regulations (international standards for aviation fuels). For example, ASTM certification currently allows aircraft to only operate using a maximum 50 percent blend of SAF and fossil kerosene.[93] ASTM fit-for-purpose testing can also cost several million dollars and can take years to be approved[94]
- Reducing conversion losses that occur when using renewable electricity to make hydrogen to make Synthetic-SAF. These losses are high compared with the direct use of hydrogen in other sectors, such as industry
- Price of Synthetic-SAF compared to fossil fuel and Bio-SAF
  - The largest cost components of Synthetic-SAF are producing hydrogen and obtaining CO_2 by direct air capture. Synthetic-SAF is currently estimated to be five times more expensive than kerosene if it uses CO_2 captured in industrial processes, and over eight times more expensive if using CO_2 from direct air capture (DAC). Synthetic SAF could become competitive with kerosene between 2030-2040, subject to the development of a carbon price[95]
  - There is likely to be competition between Synthetic-SAF and Bio-SAF; however, Synthetic-SAF using hydrogen is expected to become more competitive over time
- Technological developments of low-carbon alternatives, such as BE aircraft being able to fly longer routes with more passengers, may also impact the uptake of hydrogen
- Capital cost of hydrogen technologies. High capital cost of hydrogen technologies may limit uptake. There are long investment horizons and long fleet renewal cycles, which add complexities
  - Hydrogen combustion aircraft require significant technological advancements to be made viable. Aircraft manufacturers claim this may take years to develop[96]
  - HFC aircraft and hydrogen combustion aircraft require significant redesign of current aircraft. As aircraft have long economic lives, it may take time for deployment at scale. Reducing the amount of redesign required may increase the competitiveness of hydrogen technology.

92 https://www.airbus.com/newsroom/stories/hydrogen-aviation-understanding-challenges-to-widespread-adoption.html

93 https://simpleflying.com/airbus-a350-biofuels/

94 https://www.energy.gov/sites/prod/files/2020/09/f78/beto-sust-aviation-fuel-sep-2020.pdf

95 https://www.shell.com/promos/energy-and-innovation/v1/decarbonising-aviation-cleared-for-take-off/_jcr_content.stream/1632757263451/e4f516f8d0b02333f1459e60dc4ff7fd1650f51c/decarbonising-aviation-industry-report.pdf

96 https://www.shell.com/promos/energy-and-innovation/v1/decarbonising-aviation-cleared-for-take-off/_jcr_content.stream/1632757263451/e4f516f8d0b02333f1459e60dc4ff7fd1650f51c/decarbonising-aviation-industry-report.pdf

3.1.6 Marine transport

Hydrogen could play a role in decarbonising maritime applications through hydrogen technologies such as HFC boats or fuel used in combustion engines. Ship generators can also combust green ammonia. Marine transport contributed 324 Kt $C0_2$-e in 2019, approximately 2 percent of total transport emissions. Emissions from international shipping are not currently part of the 2050 targets in New Zealand.

The uptake of hydrogen for marine transport depends on the competitiveness of fuel costs, storage and infrastructure costs, and maritime regulations.

Hydrogen can contribute to emissions reduction in maritime applications by HFC vessels for small vessels and some larger vessels, or as a fuel in combustion engines for deep-sea and large fleets

While hydrogen has the highest energy content per mass compared with other marine fuels, it is not yet clear which low- or zero-emissions fuel or alternative technology will be least-cost and “win” the market. The CCC assumes that New Zealand shipping, including the Cook Strait ferries, switches to zero-emissions fuels at the same rate as heavy trucks.[97] KiwiRail recently purchased two large diesel-electric battery hybrid ferries designed to use a power plant configuration that produces significant carbon reduction. The vessels also have flexibility to allow future technologies and fuel sources to be deployed, such as HFCs and hydrogen as a combustion fuel. The American Bureau of Shipping (ABS) projects over 30 percent of marine fuel use will be hydrogen or ammonia by 2050.

HFCs are in the early stages of development for marine transport propulsion. The first HFC powered vessel in the United States is currently undergoing trials, and will be operated in the San Francisco Bay Area.[98] The European innovation project ‘Flagships’ is preparing to deploy the world’s first commercial cargo transport vessel operating on hydrogen through HFCs. The vessel will be inland and scheduled for delivery in September 2021.[99] Emirates Team New Zealand also utilises HFCs in their new foiling chase boat.[100]

HFCs appear most viable for small vessels and some large vessels such as cargo vessels. Due to the low volumetric density of pure hydrogen, more hydrogen is required to be stored on vessels than alternative fuels, and it requires specific on-board infrastructure, or more frequent refuelling. Using pure compressed or liquefied pure hydrogen may therefore only be practical for small vessels with frequent access to bunkering stations or large ships that can accommodate storage space.[101]

Marine transport can use hydrogen for combustion engines, in pure compressed or liquid form, through hydrogen carriers, such as Liquid Organic Hydrogen Carriers (LOHCs) (e.g., toluene/methylcyclohexane), ammonia (NH_3), or methanal (MeOH). Alternatively, marine transport may be able to use green methanol directly. There are challenges with storage and supporting infrastructure for these options.

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97 https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf, p.110.

98 https://absinfo.eagle.org/acton/attachment/16130/f-bd25832f-8a70-4cc9-b75f-3aadf5d5f259/1/-/-/-/-/hydrogen-as-marine-fuel-whitepaper-21111.pdf

99 https://www.offshore-energy.biz/flagships-set-to-debut-worlds-1st-hydrogen-powered-commercial-cargo-ship/

100 https://robbreport.com/motors/marine/team-new-zealands-new-hydrogen-foiling-chase-boat-for-americas-cup-1234631250/

101 https://safety4sea.com/understanding-the-potential-of-hydrogen-as-a-marine-fuel/?__cf_chl_jschl_tk__

Ammonia, methanol, and LOHCs have higher energy density than pure hydrogen, which reduces the amount of stored hydrogen required. These materials are used as a hydrogen carrier, which eliminates the need for compression, and are then converted back into hydrogen when fuel is required (and used in engines or fuel cells).[102] However, energy losses occur when converting the synthetic fuel back to hydrogen to be used as fuel, which may make other hydrogen technologies such as HFCs more viable in some applications.[103] In addition, ammonia and LOHCs have toxicity and combustion risks, which complicates their management and use.

Green ammonia used as a direct combustion fuel for vessels is in early stages of development. Green ammonia is synthesised from hydrogen. Using ammonia directly can slightly reduce the size of the tanks needed to storge hydrogen[104] while also mitigating energy losses that occur through conversion.[105] Ammonia does, however, require storage in cold temperatures and needs to be burned at higher temperatures.[106] As a direct combustible fuel source, ammonia may be most viable for a deep-sea fleet or large vessels not impacted by loss of cargo space. It may also be viable for other smaller vessels, depending on storage requirements.[107]

Ammonia may also be used as a fuel for a high-temperature solid oxide fuel cell (SOFC). This technology is developing, and is considered more efficient than converting ammonia back to hydrogen or burning it as a combustion fuel. This technology currently offers poor power density, which may limit its application.[108]

BE vessels are the main competing technology, and advanced biofuel is the main competing fuel source

Small commuter ferries in New Zealand have already begun to electrify and, in some cases, are already cost-effective on a total cost of ownership basis.[109] This suggests BE maritime applications are likely viable for vessels with very short routes and have frequent charging possibilities. BEs are impractical for vessels taking long routes and bigger vessels because of low energy density.

Advanced biofuels are being developed and offer an alternative low-carbon fuel source for marine applications. Availability and costs of advanced biofuels are uncertain as there is demand competition from other sectors for a limited supply of sustainable biomass.[110] In addition, fuel sulphur regulations and other compliance costs may limit the economic viability

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102 https://safety4sea.com/understanding-the-potential-of-hydrogen-as-a-marine-fuel/?__cf_chl_jschl_tk__&__cf_chl_jschl_tk__=pmd_NlCZtOm6gX8gF6ztClh8RYUw9tNIwCHQvtoHrTOXaVs-1635372050-0-gqNtZGzNAmWjcnBszQiR

103 https://maritimecyprus.com/wp-content/uploads/2021/06/ABS-hydrogen-as-marine-fuel.pdf

104 Ammonia carries about 70 percent more energy than liquid hydrogen by volume, and nearly three times as much energy as compressed hydrogen gas. https://newatlas.com/energy/green-ammonia-primer-clean-fuel/

105 https://safety4sea.com/understanding-the-potential-of-hydrogen-as-a-marine-fuel/?__cf_chl_jschl_tk__&__cf_chl_jschl_tk__=pmd_NlCZtOm6gX8gF6ztClh8RYUw9tNIwCHQvtoHrTOXaVs-1635372050-0-gqNtZGzNAmWjcnBszQiR

106 It is also unlikely to be acceptable for people living in urban environments to store ammonia and some LOHCs. This is another challenge with using ammonia and some LOHCs for some applications. Some LOHCs have toxicity similar to petroleum products, so may be safe in urban areas.

107 https://safety4sea.com/understanding-the-potential-of-hydrogen-as-a-marine-fuel/?__cf_chl_jschl_tk__

108 https://newatlas.com/energy/green-ammonia-primer-clean-fuel/; https://www.fch.europa.eu/news/major-fch-ju-funded-project-will-install-world%E2%80%99s-first-ammonia-powered-fuel-cell-vessel

109 https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf

110 https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf

of biofuels. If viable, biofuels are likely most beneficial for maritime shipping and long-distance transportation.

Marine uptake of hydrogen mainly depends on competitiveness of fuel costs, as well as storage and infrastructure costs, and maritime regulations

Marine hydrogen use, whether in HFCs or as the basis for other fuel, mainly depends on competitiveness of fuel costs. Other factors include:

- The cost of bunkering facilities and infrastructure for hydrogen, some LOHCs, and ammonia is significantly more expensive than fossil fuel.[111] However, these costs are only a small proportion of total marine transport costs, with energy costs representing the bulk[112]
- Development of using green ammonia for direct combustion uses
- Future development of maritime guidelines for hydrogen fuel and technologies, as well as for alternatives such as biofuel (e.g., for toxicity and combustion risks)[113]
- Competitiveness of BE vessels and advanced biofuels will also impact the uptake of hydrogen for marine transport.

3.1.7 Rail transport

Hydrogen technology, specifically HFC trains, and hydrogen as a feedstock for ammonia may play a role in decarbonising rail travel on some non-electrified routes in New Zealand. The rail sector currently contributes approximately 141 kt CO_2-e annually, equivalent to 1 percent of total transport emissions. The CCC expects the use of rail for freight and passenger travel to grow to reduce emissions from the transport sector and to relieve congestion. Freight tonnage is expected to increase by 40 percent in New Zealand, and the CCC advises the share of rail to increase to accommodate this.[114]

The uptake of hydrogen in the rail sector will depend on capex costs, the cost of hydrogen, developments of hydrogen infrastructure, and diesel purchasing volumes.

HFC trains may play a role in applications that require long-range, high-power demands, low service frequency, and fast refuelling times; green ammonia may also be used as a direct fuel source

HFC trains perform to the rail system specifications in the same way as diesel technology trains, and also offer increased range compared to battery-powered trains, higher power, quicker turnaround times, and less operational constraints. Modelling by Roland Berger expects HFC trains to be competitive with diesel trains and electric alternatives, providing high annual utilisation and low energy sourcing cost.[115] HFC trains have been trialled and one major manufacturer Alstom has several orders for Italy, France, and Austria.[116] HFC and HFC-BE

[111] LOHC toluene/methylcyclohexane would require similar bunkering infrastructure as petroleum products, so existing storage and handling facilities could be used, thereby reducing costs.

[112] https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf

[113] https://absinfo.eagle.org/acton/attachment/16130/f-bd25832f-8a70-4cc9-b75f-3aadf5d5f259/1/-/-/-/-/hydrogen-as-marine-fuel-whitepaper-21111.pdf

[114] https://www.transport.govt.nz/assets/Uploads/Report/The-New-Zealand-Rail-Plan.pdf

[115] On behalf of the Fuel Cells and Hydrogen 2 Joint Undertaking (FCH 2 JU) and the Shift2Rail Joint Undertaking (S2R JU), available here: https://www.fch.europa.eu/sites/default/files/05.S2R%20FCH%20study_PRD%20%28ID%207324926%29.pdf

[116] https://www.railway-technology.com/features/next-stop-hydrogen-the-future-of-train-fuels/

hybrid trains are also expected. These trains allow trains to run on overhead electrical power supply where available and switch to HFC as needed.[117]

Green ammonia as combustible fuel source for trains is in early stages of development. Space and storage infrastructure requirements may limit fuel use on trains. Ammonia as a direct combustible fuel source may be most viable for large trains that are not impacted by loss of cargo space for ammonia storage requirements.

The main competing technology is the electrification of railway lines, while biofuel is the main competing fuel source

The most credible low carbon alternative for rail is electrification. HFC trains are expected to compete with diesel and electric alternatives for non-electrified routes. The competitiveness of HFC trains will depend on the relative costs of electrifying or upgrading electric lines where significant renewal is needed. In New Zealand, significant parts of the New Zealand rail network are electrified. However, stretches of non-electrified track exist on parts of the North Island Main Trunk (NIMT). All of the South Islands remains unelectrified.[118]

KiwiRail is exploring the use of biofuel for its trains. Biodiesel was used on passenger trains in 2010, but it became too expensive when subsidies were removed.[119] Biofuel may be used for rail again if supply increases and the economics are beneficial.

Reduction in the capex costs, the cost of hydrogen and developments of hydrogen infrastructure, and diesel purchasing volumes will be key to deployment of hydrogen technology on railway lines

Locomotive capex is decisive for a competitive total cost of ownership compared to electrification.[120] Competitiveness will also depend on the opex of buying, fuelling, and maintaining infrastructure for HFC trains. High utilisation of hydrogen infrastructure is likely to impact the total cost of ownership positively. In addition, synergies across other hydrogen use cases, for example, transportation of hydrogen fuel for transport or co-location of refuelling facilities at transport hubs, will support uptake.

The market potential will also depend on locomotive fleet renewals. For example, KiwiRail is buying 57 low emission diesel engines for its South Island operations. The new engines replace a fleet with some trains close to 60 years old. KiwiRail expects the new engines to enter service from 2024.[121] It is possible that HFCs can be added to current diesel-electric trains, which could increase the viability of HFCs for rail in the short-term.

HFC technology is likely to only be economical for non-electrified routes over a minimum of 100 km and where there is low-frequency line usage that does not justify electrification of the line.[122] For New Zealand, HFC technology is likely to be competitive for specific lines in New Zealand, such as the Wellington-Wairarapa and Wellington-Palmerston North commuter lines and possibly some South Island freight routes. A major part of the cost of electrifying rail is

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[117] https://global.toyota/en/newsroom/corporate/33954855.html; https://cleantechnica.com/2021/04/09/toyota-applies-diesel-killing-hydrogen-fuel-cell-muscle-to-eu-railways/

[118] Parts of the South Island have previously been electrified but are now decommissioned.

[119] https://www.rnz.co.nz/news/national/392180/kiwirail-firms-up-plans-for-biodiesel-trials-despite-supply-doubts

[120] https://www.fch.europa.eu/sites/default/files/05.S2R%20FCH%20study_PRD%20%28ID%207324926%29.pdf

[121] https://www.rnz.co.nz/news/business/453383/kiwirail-bringing-trains-from-spain-to-roll-on-the-plains

[122] https://shift2rail.org/wp-content/uploads/2019/04/Final-version_study-on-the-use-of-fuel-cells-and-hydrogen-in-the-railway-environment.pdf

high catenary electrification investments. If already electrified, it is unlikely to be economic to deploy hydrogen alternatives.

3.2 Energy and electricity system services

Hydrogen technologies could provide a range of energy and electricity grid services, including electricity generation, capacity, and short-term and long-term grid stability and storage. Large-scale hydrogen storage and generation could support security of supply and can also provide a demand response option.

Hydrogen can also be used for small-scale storage and generation, such as in small-scale HFC batteries or integrated into off-grid systems which rely on diesel generation, by off-grid or remote users. It is less likely that New Zealand will utilise hydrogen for small-scale storage and generation due to viable electricity and battery alternatives. However, HFCs may have niche uses for intra-day or intra-week periods, which batteries cannot meet. Airports and ports are particularly interested in this application, discussed in section 3.1.3. In this section, we discuss only the use of hydrogen in large-scale applications.

3.2.1 Hydrogen can play a role in decarbonising electricity production

New Zealand is transitioning to an increasing share of variable renewable electricity sources, such as solar and wind. An optimal electricity system requires a range of technologies with different technological characteristics. Table 3.2 displays CCC's suggested increases to renewable electricity to 2035. Under CCC's suggestions, fossil fuels will make up just 2 percent of electricity generation in 2035.

Table 3.2: Electricity generation sources as percentage of total electricity supply in CCC's pathway[123]

Source	Percentage of total supply in 2021 (%)	Percentage of total supply in 2035 (%)
Hydro	55.6	46.5
Geothermal	17.7	19.6
Wind	7.6	25.6
Solar	0.5	4.2

Note: This table includes renewable electricity sources only

Hydrogen could support security of supply

Using hydrogen as electricity storage over various time horizons could help improve the resilience of the electricity system transitioning to net zero emissions. During periods of low electricity demand, excess energy from variable renewable generation can be converted to hydrogen via electrolysis and stored. Stored hydrogen can then be used to produce electricity for the grid during periods of high demand or during a dry year. Hydrogen could also be imported and then used when required.

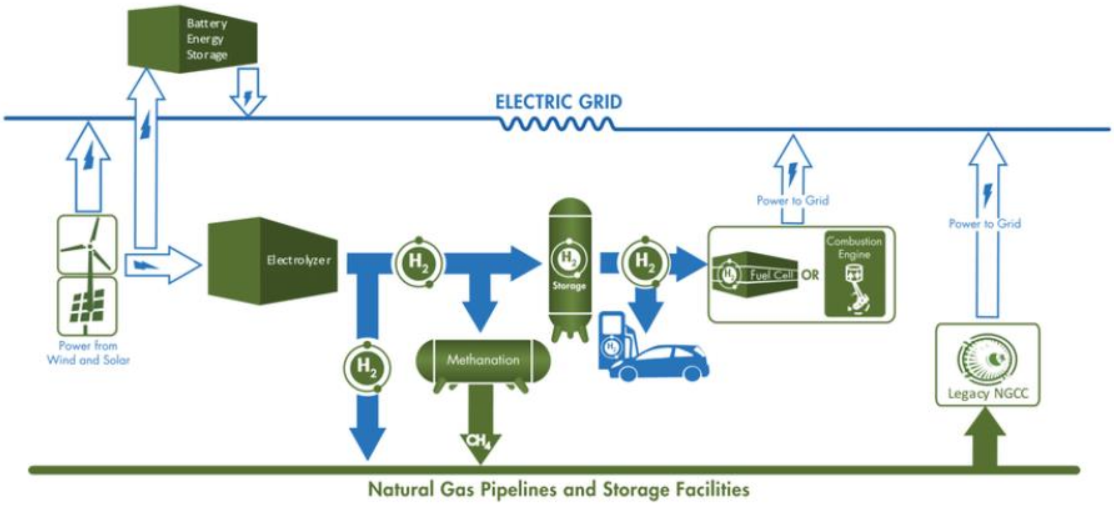
Hydrogen can be stored in multiple ways, including:

[123] https://www.newsroom.co.nz/calculating-nzs-renewable-electricity-gap;

- Underground as dried or compressed gas in geological formations, such as salt caverns or depleted gas wells
- In the natural gas network
- In an HFC
- In high-pressure cylinders
- As a cryogenic liquid in insulated tanks
- In a chemical compound, such LOHCs, ammonia, or methanol.

Figure 3.2 shows different storage technologies. Each storage option has unique benefits and challenges and can be used for different purposes.

Figure 3.2: P2G and hydrogen energy storage



Source: Fred Bockmiller[124]

Storing hydrogen for intra-seasonal security of supply

Hydrogen storage could help mitigate dry year risk in the New Zealand electricity grid. Dry year risk is a major concern for electricity security of supply in New Zealand. A dry year occurs when hydro inflows are lower than usual, meaning less energy is stored in the form of water. This is exacerbated if combined with demand peaks in winter. Currently, New Zealand generators rely on fossil fuel powered peaking plants to meet winter capacity margin. The Huntly power station held a coal stockpile of approximately 0.9 TWh in 2020.[125]

Winter capacity margin will be exacerbated as variable RE grows as a share of total generation, and as electricity demand grows overall. An increasing share of variable RE increases the difficulty of instantaneously balancing supply and demand. Electricity grids with high shares of

[124] https://www.researchgate.net/figure/Various-use-cases-for-power-to-gas-and-hydrogen-energy-storage_fig20_330290722

[125] Stockpile was 423 Kt, which is equivalent to 9.3 PJ and through a 33 percent efficient Rankine turbine equates to approximately 0.9 TWh.

variable RE (20 percent or more) are expected to experience flexibility issues.[126] Transpower estimates that between approximately 303 MW and 600 MW of new generation investment is required by 2029 to meet winter capacity margin.[127] Additional capacity will also be required if electrification is accelerated to mitigate GHG emissions in other sectors. Industry experts working with MBIE advise that New Zealand needs approximately 3–5 TWh to manage a bad dry year without a rapidly flexible electricity supply chain.[128]

Hydrogen storage and generation could also provide overall system stability and mitigate dry year risk by storing the hydrogen and using it to generate electricity in an HFC of CCGT plant. Given the loss of energy in producing green hydrogen, this process is only likely to be economic if there is a big enough difference between the cost of electricity when the hydrogen is produced, and the price of electricity on the market when the hydrogen is use in the HFC or combusted in the CCGT plant. Hydrogen storage technologies include power-to-gas (P2G), storage in geological formations such as depleted gas wells, and other large infrastructure storage options. Stored hydrogen can be used in combined cycle gas turbines (CCGT) to produce electricity.

P2G is a conversion of electrical power into a gaseous energy carrier. For hydrogen, P2G involves converting surplus RE into hydrogen gas through PEM electrolysis technology.[129] Hydrogen gas shares similar properties as natural gas and can be used, stored and transported like natural gas. P2G effectively acts as hydrogen storage. There is global interest in P2G. Canada opened its first P2G facility in 2018.[130] Japan is using imported hydrogen to generate electricity and currently has an 80 MW plant in operation.[131]

Hydrogen can also be stored in large geological formations. Estimates show that large-scale hydrogen storage can be cheaper than electric batteries in these applications and have other advantages, such as not losing charge over time. In New Zealand, viable storage locations are most likely to be oil and gas wells. Salt caverns are the ideal formation, but these are not known to exist in New Zealand. First Gas have explored options to store hydrogen to mitigate dry year risk in the Ahuroa Gas Storage Facility. First Gas has initially examined storing renewable natural gas (using wood waste as a feedstock) and future options to transition to hydrogen storage once the gas network is adapted to carry it.[132] First Gas's study on hydrogen storage potential at Ahuroa requires further geological investigation before an assumed number for hydrogen storage could be arrived at.[133] GNS and University of Canterbury are researching other geological and technical storage options.[134]

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126 https://energyinnovation.org/wp-content/uploads/2016/05/Grid-Flexibility-report.pd

127 https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/Final%20SoS%20Annual%20Assessment%202020%20report%20AS%20PUBLISHED.pdf

128 Personal communication with MBIE.

129 https://nelhydrogen.com/market/power-to-gas/

130 https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

131 https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

132 Personal communication with First Gas.

133 Personal communication with First Gas.

134 Personal communication with First Gas.

Chiyoda and Mitsubishi Corporation have developed SPERA Hydrogen technology (SPERA) which stores hydrogen which could be used to produce electricity in modified CCGT plants. SPERA is an LOHC, which chemically fixes hydrogen molecules to a liquid carrier (toluene, TOL), converting it to methylcyclohexane (MCH). A dehydrogenation process extracts the hydrogen from the carrier (MCH), which leaves TOL behind. The toluene is then shipped back to the hydrogenation location to continue the cycle.[135] Chiyoda and Mitsubishi Corporation's study states that it is possible to use SPERA to store up to 4 TWh of energy in New Zealand.[136] Global trials are underway to validate using hydrogen in converted and newly designed CCGT plants.[137]

In the medium term, blended hydrogen at low concentrations could be used in existing natural gas applications, for example, as a direct feedstock in industry and for electricity production. This can decrease the GHG emissions associated with current natural gas use

Intra-day security of supply

Hydrogen storage could also help meet daily peaks in demand. Hydrogen can be produced in periods of low demand where variable renewables would otherwise be curtailed, stored, and then used during periods of high demand. Approximately 0.5–1 TWh of hydrogen energy is required for short-term rapid ramp up electricity generation in New Zealand.[138]

The most viable hydrogen storage option for short durations is in compressed form in cylinders. The hydrogen can then be converted to electricity in HFCs.

There are various competing technologies to support inter-seasonal and intra-day security of supply

There are a number of low emission alternatives for electricity generation and storage. An optimal electricity system requires a range of technologies with different characteristics. Increasing the share of variable renewable capacity alongside pumped hydro and biomass are likely to be the most cost-effective solutions for New Zealand to achieve a 100 percent renewable electricity industry.

Pumped hydro (hydroelectric power) has been identified as a way to store and use water regardless of water flows. This alternative would offer storage and flexible firm capacity, which could therefore help meet the winter capacity margin and facilitate an increasing penetration of variable renewables. This is the key competing technology for inter-seasonal security of supply. The CCC estimates this is the most economic solution to dry year risk with a marginal abatement cost of NZ$250/$tC0_2$-e. MBIE is exploring this option in the NZ Battery Project.[139]

Using biomass for turbine-driven power plants could also provide flexible firm capacity. However, this would require significant biomass storage, which may be challenging. Biomass is also scarce and may face competition from other use cases.

135 Chiyoda and Mitsubishi Corporation, Techno-economic analysis for green hydrogen and energy hub in New Zealand, September 2020.

136 Chiyoda and Mitsubishi Corporation, Techno-economic analysis for green hydrogen and energy hub in New Zealand, September 2020.

137 https://www.powermag.com/mhps-will-convert-dutch-ccgt-to-run-on-hydrogen/; https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/

138 Personal communication with industry stakeholders.

139 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery/

Storage from electric batteries is a potential competing technology for storage for intra-day security of supply. Electric batteries can be charged when electricity prices are low and discharged when peak demand occurs. To date, no large-scale battery storage capable of mitigating New Zealand's dry year risk has been built or operated. Technological developments may enable electric batteries to assist the electricity grid when lake storage is low in winter. However, batteries are unlikely to be economically viable. Batteries are expensive and earn revenue by charging when prices are low and discharging when prices are high—the more charge and discharge cycles over the asset life, the more economic the battery. Having a battery sitting at full, waiting to be discharged, when a dry year occurs (approximately once every 10 years) does not provide a lot of revenue. The CCC estimate the marginal abatement cost of using electric batteries to mitigate dry year risk to be NZ$89,000/t$CO_2$-e.[140] At this stage, pumped hydro and hydrogen are currently the only large, long-term storage option.

Carbon capture and storage (CCS)[141] is also an alternative technology that can reduce emissions from electricity generated from fossil fuels.[142] It would reduce the emissions profile of peaking plants used to meet the winter capacity margin. However, the effectiveness and viability of CCS technology is not yet confirmed, and research is underway to determine whether suitable geographical features exist in New Zealand. To date, international studies have not yet proven the effectiveness or economic viability of large-scale CCS.

Hydrogen generation capex costs, hydrogen storage costs, and competitiveness of competing energy sources and technologies will be key determinants for the uptake of hydrogen for electricity production and storage

Hydrogen storage costs will be a key determinant of the uptake of hydrogen for security of supply. Factors that impact cost of hydrogen storage include equipment costs, availability of suitable geographic and geological features, volume stored, and duration stored. Technical solutions exist for long-term and short-term storage. However, it is not clear what the most effective storage solutions for New Zealand are, and the cost competitiveness of these solutions relative to other energy storage tools is not settled.

The cost of hydrogen production will also be a key determinate. It is likely that hydrogen storage to support security of supply may only be viable when hydrogen production and storage is low-cost (this could also include imported hydrogen) and there are synergies with other hydrogen demand in the New Zealand market.

Large-scale hydrogen storage and electricity generation alternatives include pumped hydro, biomass, and possibly CCS. These options require further research to determine their competitiveness. Electric batteries may have applications for intra-day security of supply.

3.2.2 Hydrogen production facilities could be source of capacity

Large-scale hydrogen production facilities could provide capacity to the electricity system via demand response. Hydrogen production is an interruptible process and can be ramped down and up relatively quickly. Large-scale electrolysers can be shut off during periods of peak

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140 https://www.iccc.mfe.govt.nz/assets/PDF_Library/daed426432/FINAL-ICCC-Electricity-report.pdf

141 CCS describes a range of technologies that capture waste carbon dioxide, which is then transported to a storage site where it is deposited and not released into the atmosphere.

142 For information about CCS, see MBIE website here: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/carbon-capture-and-storage/

demand, which enables the electricity supply to be allocated for other non-interruptible loads. This would reduce the required level of installed capacity to meet grid reliability and security of supply standards.[143] This is a key feature of the business model for the Southern Green Hydrogen opportunity in Southland.[144] The existing aluminium smelter at Tiwai Point has a dedicated transmission connection to the 800 MW Manapouri hydropower station. The smelter cannot be ramped down at short notice. On the other hand, a large-scale hydrogen facility can provide demand response. In principle, this business model could apply elsewhere in New Zealand, either at single large-scale production facilities or by coordinating the demand response of numerous smaller facilities.

Hydrogen production can follow electrical load flexibly. Hence, if a significant proportion of electricity is used for the electrolysis process, that itself will help balance supply and demand. These load following capabilities could also provide load management services, relieving congestion on the electricity network. Industrial sites that host electrolysers (like a smelter) can also use the demand response capabilities to have higher load factors and, therefore, reduce their average electricity costs. These factors are impactful for industrial plants with variable loads where peak demand changes are disproportionately high. Hydrogen projects can participate in frequency, ancillary and system strength services markets because electrolysis is an interruptible process.[145] The technical characteristics of electrolysers could allow them to offer emerging services, such as Fast Frequency Response.[146] Electrolysers connected through particular inverter designs could also be designed to offer voltage support services to the transmission or distribution networks.

3.3 Industry

Utilising hydrogen as a feedstock and for combustion can significantly reduce emissions in industry by replacing fossil fuels. The government’s 2050 emissions targets require significant adoption of hydrogen technologies in industry. Emissions from industrial processes and produce use (IPPU) were 5,115.9 kt CO_2-e in 2019, which accounted for 6.2 percent of total gross GHG emissions in New Zealand.[147] The CCC expects industry emissions to reduce by 2050 under current policies.[148]

Chemical industry (including ammonia) accounted for 290.5 kt CO_2-e (4 percent) of total industry emissions in 2019. Metal industry (including iron and steel production) accounted for 2,325.2 kt CO_2-e (45 percent) of total industry emissions in 2019.

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143 https://www.ea.govt.nz/operations/transmission/grid-reliability-standards/

144 https://www.southerngreenhydrogen.co.nz/

145 https://www.aemc.gov.au/hydrogen-new-australian-manufacturing-export-industry-and-implications-national-electricity-market#:~:text=Hydrogen%20can%20provide%20significant%20services%20to%20the%20NEM%2C,frequency%20response%20and%20provide%20significant%20flexible%20demand%20response

146 https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--10.pdf?la=en

147 Time series emissions data 1990 to 2019 from New Zealand's Greenhouse Gas Inventory published in 2021. Figures are rounded to 1 decimal place. Available at: https://environment.govt.nz/publications/new-zealands-greenhouse-gas-inventory-1990-2019/

148 https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf

3.3.1 Fertiliser production

Hydrogen could play a role in reducing emissions in fertiliser production by replacing the role of natural gas as a feedstock. There may also be other industrial chemicals that can be manufactured with hydrogen as a feedstock in future, for example, methanol (which can be used as an eFuel or as a hydrogen storage compound)[149] and hydrogen peroxide[150].

Emissions from ammonia production (which is processed into urea and used as fertiliser) accounted for less than 1 percent of New Zealand's total industry emissions in 2019 (22.8 kt CO_2-e).[151] However, New Zealand imports urea from overseas, which is produced in emissions-intensive processes. New Zealand imports approximately 654,000 tonnes of fertiliser annually, predominantly from Saudi Arabia and Malaysia, but also China, Bahrain, and the Netherlands.[152]

The uptake of hydrogen for urea production will depend on the cost of hydrogen and the competitiveness of alternatives.

Hydrogen as feedstock could play a key role in future fertiliser production if costs come down and technological processes improve

Ammonia is mostly produced through the Haber-Bosch process, in which nitrogen (from the air) is combined with hydrogen (formed through reacting natural gas and steam at high temperatures) in the presence of an iron catalyst. Urea is then produced by ammonia and carbon dioxide reacting at high pressure and temperature[153]

Natural gas is currently used as a feedstock, typically reformed to grey hydrogen in the process. Converting to green hydrogen creates 'green ammonia-urea', which can reduce emissions from ammonia-urea production by 100 percent.[154] However, green ammonia costs approximately two to four times as much to make as conventional ammonia.[155] The process of synthesising urea from ammonia requires additional cost and another source of carbon dioxide. These feedstock molecules are available in natural gas in conventional urea production. Technological and cost improvements are required to make green ammonia-urea economic. In the meantime, hydrogen can reduce fossil-fuel-based urea production emissions intensity.

Ballance Agri-Nutrients (Ballance) owns New Zealand's only ammonia-urea manufacturing plant , located at Kapuni, Taranaki. Kapuni produces approximately 730 tonnes of urea each day, or 265,000 tonnes annually and uses 7 PJ of natural gas annually.[156] Ballance has entered a joint development agreement with Hiringa Energy to produce hydrogen and use it at Kapuni. The manufacture of green ammonia-urea domestically will offset up to 12,000 tonnes of

149 https://www.man-es.com/company/press-releases/press-details/2021/07/07/man-energy-solutions-to-supply-methanol-reactor-for-porsche-ag-efuels-pilot-plant-in-chile; https://core.ac.uk/download/pdf/140946.pdf

150 https://gtr.ukri.org/projects?ref=EP%2FI006060%2F1

151 The emissions emitted when the urea is used as fertiliser is not included in this figure. Time series emissions data 1990 to 2019 from New Zealand's Greenhouse Gas Inventory published in 2021. Figures are rounded to 1 decimal place. Available at: https://environment.govt.nz/publications/new-zealands-greenhouse-gas-inventory-1990-2019/

152 https://wits.worldbank.org/trade/comtrade/en/country/NZL/year/2018/tradeflow/Imports/partner/ALL/product/310210

153 https://nzic.org.nz/app/uploads/2017/10/1A.pdf

154 https://royalsociety.org/topics-policy/projects/low-carbon-energy-programme/green-ammonia/

155 https://cen.acs.org/business/petrochemicals/ammonia-fuel-future/99/i8

156 https://www.ruraldelivery.net.nz/stories/Kapuni-Urea-Plant-2017-04-03-23-47-22Z

domestic emissions. It will also avoid the import of 7,000 tonnes of urea, which can also contribute to reducing global emissions.[157] The CCC forecasts nitrogen fertiliser use on dairy farms to reduce by 20 percent by 2030.[158]

Biofuel is an alternative feedstock but is unlikely to compete with hydrogen in the long-term

Biofuel can be used as feedstock to produce ammonia, replacing fossil fuel energy. This process is already being undertaken to make green ammonia-urea. Biofuel is beneficial for utilising biomass that would not otherwise be used and requires limited infrastructural changes to current production. However, the development of hydrogen as a feedstock, which can directly replace the natural gas process to make hydrogen, has reduced the desire to develop biofuel for green ammonia-urea production. In addition, biofuel is likely to be most useful for small urea production, which is likely to be a barrier in New Zealand given the country has one large urea manufacturing plant

Scientists have also developed an electrochemical reaction that directly converts nitrogen gas and carbon dioxide into urea. The efficiency and production of the reaction is currently in early stages; however, it is feasible that by 2050 urea could be made by bypassing the use of ammonia and thereby removing the need for fossil fuels in the process.[159]

Cost of hydrogen and competitiveness of alternatives are key determinants for hydrogen as feedstock for fertiliser production

Hydrogen as feedstock is likely to be the most viable option for decarbonising ammonia-urea production and is already being developed in partnership by New Zealand's only urea manufacturer. The uptake of hydrogen as feedstock in this use case is dependent on:

- Technological development of biofuel and electrochemical reactions, particularly for large-scale green ammonia-urea production
- The cost of hydrogen relative to biofuel
- The ability to produce hydrogen in decentralised locations.

3.3.2 Feedstock for steel

Hydrogen (together with electricity) could play an important role in reducing emissions from steel production by replacing coal as a feedstock. Electricity is used as a heat source because hydrogen combustion is too expensive.

Emissions from the metal industry accounted for 2,325.2 kt CO_2-e (45 percent) of total gross industry emissions in 2019. Steel production alone emitted 1,661.6 kt CO_2-e in 2019.[160] The Glenbrook steel mill (the only steel mill in New Zealand) produces 650,000 tonnes per annum.[161] Steel consumption in New Zealand is expected to grow, particularly to build

[157] https://ballance.co.nz/Kapuni-hydrogen-project

[158] https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf, p.117.

[159] https://cen.acs.org/synthesis/One-step-synthesis-urea-green/98/i24

[160] Time series emissions data 1990 to 2019 from New Zealand's Greenhouse Gas Inventory published in 2021. Figures are rounded to 1 decimal place. Available at: https://environment.govt.nz/publications/new-zealands-greenhouse-gas-inventory-1990-2019/

[161] https://www.nzsteel.co.nz/new-zealand-steel/

infrastructure and ensure buildings are earthquake-resilient. Global demand for steel is also expected to increase as it is required for the build-out of RE infrastructure.[162]

The uptake of hydrogen will depend on the cost of hydrogen and electricity, and competitiveness of alternatives.

Hydrogen as feedstock could play a key role in future steel production

Hydrogen-direct reduced iron (DRI) technology can be used as a feedstock (rather than a heat source), reducing emissions from steel manufacturing by replacing coal. At present, DRI using green hydrogen technology is not commercially available, although there is active research on this at the Robinson Institute. Several firms are attempting to develop the technology at commercial scale.[163] Using hydrogen as a feedstock is the only viable alternative to the use of coal in steel production.[164]

New Zealand could develop an integrated green hydrogen to zero-CO_2 DRI plant, or steel manufacturers (such as Glenbrook) could be large industrial hydrogen customers. Glenbrook (or an equivalent) would require approximately 48 tonnes of hydrogen per day, and 16 kt of hydrogen per year (approximately 100 MW of electrolysers).[165]

Hydrogen as a feedstock for steel production has multiple benefits:

- Significantly reduces emissions from the sector
- Removes the decarburisation process step from steelmaking
- Produces high purity molten iron containing zero dissolved carbon
- Enables high flexible composition of steel alloys
- Hydrogen requires ten percent mass quantity of coal
- Reduces steel production time and increases output
- A large industrial off-taker could kick-start or support the hydrogen economy in New Zealand.[166]

At this stage, steel production using hydrogen feedstock is the only zero-emission alternative to traditional steelmaking; however, CCS may be used to reduce emissions after production

At this stage, steel production using hydrogen feedstock is the only zero-emission alternative to traditional steelmaking. Scrap-based electric arc furnace (EAF) technology, which uses nearly 100 percent steel scrap as its feedstock, can reduce emissions during the steel production processes.[167] However, this process is unlikely to compete with hydrogen because it is not a zero-emission approach to steel making, and scrap steel is in limited supply.

CCS is an alternative mechanism to decarbonising steel manufacturing, which could be a viable option for steel manufacturers. Waste carbon dioxide can be captured at the steel mill (or from another large source point), and transported to a storage site where it is deposited and

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[162] Personal communications with Robinson Research Institute.

[163] SSAB/LLKB, Thyssenkrupp, ArcelorMittal, Nippon, US DoE/Utah, POSCO.

[164] Personal communication with stakeholders in the steel industry.

[165] Personal communication with stakeholders in the steel industry.

[166] Robinson Research Institute, The Potential for Hydrogen Steelmaking in NZ: Opportunity and Challenge, August 2021.

[167] https://www.bhp.com/news/prospects/2020/11/pathways-to-decarbonisation-episode-two-steelmaking-technology

not released into the atmosphere.[168] CCS can potentially be retrofitted onto conventional DRI facilities. Steel manufacturers could use CCS to reduce emissions, but probably not eliminate emissions from the traditional steelmaking process.

The DRI unit at Emirates Steel in Abu Dhabi has an operational CCS plant. The plant can capture 800 kt of CO2 per year, which is compressed, dehydrated, and then pumped through a pipeline and injected into a mature onshore oil field for enhanced oil recovery (EOR) operations.[169] A key challenge with CCS is transporting compressed carbon dioxide from the point of source to a storage site. In addition, finding a CCS site in New Zealand that is geologically suitable and passes environmental and social standards is likely to be difficult.

Cost of hydrogen and electricity and competitiveness of alternatives will be key determinants for hydrogen as feedstock for steel production

The use of hydrogen as feedstock is dependent on a range of factors:

- Technological development to enable the use of hydrogen as a feedstock in steel manufacturing[170]
- Capital cost of the reactor design
- Input hydrogen costs and electricity costs
- Development of viable alternatives that are more cost-effective than hydrogen
- Price premium for zero-carbon steel.

3.3.3 Process heat

Hydrogen can be a substitute for combustion of fossil fuels in applications where high-grade heat is needed and where electric or biomass heating is not the best option. The industrial sector uses natural gas and coal as a source of process heat and fuel for the generation of steam. A large proportion of emissions from the industry sector come from process heat.[171] Process heat makes up 33 percent of New Zealand's overall energy use and contributes approximately 6,700 kt CO2-e per year (9 percent of gross emissions).[172]

The uptake of hydrogen will depend on the future cost of hydrogen and other energy sources.

Hydrogen as a combusted heat source can play a key role for future uses of high-temperature process heat

Industry in New Zealand uses 78 percent of New Zealand's process heat. Manufacturers that turn resources into products are heavy users of process heat, for example:

- Wood, pulp, and paper processing
- Petroleum, basic chemicals, and rubber product manufacturing

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168 https://www.worldsteel.org/en/dam/jcr:9480b8a4-1ff8-4b46-80c7-0a78fcd2d04b/Carbon%2520Capture%2520Storage_vf.pdf

169 https://www.worldsteel.org/en/dam/jcr:9480b8a4-1ff8-4b46-80c7-0a78fcd2d04b/Carbon%2520Capture%2520Storage_vf.pdf

170 Stakeholders predict it will take approximately 10 years for technology to be mature enough to use in steel production.

171 60 percent of process heat is supplied using fossil fuels. https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/process-heat-in-new-zealand/

172 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/process-heat-in-new-zealand/

- Dairy manufacturing, including processing milk into powder and sanitising equipment.[173]

Each process requires different temperature needs. Temperature requirements can be classified as low (less than 100℃), medium (between 100 and 300℃), or high (greater than 300℃). 68 percent of process heat is generated in boilers. Hydrogen-fired industrial boilers are being developed and trialled, which may apply for low and medium-temperature process heat requirements.[174] However, the uptake of these technologies is uncertain because there are viable alternatives for low and medium-temperature process heat requirements. High-temperature process heat requires direct heating in ovens, furnaces, and kilns.[175] Swapping high-temperature natural gas and coal burners for hydrogen burners will be the most likely use of hydrogen for process heat.

Sectors such as petroleum, basic chemicals, and rubber product manufacturing could be key users. This sector consumes 35 PJs (second-largest industrial consumer) of process heat.[176] The CCC assumes continued use of fossil gas and coal for high-temperature process heat until 2035, at which point low-carbon technologies will be mature enough to deliver high-temperature process heat.

Electricity and biomass are effective heat sources for low and medium-temperature process heat

Electricity and biomass are likely to be more viable for most low and medium-temperature process heat, namely sanitisation of equipment in the food processing sector (low temperature) and drying wood and food products (medium temperature). Coal and fossil gas boiler systems are already being replaced with biomass or electric boilers.

Government policy supports uptake of biomass and electricity boilers by banning new coal boilers in manufacturing and production and has proposed a phase-out of existing coal boilers by 2037.[177] The CCC predicts that biomass use in the food processing sector alone will reach approximately 13 PJ by 2035, while electricity use will reach 13 PJ by 2030.

Biomass boilers are particularly useful for wood, pulp, and paper processing facilities because residues from processing operations are used as fuel. Electricity boilers are a straightforward conversion for other processing facilities requiring heat below 300℃ as they can use their existing electricity supply. Biomass is less suitable than electricity for high-temperature direct heating.

Electric kilns may also be possible for high-temperature process heat as technology develops. However, this would entail high capital costs to replace existing equipment and would require a large amount of electricity.

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173 https://www.mbie.govt.nz/assets/8c89799b73/process-heat-current-state-fact-sheet.pdf

174 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf, p.56

175 https://www.mbie.govt.nz/assets/8c89799b73/process-heat-current-state-fact-sheet.pdf

176 https://www.mbie.govt.nz/assets/8c89799b73/process-heat-current-state-fact-sheet.pdf

177 https://www.rnz.co.nz/news/national/440037/coal-boilers-to-be-phased-out-by-2037#:~:text=Coal%2Dfired%20boilers%20used%20by,a%20thing%20of%20the%20past.&text=The%20government%20has%20announced%20a,out%20existing%20ones%20by%202037.

Cost of hydrogen relative to other energy sources will be the key determinants of hydrogen for process heat uptake

The CCC's demonstration path for industry sees a steady but reasonably rapid rate of conversion to RE sources or carriers, particularly electricity and biofuel for food processing, before 2040. Hydrogen is likely to provide a viable option for moving away from coal and fossil gas for industries that need high-temperature process heat. Hydrogen boilers may be used for low and medium-temperature process heat.

The use of hydrogen for high process heat is dependent on a few key factors:

- The cost of biomass and electricity if boiler technology improves to be able to provide process heat above 300°C
- The availability of biofuels for process heat is limited unless imported or second or third generation biofuels are developed and utilised. While supply remains limited, it is uncertain whether process heat or transport will be the key user
- Development of hydrogen boilers and competitiveness against other boiler alternatives
- Cost of hydrogen relative to biomass and electricity.

3.3.4 Domestic and commercial combustion uses

Hydrogen has been promoted internationally for reducing emissions in heating and cooking applications by providing an alternative to natural gas and fossil fuels. It is unlikely that 100 percent hydrogen for domestic and commercial combustion uses will be a major use case in New Zealand in 2050 because direct electric alternative options are available. However, blended hydrogen and natural gas could have medium-term demand.[178]

Public electricity and heat production accounted for 4,181.3 kt CO_2-e in 2019.[179] Natural gas is used by about 295,000 industrial, commercial, and residential customers in New Zealand, and accounts for approximately 22 percent of total primary energy supply and 11 percent of total residential energy use.[180] The CCC recommends that no natural gas connections to the grid or bottled LPG connections occur after 2025. The CCC also assumes a 30 percent reduction in new commercial and public buildings' heat demand by 2035 compared to today's performance and assumes that existing buildings' heat demand will reduce by 25 percent by 2035.[181]

The uptake of hydrogen for direct combustion uses will depend on the cost of hydrogen relative to other energy sources or carriers and the cost of upgrading piped infrastructure. It may be attractive to some consumers wanting a direct flame source for cooking (e.g., barbeque or commercial kitchens).

Hydrogen as a combusted heat source may play a role in decarbonising domestic heating and cooking

Hydrogen can be combusted for low emissions domestic heating and cooking. It is likely Hydrogen will be supplied via the existing natural gas network for these uses. An alternative

[178] This use case is discussed in more detail in section 3.2.1.

[179] Time series emissions data 1990 to 2019 from New Zealand's Greenhouse Gas Inventory published in 2021. Figures are rounded to 1 decimal place. Available at: https://environment.govt.nz/publications/new-zealands-greenhouse-gas-inventory-1990-2019/

[180] https://www.gasindustry.co.nz/about-the-industry/

[181] https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf

supply option could be to produce hydrogen for cooking fuel in isolated communities on a small scale. First Gas are exploring hydrogen blending into its existing gas network for domestic heating and cooking uses. HFC-EVs could also use the existing natural gas network, however the hydrogen will require additional purification.

First Gas intends to blend hydrogen up to 20 percent by volume from 2030. No changes to appliances or pipeline infrastructure are expected at this level. 100 percent hydrogen gas is planned from 2035 and, potentially, the network be completely converted by 2050.[182] This scheduling allows time for appliances and network infrastructure to be upgraded and/or replaced (if required) to combat embrittlement.[183] First Gas have stated that the 2050 timeframe would be achieved faster if they received government support for capital replacement.

Other technologies that may utilise hydrogen are:

- Hydrogen boilers, which can replace natural gas boilers, are being developed and are estimated to be commercially available by 2025.[184] Hydrogen boilers are more likely to be a key technology in places like the United Kingdom with many customers using natural gas boilers. Given a large share of New Zealand households already utilising electric heat pumps, this is unlikely to be a large market
- Hydrogen stoves, which operate similarly to electric stove tops, are also being developed.[185] Gas stoves can also be modified to burn hydrogen gas safely. This application could be an important use for applications that prefer open flames, such as BBQs and restaurants.

Electricity and biogas are competing energy sources to hydrogen

Heat pumps and electric stoves are key competing technologies to utilising hydrogen in existing appliances. These technologies are widely used and match the price of alternative. The CCC recommends no new natural gas connections to the network or bottled LPG connections should be allowed after 2025. The CCC's modelling assumes that the uptake of electric heating and hot water systems will increase from 2025, with nearly 100 percent decarbonisation of heating systems by 2050. The CCC anticipates that electricity will account for the majority of the energy used in buildings, over 80 PJ, in 2035. Electric appliances are simple swaps for existing gas appliances and are likely to dominate the market in the future

Biogas can be utilised to decarbonise heating and cooking. After biogas has been created[186], it can either be used for direct energy or cleaned and refined into biomethane. Biomethane can be injected into natural gas networks, transported, and used as a direct substitute for natural gas.[187] A potential pathway for biomethane in New Zealand's energy transition has been

[182] First Gas Hydrogen Feasibility Study 2020, page 31.

[183] https://firstgas.co.nz/news/firstgas-group-announces-plan-to-decarbonise-gas-pipeline-network-in-new-zealand/#:~:text=In%20Monday's%20announcement%2C%20Firstgas%20Group,to%20existing%20appliances%2C%20it%20said

[184] https://www.britishgas.co.uk/the-source/greener-living/hydrogen-boilers.html

[185] https://www.empa.ch/web/self/hydrogen-cooker

[186] Using anaerobic digestion of high-energy organic wastes.

[187] https://www.beca.com/getmedia/4294a6b9-3ed3-48ce-8997-a16729aff608/Biogas-and-Biomethane-in-NZ-Unlocking-New-Zealand-s-Renewable-Natural-Gas-Potential-Final.pdf

identified.[188] The CCC anticipates that biomass will account for some of the energy used in buildings, approximately 10 PJ, in 2035.

Cost of hydrogen relative to other energy sources and the cost of upgrading piped infrastructure will be key determinants of hydrogen for uptake combustion uses

The CCC's demonstration path for household cooking and heating does not factor in the use of hydrogen. By 2050, direct electric alternatives are likely more viable in most instances than utilising 100 percent hydrogen for combustion uses. However, hydrogen may have some uses for cooking and heating, such as restaurant stoves and BBQs, if injected into the existing natural gas network, or if used in isolated settlements where it is produced on-site.

3.4 Exports

Hydrogen in New Zealand can support decarbonisation efforts overseas through export trade. The global demand for low-carbon intensity hydrogen (or hydrogen derivatives such as ammonia) could be as high as 553 million tonnes by 2050, with demand growing by 7 percent per annum from 2020.[189] New Zealand can capitalise on this demand, particularly focusing on supplying hydrogen to Asia, due to high demand requirements and proximity.

Demand for exported New Zealand hydrogen is dependent on long-term supply arrangements and competitiveness of New Zealand hydrogen production costs compared to other countries.

Hydrogen produced in New Zealand could help meet global demand

New Zealand's RE hydro and wind, and some solar resources could be utilised to produce hydrogen for global markets. Hydrogen can then be exported as ammonia, liquid hydrogen, or via another chemical carrier. It is not clear which is the preferred energy carrier. There is particular interest in developing a hydrogen plant in Southland to utilise excess electricity production when Tiwai Point aluminium smelter shuts in 2024.[190]

Asia, particularly Japan and Korea, presents the most significant opportunity for future green hydrogen exports from New Zealand. The governments of Japan and Korea have expressed their intentions to import hydrogen from abroad, and both the governments and the private sectors have been making large investments in hydrogen projects. Japan is expected to announce increased 2030 demand targets of 10 Mt hydrogen and 3 Mt ammonia[191] Korea estimates that 50 percent of the country's hydrogen needs from 2030 onwards will be met through imports, equating to approximately 4 Mt of hydrogen.[192] Singapore has also expressed interest in being a user and distributor of New Zealand hydrogen—Singapore's government is looking at being a hydrogen hub for the Asia region, in a similar way as it is currently a hub for oil and gas.[193]

[188] https://www.beca.com/getmedia/4294a6b9-3ed3-48ce-8997-a16729aff608/Biogas-and-Biomethane-in-NZ-Unlocking-New-Zealand-s-Renewable-Natural-Gas-Potential-Final.pdf

[189] https://www.datocms-assets.com/49051/1626295071-the-nz-hydrogen-opportunity.pdf

[190] https://www.datocms-assets.com/49051/1626295071-the-nz-hydrogen-opportunity.pdf

[191] https://www.datocms-assets.com/49051/1626295071-the-nz-hydrogen-opportunity.pdf

[192] https://www.mfat.govt.nz/br/trade/mfat-market-reports/market-reports-asia/republic-of-korea-the-hydrogen-economy-22-february-2021/; https://www.ifri.org/en/publications/editoriaux-de-lifri/edito-energie/south-koreas-hydrogen-strategy-and-industrial

[193] Personal communication with MBIE.

Other countries with low-cost energy sources will compete with New Zealand in the global market

Previous Castalia analysis indicates New Zealand will probably compete with the following countries in the export market:

- The Middle East, with solar resources and existing port and gas infrastructure
- Australia with solar resources
- Canada with hydro resources
- Chile with hydro, wind, solar, and geothermal resources.[194]

Modelling of exporting hydrogen to Japan indicates that New Zealand would be competitive against the expected cost of competition from blue hydrogen from the Middle East through to 2030, or potentially longer if CCS is uneconomic.[195] Green hydrogen produced in the Middle East, Chile, and Australia from large-scale solar and wind facilities is expected to be internationally competitive in the long term.[196]

Demand for exported New Zealand hydrogen is dependent on long-term supply arrangement and competitiveness of energy sources

The uptake of hydrogen produced in New Zealand will depend on the following key factors:

- Long-term supply contracts in key markets such as Japan, Korea, and Singapore. Purchasers will likely want to ensure hydrogen is supplied from a range of countries to reduce reliance on one country
- New Zealand's production costs and shipment and transhipment are below the market clearing price.

Other key factors for export cost competitiveness are the utilisation rate of the production plant and electricity costs. Capex costs will be the same globally, but capital cost recovery depends on the utilisation of the electrolyser. RE that has a high-capacity factor, such as hydro or geothermal, can ensure the capital recovery factor is high. Locations where existing port facilities can be easily upgraded for hydrogen infrastructure will have an advantage. Locations where hydrogen could be produced and then transported to a port via rail or pipeline, are also feasible. Access to and cost of water at sufficient quantities may also be a factor, for example in the Middle East and Australia, where desalination or wastewater treatment may be required.[197] However, it is difficult to account for the impact of this on production costs.

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194 Castalia analysis.

195 https://www.datocms-assets.com/49051/1626295071-the-nz-hydrogen-opportunity.pdf

196 https://www.datocms-assets.com/49051/1626295071-the-nz-hydrogen-opportunity.pdf

197 Australia's National Hydrogen Strategy considers desalination a priority for hydrogen production taking place in areas such as the Northern Production https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf. Abu Dhabi and Saudi Arabia: https://www.globalwaterintel.com/news/2021/27/abu-dhabi-explores-major-hydrogen-from-desal-plans

4 Pathways to the hydrogen economy under BAU

This section describes the development of New Zealand's hydrogen economy under current government targets and objectives.

- Section 4.1 outlines the production cost scenarios for New Zealand (the supply side)
- Section 4.2 outlines the pathways for hydrogen uptake in key use cases (the demand side).

The BAU scenario analyses hydrogen production and use by determining competitiveness with other zero-emission technologies. We make the following assumptions in this section:

- Government interventions and technological development will drive the pace of decarbonisation. This means there is a continuation of a broadly supportive policy environment for decarbonisation, and the carbon price increases over the 30-year modelling timeframe
- Technology costs fall over time
- Government intervention is neutral as to technology types, and technologies for hydrogen use will compete on underlying costs
- The government completes the regulatory framework necessary to permit usage of hydrogen technology. Stakeholders in the hydrogen sector comment that current regulations prevent uptake of hydrogen technology, including regulations under the Hazardous Substances and New Organisms Act 1996, Gas Act 1992, Electricity Act 1992, Transport Act, and planning rules under the Resource Management Act 1991.

4.1 Production cost pathways for hydrogen in New Zealand

Delivered hydrogen costs in New Zealand depend on production and distribution costs. These costs are modelled using our Castalia-MBIE model, updated with 2021 data. We compare the Castalia-MBIE model forecasts with global benchmarks.

There are two main methods to produce and distribute hydrogen:

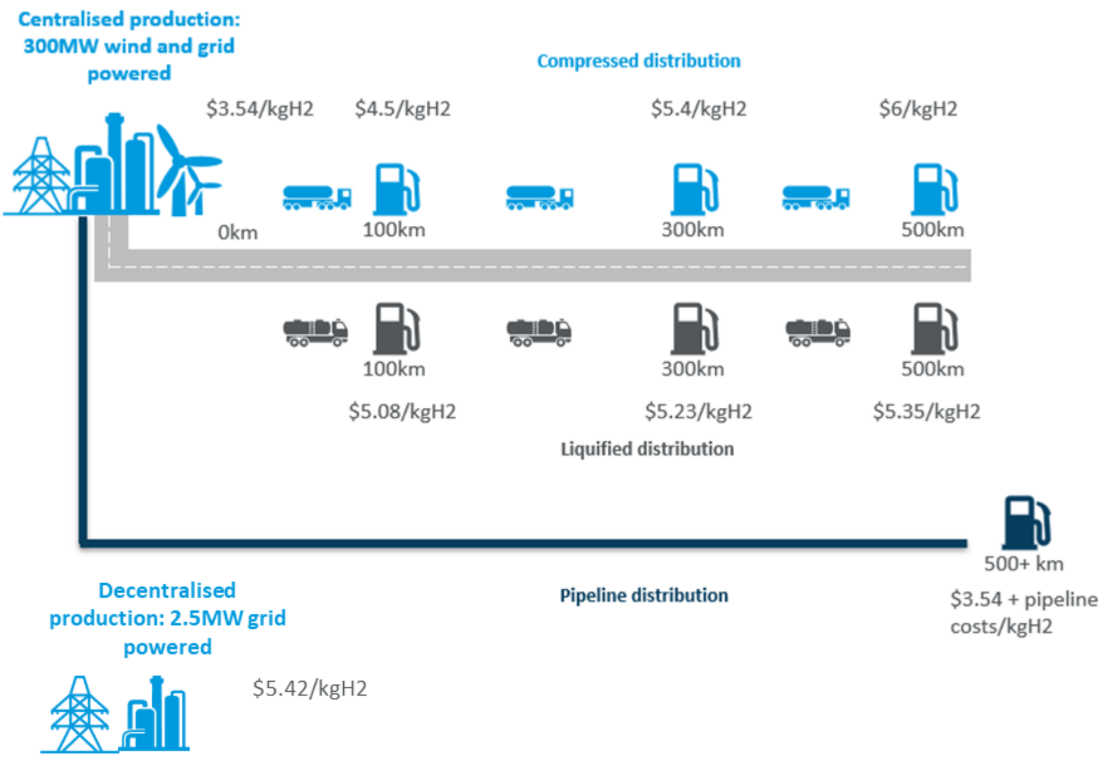
- Production at scale at a centralised location, with distribution to end-users via trucking or pipeline. Scale production benefits from lower electricity prices, lower capital costs, but higher distribution costs
- Production at smaller volumes at locations where end users can take hydrogen directly. Smaller volume production has higher electricity prices, higher capital costs, but no (or low) distribution costs.

Cost competitiveness of centralised vs decentralised production is broadly comparable

Our modelling suggests that the trade-off between production at scale and production at smaller volumes will depend on the distance of the scale plant from end-users, and the difference in wholesale RE electricity prices and grid electricity prices. Centralised production and distribution by truck seems to make sense for distances up to around 300 km from the production site. Figure 4.1 illustrates the difference in delivered hydrogen prices. It compares a 300 MW centralised plant to a 2.5 MW decentralised plant. The distribution from the centralised plant is via trucked compressed or trucked liquified hydrogen.

The cost components of centralised production and compressed distribution include the levelized cost of green hydrogen production, compressor capex and opex, trailer capacity and utilisation and distance-based delivery costs. For liquified distribution, the cost components include the cost of production, trailer costs and other terminal costs, and distance-based delivery costs of liquified hydrogen.

Figure 4.1: Illustration of centralised vs decentralised production in 2035 (US$)



Distribution via pipelines is likely to be cost-competitive, but costs are difficult to estimate

The option of piping hydrogen from a centralised production plant to the end-user is also available. The pipe transmission costs vary by type and throughput. We discuss this below.

4.1.1 Centralised production of hydrogen and distribution to end-users

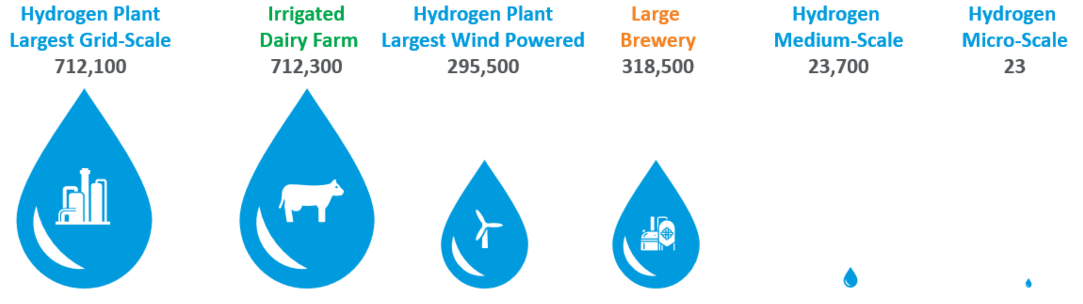
Centralised production will be cost-competitive depending on the economies of scale, availability of low electricity prices, and distribution costs to end-users.

Production costs at scale

The lowest-cost option for centralised hydrogen production would be from wind and grid powered facility at the largest efficient scale of 300-600 MW. A 300 MW plant would have a daily production capacity of approximately 120,440 kg. The lowest cost production plant would use a combination of grid and wind power to maximise plant utilisation and lowest cost electricity. We assume a levelised cost of electricity (LCOE) for the largest efficient scale production plant at US$0.08 per kWh for grid power and US$0.05 for wind power. Modelling suggests that production costs at this largest scale will fall from a current price of US$4.49/kgH2 to US$2.69/kgH2 by 2050.

Water is not a significant factor in production costs in New Zealand.[198] Hydrogen production will use around 18 litres of water per kilogram of hydrogen produced. The largest plant has water needs similar to a single dairy farm.[199] Figure 4.2 highlights water usage in New Zealand across different parts of the economy.

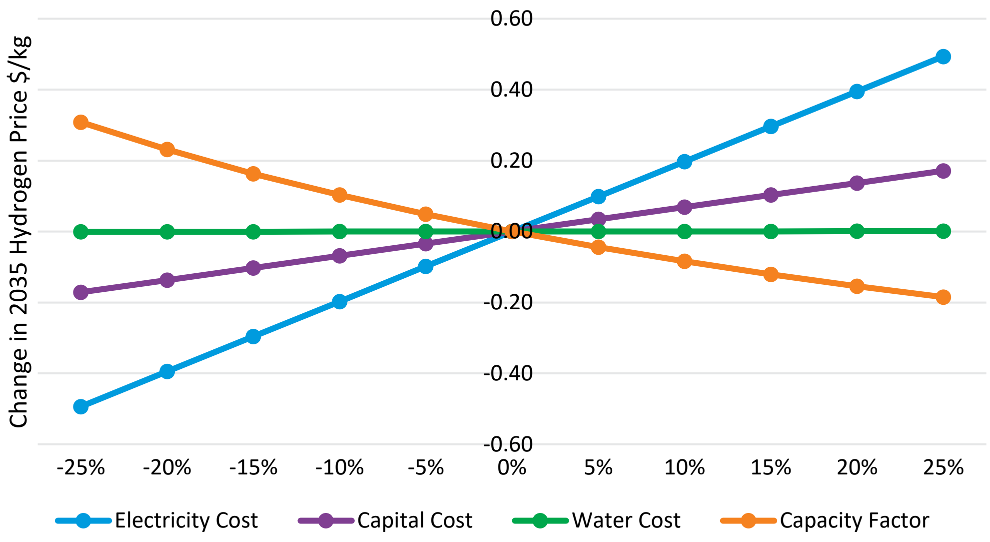
Figure 4.2: Water usage in the New Zealand economy (cubic metres per annum)



Note: Hydrogen Plant Largest Grid-Scale involves a 300MW GH2 electrolyser at 90% utilisation.

Figure 4.3 illustrates the sensitivity of hydrogen production at scale to changes in different inputs. The production plant's electricity price and utilisation rate are the two more significant contributors to hydrogen production cost.

Figure 4.3: Sensitivity of hydrogen production at scale to inputs



Distribution costs

Hydrogen can be distributed from a centralised plant by truck, rail or pipeline.

[198] As mentioned above, desalination costs may impact the production cost of hydrogen for some countries.

[199] Castalia analysis, 2020

Liquified and compressed trucked hydrogen

We have modelled trucked costs for compressed hydrogen (300-600 kg capacity trucks) and liquified hydrogen (4,000 kg capacity trucks). The liquification process at the plant gate is costlier, and involves more electricity and higher capex for the liquification and trailer unit. Compression is more straightforward, but lower truck capacity means transport cost is higher for further distances from the plant.

Piped hydrogen

Piped hydrogen distribution costs are highly dependent on the cost of building a new pipeline or converting an existing natural gas network. Zen estimates a newly built 100 ton per day capacity pipeline costs US$0.38, US$1.00, and US$1.60 per kg of hydrogen for 100, 300, and 500 km distances, respectively.[200] Piping costs via an upgraded existing pipeline network, such as the New Zealand gas transmission and local distribution network is estimated to be around one-quarter of the cost of a new pipeline network.

4.1.2 Decentralised production and delivery of hydrogen to end-users

Decentralised production is at a lower scale and has higher per unit hydrogen production costs. However, it avoids distribution costs, because plants can be built at the point of use. For example, Ports of Auckland is building a 1 MW production and dispensing facility at the Waitemata port site to serve trucks, buses, light-duty vehicles and port vehicles.

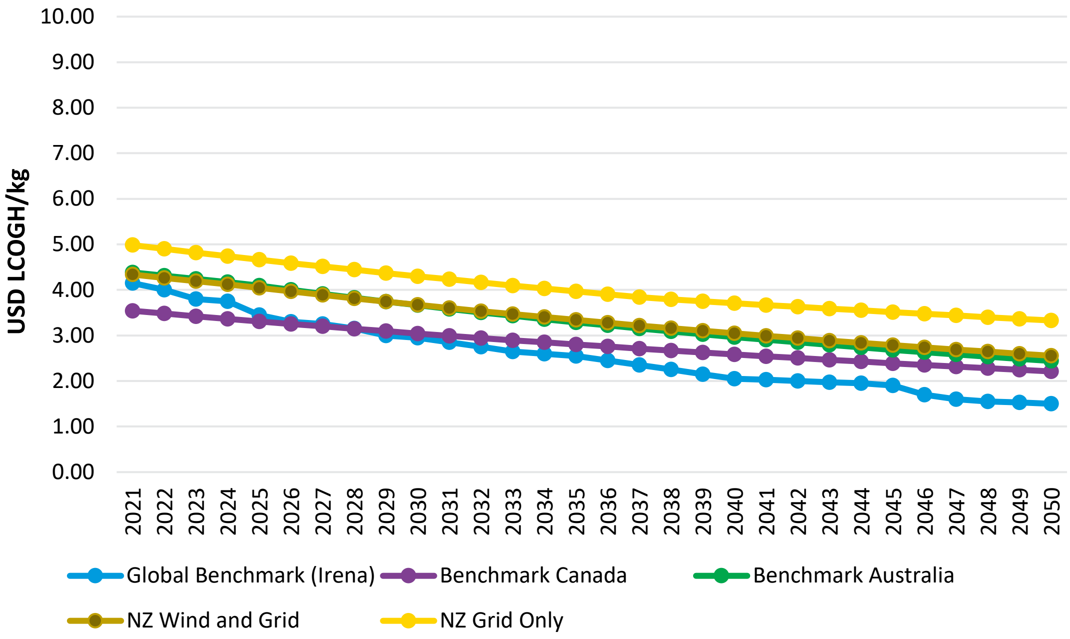
We modelled production costs for a 2.5 MW plant, with a capacity of around 1,000 kg per day, which would be sufficient for around 50 heavy trucks or truck equivalents. Using grid power at US$0.10/kWh the plant could produce hydrogen at US$6.89 in 2021, falling to US$4.24 by 2050.

4.1.3 Comparisons to global production cost benchmarks

It is important to check the modelling results against assumptions for other countries and benchmarks. The model results for New Zealand hydrogen production costs are comparable with modelled global benchmarks in Australia and Canada. The New Zealand model results are also broadly comparable with IRENA forecasts.

[200] Zen from project experience, 2021.

Figure 4.4: New Zealand and global comparator hydrogen production costs



4.2 BAU pathways for key use cases

Table 4.1 details the total estimated hydrogen demand in New Zealand under the BAU pathway, the base case. The high demand case assumes a low LCOGH based on an optimistic price path for green hydrogen production in Chile plus a 25 percent distribution cost. The low demand case assumes a grid price of electricity of NZ$0.14/kWh and no change in the carbon price over time. A breakdown of this table is included in Appendix A.

Table 4.1: Estimated total hydrogen demand under BAU (in tonnes)

Case	2030	2040	2050*
High case	127,982	329,762	1,987,903
Base case	111,392	237,212	1,889,384
Low case	108,892	213,900	1,809,320

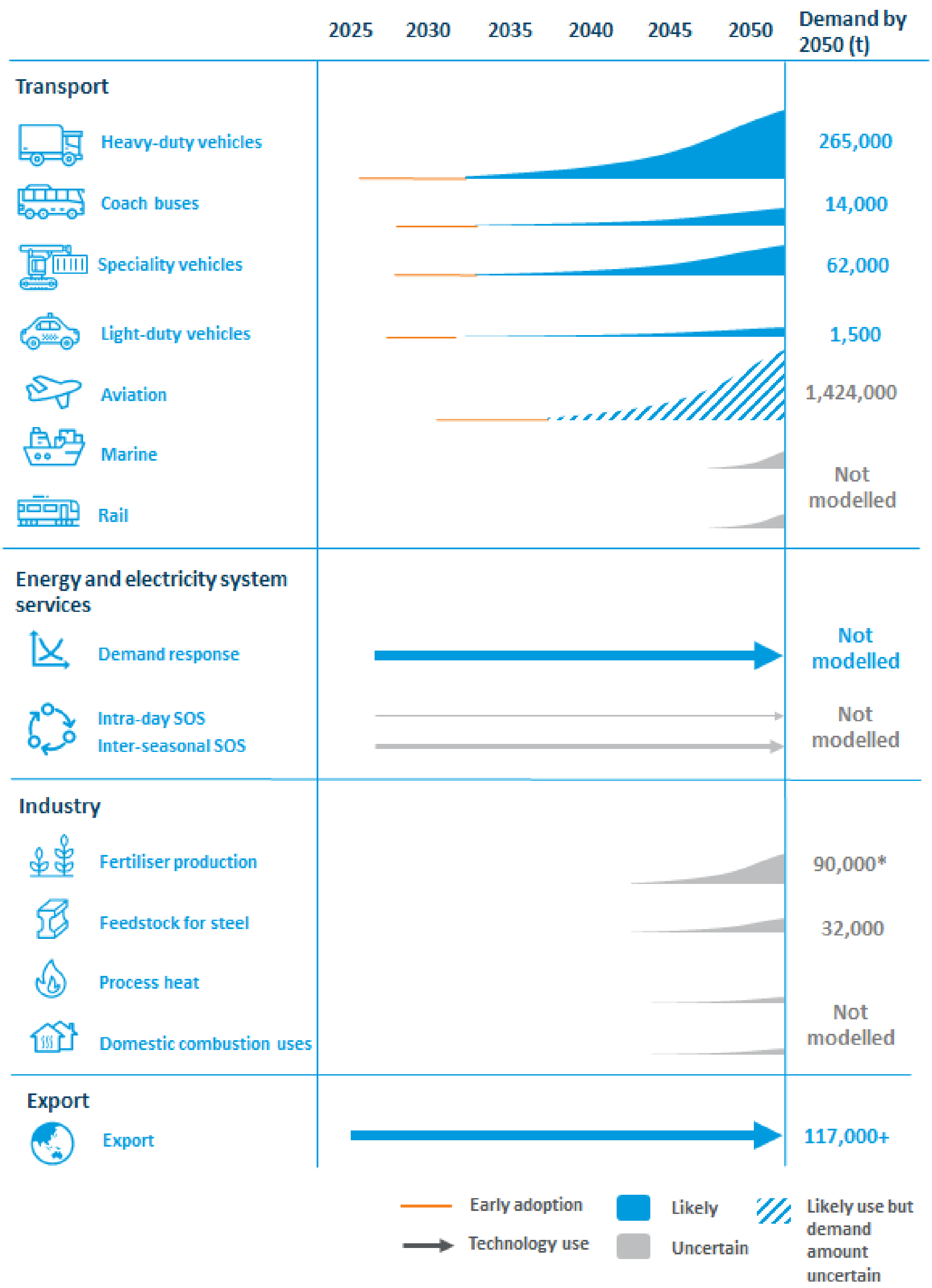
Note: 2050 includes demand for aviation, which we consider less likely, at 1,424,361 tonnes of hydrogen.

Overview of hydrogen demand by sector and use cases

Making predictions over a 30-year period is inherently imprecise. Multiple factors can change and influence development of the hydrogen economy. The modelling in this report indicates which hydrogen use cases are more likely than others to develop, and approximate timeframes.

Figure 4.5 illustrates the uptake timeframes for each use case and an assessment of likelihood of development. It also shows the approximate hydrogen demand by 2050 in the base case.

Figure 4.5: Illustration of hydrogen uptake in BAU scenario



Note: Figures are rounded.
**For fertilizer production, around 1 percent of annual demand will be produced in the short-term using green hydrogen from wind-powered hydrogen production at Kapuni.*

Key assumptions that apply to all use cases in the BAU scenario

We make core modelling assumptions in the BAU scenario of pathways for use cases. These include:

- 30-year time frame
- WACC: 5%[201]
- Diesel price NZ$1.23 per litre, increasing by 3 percent per annum
- Hydrogen for the use cases is sourced from a combined wind and grid-powered large-scale plant with an electricity price of: NZ$0.092/kwh[202]
- Cost components include capital cost recovery factor, water cost per kg, electricity cost per kg and other O&M costs per kg
- Sector-specific assumptions were also used.

Other key points to note are:

- The relationship between variables, such as volumes of hydrogen and prices, matters more than the absolute values that are outputs of the modelling—"the map is not the territory"
- Our modelling indicates the tipping point at which the average use case becomes economically viable, compared to using other technologies or energy sources. There is likely be uptake in each use case before the tipping point
- Our modelling is highly sensitive to technological developments.

In the following, we outline the BAU scenario with the modelled demand for each use case under four sectors.

4.2.1 Transport

The tipping point at which significant transport demand for hydrogen begins is around 2030 when the per km cost of hydrogen trucks is lower than the diesel equivalent. This is when mass adoption by cost-focussed commercial users should occur, as existing fleet vehicles are replaced, and new vehicles are added due to overall fleet growth. The modelling reflects typical commercial use—that is, relatively high utilisation of the capital plant (vehicle). There will be demand for high frequency users and specific use cases prior to this.

The tipping point for hydrogen industrial vehicle demand occurs somewhat later. Industrial vehicles such as excavators, straddle carriers, and cranes are still in early stages of development. Therefore, we assume that the demand will occur with a time lag of five years compared to hydrogen trucks.

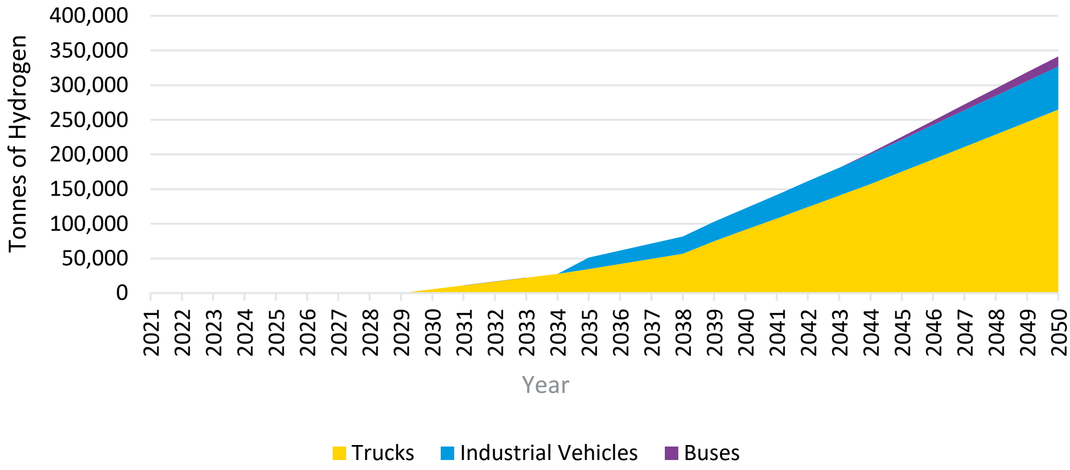
The modelling results do not preclude demonstration projects or adoption for particular use cases. Early adoption may be likely when the higher vehicle and infrastructure capital costs of

[201] Real WACC (pre-tax).

[202] Wholesale price of electricity.

hydrogen technologies can be justified; such as for use cases with high utilisation rates and high energy demands.

Figure 4.6: Demand for hydrogen in transport applications



The core assumptions for the transport demand analysis are:

- Price of carbon: NZ$65 in 2021, with annual 4.5% increase
- Grid price of electricity: NZ$0.1079/kWh[203]
- Diesel price NZ$1.23 per litre (US$0.91)
- Model compares all costs associated with heavy vehicle transport, vehicle capital cost, energy/fuel cost, refuelling/recharging infrastructure
- Include heavy trucks (based on load capacity), coach buses (based on load capacity), speciality vehicles (proxy fleet numbers based on annual diesel consumption by mining and construction industry)
- Uptake is based on switching for new vehicles between diesel, electric, and hydrogen vehicles by relative price.

High-demand and low-demand cases

We also model a high demand and low demand case for the transport sector. This illustrates the change in hydrogen uptake timing and volume if key drivers of cost change. Figure 4.7 illustrates the high and low demand estimates.

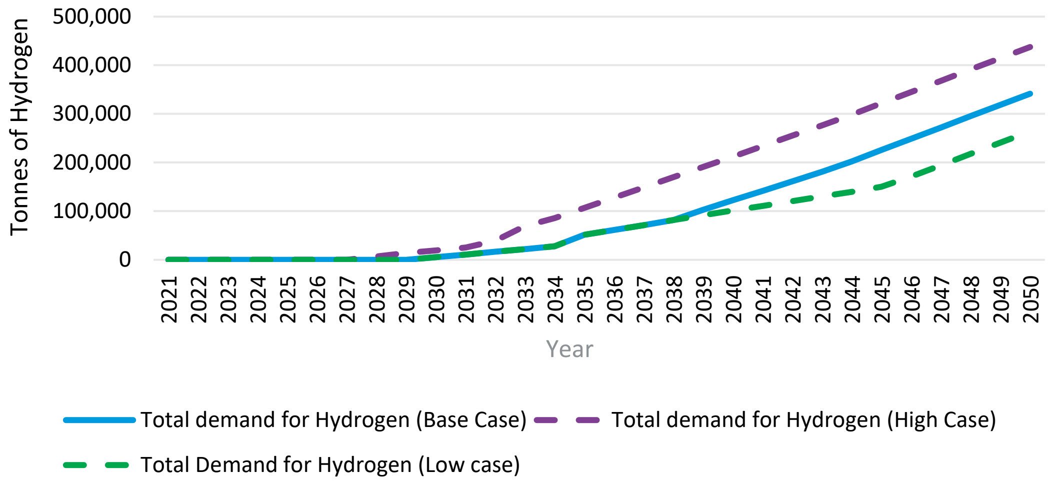
The high demand case assumes a low LCOGH based on an optimistic price path for green hydrogen production in Chile plus a 25 percent distribution cost[204].

The low demand case assumes a grid price of electricity of NZ$0.14/kWh and no change in the carbon price over time.

[203] The retail price of electricity is used for transport demand analysis.

[204] https://energia.gob.cl/sites/default/files/national_green_hydrogen_strategy_-_chile.pdf

Figure 4.7: High demand and low demand estimates for hydrogen in transport applications



Highest likelihood of demand for heavy vehicles, coach buses and speciality vehicles

In this section, we describe the modelling results for each vehicle type. As mentioned, our modelling indicates the tipping point at which the average use case becomes economically viable, compared to using other technologies or energy sources. There is likely to be uptake in each use case before the tipping point.

Heavy vehicle demand is the largest source of estimated demand

We estimate the tipping point for the adoption of hydrogen in heavy vehicles to start around 2030. Demand will likely grow to around 264,000 tonnes by 2050. Hydrogen heavy trucks greater than 12,000kg load capacity become cheaper in terms of "total cost per year per km" than diesel trucks in 2030, whereas heavy trucks with load capacity below 12,000 kg become cheaper in 2039. Lower load capacity trucks also have electric vehicles as competing technologies. We modelled total replacement and new additions for heavy trucks based on all load capacity categories (from 5,000 kg to over 30,000 kg).

Coach buses

We estimate mainstream demand for hydrogen in coach buses to emerge around the 2040s, when total cost of ownership for particular routes (e.g., long and/or undulating routes) falls below equivalent BEBs and diesel alternatives. Estimated demand for hydrogen will grow to around 14,300 tonnes by 2050. The competing technology for buses is BEBs. We modelled fleet retirements and new additions for buses over three load capacities comparing BEBs, FCEBs, and diesel buses total cost of ownership.

Again, it there may be specific use cases that justify using FCEBs earlier. These could be routes that are particularly hilly, or have transport tasks demanding high weights/loads. With the development of widespread re-fuelling infrastructure for HFC heavy trucks around 2030s, it will be relatively easy to integrate HFC coach buses into the fleet.

Speciality vehicles

We estimate demand for hydrogen in speciality vehicles to start in the mid-2030s. This will grow to around 62,500 tonnes by 2050. Detailed fleet size information for speciality vehicles such as excavators, forklifts, and mining trucks was not available. We modelled annual diesel consumption for off-road vehicles across the mining and construction industry and estimated a proxy for total vehicle fleet for speciality vehicles based on assumptions about annual diesel use by industrial vehicles. Due to differences in speed of technological development, we expect a short lag in scale manufacturing of HFC speciality vehicles compared to heavy trucks. This is reflected in the modelling.

Light-duty vehicles

Our modelling shows that once the capital costs of HFC-EV light-duty vehicles and BEVs reach parity, the total cost of ownership is comparable. This will justify using or switching to HFC-EV light-duty vehicles for some users who have high travel demand and when EV charging time is a constraint. We used projections made by the CCC for total kilometres travelled by ridesharing and taxi vehicles between (2030-2050) to estimate total potential demand for hydrogen. Assuming vehicle capital cost parity is reached by 2031, our modelling suggests that total demand for hydrogen for light-duty commercial use is approximately 1,449 tonnes by 2050.

Demand in aviation will emerge; however, it is unclear which technologies will be dominant and how much demand will be. Some demand may emerge in aviation, marine and rail

We modelled aviation, marine and rail demand at a high level. Demand is highly uncertain in these applications because the technologies that could decarbonise the sectors are in development.

Aviation hydrogen demand will depend on which technology "wins"

Hydrogen is likely to be used in aviation applications; however, because technologies are still developing, it is not clear how hydrogen will be used and how much demand there will be.

If hydrogen technology were to emerge as the favoured option, then we should expect current demand for energy in jet aviation to be replaced by the equivalent in hydrogen fuel. New Zealand's domestic jet fuel energy demand was 13.2 PJ in 2018. We forecast that to increase to 31.30 PJ by 2050. Meanwhile, New Zealand's international jet fuel demand was 57.10 PJ in 2018 and we forecast that to increase to 118 PJ by 2050. Hence, the combined jet fuel demand for aviation in New Zealand is likely to be 149.30 PJ by 2050. We assume that demand for aviation services grows at a constant rate. If hydrogen were to replace 75 percent of domestic jet fuel demand and the entire demand for international jet fuel, we expect the demand to be 1,424,400 tonnes by 2050.

Marine hydrogen demand is highly uncertain

Demand for hydrogen in marine use in New Zealand is uncertain. It is not clear which technologies will 'win' and emerge as cost-competitive. Therefore, we do not model the potential uptake. Since hydrogen demand in New Zealand is most likely in heavy vehicle transport, refuelling facilities are likely to centre around logistics centres, such as ports. Therefore, uptake in the marine sector will require only relatively minor investment to extend fuel supply from heavy vehicles to marine craft.

Rail hydrogen demand

Demand for hydrogen in rail use in New Zealand is also uncertain. There are rail routes that are not directly electrified where the use of hydrogen trains could be cost-effective compared to electrifying a rail line. It is unclear how many trains would convert to hydrogen fuel in the future. We do not model the potential uptake in the rail sector. Similarly to the marine sector, rail lines terminate at or near ports and are adjacent to major trucking logistics centres. Therefore, the future use of hydrogen trains should not require major infrastructure upgrades.

4.2.2 Energy and electricity system services

Hydrogen technology is likely to support the energy and electricity system as a demand response tool. Hydrogen technology may also support inter-seasonal security of supply, but is unlikely to support intra-day security of supply. Other hydrogen demand in the market will likely be required for it to be economic to use hydrogen technologies to support the energy and electricity system.

Large-scale hydrogen production can provide capacity through demand response

A large-scale hydrogen production facility can ramp up and ramp down production easily. The only cost is the opportunity cost of the hydrogen that is not produced. Currently, the Tiwai Point aluminium smelter cannot quickly ramp down production as this incurs significant costs with aluminium hardening in the plant's pots. A scale hydrogen plant can free capacity for the grid and rapidly ramp down production for a fee.

Hydrogen production is interruptible and could therefore be optimised to coincide with periods of high electricity prices when production is halted, and demand response capacity is sold into the spot market, and then on-site hydrogen storage is used to generate electricity. However, it is unlikely that hydrogen production from captive wind or solar would be curtailed because production periods are likely to coincide with widespread availability of capacity, for example during periods of high wind or sunshine. This means that Figure 4.8 may not be fully reflective of the optimal use of hydrogen. However, it is unlikely that hydrogen production and storage solely for electricity generation would be economic; other demand in the market would also be required.

Hydrogen may be a viable means to overcome inter-seasonal security of supply but is unlikely to be used to support intra-day security of supply

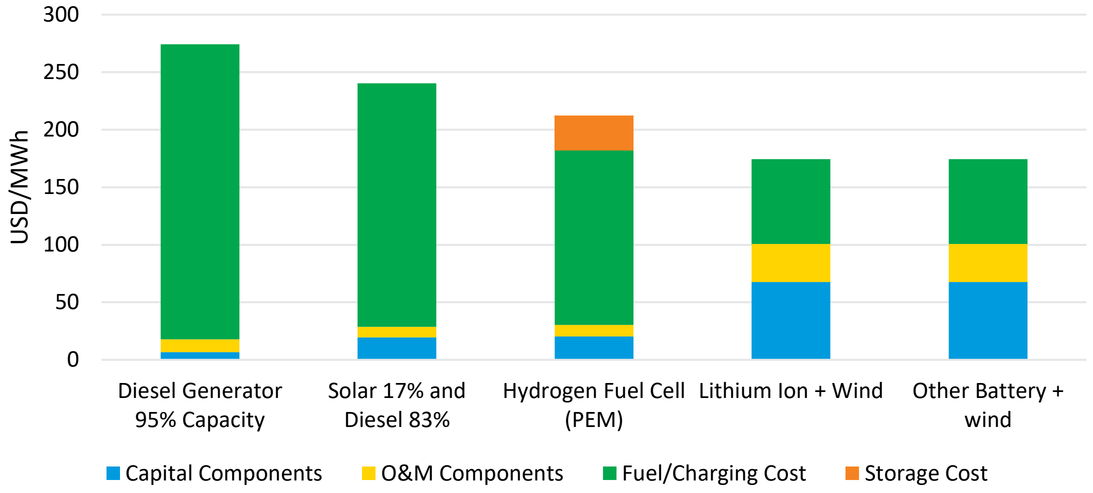
Using hydrogen for generation and as electricity storage over various time horizons could help improve the resilience of the electricity system. However, it is not clear which storage or generation options are most viable for New Zealand, if at all.

Figure 4.8 illustrates the comparative costs of different methods of producing and storing energy. Hydrogen storage technologies are most likely to be viable for long duration storage when there is low-cost hydrogen production (or low-cost imported hydrogen), economically and environmentally viable storage, and there is existing demand in New Zealand, such as from the transport sector. Further research is required to understand which storage options are most economic.

Hydrogen storage technologies are less likely to provide intra-day security of supply due to viable alternatives. There may be some applications in highly specific scenarios where multiple uses for hydrogen are possible, for example, where the hydrogen could be used for vehicle fuel and in a fuel cell. A rapid, fluid hydrogen supply chain that is used for applications other than electricity will likely be required for these applications to be economic.

There are competing technologies for electricity storage and generation, which may be lower cost than hydrogen for both inter-seasonal and intra-day security of supply. Inter-seasonal security of supply may be more likely to be met from lower-cost options, including optimising hydro dam storage with much larger scale deployment of RE wind and solar, demand response solutions or pumped hydro. The least-cost intra-day security of supply options includes RE and battery combinations. It is possible that in 2050, hydrogen technology may be more expensive for electricity storage and production than battery plus wind generation.

Figure 4.8: Comparative energy costs of different electricity production and storage technologies in 2050 for 1MW isolated systems



4.2.3 Industry

Hydrogen is an alternative feedstock for emissions-intensive industrial processes. However, in New Zealand it is likely to have small-scale uses.

Hydrogen may have some relatively small-scale uses, but industrial demand will not drive hydrogen production decisions

Hydrogen is a feedstock in multiple industrial processes. It is almost universally sourced from hydrocarbons (brown or blue hydrogen), usually with a complementary chemical or refining process. The use of green hydrogen for the same industrial processes is unlikely in New Zealand at a large-scale.

Green hydrogen will be used in ammonia and urea production at Kapuni during the transition period from fossil fuels. The annual urea production is 265,000 tonnes. The Kapuni plant uses mostly natural gas feedstock and will add additional hydrogen from an on-site electrolyser. An on-site renewable wind generation plant is also planned, which will provide energy for the ammonia-urea production process. The project's environmental consents are currently being considered, and completion is expected in the next few years. This process only reduces the carbon intensity of a fossil fuel-based process by replacing some of the natural gas feedstock with hydrogen. It is not yet a solution to achieve 100 percent green urea.

If New Zealand's entire urea demand was replaced by synthesising ammonia from 100 percent green hydrogen with carbon dioxide (with no natural gas involvement), then potential demand for hydrogen in urea production could be up to 90,000 tonnes of hydrogen by 2050. This demand assumes fertiliser production using 100 percent pure hydrogen, and assumes there is no reduction in agricultural demand for urea.

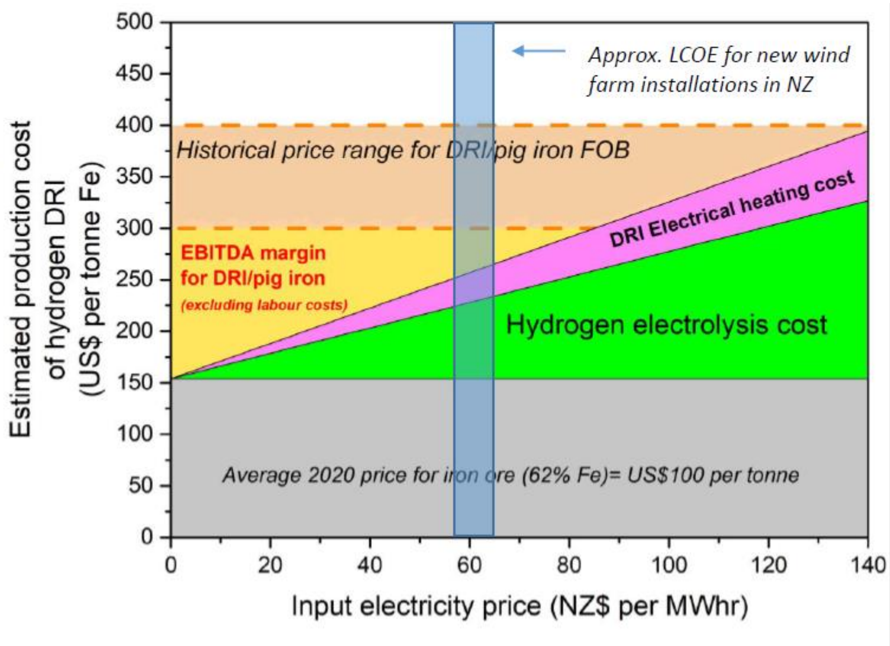
However, this estimate is unlikely to materialise because the green urea would probably cost more than current urea from fossil fuels, reducing demand in agricultural uses. It would also require a low-cost method of green hydrogen production, combined with a low-cost source of carbon dioxide, and no change in demand for agricultural urea.

Hydrogen could be used in steelmaking, but demand will be modest

Hydrogen could play a major role in domestic steelmaking, which is highly dependent on overseas steel production costs, and development of lower-cost production techniques. New Zealand's only steel mill has the potential to convert to production of steel using the direct reduction of iron (DRI) method using hydrogen as a reductant.[205] However, the cost competitiveness would depend on decarbonisation of steelmaking overseas. If the steel mill can convert its entire production process, potential demand for hydrogen in steelmaking would be between 30,000-35,000 tonnes per year.[206] This assumes that all current steel production could continue using the DRI process and there is no impact on domestic steel demand from a change in steel price.

Figure 4.9 illustrates the costs of steel making using the DRI method. Electricity costs of $0.06/kWh are required to for economic feasibility. However, this is based on a highly uncertain estimate of capital costs.

Figure 4.9: Illustration of DRI steel production costs and implied electricity cost



Victoria University of Wellington, Robinson Research Institute (2021)

Direct use in combustion applications is likely to be limited due to viable alternatives

Demand for hydrogen in combustion applications at 100 percent purity appears unlikely to have widespread use. Gas combustion for domestic cooking and heating can already be converted to direct electrification relatively easily. New Zealand does not have the same widespread use of boilers and radiators in households internationally, such as in the United Kingdom. In New Zealand, heating can be converted to heat pump and cooking to direct use of electricity, most likely at lower cost than 100 percent hydrogen combustion. In addition, there

[205] https://www.hydrogen.energy.gov/pdfs/progress19/ins_sa172_elgowainy_2019.pdf

[206] Based on annual Glenbrook steel mill production of around 650,000 tonnes and using 47-50 kg hydrogen per tonne of steel output. Source: VUW

are capital costs to upgrading or replacing gas distribution infrastructure that would add to total hydrogen costs relative to electricity.

4.2.4 Exports to support decarbonisation overseas

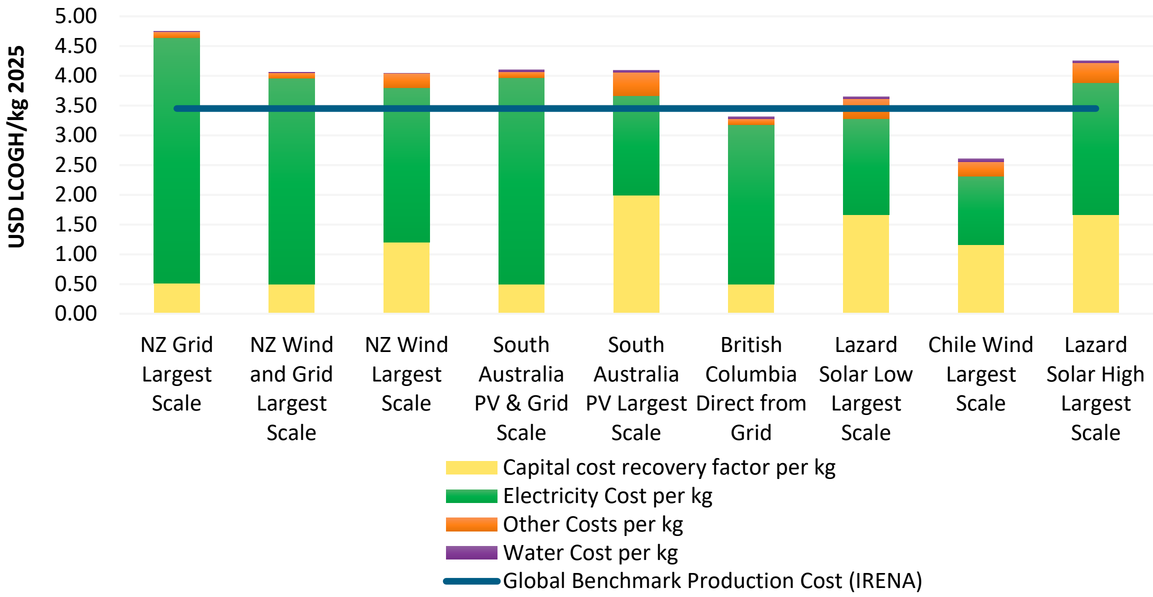
New Zealand-produced hydrogen is likely to be cost-competitive for consumers in key trading partner countries.

Large-scale New Zealand production is cost-competitive with other jurisdictions

New Zealand hydrogen compares favourably to other jurisdictions where hydrogen could be produced. The availability of large amounts of renewable electricity at relatively low cost and is critical for global competitiveness. The capacity factor of the electricity source and the utilisation rate of the hydrogen electrolyser(s) will determine the cost-competitiveness of New Zealand's global competitors.

New Zealand could have excess renewable electricity at relatively low cost if the aluminium smelter ceases operation. The Southern Green Hydrogen proposal in Southland could utilise significant capacity (up to 800 MW) from the Manapouri power station at a high utilisation rate. This proposal compares favourably to overseas production options, such as solar-powered production in Australia and hydro-powered production in Canada. Figure 4.10 illustrates this.

Figure 4.10: Comparison of New Zealand and overseas production costs in 2025



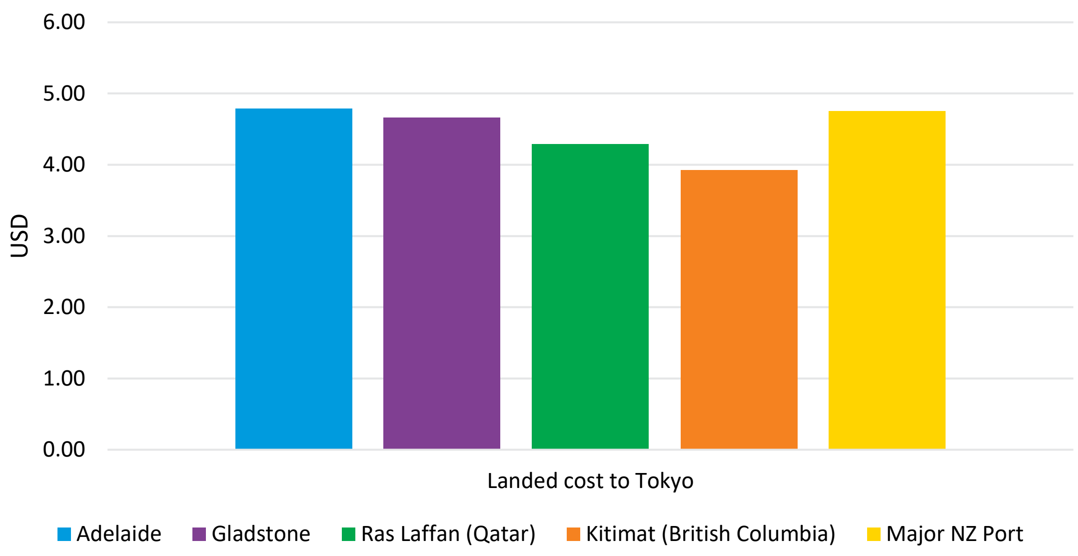
Note: For the Global Benchmark Production Cost (IRENA), we derived a cost curve based on forecasts for specific years provided in the IRENA report for 2020 -2050[207]

[207] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf

Production of hydrogen for export likely if overseas demand exists

New Zealand may export hydrogen if significant demand emerges overseas. The key markets of Japan and South Korea, which both have poor domestic RE sources, appear the most promising export markets in the medium term. Singapore is also a key market and seeks to establish itself as a hydrogen hub for Asia. Figure 4.11 shows the cost of landing New Zealand hydrogen in export markets, which is higher than other likely export countries. This modelling is based on theoretical production and transport costs, is highly sensitive to electricity price assumptions, and is not situation specific. Below we discuss New Zealand's competitive advantage at specific sites.

Figure 4.11: Comparison of landed hydrogen costs to Tokyo, Japan (2035)



New Zealand has a competitive advantage over other countries in the short-term

New Zealand's hydrogen export advantage will emerge where existing infrastructure or natural features provide a relative advantage to other countries with excess RE. For example, utilising energy from Lake Manapouri could give New Zealand a competitive edge in the short-term. This competitive advantage may mean that New Zealand could also support international partnerships to test hydrogen use or integrate with international projects. This could develop a wider range and volume of demand, which could be beneficial for kick-starting New Zealand's hydrogen economy. We estimate possible export of New Zealand hydrogen to be over 117,000 tonnes in 2050.[208]

However, New Zealand will have to act quickly to capitalise on the potential to be a low cost, early supplier of hydrogen, but could miss out if it lags. Other countries are already ahead of New Zealand in establishing a hydrogen export industry. For example, Australia is loading up the first purpose-build hydrogen tanker and shipping the first load of liquid hydrogen to

[208] This modelling is based on the production capacity from the largest scale Tiwai Point plant.

Japan.[209] Australia is also setting up multiple hydrogen 'hubs', where hydrogen users, producers and potential exporters are co-located.[210] Memorandums of understanding (MOU) between Japan countries such as Australia, the United Arab Emirates, and Canada seek to ensure large scale hydrogen for export to Japan.[211] New Zealand is unlikely to have an opportunity if these countries build out at scale at scale before New Zealand.

209 https://www.pv-magazine.com/2022/01/21/australia-to-make-worlds-first-liquefied-hydrogen-shipment-to-japan/#:~:text=Australia%20is%20set%20to%20become,Latrobe%20Valley%20to%20Kobe%2C%20Japan.

210 https://www.industry.gov.au/policies-and-initiatives/growing-australias-hydrogen-industry

211 Australia: https://www.reuters.com/business/sustainable-business/japan-australia-firms-look-build-large-scale-green-liquefied-hydrogen-supply-2021-09-15/; UAE: https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/040821-japan-signs-first-hydrogen-cooperation-deal-with-uae-to-consider-supply-chain; Canada: https://www.reuters.com/business/energy/japans-mitsubishi-partners-with-shell-canada-clean-energy-push-2021-09-08/

5 Pathways to the hydrogen economy with interventions

The interventions examined in this section are not current government policy. They are indicative policies that Castalia has identified that the government may or may not choose to investigate further at a later date.

The government could use several interventions to change the pace of hydrogen technology or fuel uptake or influence infrastructure options in the hydrogen supply chain. Interventions may also reduce the likelihood of path dependencies.

We note that New Zealand's legislative and regulatory system is not yet up to date to accommodate and safely regulate hydrogen production and use. Additional policy support is required to achieve this; however, this is beyond the scope of this report.

5.1 Interventions that change the pace of hydrogen uptake

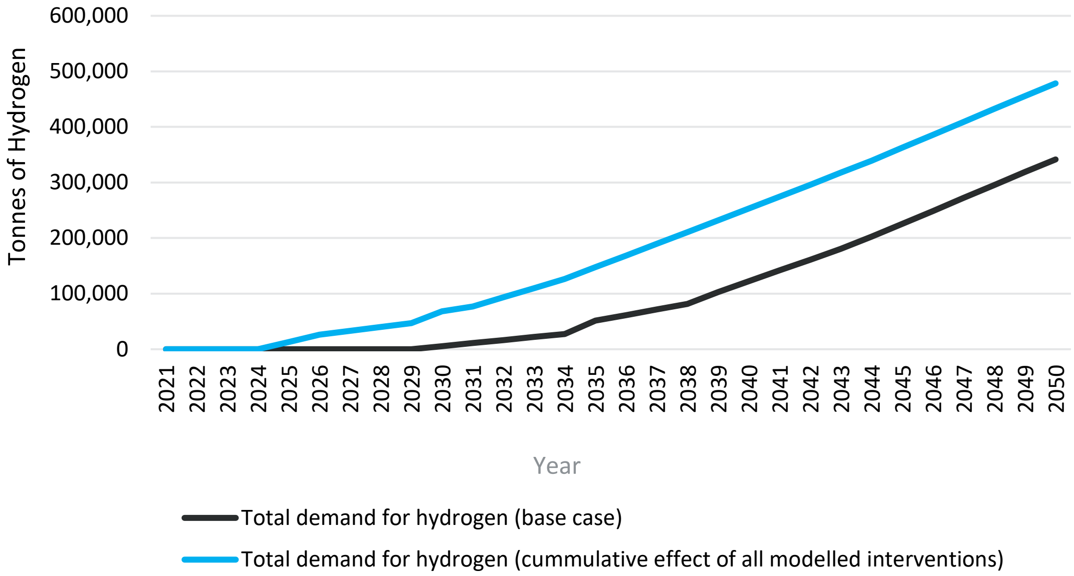
Interventions that could change the pace of uptake fall into two categories:

- Interventions that reduce the cost of hydrogen technologies relative to other technologies—demand side
- Interventions that reduce the cost of hydrogen fuel relative to other energy sources or carriers—supply side.

Interventions that increase supply can be combined with interventions that increase demand. In addition, both demand and supply side interventions would lower the cost of the hydrogen use case. For transport, interventions can reduce the price of hydrogen-powered vehicles or increase the price of competing technologies. For industrial uses, interventions can also reduce the cost of hydrogen relative to other options.

If we add all the interventions discussed in this section 5.1 together the effect is illustrated in Figure 5.1 below. This is for illustrative purposes only, and does not include the potential costs of policy interventions nor other policies aimed at emissions reductions.

Figure 5.1: Demand for hydrogen with cumulative effect of all modelled interventions



5.1.1 Reducing capital cost of hydrogen technologies relative to other technologies—demand side

A range of interventions could be pursued to change the cost of hydrogen technologies relative to others. These include subsidies and taxes on technologies, mandates and bans on technologies, fuel subsidies and taxes, and changing emissions taxes or the ETS. All of these interventions affect the relative cost of the technology. The amount of subsidy or tax will impact uptake. Below we outline the possible impact of these interventions.

Subsidies on technologies

A subsidy on hydrogen-powered vehicles or tariff on alternatives ultimately impacts the relative cost of hydrogen-powered vehicles. Both can be modelled and considered in scenarios in the same way.

Subsidies for HFC-EVs would accelerate the uptake of the technology relative to diesel or other alternatives. There are various ways to structure the subsidy (feebate or direct subsidy). The subsidy would have economic costs, that would need to be assessed against any benefits. In addition, full consideration of complementary interventions would be required. For example, the ETS.

Subsidies for industrial users, such as fertiliser and steel production facilities, utilising hydrogen feedstock or technologies could also support demand.

Mandates or bans of particular technologies

Bans and vehicle mandates, such as a zero-emissions vehicle (ZEV) mandates, largely impact vehicle manufacturers, who are required to comply with regulations requiring particular technologies. ZEVs have been effective in the United States and Canada. The impact on changing the supply of hydrogen vehicles depends on the responsiveness to changes in demand for various types of technology.

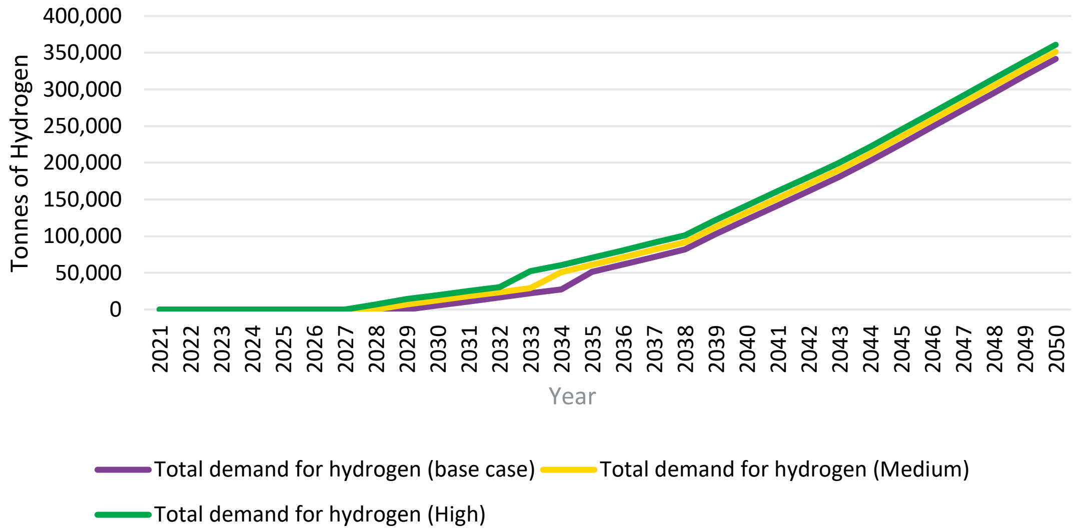
Low carbon fuel standards (LCFS) impact fuel suppliers, who are required to sell fuel with an average carbon intensity value at or below the required level. LCFS can also impact the types of vehicles manufactured as supply of low-carbon fuel options, such as hydrogen, becomes available.

Taxes on particularly technologies

The capex cost of diesel or other high emitting vehicles relative to low emissions vehicles could be increased through tax.

Our modelling suggests only a slight increase in demand for hydrogen, even with a 20 percent increase in tariffs on diesel vehicles. This is because the additional cost of the tariff increase is spread over the vehicle's useful life. A 10 percent increase in tariffs has no impact on overall demand for hydrogen in the transport sector. Figure 5.2 details the demand for hydrogen after a capex tax on diesel vehicles.

Figure 5.2: Demand for hydrogen after capex tax on diesel vehicles



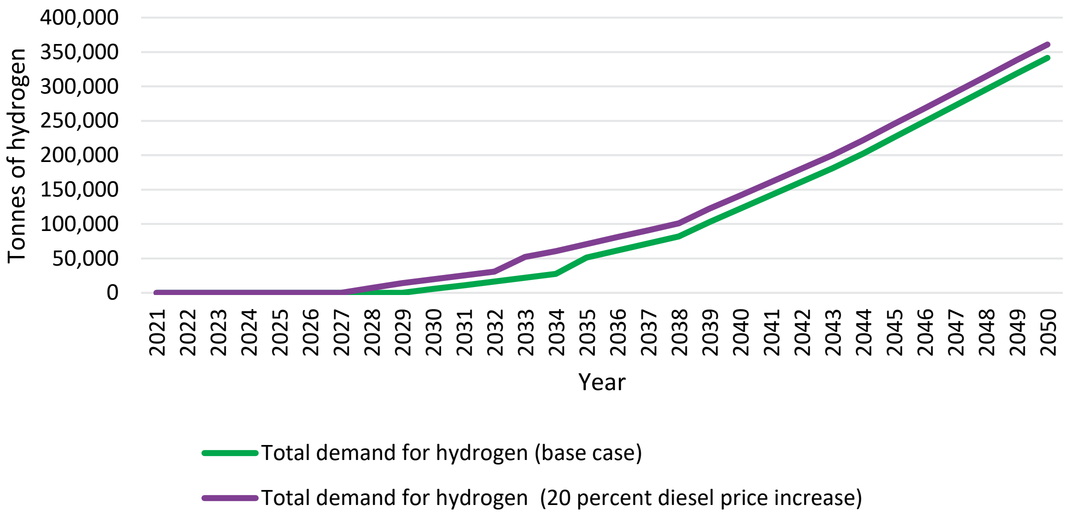
Fuel subsidy or tax

Taxes on petrol and diesel and other high-emitting fuels, or subsidies on low-carbon fuel options could theoretically make hydrogen competitive with other energy sources.

However, our modelling suggests that changing the price of diesel fuel would also have little impact on the timing of uptake of hydrogen vehicles. Figure 5.3 details demand for hydrogen after a 20 percent increase in the price of diesel. The model assumes that vehicles are replaced at the end of their useful life and the tipping point occurs at the point when total cost of ownership for a particular vehicle type is lower compared to other technologies. The diesel price would need to increase by approximately 76 percent from 2021 to 2025 to bring the tipping point of demand forward by 5 years.

We took a 10-year average of NZ MBIE diesel price assuming 3 percent annual in the base case scenario. There has been a recent surge in diesel prices due to the Ukraine invasion and geopolitical tensions. If this causes a permanent change in the oil price, then we would expect the uptake of hydrogen trucks to begin from 2025. Our modelling suggests that this would cause an 18 percent increase in total demand for hydrogen (for transport applications) in 2050 compared to hydrogen demand in our base case scenario.

Figure 5.3: Demand for hydrogen after 20 percent increase in diesel price



Emissions taxes or ETS pricing

Changes to the Emissions Trading Scheme (ETS), such as increasing the price of NZUs or introducing another emission tax, could make hydrogen production more cost competitive with other energy sources. An ETS sets a regulatory limit and puts a price on emissions. Participants of high-emitting sectors are then required to acquire, surrender, and/or trade New Zealand Units (NZUs).[212] These schemes are market-based approaches for reducing emissions as they send price signals to producers, consumers and investors that encourage lower emission behaviour.[213]

5.1.2 Reduce the cost of hydrogen fuel relative to other energy—supply side

Interventions could change the cost of hydrogen production relative to other energy sources. Support could make scale production viable, or support distribution. Interventions could impose penalties on emissions, thus making hydrogen production more viable. Supply side interventions that lower the cost of hydrogen relative to other fuels would increase demand for hydrogen. Local large-scale research and development support is unlikely to affect hydrogen production in New Zealand.

Supporting scale supply

The government could guarantee offtake of hydrogen from scale plants. This would underpin demand and enable a production facility to be built at a larger scale that would otherwise be economic. This option could be paired with options to increase demand, so that extra offtake

[212] New Zealand Units (NZUs) are the primary domestic unit of trade in New Zealand's ETS. An NZU represents one metric tonne of carbon dioxide equivalent and can cover both emissions and removals.

[213] A guide to the New Zealand ETS can be found here: https://www.motu.nz/assets/Documents/our-work/environment-and-agriculture/climate-change-mitigation/emissions-trading/ETS-Explanation-August-2018.pdf

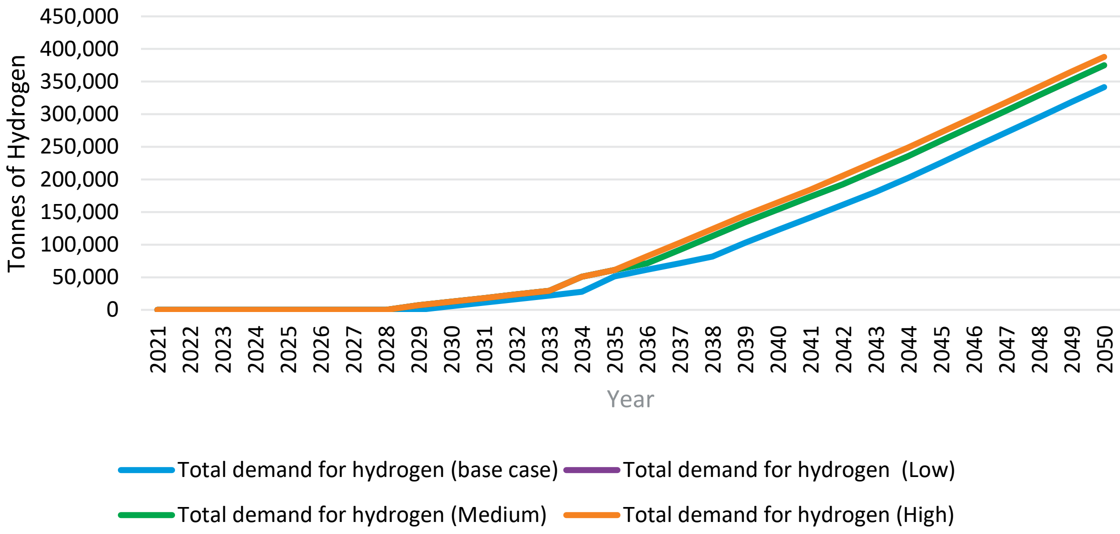
was utilised. The government could also guarantee preferential electricity rates for hydrogen production. This is being increasingly recognised globally, for example, in Canada, where a hydrogen-specific electricity tariff is currently under consideration.[214]

Production or distribution subsidies

Production subsidies could make production lower cost compared to other energy sources. Distribution cost subsidies could be used to lower the cost of getting hydrogen to end-users. This could be support for road or rail transport or support for pipeline distribution.

Our modelling suggests that large subsidies for the capex cost of building a plant (25-45 percent subsidy) would have only a modest impact on timing of hydrogen demand. Subsidies on plant capex have a larger impact after 2038 compared to the base case. This is because hydrogen trucks below 12,000 kgs become viable earlier due to the cheaper cost of producing hydrogen. This conclusion assumes only supply-side subsidies. These modelling results are displayed in Figure 5.4.

Figure 5.4: Demand for hydrogen with production plant capex subsidies



Note: The 'Medium' scenario overlaps the 'Low' scenario in this graph

Large-scale research and development support is unlikely to impact global industry

There are major investments and research and development programs underway with private sector businesses and government support. These will improve the cost-competitiveness of hydrogen technologies relative to alternatives. This research and development will also lower hydrogen production costs and reduce the energy cost relative to other energy sources. However, the impact of research and development is likely to occur over a longer timeframe, at least 10-15 years.

New Zealand is a relatively minor participant in the global hydrogen economy. Government agencies already support research and development, and pure science research that is

[214] https://www.bennettjones.com/Blogs-Section/British-Columbia-Introduces-CleanBC-Industrial-Electrification-Rates-Facilities-Electrification-Fund

supporting the hydrogen sector. While these initiatives are valuable, given the differences in scale and research budgets, the major advances in hydrogen technology and production techniques are likely to occur overseas. Domestic government interventions focussed only on research and development of hydrogen technologies or hydrogen production costs are unlikely to materially change the pace of hydrogen uptake. Niche work, such as by GNS on hydrogen catalysts, could have a significant multiplier effect.

5.2 Interventions that preserve infrastructure options

New Zealand has infrastructure that may be decommissioned due to decarbonisation interventions. This infrastructure includes:

- North Island gas transmission and distribution network
- South Island local gas distribution network
- Petroleum import and storage terminals, and
- Petroleum pipelines.

This infrastructure will lose value when it is phased out, and can be considered a sunk cost. Sunk costs have lasting presence in the market. Infrastructure sunk costs are generally specific to a particular technology or usage—if demand for infrastructure services were to cease, then the asset would be worth a fraction of its construction cost and the service provider loses value.

There may be future uses for existing infrastructure to provide services in the hydrogen economy. Preserving this infrastructure may provide options that avoid additional sunk costs or enable wider range of decarbonisation technologies. A range of interventions could be used to preserve the infrastructure.

5.2.1 Enabling future use of gas pipeline infrastructure

New Zealand could retain its existing natural gas pipeline infrastructure for hydrogen. Depending on throughput, piped distribution costs can be lower than alternative distribution means. According to European gas network analysis, the costs of building a new hydrogen transmission and distribution pipeline are around five to six times higher than repurposing an existing natural gas pipeline.[215] Piped hydrogen costs are lower than trucking or rail transport. Therefore, there may be a case for considering repurposing the pipelines even before demand exists to avoid the future cost of building a new pipeline, or costlier trucked or railed hydrogen. The existing gas infrastructure covers much of the North Island's major urban centres. It also extends to industrial facilities. The natural gas network is shown in Figure 5.5. On the South Island, local gas distribution networks exist in some towns.

However, it is possible that natural gas demand or supply could reduce to a level where maintaining the pipeline is uneconomic for the owner. For example:

[215] Hydrogen Europe (2021), How to Transport and Store Hydrogen: Fact and Figures, available at: https://www.hydrogeneurope.eu/wp-content/uploads/2021/05/ENTSOG_GIE_HydrogenEurope_QandA_hydrogen_transport_and_storage_FINAL.pdf

- Government policy may lead to major users of natural gas shutting down:
  - Renewable electricity generation targets may force gas-fired power plants to shut down. In 2020, gas demand for electricity generation accounted for 29 percent of total gas demand[216]
  - Emissions related interventions may force the Motonui methanol and Kapuni ammonia-urea production plants to shut. In 2020, energy transformation accounted for 48 percent of total gas demand, whereas gas demand for industrial use (chemicals) accounted for 17 percent of total gas demand[216]
- The cost of carbon could increase so that direct electrification or other energy sources such as biomass is cheaper than natural gas
- Stable natural gas supply may cease due to decisions by producers to reduce investment or shut down extraction plants due to government interventions or other factors.

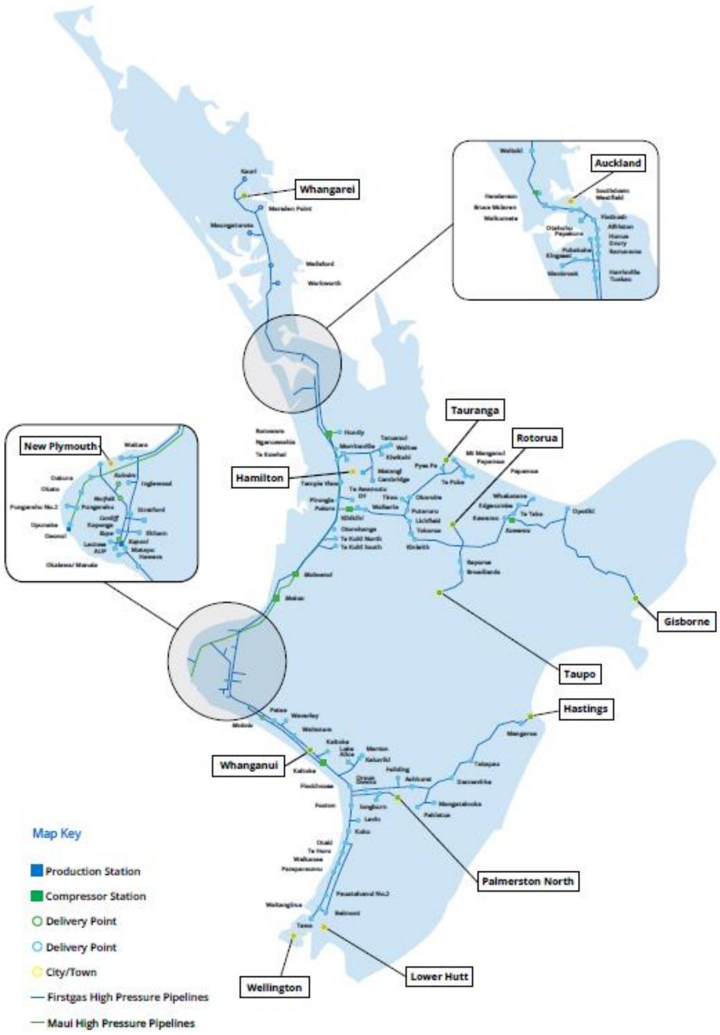
It is, therefore, possible that gas pipeline infrastructure may be decommissioned by its owners before a hydrogen production and supply chain develops. The infrastructure would not be available to be adapted for hydrogen if such an option were economic. This might hinder the development of the hydrogen economy.

There are ways in which the natural gas network could be preserved until hydrogen demand and supply are sufficient, and infrastructure has been upgraded. Viable options are:

- Blended hydrogen could be used to decarbonise existing uses of natural gas, such as for industry and domestic and commercial heating and cooking applications
- Blended hydrogen could be distributed through the natural gas network and combusted by CCGT for electricity generation
  - In future, higher concentrations of hydrogen could also be used for combustion and existing uses. However, changes to infrastructure and appliances would likely be required
- In the future, pipeline infrastructure could distribute higher purifications of hydrogen, such as for transport uses
  - The existing natural gas pipeline can be used to distribute hydrogen for transport uses, once higher purifications of hydrogen (i.e., 100 percent hydrogen) can be distributed through the network
  - The pipeline could also be extended to existing refuelling stations, ports, airports, or other transport hubs, and used by a range of HFC vehicles.

[216] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/

Figure 5.5: First Gas natural gas transmission and distribution network



Source: First Gas Hydrogen Feasibility Study 2020, page 17

5.2.2 Enabling future use of storage and distribution facilities

Hydrogen's low volumetric energy density makes storing hydrogen as a bulk commodity at point of production a challenge. There is a range of existing storage and distribution infrastructure that could be utilised. Preserving these options for hydrogen could significantly change the potential role hydrogen could play in New Zealand's economy.

Existing storage and distribution facilities could be used for hydrogen. As discussed above, hydrogen can be stored in some of New Zealand's oil and gas wells. Hydrogen can be stored underground as dried or compressed gas in depleted gas wells indefinitely until the hydrogen is required[217] Geological studies would need to verify if the formations available in New Zealand could support hydrogen storage. This is a fruitful line of inquiry.

Existing petroleum storage and distribution facilities could also be used. Hydrogen can be stored like petroleum when it is a liquid, which requires cooling below –253°C. Cooling currently requires significant energy, but there are efficiencies with storing and moving hydrogen as a liquid as higher quantities are needed. There is petroleum storage at most ports, which could store imported hydrogen or domestically produced hydrogen for export. For example, the Marsden Point terminal, which will become an import-only terminal from April 2022,[218] could also store domestically produced or imported hydrogen. The existing Marsden Point to Auckland pipeline could be adapted to distribute hydrogen.

The scale of adapted petroleum storage infrastructure would not be sufficient for inter-seasonal energy storage, but could be a complement energy source for peak generation, particularly if users of hydrogen share storage costs in transportation. New technologies could support use of existing petroleum storage and distribution facilities. For instance, Chiyoda's SPERA Hydrogen is liquid at ambient pressure and temperature, stable, and a conventional petrochemical. This enables the hydrogen to be stored and distributed via existing petroleum infrastructure such as pipelines, storage tanks, and chemical tankers without energy and infrastructure required to cool the hydrogen.[219]

5.2.3 Enabling future use of electricity generation infrastructure

It may be optimal to adapt existing electricity generation infrastructure to enable hydrogen combustion as an option, provided that sufficient hydrogen supply exists for other economic uses, such as heavy vehicle fuel.

New Zealand's existing gas storage, gas pipeline, and CCGT infrastructure could be adapted to combust hydrogen. This could provide a valuable option to complement other security of supply initiatives such as overbuilding of renewables or pumped hydro. The hydrogen could be domestically produced or imported. The economic viability of combusting green hydrogen for electricity will depend on the magnitude of the difference between electricity input costs for hydrogen production and the market electricity price at peak times.

Existing CCGT plants like the Huntly Unit 5 plant (Energy Efficiency Enhancement Project (E3P)) could be used. It burns natural gas with a heat recovery boiler and steam turbine to generate 385MW. The plant can rapidly ramp up and down to meet electricity demand.[220] Unit 5 could operate with a blended hydrogen and natural gas fuel supply of 30 percent hydrogen by volume in the medium-term. In the longer-term, modifications to or replacement of

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[217] https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

[218] https://www.rnz.co.nz/news/business/456277/refining-nz-confirms-marsden-point-switch-to-import-only-terminal-from-april-2022

[219] Chiyoda and Mitsubishi Corporation, Techno-economic analysis for green hydrogen and energy hub in New Zealand, September 2020.

[220] https://www.mbie.govt.nz/dmsdocument/12554-2020-thermal-generation-stack-update-report-pdf

infrastructure and equipment would be required to combust larger proportions of hydrogen in existing power plants.[221]

5.3 Interventions that reduce likelihood of import path dependency

Imported hydrogen may be lower cost than domestically produced hydrogen before scale production and a domestic supply chain is built. This could lead to a path dependency where it is not economic to build a competing domestic supply chain.

Countries that can produce hydrogen at lower cost may seek to export hydrogen to New Zealand sooner than New Zealand hydrogen producers can achieve equivalent production costs. While demand is likely to be higher in Asia, New Zealand may still be an attractive export option if domestic use cases emerge (for example, if government supports these).

Brown and blue hydrogen are currently significantly lower cost than green hydrogen. The production and shipping costs to New Zealand would be much lower than the cost at which hydrogen can be produced here. Our modelling suggests that a number of countries have excellent plentiful RE resources and well-developed port infrastructure facilities enabling low-cost green hydrogen production.

Furthermore, New Zealand's ports are close to the major demand centres for hydrogen transport. This means that imported hydrogen may be attractive to consumers if landed costs of imports are lower than the domestic cost of producing and distributing hydrogen. Interventions may be required to ensure such a path dependency does not occur.

Modelling shows that such a path dependency is possible. Imports could be cheaper during the period before New Zealand's hydrogen production and supply chain develops. Figure 5.6 shows the outputs of the Castalia-MBIE model (updated with 2021 data), of landed costs of hydrogen at Auckland or Lyttleton in 2035, compared to least-cost domestic production and transport to the same cities. It is also possible that imported hydrogen has a price premium due to high global demand. New Zealand may be outbid by other countries that lack alternatives, which would reduce the likelihood of this path dependency occurring.

[221] Chiyoda and Mitsubishi Corporation, Techno-economic analysis for green hydrogen and energy hub in New Zealand, September 2020.

Figure 5.6: Landed costs of hydrogen to Auckland or Lyttleton compared to local production (2035)

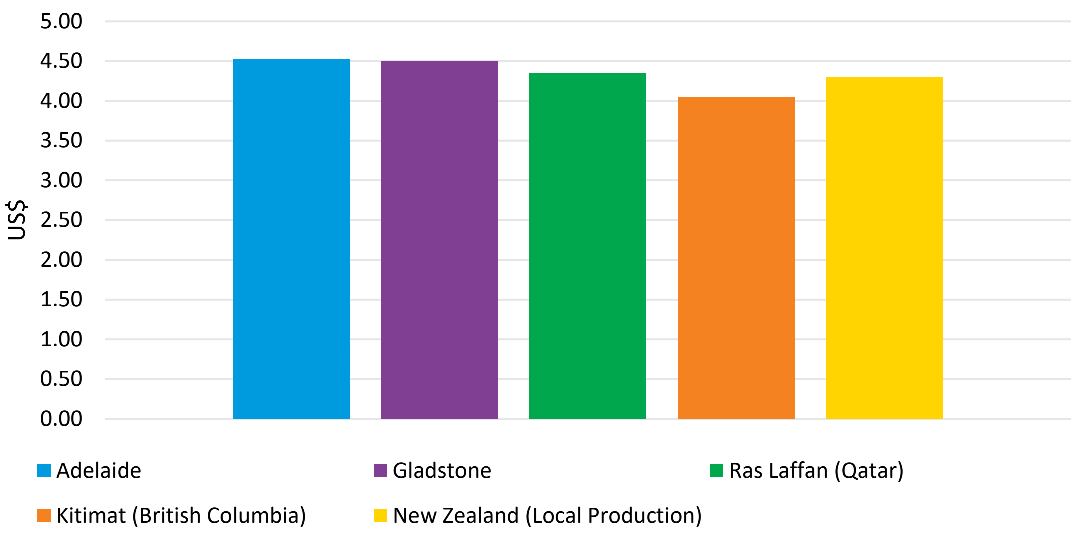
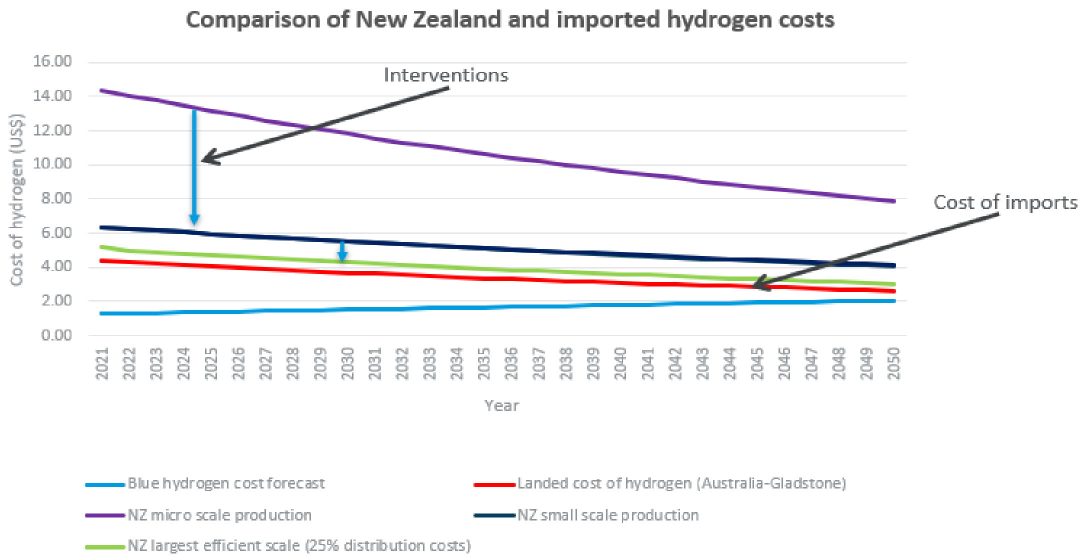


Figure 5.7 highlights domestic production costs compared with imported hydrogen costs. It shows that other countries are likely to be larger export markets than New Zealand, and New Zealand could have higher domestic production costs.[222]

Figure 5.7 also highlights that imports might be cheaper, leading to an import path dependency. However, interventions could lower domestic production cost, reducing the risk of this dependency.

Figure 5.7: Comparison of New Zealand and imported green hydrogen costs



[222] The figure does not take into account location specific advantages, such as in Southland.

Appendix A: Breakdown of total hydrogen demand in New Zealand

Table A.1 breaks down the total demand for hydrogen in New Zealand across sectors and use cases across high, base, and low cases.

Table A.1: Breakdown of total demand for hydrogen in New Zealand across sectors and use cases (in tonnes)

Sector	Use Case	High case			Base case			Low case		
		2030	2040	2050	2030	2040	2050	2030	2040	2050
Transport	Heavy duty vehicle	19,595	174,006	347,539	5,505	91,187	264,721	5,505	70,375	193,398
	Coach buses	0	1,933	22,228	0	0	14,325	0	0	8,084
	Speciality vehicle	0	36,397	67,780	0	31,099	62,482	0	31,099	62,482
	Light-duty vehicle	0	1,361	1,449	0	1,361	1,449	0	1,361	1,449
	Aviation	0	0	1,424,361	0	0	1,424,361	0	0	1,424,361
Industry	Fertiliser production	73,387	81,065	89,546	73,387	81,065	89,546	73,387	81,065	89,546
	Feedstock for steel	35,000	35,000	35,000	32,500	32,500	32,500	30,000	30,000	30,000
Total		127,982	329,762	1,987,903	111,392	237,212	1,889,384	108,892	213,900	1,809,320

Appendix B: Stakeholder engagement

Below we detail the stakeholders that have been engaged to date for this project.

Mini-Hydrogen Workshop—21 September 2021

- Andrew Clennett (Hiringa)
- Dion Cowley (Hiringa)
- Matt Carnachan (Hiringa)
- Jacob Snelgrove (Air New Zealand)
- Rori Moore (Toyota)
- Grant Doull (Hyundai)
- Gavin Young (Hyundai)
- Steve Canny (Great South)
- Linda Wright (NZ Hydrogen Association)
- Tony Vranjes (First Gas)

Meeting with Southern Green Hydrogen—28 September 2021

- James Flannery (Contact)
- Murray Hill (Meridian)

Meeting with GNS Science—5 October 2021

- Nick Kirkman (GNS)
- Mark Pickup (MBIE)
- Jerome Leveneur (GNS)
- Christina Houlihan (GNS)
- Mike Hensen (NZIER)
- Basil Sharp (Auckland University)
- Selena Sheng (Auckland University)
- Geordie Reid (Auckland University)
- Hugh Campbell (Otago University)
- Mereana Wilson-Rooy (GNS)

Other meetings

- Chris Bumby (VUW/Robinson Institute)—10 September 2021
- Mark Booth (Chiyoda/Mitsubishi Corp)—18 November 2021
- Ewan Delany and Richard Cross (MoT)—29 November 2021
- GNS Science—2 December 2021
- Jacob Snelgrove and Jenny Sullivan (Air New Zealand)—16 December 2021
- Tony Vranjes (First Gas)—13 December 2021

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