Hydrogen Economic Modelling Results

Final Report

08 December 2023

Release Notice

Ernst & Young was engaged on the instructions of the Ministry of Business, Innovation and Employment ("Client") to deliver a report describing the modelling and outcomes completed to understand various hydrogen scenarios in New Zealand, to inform the development of the government's Hydrogen Roadmap, in accordance with the engagement letter dated 26 January 2023.

The results of Ernst & Young's work, including the assumptions and qualifications made in preparing the report, are set out in Ernst & Young's report dated 03 August 2023 ("Report"). The Report should be read in its entirety including the transmittal letter, this notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

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Re-issue Notice

This report (Updated Report) replaces and supersedes the version of the report issued on 3 August 2023 (Superseded Report).

During review of the emissions calculations in the Superseded Report, we identified that estimated emissions reductions from transport use cases were understated in the model. This was due to:

- incorrectly interpreting a tonne km emissions factor as per emissions km factor
- treating some fuel cell vehicles as hybrid vehicles in the estimates for hydrogen demand and diesel displaced; and
- linking some calculations to new hydrogen vehicles entering the fleet rather than the total hydrogen fleet.

These errors have been fixed in the Updated Report.

The Updated Report shows a significantly increased contribution from road transport to the emissions reduction estimates and brings the emissions reduction potential in line with other modelling undertaken for MBIE on this topic.

While making this change, we also identified and implemented methodological improvements to how emissions are calculated in our estimates. Emissions calculations for heavy road transport in the Superseded Report were based on previous modelling on hydrogen supply and demand commissioned by MBIE and published in 2022.[1] The estimates in the updated report:

- change the emissions calculation for fuel cell heavy vehicle road transport to be based on the amount of diesel displaced by switching to a fuel cell heavy vehicle compared to an equivalent internal combustion heavy vehicle, rather than avoided emissions per kilometre travelled. This harmonises the road transport emission estimates with those used in the model for hybrid road transport, rail, aviation, and maritime transport. This change is in line with the New Zealand National Greenhouse Gas reporting methodology.
- delineate fuel efficiency by truck weight class rather than using an average fuel efficiency for trucks across weight classes. This better reflects the range of fuel efficiency across the fleet.

These improvements harmonise the emissions/fuel calculations across transport sectors and align with New Zealand government research and emissions reporting guidance.

As a result, there have been changes across all of the scenarios to the following sections of the report:

- Increases to the transport emission calculations. For the Base case this increased emissions reductions from 2.01 Mt CO2e to 4.08 Mt CO2e in 2050. This improved ranking of scenarios where transport is the focus relative to industrial uses of hydrogen. (section 7.1)
- Changes to the liquid fuel displacement calculations. For the Base case this increase liquid fuel displacement from 870.7 Million L to 1,559.6 Million L in 2050. However, this had no impact on the overall ranking of scenarios in relation to energy security (section 7.3.3)
- Contribution to final energy consumption (due to changes in liquid fuel displacement) but no change in ranking of scenarios in relation to decarbonisation. (section 7.1)

Finally, the review identified that there was an error in transposing the total hydrogen demand for each scenario in Table 1 and Table 5 and in as these totals excluded demand from synthetic fuel production in the industrial feedstock demand category. The total demand was correctly stated for the base case in Table 4 and charts relating to industrial feedstock in section 5.2 are correct.

[1] Hydrogen modelling tool | Ministry of Business, Innovation & Employment (mbie.govt.nz)

While there have been changes to the above, we note that the following core findings in the underlying model were not affected:

- Estimates of hydrogen supply and demand across all supply and demand sources
- The required electrolyser capacity and additional renewable electricity generation that would be required to produce the quantities of hydrogen in the supply and demand estimates
- Water input calculations
- Economic benefit calculations

1. Executive summary

In May 2022, the government set the first three Emissions Budgets and released its Emissions Reductions Plan (ERP) which outlines a comprehensive plan for reducing emissions across various sectors. One of the key actions set out in the Energy and Industry chapter of the ERP is for the government to develop a Hydrogen Roadmap which is intended to provide a pathway for the development of a hydrogen economy in New Zealand, outlining the steps required to support the growth of this emerging sector.

The Ministry of Business, Innovation and Employment (MBIE) has been charged with developing this Roadmap, which is planned to occur in two phases:

- Develop an Interim Hydrogen Roadmap to support policy discussions and consultations

- Develop a Final Hydrogen Roadmap

MBIE has commissioned EY to develop this report and associated modelling to support the development of the interim Hydrogen Roadmap. This report does not seek to recommend a particular pathway that the government should pursue, but rather provide an analysis of the potential outcomes associated with different green hydrogen futures in New Zealand and supports investigations by policymakers and stakeholders in the sector.

As part of this engagement, we worked with MBIE to develop five scenarios that represent a range of possible hydrogen futures for New Zealand's green hydrogen sector out to 2050. The first scenario is a base case that represents a future where hydrogen is pursued in hard-to-abate sectors where hydrogen is expected to be commercially viable. The other four scenarios represent alternative futures where green hydrogen is built out with different objectives as the key driver:

1. **Base case:** Hydrogen uptake is focused in hard-to-abate sectors where hydrogen is currently expected to be commercially viable.

2. **Accelerated uptake:** Hydrogen uptake and supply are accelerated and driven by the need to decarbonise and meet New Zealand's emissions reductions target.

3. **Energy security and resilience:** Hydrogen uptake and supply are driven by the need to improve New Zealand's energy resilience against global energy shocks.

4. **Export market:** Hydrogen supply is driven by both domestic demand and export demand.

5. **Value-add export:** Hydrogen supply is driven by domestic demand, export demand and as an input for value-add commodities such as methanol, steel, and fertiliser.

In each scenario, we sought to understand the potential implications that focusing on a lever has on hydrogen demand and supply. Table 1 below summarises the key demand and supply outputs for each scenario. The 'Value-add export' scenario represents a future with the highest demand and production of hydrogen, while the base case represents a future with the lowest hydrogen demand and production.

Table 1: Modelled scenarios and key differences relative to base case

	Base case	Accelerated uptake	Energy security and resilience	Export market	Value-add export
Hydrogen demand					
	► Driven mostly by industrial feedstock and heavy transport	► Uptake across domestic demand sectors higher and faster	► Uptake across domestic demand sectors higher	► Increased demand from export	► Increased demand from export and industrial feedstock (value-add commodities)
Total hydrogen demand					
2035	0.21 Mt H_2	0.81 Mt H_2	0.41 Mt H_2	0.53 Mt H_2	0.71 Mt H_2
2050	0.64 Mt H_2	1.08 Mt H_2	0.79 Mt H_2	1.22 Mt H_2	1.38 Mt H_2
Hydrogen supply					
	► Production focused in decentralised plants ► Some centralised production	► Production focused in decentralised plants ► Some centralised production	► Production focused in decentralised plants ► Some centralised production	► Production focused in centralised plants ► Some decentralised production	► Production focused in centralised plants ► Some decentralised production
Total installed electrolyser capacity					
2035	1.5 GW	6.0 GW	3.6 GW	3.8 GW	5.4 GW
2050	4.5 GW	8.0 GW	6.4 GW	8.5 GW	9.8 GW
Total electricity demand for hydrogen production					
2035	11.5 TWh	44.9 TWh	25.8 TWh	28.4 TWh	40.7 TWh
2050	33.9 TWh	60.1 TWh	45.1 TWh	63.6 TWh	73.4 TWh

Across the scenarios, the levelized cost of green hydrogen (LCOGH) is modelled to reach US$3.06-4.76/kg of hydrogen in 2035 and US$2.78-4.28/kg in 2050. Lower hydrogen costs are driven by production plants having a high utilisation and access to both the wholesale electricity market and long-term electricity contracts and/or direct investment in electricity generation. The lower bound refers to the LCOGH relating to hydrogen produced in large, centralised plants, while the upper bound relates to hydrogen produced in smaller, decentralised plants. These costs exclude transformation and distribution, which can add up to 100% to the LCOGH depending on the distribution channel (e.g., compressed trucking, liquefied shipping).

Modelling suggests that for New Zealand's hydrogen to be cost competitive and reach below US$2/kg by 2050, input electricity prices would need to reach NZ$55/MWh at a high utilisation rate. While this reduction could be possible in the long-term given the current trajectory of the levelized cost of electricity of technologies such as wind and solar, in the more immediate future, the New Zealand's hydrogen sector would be competing with the likes of the U.S. Inflation

Reduction Act, which has the potential to reduce U.S. LCOGH to ~US$3.00/kg through tax credits in the 2020s[2].

To understand the impacts that varying levels of hydrogen uptake and supply chain development will have on New Zealand, we have assessed how each scenario performs against three levers and several quantitative indicators:

- **Decarbonisation:** the volume of emissions reduction enabled by hydrogen through fossil fuel displacement and associated contribution towards emissions reductions and renewability targets.

- **Economic development**: The impact of the hydrogen economy on the wider economy in terms of Gross Value Add and employment opportunities. Gross Value Add is used as an indicator of Gross Domestic Product.

- **Energy security and resilience:** The ability of hydrogen to support the reliability of New Zealand's renewable energy supply and reduce reliance on fossil fuel imports. This outcome is measured by the volume of new electricity generation incentivised (assuming most electricity is procured from new generation plants), demand response capacity (assuming most hydrogen plants have flexibility capabilities and commercial arrangements) and liquid fossil fuel displaced by hydrogen use.

The three levers considered here are broad and reach beyond the scope of the hydrogen supply chain. As such, we have also included qualitative discussion on additional considerations that have not been explicitly modelled.

The modelled outcomes are summarised in Table 2 below. On balance, the base case has the lowest performance across the three outcome areas, primarily due to its lower hydrogen demand and consequently lower ability to contribute to decarbonisation, economic development, and energy security and resilience.

The 'Accelerated uptake' scenario has the highest performance against decarbonisation measures and liquid fossil fuel displacement. As expected, the 'Export market' and 'Value-add export' scenarios perform highly against the economic development scenarios. 'Accelerated uptake' also performs well against this outcome due to the high level of build out required. Because the 'Value-add export' scenario requires a larger build out of the hydrogen and electricity systems, this scenario performs better against the energy security and resilience outcomes, on the basis that electricity is linked to new generation plants and that flexibility is built into the hydrogen plants and is enabled by the electricity market. The 'Energy security and resilience' scenario performs in the middle range across most outcomes but performs the highly against the potential demand response capacity measure.

A challenge that may exist across all scenarios is the impact hydrogen production could have on the electricity system. In the base case, which has the lowest hydrogen production, electricity demand is modelled to reach 11.5 TWh by 2035 and 33.9 TWh by 2050, increases of 27% and 80% on New Zealand's current annual electricity demand. Based on solar and wind capacity factors, this could require 12.5 GW of new electricity generation built by 2050, more than doubling New Zealand's current generation stack. This new generation is in addition to the 10 GW+ required to support New Zealand's electrification efforts by 2050[3,4].

[2] Can the Inflation Reduction Act unlock a green hydrogen economy? - International Council on Clean Transportation (theicct.org)
[3] Whakamana i Te Mauri Hiko, Transpower.
[4] The Future is Electric, BCG.

Table 2: Summary of scenario performance against outcomes

	Base case	Accelerated uptake	Energy security and resilience	Export market	Value-add export
Decarbonisation					
Energy sector emissions reductions enabled by 2050[5]					
	4.66 Mt CO_2	7.45 Mt CO_2	7.00 Mt CO_2	4.65 Mt CO_2	4.65 Mt CO_2
Contribution to total final energy consumption by 2050 (energy supplied by hydrogen and additional electricity required for hydrogen production for industrial feedstock)					
	9.5 GWh H_2 +23.6 GWh electricity	13.4 GWh H_2 +46.7 GWh elec.	11.2 GWh H_2 + 33.9 GWh elec.	9.5 GWh H_2 + 54.1 GWh elec.	9.5 GWh H_2 + 64.0 GWh elec.
Economic development					
Total gross value add by 2050 (as an indicator for GDP)					
	$2.3 b	$4.1 b	$3.2 b	$4.4 b	$5.1 b
Total supported employment by 2050 (full-time equivalent, FTE)					
	11,900 FTE	21,800 FTE	16,700 FTE	23,300 FTE	27,000 FTE
Energy security and resilience					
New electricity generation incentivised by 2050					
	12.5 GW	22.1 GW	16.6 GW	23.4 GW	27.0 GW
Potential annual demand response capacity by 2050					
	3.8 TWh	6.7 TWh	8.0 TWh	7.1 TWh	8.2 TWh
Liquid fossil fuel volume displaced annually by 2050					
	1.56 BL	2.56 BL	2.44 BL	1.55 BL	1.55 BL

It should be noted that the emissions reductions stated above exclude industrial process emissions reductions related to the use of green hydrogen – notably in the production of methanol, steel and ammonia-urea. This is due to the complexities of greenhouse gas reporting in this sector and that there may not be a direct correlation between the proportion of process conversion and emission reduction due the exact nature of the process conversion. Furthermore, as methanol is exported, reductions in combustion emissions from the use of low carbon methanol are not included within the New Zealand greenhouse gas reporting or emission budgets. Reported industrial process emissions from the Ballance Kapuni Plant, NZ Steel and the embedded emissions from methanol exported by Methanex in 2021/22 were 2.49 Mt CO_2-e[6]. While not directly correlated to emissions that could be abated by using green hydrogen in these processes, this gives an indication that the emissions abatement potential of converting these industrial feedstocks to green hydrogen could be significant.

It is important to note that there are several limitations to this modelling that need to be considered when interpreting these outcomes. The hydrogen model has been developed using Microsoft Excel and does not aim to optimize hydrogen supply and demand to identify a market equilibrium based on supply costs and willingness to pay or provide recommendations for New Zealand's future

[5] Excludes industrial process emissions reductions and methanol combustion emissions as methanol is exported.
[6] ETS Participants Emissions Report 2021 FINAL (epa.govt.nz)

pathway. Rather, it creates a range of outputs intended to aid the government in understanding how the build out of hydrogen production and demand might unfold and identify gaps that could be addressed via policy interventions.

A key limitation of this model that is discussed qualitatively in this report is the expected relationship between hydrogen production plants and the electricity system. Due to the nature of the model, the model does not include the demand profile of electrolysers for electricity at smaller timespans than a single year. Consequently, the model does not assess the hourly impacts on the grid, electricity spot prices, or the exact mix of additional renewable generation capacity required to meet the electrolyser's electricity demand. Instead, the model assumes static electricity input prices and provides an estimate of the generation required based on wind and solar capacity factors.

Other limitations of the modelling include the uncertainty of future technology uptake, limited modelling of the dynamic relationship between hydrogen and electricity markets, limited import and export considerations and the use of Input-Output tables to measure the impact of hydrogen spending on the wider economy. Furthermore, the assumptions used in this model are based on our current understanding of hydrogen, desktop research and some consultation with industry, and can be improved upon as the sector engages with the Interim Hydrogen Roadmap.

Taking these limitations into account, the model strives to cover the full scope of the economy at a macro level and establishes the foundation for more exhaustive economic and technical studies into the potential of hydrogen. To build on this work, further analysis and modelling could be completed to better understand how industries might switch based on the total cost of ownership and/or market equilibrium models, the relationship between hydrogen production and the electricity system at a more granular level (e.g., hourly), regional impacts of hydrogen production and more detailed policy impact assessments.

Contents

2. Introduction

2.1 Background

In May 2022, the government set the first three Emissions Budgets and released its Emissions Reductions Plan (ERP) which outlines a comprehensive strategy for reducing emissions across various sectors.

One of the key actions set out in the Energy and Industry chapter of the ERP is for the government to develop a Hydrogen Roadmap. This roadmap is intended to provide a pathway for the development of a hydrogen economy in New Zealand, outlining the steps required to support the growth of this emerging sector.

The Ministry of Business, Innovation and Employment (MBIE) has been charged with developing this Roadmap, which is planned to occur in two phases:

- Develop an Interim Hydrogen Roadmap to support policy discussions and consultations

- Develop a Final Hydrogen Roadmap

This report and associated modelling are supporting the development of the Interim Hydrogen Roadmap.

2.2 Purpose of this report

The potential for a green hydrogen economy in New Zealand and its associated costs and benefits remain highly uncertain. To address this uncertainty, MBIE commissioned EY to develop and model a set of scenarios that are representative of a range of possible hydrogen futures for the country.

In undertaking this work, we examined various aspects of the hydrogen supply chain, including production volumes and demand, as well as the potential impacts on the economy and wider energy system. Our goal was to provide a wide-ranging analysis of the potential outcomes associated with the scenarios and support investigations by policymakers and stakeholders in the sector.

During the scenario and model development phase of this work, we held several workshops with MBIE energy policy teams to better understand the varying expectations of the role that hydrogen could play in New Zealand's energy future. We also held a workshop and sought offline feedback from Hydrogen Council members to explore various scenarios and key assumptions in the model.

Following the initial workshops, we had limited individual conversations with key players in the hydrogen industry. These one-on-one discussions with stakeholders, experts, and industry players provided us with additional insights, perspectives, and a deeper understanding of the nuances within the hydrogen sector. These conversations enriched our knowledge with valuable information and real-world experiences that may not have been covered in the larger workshop setting.

In this report, we present the findings of the modelling exercise. Through the analysis, we aim to provide clarity on the different possible futures of the hydrogen economy in New Zealand and the potential associated costs and benefits.

3. Modelling methodology and limitations

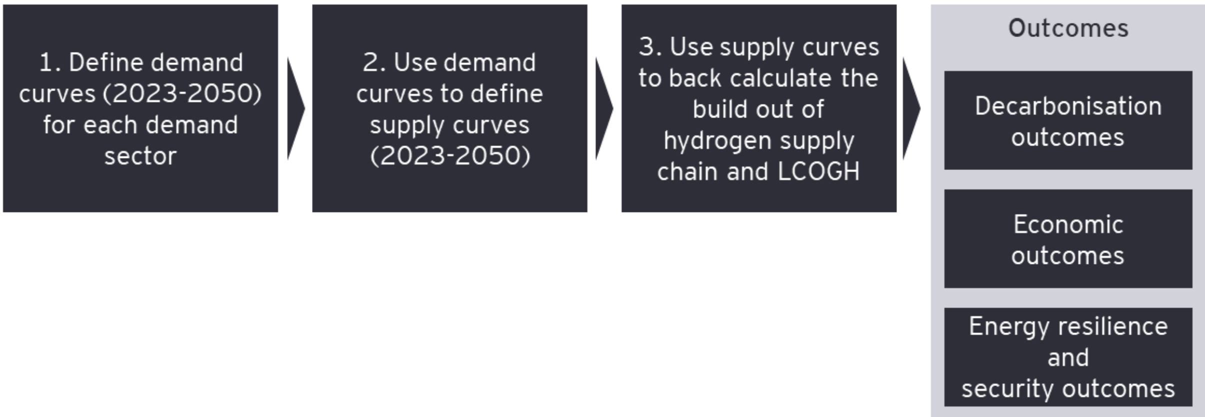
The objective of the hydrogen model is to formulate a series of outputs that provide insights for the development of the Government's Hydrogen Roadmap. The model is designed to evaluate a set of hydrogen scenarios and support the Government in understanding the prospective economic costs and benefits, along with the risks and opportunities that may ensue. The model strives to cover the full scope of the economy at a macro level and establishes the foundation for more exhaustive economic and technical studies into the potential of hydrogen. This model considers only green hydrogen.

The hydrogen model has been developed using Microsoft Excel. The hydrogen model does not aim to optimize hydrogen supply and demand to identify a market equilibrium based on supply costs and willingness to pay or provide recommendations for New Zealand's future pathway. Rather, it creates a range of outputs intended to aid the government in understanding how the build out of hydrogen production and demand might unfold and identify gaps that could be addressed via policy interventions.

For consistency with other ongoing government energy sector modelling, (as far as possible) we have aligned with and adopted modelling outputs from a variety of sources, including the Climate Change Commission, MBIE and other Government agencies as input assumptions of this model. We leveraged the Climate Change Commission's modelling outputs where applicable to ensure consistency across drivers as their modelling affords the largest coverage of the economy and energy system. We have also relied on New Zealand sector-specific analyses conducted by other entities, to serve as input assumptions for this model.

Below is an outline of the model approach. Modelling periodicity is annual and hydrogen outcomes are modelled from 2023 to 2050.

Figure 1: High-level model approach

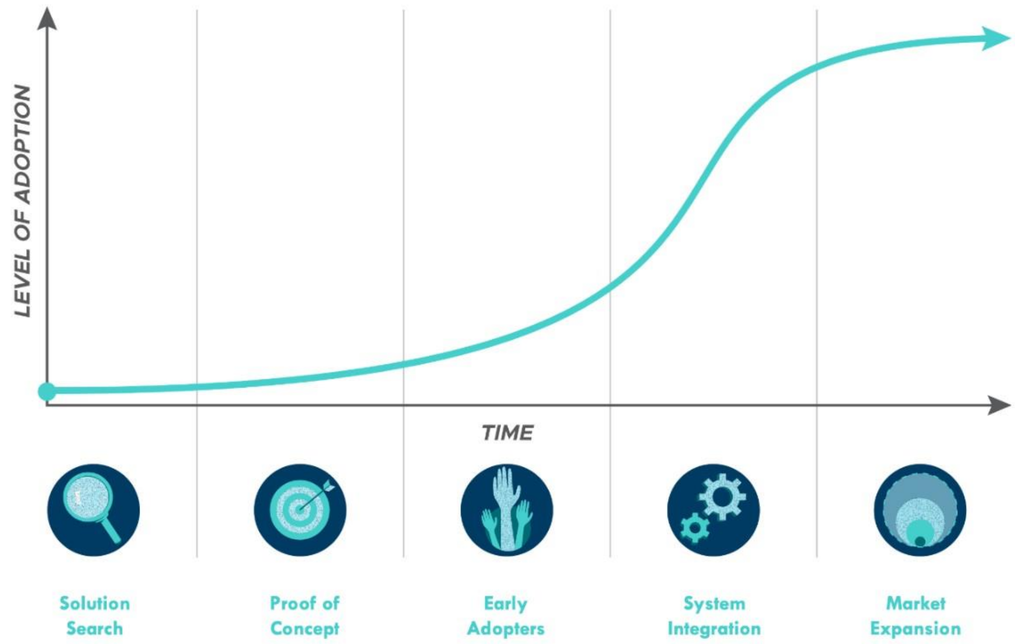


Limitations due to technology uncertainty

Building a hydrogen economic model based on technology that is still in its early stage of maturity is challenging due to the uncertain future trajectories of hydrogen technology. This uncertainty makes it difficult to accurately model the future potential uptake of hydrogen.

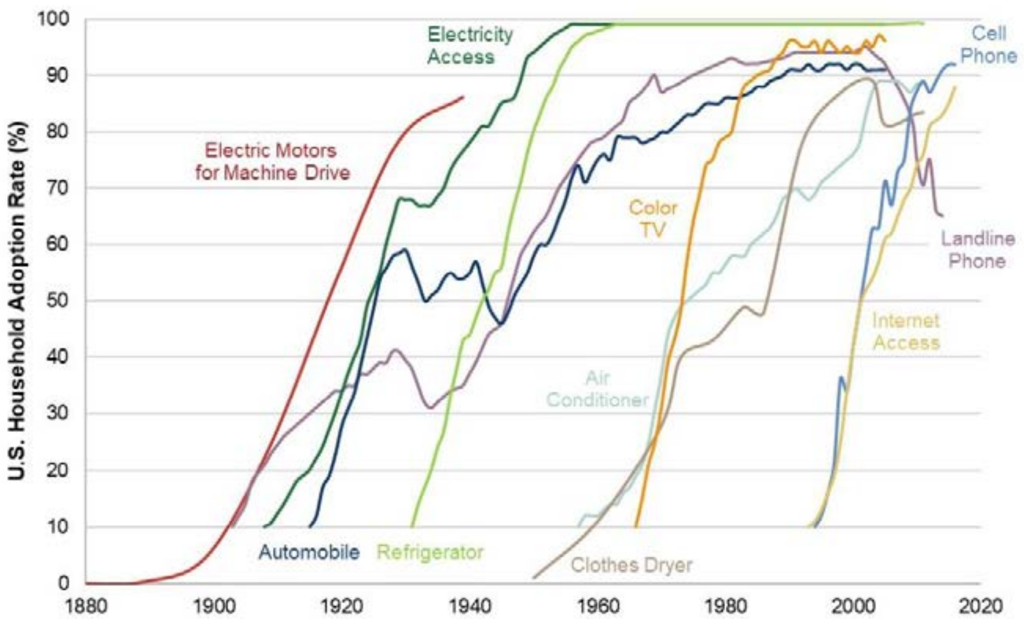
Several hydrogen technologies are still in the early stages of development. The lack of data and certainty around their widescale deployment makes modelling uptake out to 2050 difficult. The approach for constructing the uptake curve involved utilising an 's' curve model of adoption. This generic curve maps a path between early adoption and significant uptake of a technology, as shown in Figure 2 below.

Figure 2: Illustration of 's' curve[7]



The use of an 's' curve is based on the observation that technology adoption has typically followed an 's' curve shape, as shown in Figure 3 below. As evident in the figure, the duration that a technology can move from early adoption to plateau varies by technology. Where there is limited data available on the potential shape of the 's' curve for a hydrogen technology, the assumptions used in this model consider datapoints from existing projects to estimate the likely year that the technology is expected to become commercially available in New Zealand, the likely year that uptake in New Zealand materially ramps up and the estimated proportion of energy or feedstock demand in 2050 that is delivered by hydrogen.

Figure 3: Examples of historical 's' curves for technologies[8]



[7]Harnessing the Power of 's' Curves – Rocky Mountain Institute.
[8] Role of Electric Vehicles in the U.S. Power Sector Transition: A System-level Perspective, National Renewable Energy Laboratory (NREL)

International sources such as the International Renewable Energy Agency (IRENA) and the International Energy Agency (IEA) have been used to understand long-term hydrogen demand projections and gain insights into global hydrogen trends. Additionally, existing modelling and research specific to New Zealand, along with information from announced industry projects, have been considered to better understand the local dynamics and opportunities related to hydrogen. In the absence of sound external data, subjective judgment decisions have been made on uptake by 2050 based on the best available knowledge.

These two input sources have allowed us to estimate demand growth trajectories for each end use as shown in Table 3 below in notional form.

Table 3: Construction of notional demand growth trajectory

Scenario	End Use	Beginning of early adoption	Height of rapid growth	Maximum Uptake by 2050
Scenario description	End use description	Year of early adoption	Year of rapid growth	Maximum uptake value

The assumptions used in this model are provided in Appendix B. They are based on our current understanding of hydrogen, desktop research and some consultation with industry, and can be improved upon as the sector engages with the Interim Hydrogen Roadmap.

Electricity market and wider energy system limitations

It is important to note that this model focuses solely on the build out of the hydrogen supply chain and does not consider the complex dynamics between hydrogen and electricity, nor the progress of other renewable energy sources such as biomass or biofuel. As a result, factors like the relationship between hydrogen production and electricity generation and price, as well as the integration of various renewable energy technologies, are not explicitly considered in this model.

Due to the nature of the model, the model does not consider the demand profile of electrolysers for electricity at smaller timespans than a single year. Consequently, the model does not assess the hourly impacts on the grid, electricity spot prices, or the exact mix of additional renewable generation capacity required to meet the electrolyser's electricity demand. Instead, the model provides an estimate of the generation required based on wind and solar capacity factors. The intricate workings of the network and grid, including the effects of hydrogen production on electricity demand, pricing, and the necessary renewable energy infrastructure, fall outside the scope of this model and could be a subject for further analysis.

Import and export considerations

The model only considers a future where domestic demand for hydrogen is met by domestic production and does not consider the possibility of importing hydrogen from lower cost countries. Part of the reason for this is that the model does not directly compare how much hydrogen New Zealand produces with the production in other countries and therefore we do not assess whether it is feasible or competitive to import hydrogen. We understand that the capital cost of developing an import terminal is significant and the business case may not be supported without significant domestic volumes, which lessens the attractiveness of this investment in the near term.

When it comes to exporting, instead of determining when and how much hydrogen New Zealand should export, it is assumed that there is a fixed international demand for it. By assuming a fixed demand, we focus on understanding if we can meet the export requirements without looking specifically at the best timing or quantity for exporting hydrogen. It is also assumed that New Zealand can compete with its hydrogen prices in the export market.

Whether New Zealand decides to import or export hydrogen will depend on how much it costs to produce hydrogen locally compared to other countries. If New Zealand's hydrogen production costs are competitive, it could make exporting hydrogen economically viable. We provide commentary on the export potential later in this report.

Economic output limitations

Input-Output tables (IO tables) have been used to measure the impact of hydrogen investment and spending on the wider economy. IO tables have several limitations that should be considered when interpreting results, such as aggregation of industries, static nature, and the assumption of unlimited resources. We discuss these limitations in more detail in section 7.2.

Overall, IO tables can be a valuable tool for modelling economic systems, but they should be used in conjunction with other methods and approaches to provide a more complete picture of an economy. Careful consideration of their limitations is necessary to ensure that the model is accurate and useful for the intended purpose.

As part of the modelling, inflation has not been applied to the calculations meaning that all figures presented are in real terms (RT 2023). Furthermore, calculated economic benefits have not been discounted back to the present value. A weighted average cost of capital (WACC) of 5% has been applied to electrolyser plant costs to calculate the LCOGH.

4. Hydrogen scenarios

As part of this modelling exercise, we worked with MBIE to develop five scenarios that represent plausible but stretch futures for New Zealand's hydrogen ecosystem out to 2050.

In each scenario, we sought to understand the potential implications that focusing on a lever has on hydrogen demand, supply and three outcome areas: decarbonisation, economic development, and energy security and resilience. In the remainder of the report, we will use the framework shown in Figure 4 to describe and compare the different scenarios.

Figure 4: Hydrogen scenario framework

Hydrogen sector

Hydrogen demand

- Industrial feedstock
- Transport
  - Heavy transport
  - Light commercial transport
  - Rail
  - Marine
  - Aviation
- High temperature process heat
- Hydrogen to power
- Residential/commercial use
- Exports

Hydrogen supply

- Large centralised and small decentralised plants
- Costs of production, transformation and distribution
- Electricity system demand

Outcomes

Decarbonisation

- Emissions reductions
- Contribution to government targets

Economic development

- Economic activity (GDP)
- Employment (FTEs)

Energy security & resilience

- Electricity system support
- Reduction in energy imports

Figure 5 shows a high-level summary of the five scenarios modelled. The first scenario is a base case that illustrates a future where hydrogen is used for domestic decarbonisation where it is currently expected to be commercially viable. It is not intended to represent the current trajectory of New Zealand's hydrogen sector, but rather a future where hydrogen is only pursued in certain applications. The other four scenarios represent alternative futures where hydrogen is built out with different objectives as the key driver, as signalled by their names in Figure 5.

As New Zealand has a highly renewable electricity system, it is assumed across all scenarios that electrification will play a significant role in decarbonising the economy, and that hydrogen uptake is in the harder-to-electrify sectors.

Figure 5: Modelled scenarios and key differences relative to the base case

	Base case	Accelerated uptake	Energy security and resilience	Export market	Value-add export
Hydrogen demand	► Driven mostly by industrial feedstock and heavy transport	► Uptake across domestic demand sectors higher and faster	► Uptake across domestic demand sectors higher	► Increased demand from export plants	► Increased demand from export plants and industrial feedstock
Hydrogen supply	► Production focused in decentralised plants ► Some centralised production	► Production focused in decentralised plants ► Some centralised production	► Production focused in decentralised plants ► Some centralised production	► Production focused in centralised plants ► Some decentralised production	► Production focused in centralised plants ► Some decentralised production
Expected outcomes	► Lower performance against decarbonisation, energy security and resilience and economic development ► Lower risk to electrification	► Highest emissions reduction potential	► Higher displacement of liquid fossil fuels and increased support for the electricity system	► High economic value	► Highest economic value

For more details on each scenario and their intended outcomes, see Appendix A.

5. Modelled hydrogen demand

The following section describes the modelled output of hydrogen demand across each scenario.

5.1 Total annual demand

This section of the report will examine the modelled output of total annual demand for hydrogen across the scenarios.

5.1.1 Base case

In the base case, the modelling shows that the total demand for hydrogen is modelled to reach approximately 212,400 tonnes in 2035 and 642,300 tonnes in 2050.

Hydrogen uptake has been modelled across six major demand sectors, with industrial feedstock driving the largest hydrogen demand, followed by transport, process heat, and power generation as shown in Figure 6. The following subsections describe the assumptions used for each of these sectors in more detail.

The industrial feedstock demand sector refers to Methanex, Ballance, NZ Steel and potential new synthetic fuel production which collectively represent approximately 56% of the modelled hydrogen demand by 2050 in the base case. Following industrial feedstock, the next largest demand sector is transport, making up 31% of total demand by 2050, and high temperature process heat, which is modelled to reach 13% by 2050.

In the model, power generation is minimal in comparison and largely due to backup/remote power applications. In the base case, it is assumed that there is no residential and commercial demand and no export demand for the purpose of modelling. However, it is expected that large plants may choose to export any hydrogen produced that is not consumed in New Zealand.

Figure 6: Hydrogen demand by sector in the base case (2023-2050, tonnes)

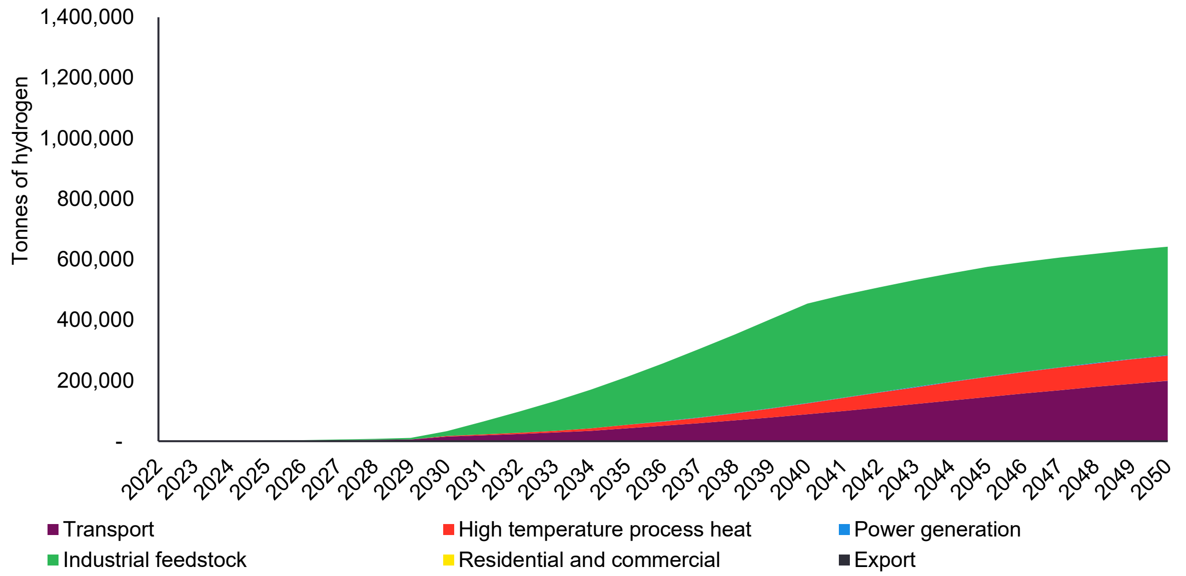


Table 4: Hydrogen demand in the base case (2035 and 2050)

Sector	2035		2050	
	tonnes	% of total	tonnes	% of total
Industrial feedstock	158,423	75%	357,783	56%
Transport	43,093	20%	199,493	31%
High temp. process heat	10,683	5%	83,218	13%
Residential and commercial	0	0%	0	0%
Power generation	235	0%	1,830	0%
Export	0	0%	0	0%
Total	**212,434**	**100%**	**642,324**	**100%**

5.1.2 Alternative scenarios

Figure 7 and Table 5 below illustrate the difference in total hydrogen demand across the scenarios. For more detail on the variations between scenarios, refer to the latter sub-sections on each sector.

All four alternative scenarios represent an increase in demand compared to the base case, with the highest demand found in the 'Value-add export' scenario at 1.38 million tonnes of hydrogen by 2050. This is driven primarily by the increased effort to convert existing industrial feedstock plants to green hydrogen and produce green urea, steel, and methanol. All other scenarios fall in between the base case and 'Value-add export' and represent increased and more rapid hydrogen uptake in various sectors in comparison to the base case.

The hydrogen demand growth curve begins earlier in the 'Accelerated uptake' scenario (2025 compared to 2030 for others) which represents a faster push to decarbonise harder-to-abate sectors such as heavy transport, industrial feedstock and high temperature process heat via hydrogen.

Figure 7: Hydrogen demand across all scenarios (2023-2050, tonnes)

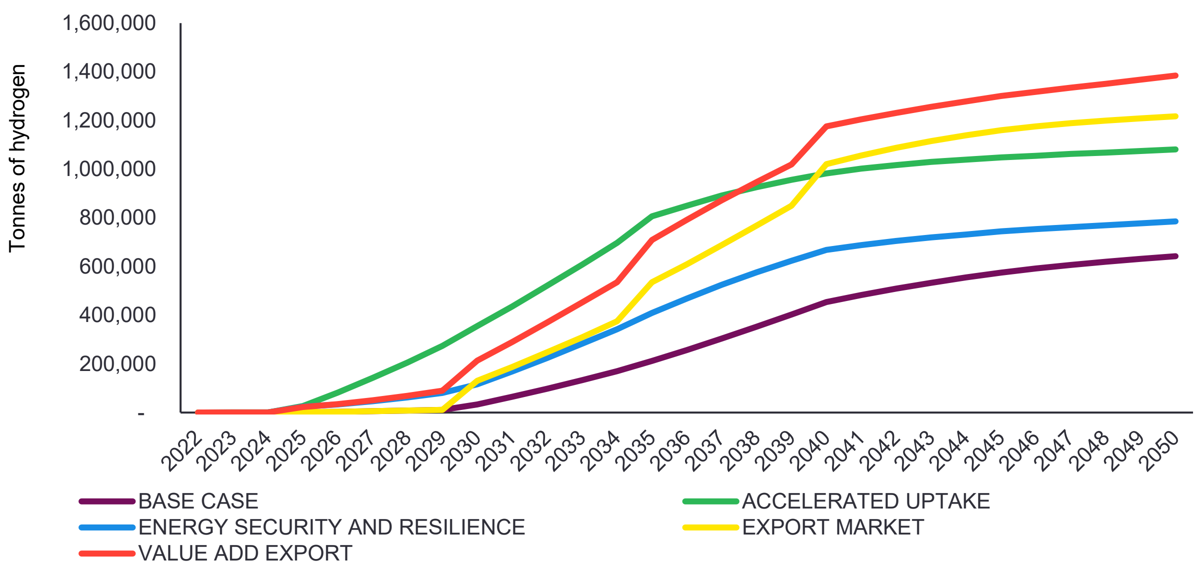


Table 5: Hydrogen demand across all scenarios (2035 and 2050)

Scenario	2035		2050	
	tonnes	+/- Base case	tonnes	+/- Base case
Base case	212,434	0%	642,324	0%
Accelerated uptake	806,037	+279%	1,081,114	+68%
Energy security and resilience	409,110	+93%	785,475	+22%
Export market	534,952	+152%	1,217,097	+89%
Value-add export	709,703	+234%	1,384,513	+116%

5.2 Industrial feedstock

The use of hydrogen in industrial feedstock has been modelled to reflect the decarbonisation of industries that currently use fossil-fuel derived hydrogen or could use green hydrogen in their processes in the future. The modelling has considered the conversion of Methanex (methanol), NZ Steel (steel) and Ballance (fertiliser) plants to use green hydrogen as a feedstock to estimate the potential hydrogen demand as an input for low carbon commodities. The model also includes the development of low-carbon synthetic fuels in New Zealand. In all scenarios, the modelling suggests that industrial feedstock will be the largest demand source for hydrogen.

For more information on the assumptions used, refer to section B.2.1 of the appendix.

Modelling assumptions – Base case

In the base case, the hydrogen demand curve is based on the following uptake assumptions:

- **Methanex converts 50% of its plant to use green hydrogen as a feedstock over ten years between 2030 and 2040 and begins to create lower carbon methanol.** It is assumed that Methanex will continue operations beyond their current natural gas contract, due to the growing global demand for methanol as a low-carbon fuel. Methanex has not made any announcements about the potential of converting their New Zealand operations to green hydrogen, therefore this assumption may be refined with further context from Methanex. However globally, Methanex has indicated that they are completing feasibility studies of incorporating renewable hydrogen into existing plants[9]. In this modelling, it is assumed that all methanol produced from hydrogen is exported and is not consumed domestically.

- **NZ Steel converts 50% of its Glenbrook site to use green hydrogen as a feedstock for steel gradually over ten years between 2035 and 2045.** NZ Steel has not made any announcements about whether they are seeking a full or partial conversion to hydrogen for their iron ore processes, therefore this assumption may be refined with further context from NZ Steel.

  In May 2023, the Government and NZ Steel announced that they are co-investing in an electric arc furnace to replace the existing steelmaking furnace and two of the four coal-fuelled kilns. With this investment, NZ Steel plans to reduce its steel production from iron ore and increase its production from scrap steel recycling, producing at least 50% of its steel from scrap metal before 2030[10,11]. Based on this announcement, it is assumed in this model that the remaining 50% of the steel produced by NZ Steel will use a hydrogen-based iron reductant process over time, resulting in 16,750,000 kg of annual hydrogen demand once fully converted. It is possible

[9] Sustainability Report 2022, Methanex
[10] NZ's biggest ever emissions reduction project unveiled | Beehive.govt.nz
[11] Govt helps NZ Steel reduce the Glenbrook steel mill's carbon footprint | interest.co.nz

that NZ Steel may increase its production from scrap steel beyond 50% and is incentivised to do so through incentive payments from the government, however the extent of this is uncertain and therefore have not been considered in the model[12]. The effect of further increasing production from scrap metal and decreasing production from iron ore, would be a reduction in the hydrogen demand modelled.

NZ Steel is actively supporting and collaborating with tertiary institutions that are investigating alternative hydrogen-based iron reductant processes.[13] It has also signed an agreement with BOC for the supply of green hydrogen which will displace 300 tonnes of CO_2 per year[14] for metal coating and treatment processes.

- **Ballance converts 100% of its hydrogen produced via Steam Methane Reformation to green hydrogen gradually from 2025 to 2050.** Ballance has not made any announcements about whether they are seeking a full or partial conversion to green hydrogen, therefore this assumption may be refined with further context from Ballance. Ballance has already partnered with Hiringa Energy to develop a green hydrogen plant at Ballance's Kapuni site. Green hydrogen was set to be available from the plant in Q3 2024 however recent developments suggests this may be delayed[15].

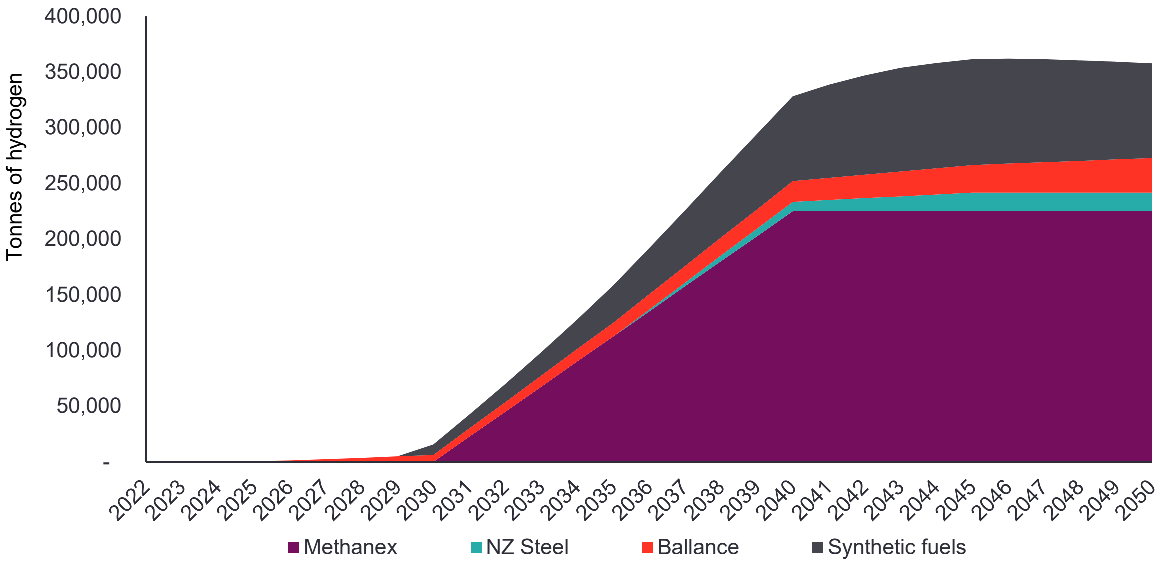
- **Synthetic fuel production begins in 2030 and supplies a volume that is equivalent to 8% of the liquid fuel demand modelled by the Climate Change Commission by 2050.** This industrial feedstock is not modelled in reference to any specific plant in New Zealand. Hydrogen demand from synthetic fuel (such as ammonia, biofuels, e-fuels, and sustainable aviation fuel) is forecast to grow significantly over the coming decades to address emissions from hard-to-abate sectors. The IEA's NZE scenario projects that 5.6 mb/d of hydrogen-based fuels will be required in 2050 or 16% of global liquid fuel demand[16]. Based on this figure, the model assumes 16% of liquid fuel demand in New Zealand will be a hydrogen-based synthetic fuel in 'Accelerated uptake', 'Energy security and resilience' and 'Value-add export'. Half of this figure, 8%, is assumed for the base case and 'Export market' scenarios to represent lower uptake. The model does not specify the fuels that are produced in the model, or which domestic or international demand sectors they will supply energy to. It is also possible that the development of synthetic fuels in New Zealand will impact the economics and dynamics around fuel bunkering which have not been considered in this model.

Modelling outputs – base case

Figure 8 below illustrates the total demand for hydrogen from industrial feedstock in the base case. As evident in the figure, demand for hydrogen is modelled to grow from 2030. Demand reaches 158,400 tonnes of hydrogen per annum by 2035 and 357,800 tonnes per annum by 2050. As shown in the figure, the greatest proportion of hydrogen demand is from Methanex, which makes up 63% of the demand for hydrogen by 2050. This is followed by synthetic fuels (24%), Ballance (9%) and NZ Steel (5%).

[12] NZ's biggest ever emissions reduction project unveiled | Beehive.govt.nz
[13] Feedback on the Climate Change Commission's 2021 Draft Advice for Consultation, New Zealand Steel
[14] BOC to supply 'green' carbon-free hydrogen to NZ Steel at Glenbrook, NZ Herald
[15] Hiringa Energy shocked and disappointed by Greenpeace going to Court of Appeal to stop hydrogen production - NZ Herald
[16] World Energy Outlook 2022 (Table 7.1), International Energy Agency

Figure 8: Industrial feedstock demand for hydrogen by subsector in the base case (2023-2050, tonnes)



Modelling assumptions – alternative scenarios

In addition to the base case assumptions discussed above, the following assumptions are used in the alternative scenarios.

Hydrogen demand growth begins earlier in 'Accelerated uptake' due to a faster uptake for decarbonisation. In 'Accelerated uptake', it is assumed that NZ Steel and Methanex bring forward the start of their gradual plant conversions by five years to start in 2030 and 2025 respectively. It is also assumed that Methanex can convert 100% of its plant to represent higher uptake levels for decarbonisation. Ballance is assumed to convert all its hydrogen demand by 2040 and grow its demand beyond that to displace imported urea. Finally, synthetic fuel production is modelled to deliver up to 16% of liquid fuel energy demand by 2050, double that of the base case.

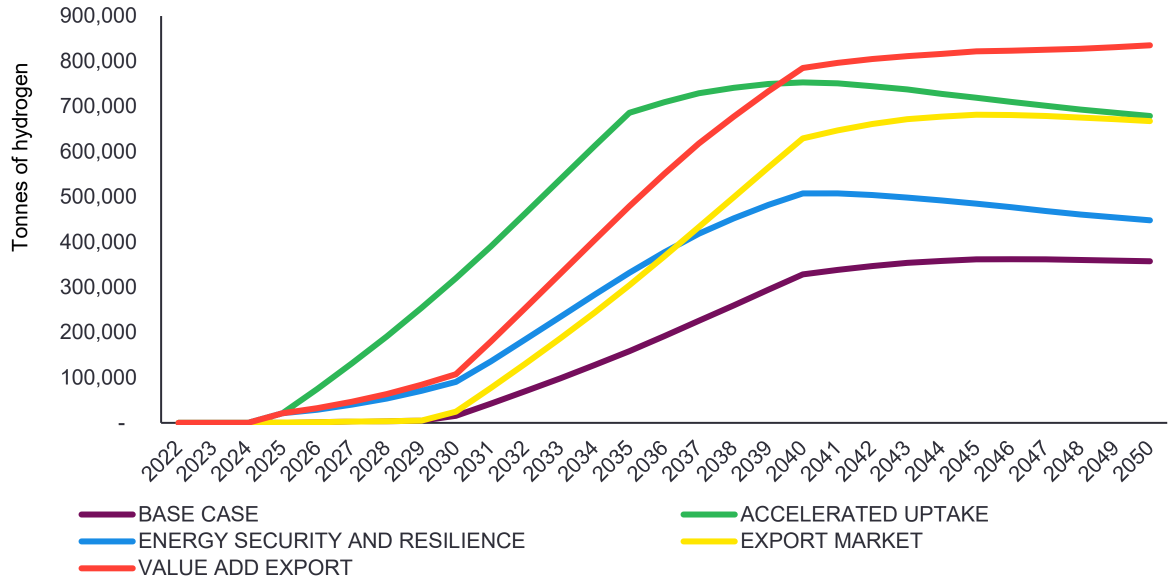
The 'Export market' and 'Value-add export' scenarios have similar uptake and conversion levels as the 'Accelerated uptake' scenario but maintain a timing that is consistent with the base case and 'Energy security and resilience'.

An additional dynamic in the 'Value-add export' scenario is the ongoing growth in hydrogen demand after plants have converted their current operations to green hydrogen. In this scenario, all plants modelled increase their hydrogen demand in line with GDP. This represents the growing output of low-carbon commodities for export.

Modelling outputs – alternative scenarios

Figure 9 below illustrates the total demand for hydrogen from industrial feedstock in each scenario. As evident in the figure, demand for hydrogen from industrial feedstock in 2035 is the highest in 'Accelerated uptake', reaching 686,000 tonnes of hydrogen. The lowest scenario is the base case. By 2050, hydrogen demand is greatest in the 'Value add export' scenario reaching 835,200 tonnes, more than double that of the base case.

Figure 9: Total industrial feedstock demand for hydrogen by scenario (2023-2050, tonnes)



Key uncertainties and dependencies

The modelling of industrial feedstock demand for hydrogen depends heavily on individual commercial decisions made by the likes of NZ Steel, Methanex, Ballance and other parties that may choose to invest in the creation of synthetic fuels or other commodities that use green hydrogen as a feedstock. Because each of the plants modelled makes up a substantial proportion of New Zealand's modelled hydrogen demand, any shift in the level of hydrogen demand and timing would have material implications on the overarching hydrogen demand curve. Some of these plants may also choose to not convert to green hydrogen at all and use other fuels/technologies to develop their product or exit the market.

5.3 Transport

The modelling suggests that transport is expected to be the second largest source of hydrogen demand due to the push within the wider transport sector to convert to low emission fuels.

Transport accounts for ~18% of New Zealand's gross emissions[17] and the current energy mix is dominated by fossil fuels such as petrol and diesel. As a result, there is an opportunity for hydrogen to become a source of fossil fuel displacement.

Modelling assumptions – high level

Note that the following discussion relates to transport at a high level. The following sub-sections explore individual transport sectors and underlying assumptions in more detail.

It is assumed that transport modes that may be suited to hydrogen are heavy transport, light commercial transport (small trucks, vans and utes), rail, aviation and marine.

Compared to the base case, it is assumed that there is a greater and more rapid uptake of hydrogen across all transport sectors under 'Accelerated uptake' and 'Energy security and resilience' scenarios to reflect a further focus on emissions reductions and displacement of imported fossil fuels.

[17] NZ's Interactive Emissions Tracker (environment.govt.nz)

It should be noted that the transport hydrogen uptake modelled assumes that the infrastructure required (e.g., refuelling networks) is rolled out in line with the modelled uptake and will be available to support hydrogen uptake.

Modelling outputs – high level

As shown in Figure 10, the modelling shows that demand for hydrogen from the transport sector is modelled to reach approximately 199,500 tonnes in 2050 under the base case as a result of hydrogen uptake across all transport sectors modelled. In the base case, heavy transport, aviation and marine make up the most demand for hydrogen.

Figure 10: Transport demand for hydrogen by subsector in the base case (2023-2050, tonnes)

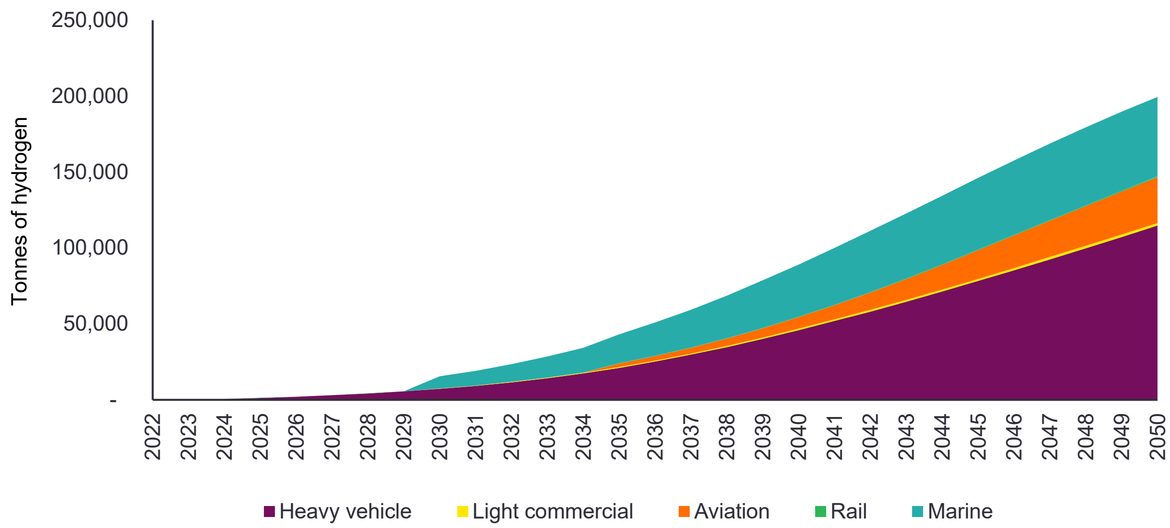
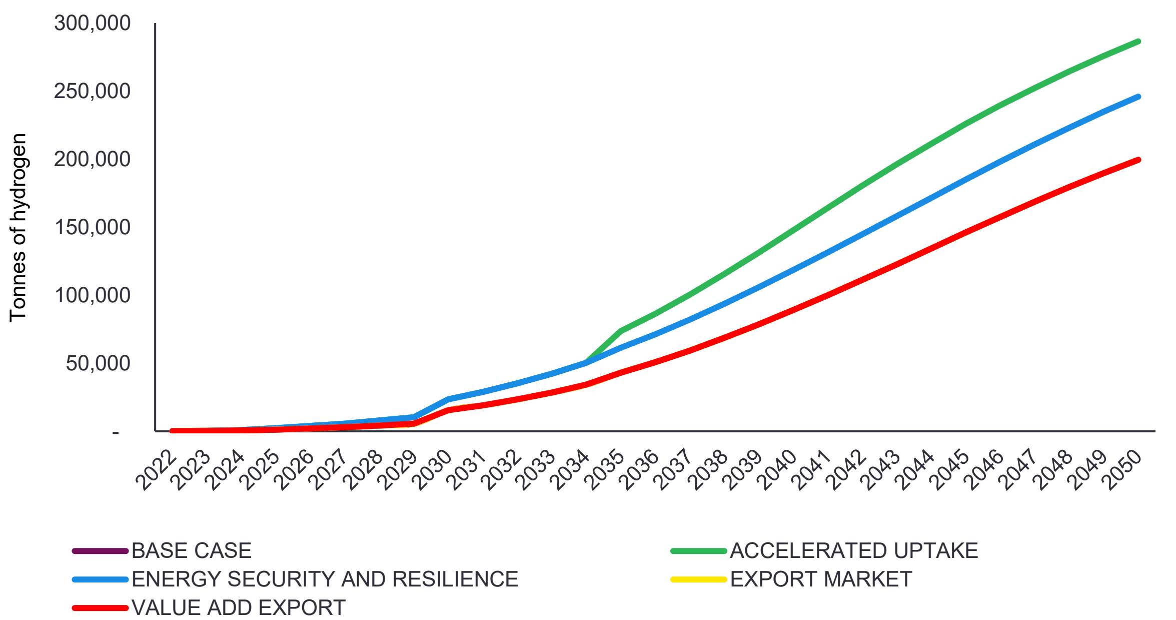


Figure 11 below shows the increased total transport hydrogen demand under the 'Accelerated uptake' and 'Energy security and resilience' scenarios in comparison to the base case.

The 'Export market' and 'Value-add export' scenarios are assumed to have the same uptake as in the base case due to more focus on export and industrial feedstock hydrogen demand.

Figure 11: Total transport demand for hydrogen by scenario (2023-2050, tonnes)



5.3.1 Heavy transport

In the heavy transport demand sector, the model considers the uptake of Fuel Cell Engine Vehicles (FCEV) and Hydrogen-Diesel hybrid combustion engine vehicles (Hybrid) in the heavy trucks and heavy bus fleets as categorised by the Ministry of Transport's fleet data.

Modelling assumptions – Base case

In the base case, modelling is based on the following uptake assumptions:

Fuel Cell Engine Vehicles (FCEV): For FCEV uptake in the heavy transport sector, it is assumed that 20% of new trucks and buses weighing over 12,000 kg will be FCEV by 2050. This is equivalent to approximately 1000 new hydrogen vehicles in 2050 and a cumulative total of 15,600 vehicles by 2050 in the base case (or 9% of the projected 2050 heavy vehicle fleet). It is assumed that uptake begins to pick up within the next five years given that fuel cell engine technology is available today and will continue to develop at a rapid pace. Only vehicles of a certain weight (>12,000 kg) are modelled to convert based on the assumption that smaller trucks and city buses may electrify.

Hydrogen-Diesel hybrid combustion engine vehicles: For hydrogen-diesel hybrid uptake in the heavy transport sector, it is assumed that 20% of new trucks and buses of any weight entering the fleet that isn't already FCEV will be hydrogen-diesel hybrids by 2050. This assumption is based on the IEA's modelling that suggests by 2050, 60% of new heavy vehicles entering the fleet will likely be battery electric. Therefore, if 20% of vehicles are likely to be FCEV, there remains 20% of the new entrant vehicles that may run on fossil fuels. These are the vehicles that are assumed to be hydrogen-diesel hybrids.

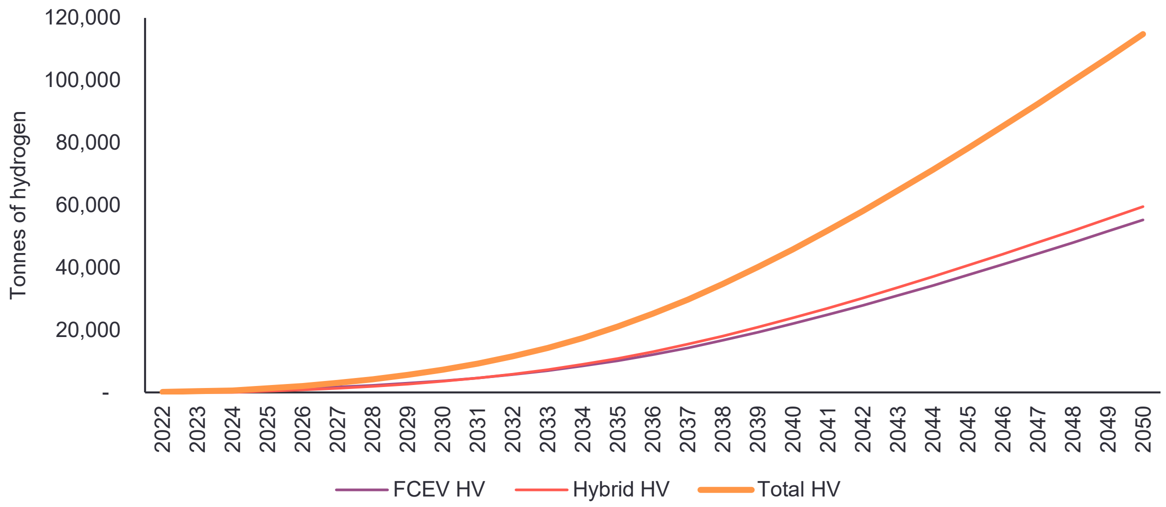
This assumption is equivalent to 2,000 new hydrogen-diesel vehicles in 2050 and a cumulative total of 29,900 vehicles by 2050 in the base case (or 18% of the projected 2050 fleet). The model assumes the uptake for hybrid heavy vehicles to pick up substantially within the next five years. Due to the lower cost of converting existing diesel trucks and buses to hybrid engines, rapid uptake assumptions are used in the model. The model assumes that 40% of the energy delivered to these hybrid vehicles is from hydrogen.

The model considers the uptake of each hydrogen technology on the expected number of additional vehicles to the domestic fleet advised by the average annual fleet growth rate, and a number of replacements advised by average retirement rates. The average annual fleet growth rate informed by the Climate Change Commission's modelling is a slower rate than historically observed. Refer to section B.2.2.1 of the appendix for detailed heavy vehicle demand assumptions.

Modelling outputs – Base case

The base case scenario results in total hydrogen demand from heavy vehicles reaching approximately 114,800 tonnes in 2050. This consists of approximately 55,300 tonnes or 48% of hydrogen demand from FCEV heavy vehicles and 59,500 tonnes or 52% of hydrogen demand from hybrid heavy vehicles. It is outside of the scope of the model to consider if and when fuel demand may plateau or decline, however, this may be a possibility in the future based on policy decisions or supply constraints.

Figure 12: Hydrogen demand from heavy vehicles by sub-sector under the base case scenario (2023-2050, tonnes)



Modelling assumptions – Alternative scenarios

Under 'Accelerated uptake' and 'Energy security and resilience' scenarios, the assumed uptake of hydrogen for new vehicles entering the fleet increases from 20% to 30% by 2050. This is assumed to represent the increased attractiveness of low emissions alternative fuel technologies such as hydrogen when a greater focus is placed on meeting carbon emission reduction targets and displacement of imported fossil fuels to improve New Zealand's energy security and resilience.

The 'Export market' and 'Value-add export' scenarios are assumed to have the same uptake as in the base case due to more focus on export and industrial feedstock hydrogen demand.

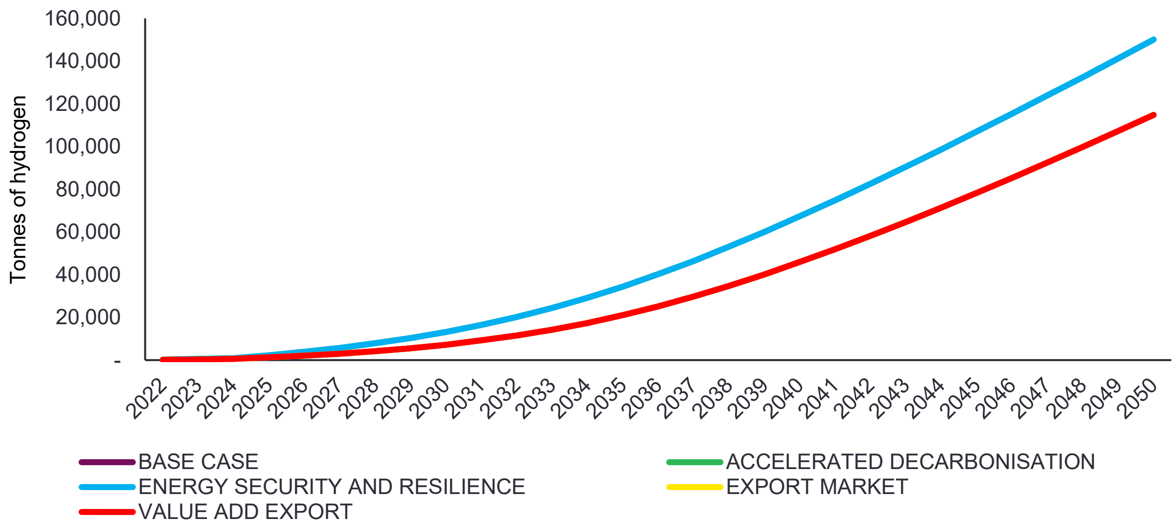
The assumptions for hybrid hydrogen-diesel trucks remain constant across all scenarios.

Modelling outputs – Alternative scenarios

As a result, in the 'Accelerated uptake' and 'Energy security and resilience' scenarios hydrogen demand for heavy vehicles increase to approximately 34,400 tonnes by 2035 and 150,100 tonnes by 2050.

The 'Export market' and 'Value-add export' scenarios have the same uptake curve as the base case.

Figure 13: Hydrogen demand from heavy vehicles by scenario (2023-2050, tonnes)



Key uncertainties and dependencies

For the modelled hydrogen uptake in heavy vehicles to be feasible, adequate re-fuelling stations and other forms of fuelling infrastructure must be established. Work has begun on this by Hiringa, who is currently undertaking a build out of hydrogen refuelling network across New Zealand.[18] However, relevant hydrogen storage and distribution technologies are not yet widely available which poses uncertainties regarding the economic viability of hydrogen heavy vehicles.

Hydrogen fuel cell vehicle production is still being developed at scale, and the assumed uptake percentage of hydrogen in the heavy vehicles sector is dependent on vehicles being available at the right cost to meet demand. Hyzon and Hiringa have announced that they intend to deliver 1,500 hydrogen FCEVs by 2026 as Hiringa expands their nationwide hydrogen refuelling infrastructure[19]. The technology for hydrogen blending is also just being trialled in New Zealand and technical feasibility is still being investigated by parties such as HW Richardson[20]. Other potential low emissions options, such as electric vehicles and biofuel-based vehicles also have the potential to become more attractive than hydrogen as those technologies develop further.

Another key uncertainty is New Zealand's ability to compete with global demand for hydrogen fuelled heavy vehicles. Due to the distance of New Zealand from the likely major producers of hydrogen vehicles, small market and right-hand drive vehicle market, New Zealand may experience challenges in procuring sufficient vehicles to meet the assumed demand.

5.3.2 Light transport

This model considers hydrogen uptake in light commercial vehicle fleets in New Zealand. Light commercial vehicles refer to vans, small trucks and utility vehicles (utes). They do not include light passenger vehicles that are used for commercial purposes (e.g., company cars).

Modelling assumptions – Base case and alternative scenarios

We have not considered hydrogen uptake to be material in light passenger vehicles due to the increasing accessibility and rapid technological advancement of electric vehicles that are well suited for light passenger vehicle duties. There are instances in New Zealand where FCEVs are being trialled for light passenger vehicles such as the Toyota Mirai trial[21]. However, given the likely dominance of electric vehicles, it is assumed that these are likely to be limited to specific use cases. We have therefore taken a view that modelling the light commercial fleet will be sufficient to capture the hydrogen demand from light vehicles.

The IEA's Net Zero Emissions by 2050 (NZE) Scenario[22] has been used to inform the expected proportion of new vehicle sales that will be hydrogen by 2050 in the 'Accelerated uptake' scenario and 'Energy security and resilience' scenario. The IEA suggests that 10% of new light vehicles entering the fleet in 2050 will be hydrogen fuel cells Given that New Zealand's light commercial fleet makes up 16% of light vehicles, this would suggest that approximately two-thirds of light commercial vehicles entering the fleet in 2050 would be hydrogen (approximately 67%), equivalent to approximately 20,000 vehicles. It would be expected that the remaining commercial vehicles would be electric.

The base case assumes half of the uptake expected under the 'Accelerated uptake' scenario to represent a more conservative uptake. This assumption is held constant for the 'Export' and 'Value-add export' scenarios.

Modelling outputs – Base case and alternative scenarios

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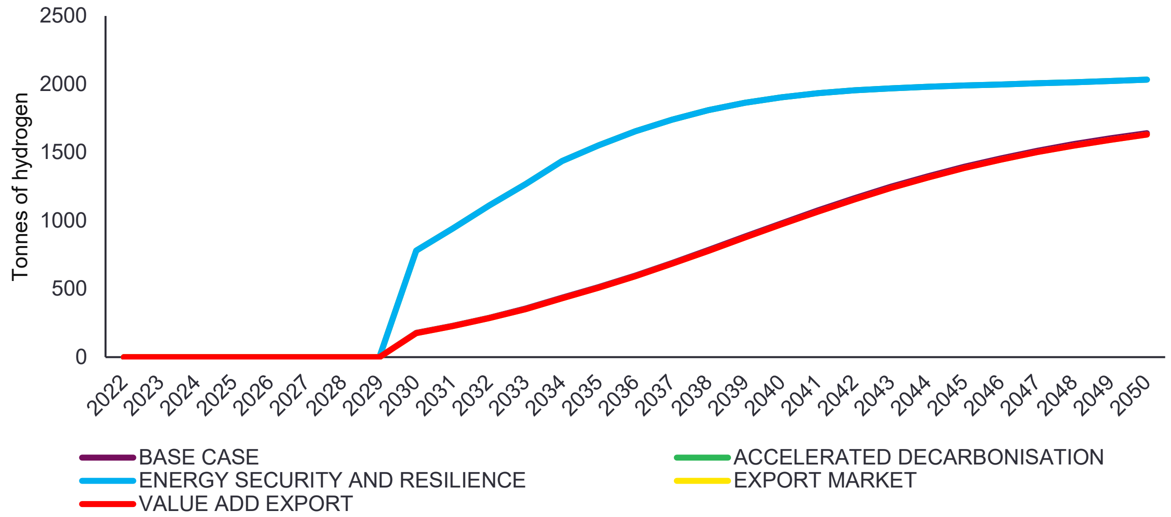
[18] Hydrogen Refuelling Network, Hiringa Energy 2022
[19] Hyzon Motors and Hiringa Energy advance partnership, Hyzon Motors
[20] HW Richardson is now using hydrogen fuel powered trucks - H2 News (hydrogenfuelnews.com)
[21] Toyota's hydrogen Mirai on NZ roads in 2022 - and on the water with Emirates Team NZ - News - Driven
[22] Net Zero by 2050 - A Roadmap for the Global Energy Sector, International Energy Agency

Figure 14 shows hydrogen demand from light commercial vehicles by scenario. In the base case, 'Export market' and 'Value-add export' scenarios, hydrogen demand is modelled to reach 514 tonnes by 2035 and 1,600 tonnes by 2050.

In 'Accelerated uptake' and 'Energy security and resilience', hydrogen uptake is modelled to reach 1,600 tonnes of hydrogen by 2035 and 2,000 tonnes by 2050.

Figure 14: Hydrogen demand from light commercial vehicles by scenario (2023-2050, tonnes)



Key uncertainties and dependencies

The uncertainties identified in the heavy transport sector around the build out of re-fuelling infrastructure, new fuel cell engine technology and New Zealand's ability to procure are also relevant for light commercial vehicles. There is also additional uncertainty around the size of the role that electric vehicles could play in decarbonising light commercial transport. For example, electric utes are already starting to come to market[23]. If costs rapidly decrease and any use case, range and charging concerns are addressed then electric vehicles may outpace hydrogen fuel cell vehicles in this sector.

5.3.3 Rail

The model includes the potential conversion of some rail to hydrogen as rail is emerging as a use case for hydrogen overseas. For example, in northern Germany, the Elkbe-Weser Railroad Company has become the first in the world to operate a fleet of hydrogen fuel cell trains in regular operation. The company has six-hydrogen powered trains running regularly between different cities, replacing conventional diesel trains[24]. Similarly, China's CRRC Corporation Ltd. launched the first hydrogen train in Asia in early 2023. India is set to receive its first hydrogen trains in late 2023[25].

Modelling assumptions – Base case and alternative scenarios

Hydrogen uptake in both urban passenger and freight rail fleets has been considered. These two types of rail are modelled to have different growth in energy demand and growth rates assumed are based on population growth and GDP growth respectively.

For the modelling, it is assumed that there is a low level of hydrogen uptake in both urban and freight rail fleets. This is because it is assumed that urban passenger rail is likely to continue to be electrified (building on the current electrification of Auckland and Wellington's network) and some freight rail is likely to be electrified. For example, in Budget 2023, the Government committed $10

[23] Electric T60 Ute | LDV NZ
[24] German railway firm ushers in new era for hydrogen trains – DW
[25] China Becomes the 1st Country in Asia to launch Hydrogen Powered Train (exampur.com)

million to take further rail electrification in the North Island to a detailed business case stage, enabling funding on major decisions to be considered within this decade. These cases include electrifying rail in the Golden Triangle (Tauranga – Hamilton – Auckland), which carries around half of all rail freight in New Zealand[26]. In the future, the extent of rail electrification in New Zealand is still uncertain, noting that South Island rail has not yet been electrified. The rate of uptake of hydrogen for rail is likely to be dependent on whether more of the network is electrified in the future.

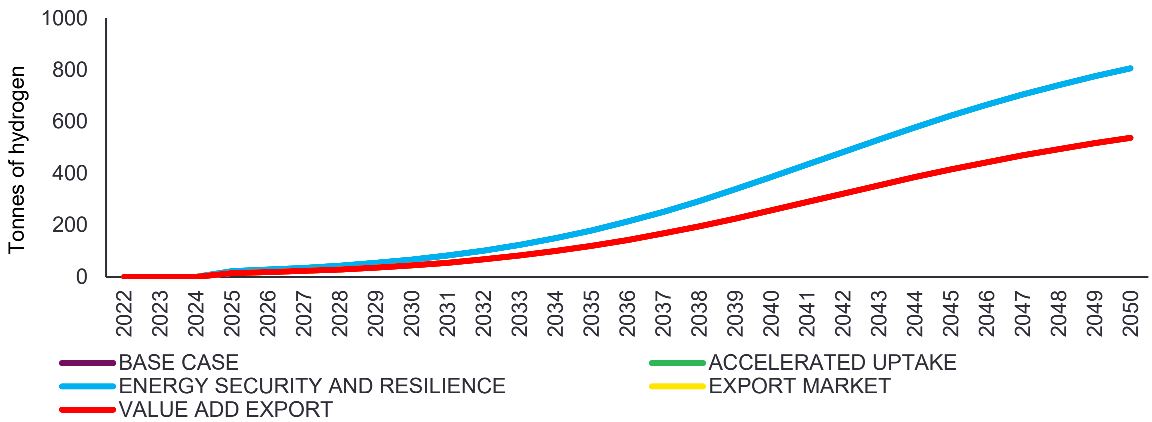
The IEA's Net Zero Emissions (NZE) Scenario[27] has been used to inform the expected uptake of hydrogen in the 'Accelerated uptake' and 'Energy security and resilience' scenarios and assume that hydrogen will supply 3% of useful energy by 2050 and that most of the growth is expected from 2035. In the base case, 'Export market' and 'Value-add export' scenarios, hydrogen uptake by 2050 is reduced to 2% and rapid growth is assumed from 2040.

Baseline assumptions for rail are based on EECA's Energy End Use Database. For freight fuel demand, 2021 figures have been used for 2022 assumptions. For passenger rail fuel demand, an average of 2017-2019 demand has been used for 2022 assumptions. This is because, over 2020-2021, passenger rail experienced a significant downturn due to COVID-19 restrictions and recovery. According to these figures, approximately 63% of energy for passenger rail and 2% of energy for freight rail is electric. Freight rail makes up approximately 80% of energy demand from rail.

Modelling outputs – Base case and alternative scenarios

As illustrated in Figure 15 below, in the base case, 'Export market' and 'Value-add export' scenarios, demand for hydrogen from the rail sector is modelled to reach 120 tonnes by 2035 and 540 tonnes by 2050. This increases to 180 tonnes in 2035 and 806 tonnes in 2050 under the 'Accelerated uptake' and 'Energy security and resilience' scenarios where there are further uptake levels to reduce carbon emissions and displace fossil fuels such as diesel.

Figure 15: Rail demand for hydrogen by scenario (2023-2050, tonnes)



Key uncertainties and dependencies

There is a modelled low uptake of hydrogen due to the assumption that a large amount of the remaining diesel fleet will be electrified. In 2022, 63% of passenger rail energy use was electricity. While the scope for electrifying freight trains is greater (only 2% of freight rail energy demand was electricity in 2022), there is potential for freight rail to be further electrified as passenger electrification is expanded. It is therefore likely that other mature technologies may become available to decarbonise a proportion of the rail fleet.

[26] Budget 2023 continues rail rebuild and looks to the future, KiwiRail
[27] Net Zero by 2050 - A Roadmap for the Global Energy Sector, International Energy Agency

Rail transport in New Zealand is operated by a few organisations such as Kiwirail (84.5%), Wellington Regional Council (10%), and Auckland Council (5.5%). As such, the decisions of these companies will drive the energy mix for rail.[28] Given the lifespan of rail vehicles, fleet replacement is likely to be over a long period. This will delay the uptake of hydrogen as vehicles are not up for replacement by hydrogen vehicles.

5.3.4 Marine

In modelling the hydrogen demand in the marine sector, the potential uptake across New Zealand's domestic and international marine fleets has been considered.

Modelling assumptions – Base case and alternative scenarios

Domestic and international marine transport are assumed to have energy demand profiles based on the CCC's Current Policy Reference.

The IEA's Net Zero Emissions by 2050 (NZE) Scenario[29] has been used to inform the expected proportion of energy that will be supplied by hydrogen (or hydrogen-derived fuel) by 2050 in the 'Accelerated uptake' and 'Energy security and resilience' scenarios. The IEA estimates that ~60% of energy demand from shipping is likely to be supplied by hydrogen or Ammonia in 2050, up from 0% in 2020 and 10% in 2030. In the base case, it is assumed that only 50% of forecast energy demand from the marine sector to be met by hydrogen (or hydrogen-derived fuel) to represent a lower uptake for decarbonisation.

It is assumed across all scenarios that demand for hydrogen grows from 2030 based on the IEA 2030 estimates.

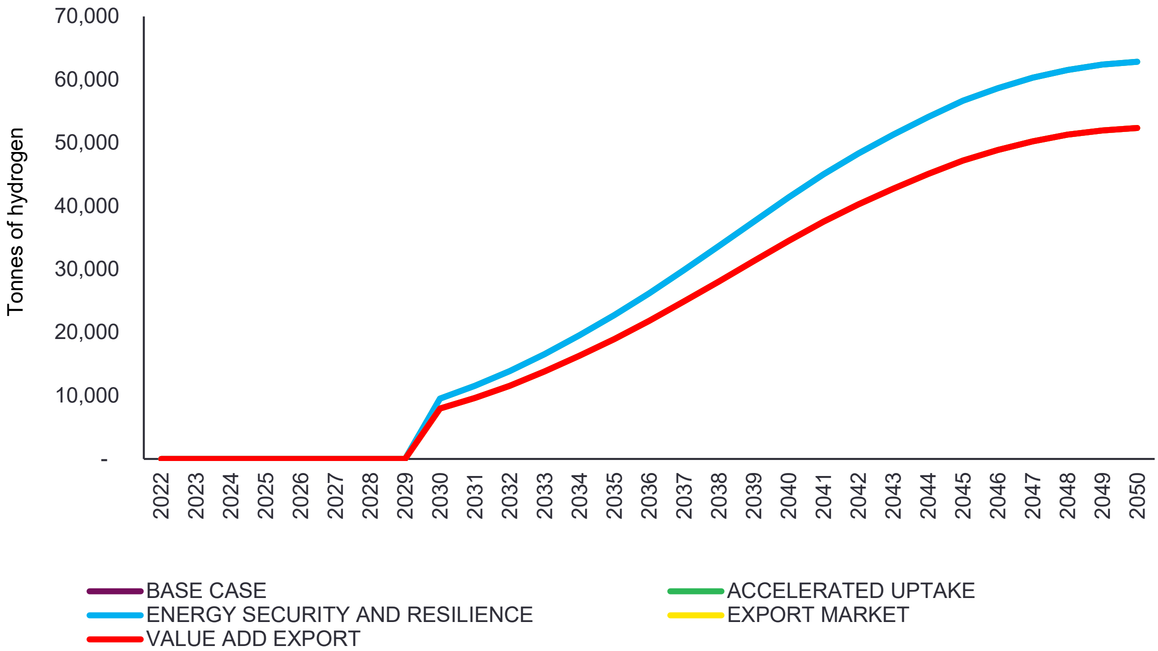
In this model, it is assumed that hydrogen for marine use is produced in addition to ammonia or methanol produced in the industrial feedstock sector. This is because it is assumed that most of the products produced by the industrial feedstock sector are for export. It is possible that some of the ammonia, methanol or other synthetic fuel produced locally can be used to supply energy for marine uses.

Modelling outputs – Base case and alternative scenarios

As shown in Figure 16 below, hydrogen uptake in the marine sector under the base case, 'Export market' and 'Value-add exports' is modelled to begin in 2030 and reach 19,000 tonnes by 2035 and 52,400 tonnes by 2050. Higher levels of hydrogen demand are modelled under 'Accelerated uptake' and 'Energy security and resilience' scenarios, reaching 22,800 tonnes by 2035 and 62,800 tonnes by 2050. This reflects increased higher rates of uptake to replace fossil fuels with low carbon alternatives.

[28] IBIS World.
[29] Net Zero by 2050 - A Roadmap for the Global Energy Sector, International Energy Agency

Figure 16: Marine demand for hydrogen by scenario (2023-2050, tonnes)



Key uncertainties and dependencies

There are several uncertainties and dependencies involved when solving for the demand for hydrogen propelled vessels. Many of the assumptions rely on the regulatory frameworks and infrastructure development of not only New Zealand but other international nations which are considered major trading partners. For widespread international adoption of this technology, hydrogen refuelling stations will need to make available in the departing and arriving ports.

The marine fuel mix is evolving rapidly – largely driven by the requirement for lower particulate fuels under MARPOL. This has driven the uptake of LNG and methanol as marine fuels, which are maturing in commercial use. However, these are not exclusively zero carbon fuels, and the industry is seeking pathways to decarbonise these fuels (such as green methanol and synthetic methane) alongside testing hydrogen and ammonia as shipping fuels. Hence, while hydrogen/ammonia may not be used directly as a marine fuel, there is potential for hydrogen to be required in the production of green marine fuels in the future.

5.3.5 Aviation

In the modelling, it is assumed that for aviation, hydrogen, electric or electric hybrid will be used for domestic flights, while sustainable aviation fuel (that may use hydrogen as a feedstock) will become the fuel (s) of choice for international flights[30]. As international aviation is likely to use sustainable aviation fuel (SAF), the modelling only considers domestic aviation. Hydrogen can be an input into SAF which is a consideration in the modelling of synthetic fuel production in the industrial feedstock sector. However, the model does not consider in detail the possibility of aviation fuel displacement from synthetic fuels for international flights due to the potential for imports.

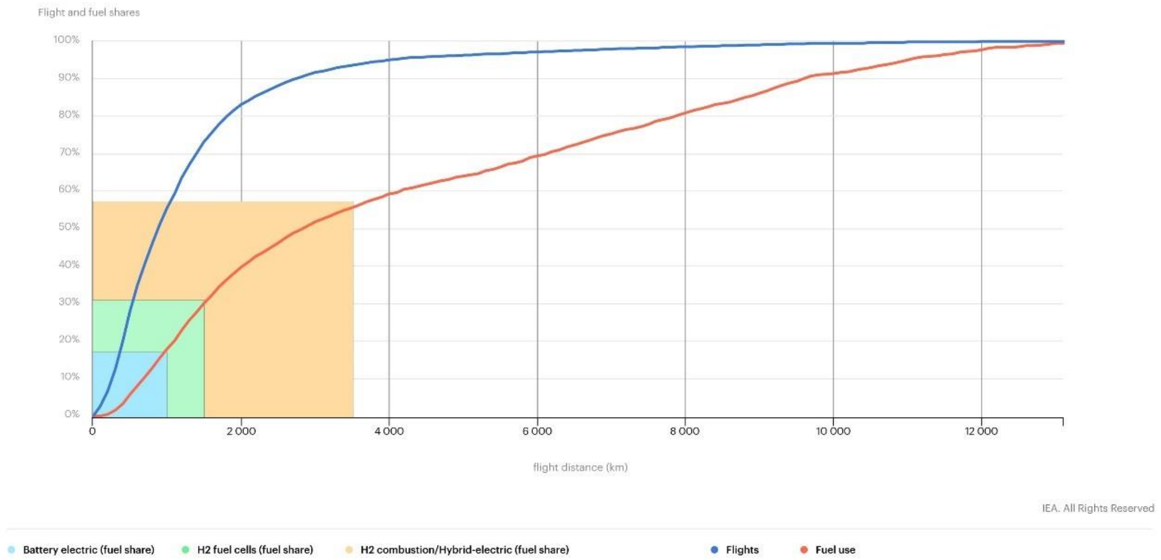
In this model, two possible hydrogen aviation technologies for domestic aircraft have been considered: hydrogen fuel cell aircraft and hydrogen hybrid aircraft.

[30] Aviation - Analysis - IEA, International Energy Agency

Modelling assumptions – Base case and alternative scenarios

The proportions in Figure 17 below have informed the proportion of energy demand supplied by hydrogen in 2050 in the 'Accelerated uptake' scenario. For the 'H2 combustion/Hybrid-electric' category, it is assumed 50% of this energy is supplied by hydrogen and 50% is supplied by electricity. In 'Accelerated uptake', it is assumed that 30% of useful energy for aviation is supplied by hydrogen and used in fuel cell planes by 2050 and 50% of input energy (which is equivalent to useful energy adjusted for efficiency losses in a combustion plane) is supplied by hydrogen and used in hybrid planes by 2050.

Figure 17: Flight and fuel shares (IEA)



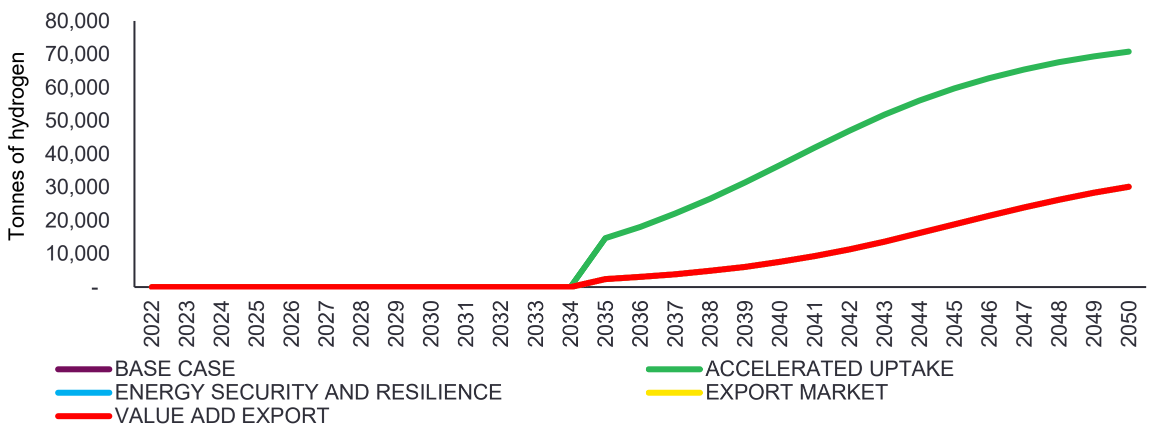
For the base case and other alternative scenarios, it is assumed that these uptake levels by 2050 are halved to represent lower levels of fuel switching.

Refer to Appendix B.2.1.3 for further information on the modelling assumptions used.

Modelling outputs – Base case and alternative scenarios

As illustrated in Figure 18 below, in the base case, 'Energy security resilience', 'Export market' and 'Value-add export' scenarios, hydrogen demand from domestic aviation is modelled to reach approximately 2,400 tonnes by 2035 and 30,000 tonnes by 2050. Under the 'Accelerated uptake' modelled hydrogen demand grows rapidly from 2034, reaching 14,700 tonnes by 2035 and 70.800 tonnes by 2050.

Figure 18: Aviation demand for hydrogen by scenario (2023-2050, tonnes)



Key uncertainties and dependencies

Feasibility studies for hydrogen fuelled aviation technologies are underway and there are still large uncertainties around the economic viability of hydrogen uptake.

Several research and development programmes are underway that could result in different timings for when hydrogen or other low carbon aircraft come to market. For example, Airbus has stated an ambition to develop the world's first hydrogen-powered commercial aircraft by 2035 and launched their ZEROe demonstrator in 2022 to test hydrogen combustion technology. They expect to achieve a mature technology readiness level for a hydrogen-combustion propulsion system by 2025.[31] Smaller aircraft manufacturers are also making progress. In January 2023, ZeroAvia flew the largest aircraft in the world, its 19-seat Dornier, to be powered by a hydrogen-electric engine[32]. Soon after in March 2023, Universal Hydrogen successfully took flew its 40-seat hydrogen-electric plane in the U.S.[33] Boeing's low emissions aircraft development is focusing on using Sustainable Aviation Fuel, targeting all commercial planes that it delivers to be certified for the capability to fly using 100% sustainable aviation fuel by 2030[34].

It is worth noting, Air New Zealand has partnered with Airbus to engage in research on the feasibility of hydrogen planes and refuelling stations in airports. They have also undertaken a process to identify zero emissions aircraft partners and start a demonstration project by the middle of this decade as part of their 'Flight NZ0' programme (which includes consideration of hydrogen aircraft)[35]. As New Zealand's national airline, the direction that Air New Zealand chooses to take in the coming decades as a result of new technological advances will have a significant impact on the hydrogen demand for aviation in New Zealand.

5.4 Process heat

The modelling suggests that process heat is the third largest hydrogen demand sector, making up around 13% of the total modelled hydrogen demand in 2050 in the base case.

Modelling assumptions – Base case and alternative scenarios

For this model, it is assumed that hydrogen is likely to only be an attractive alternative for high temperature heat processes where 300 degrees Celsius or higher is required. High temperature process heat is generally limited to materials manufacturing sectors and most of its use is in a small number of large or tightly integrated plants[36]. For this reason, it is assumed later in section 6 and Figure 23 that high temperature process heat plants may be supplied by on-site hydrogen production.

Based on EECA's Energy End Use Database, over the years 2017-2021, high temperature process heat makes up approximately 38.6 TJ or 50% of fossil fuel energy needed annually for all process heat temperatures (excluding heat needed for space and water heating and cooking).

It is assumed that lower temperature process heat is likely to be electrified or use bioenergy. Biomass or biofuels could also play a role in decarbonising high temperature process heat, but the potential split between these fuels and hydrogen have not been considered in this model. For more information on the assumptions used, see section B.2.3 of the appendix.

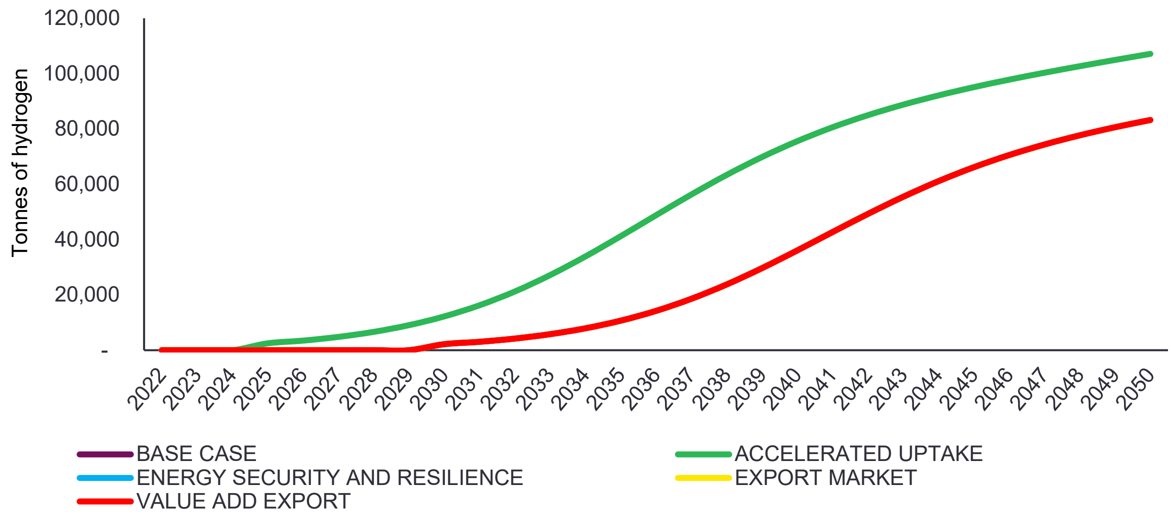
[31] China Becomes the 1st Country in Asia to launch Hydrogen Powered Train
[32] ZeroAvia
[33] 40-passenger hydrogen electric plane completes maiden flight, Electrek
[34] Demonstrator 2022, Boeing
[35] Flight NZ0 - Air New Zealand
[36] Phasing out fossil fuels in process heat, Ministry for the Environment

The IEA's Net Zero Emissions by 2050 (NZE) Scenario[37] has been used to inform the expected proportion of energy that will be supplied by hydrogen (or hydrogen derived fuel) by 2050 in the 'Accelerated uptake' scenario. The IEA estimates that ~25% of energy demand from process heat will be supplied by hydrogen in 2050. In 'Accelerated uptake' it is assumed that 25% of energy demand is supplied by hydrogen by 2050, with uptake growing rapidly from 2035. To represent lower uptake in the base case and other scenarios, it is assumed that hydrogen uptake will supply up to 20% of total energy demand by 2050 with the uptake growing rapidly from 2040.

Modelling outputs

Figure 19 below shows the comparison of hydrogen demand from process heat across the scenarios. 'Accelerated uptake' is modelled to have the highest and fastest uptake, reaching 41,200 tonnes by 2035 and 107,100 tonnes by 2050. The base case and other scenarios only reach 10,700 tonnes by 2035 and 83,200 tonnes by 2050.

Figure 19: Total process heat demand for hydrogen by scenario (2023-2050, tonnes)



Key uncertainties and dependencies

While expected to be technically feasible in some applications, hydrogen technologies are highly specified for industrial application and commercial feasibility is yet to be proven. As a result, there are uncertainties around the cost to convert plants and integration of hydrogen technologies into plants including questions around availability of workforce and safety of processes. Several projects are underway internationally to progress the use of hydrogen in process heat, such as the Hyinheat 24M EUR project[38] and the Celsian and DNV led consortium[39].

The model does not consider how regional demand for hydrogen in the process heat sector may vary, including alternative fuel availability that may vary between regions which are likely to impact the attractiveness of hydrogen as a low carbon fuel for any individual plant. As noted earlier, biomass or biofuels could also play a role in decarbonising high temperature process heat, but the potential split between these fuels and hydrogen have not been considered in this model. Regional supply chains, the proximity of hydrogen plants and forestry and transport infrastructure will likely have an influence on where hydrogen may be more attractive than alternatives such as biomass.

[37] Net Zero by 2050 - A Roadmap for the Global Energy Sector, International Energy Agency
[38] Hyinheat - Hydrogen Technologies for Decarbonization of Industrial Heating Processes, 24M EUR Project - Hydrogen Central (hydrogen-central.com)
[39] Hydrogen as a fuel for high-temperature heating processes (dnv.com)

5.5 Hydrogen to power

The model includes some hydrogen demand from power generation that uses hydrogen as a fuel due to the preference to displace diesel use in mobile power generators with low carbon alternatives. Hydrogen can be used in small, distributed fuel cell generators for power (i.e., backup generators) and will have no impact on wholesale electricity price as it is not linked to market. This is a niche use case due to the overall low round trip efficiency of hydrogen for electricity generation.

The model does not include the use of hydrogen as an input for large scale electricity generation due to its low round trip efficiency being significantly lower than other generation or grid support technologies and therefore potentially unattractive in the New Zealand market[40]. Instead, it is assumed that hydrogen production will play the greatest role in supporting security of supply as a demand response tool due to the economic efficiency of turning down plants. Depending on the nature of the commercial contracts and conditions, this demand response can support peak demand (e.g., turning down demand for a few hours a day) or dry year (e.g., turning down demand for several weeks).

Using hydrogen as a fuel for large scale electricity generation is possible and may be used if it is an economical fuel for green peaking plants in a 100% renewable electricity system. In this case, the high cost of using hydrogen as a peaking fuel, and its low round-trip efficiency, can be justified if security of supply is maintained. The use of hydrogen (in the form of ammonia) is a solution being explored by the NZ Battery project specifically to support dry year. In their Indicative Business Case[41] they noted that on its own, hydrogen is unlikely to solve the security of supply problem for dry year. In their assumptions, NZ Battery assumes that in 2050, an electrolyser can bid into the electricity market at NZ$61/MWh and a combined-cycle gas turbine plant using green ammonia would bid at NZ$266/MWh. Based on these assumed bid prices, it is possible to expect that electrolysers would play a greater role in the electricity market through demand response compared to the use of hydrogen as a green peaking fuel.

Modelling assumptions – Base case and alternative scenarios

To estimate the potential fossil fuel displacement, the model has used the stationary motive power energy profile from EECA's Energy End Use Database[42] as a baseline for off-grid generation demand. The fuel used in this dataset encompasses a broad range of energy use (e.g., motors) beyond small scale generation and therefore it is assumed that there are very low uptake proportions.

In the base case, 'Export market' and 'Value-add export' scenarios, it is assumed that hydrogen may displace fossil fuels in off-grid electricity generation by up to 5% by 2050, with uptake beginning in the next five years. In 'Accelerated uptake' and 'Energy security and resilience' it is assumed that the proportion delivered by hydrogen by 2050 reaches 10%.

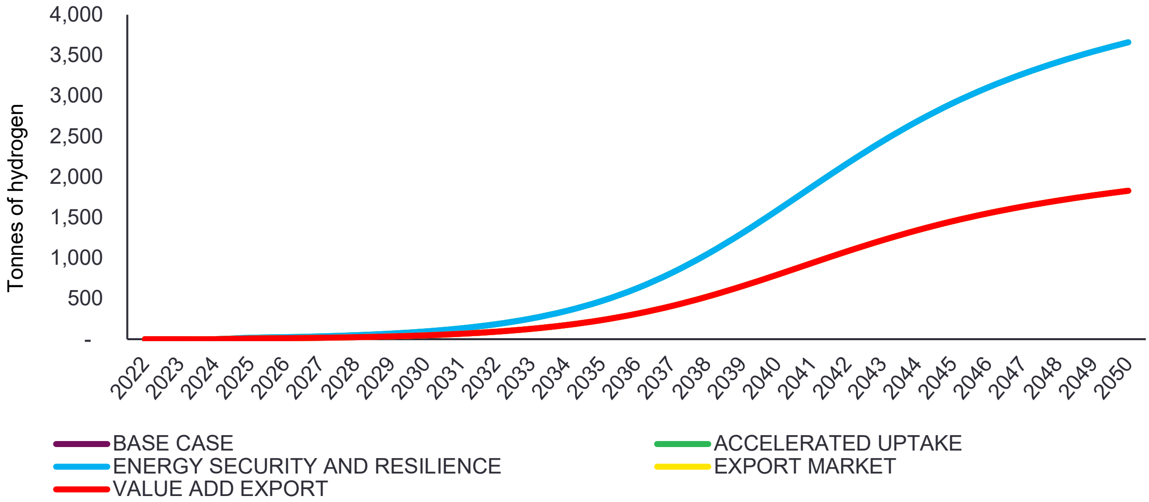
Modelling outputs – Base case and alternative scenarios

As shown in Figure 20 below, under the base case, 'Export market' and 'Value-add export', the model shows that demand for hydrogen-fuelled electricity generation for small scale, off-grid generators reaches approximately 235 tonnes by 2035 and 1,830 tonnes by 2050.

In 'Accelerated uptake' and 'Energy security and resilience' this demand for hydrogen doubles, reaching 470 tonnes by 2035 and 3,700 tonnes by 2050 in the model.

[40] The New Zealand Hydrogen Opportunity, McKinsey & Company for Meridian Energy (Meridian) and Contact Energy (Contact)
[41] New Zealand Battery Project Indicative Business Case v1.10 and Appendices – February 2023 (mbie.govt.nz)
[42] Energy End Use Database | EECA

Figure 20: Hydrogen demand from power generation by scenario (2023-2050, tonnes)



Key uncertainties and dependencies

Hydrogen combustion for large scale electricity generation has not been modelled. Due to the low round trip efficiency of hydrogen for electricity generation, this has not been considered. We have considered the use of demand response from hydrogen production supporting electricity system reliability as part of the hydrogen supply assessment (see section 6.5.2).

The generation of electricity has therefore been considered as a niche application where remote power/back up is currently used. As these applications are long lived and dependent on decision making by several disparate parties, it is difficult to forecast uptake. It is likely that price parity with diesel (being the competing fuel), capital costs and availability of equipment will drive uptake.

5.6 Exports

Export of hydrogen has been modelled in two scenarios, 'Export market' and 'Value-add export', to understand the potential impact that large demand from exports can have on New Zealand's total hydrogen demand.

Export demand has not been included in the base case, 'Accelerated uptake' and 'Energy security and resilience' due to the domestic focus in these scenarios, however, it is acknowledged that hydrogen exports of some level may still be compatible with these scenarios.

Modelling assumptions – 'Export market' and 'Value-add export'

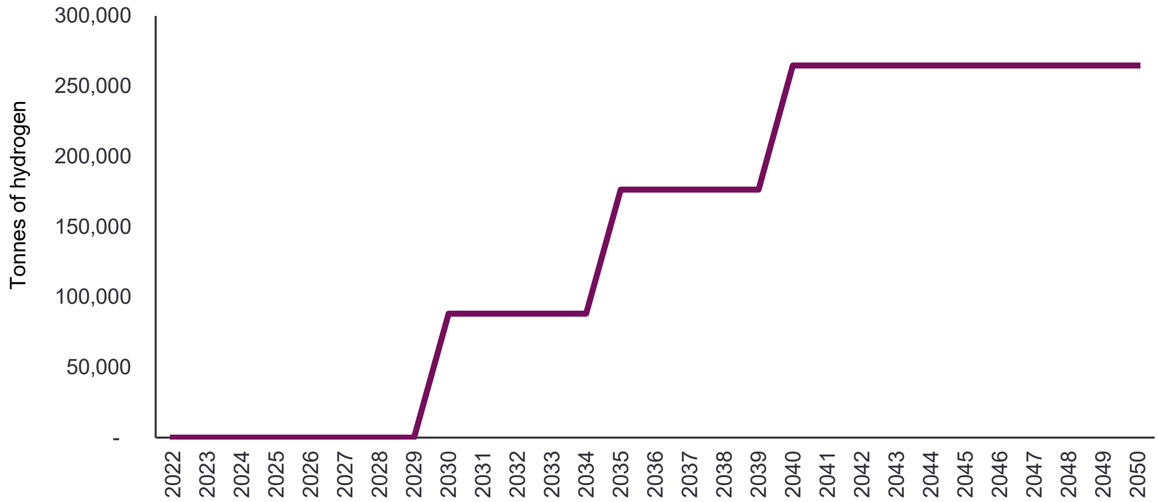
As discussed earlier, the model is not used to determine an optimal time and volume of hydrogen exporting activity. Instead, to model export demand, three large plants are modelled to come online in 2030, 2035 and 2045. Each plant is assumed to be 600MW in capacity and produce 88,250 tonnes of hydrogen demand annually, which is similar in size to Meridian's proposed Southern Green Hydrogen Project. The purpose of modelling export in this way is to understand the potential additional demand for hydrogen that exporting could add compared to domestic hydrogen demand. In reality, these plants could have more staged commissioning that results in export demand gradually increasing over time.

Modelling outputs – 'Export market' and 'Value-add export'

Figure 21 shows the modelled hydrogen demand from exports in the 'Export market' and 'Value-add export' scenarios.

As evident in the figure, export plants are modelled to come online in 2030, 2035 and 2040. By 2050, these plants are modelled to collectively produce 265,000 tonnes of hydrogen annually for export. This volume is equivalent to just under half of the total potential hydrogen demand in 2050 in the base case, which indicates that entering the hydrogen export market is likely to have a material impact on New Zealand's whole hydrogen system.

Figure 21: Total export demand for hydrogen in 'Export market' and 'Value-add export' scenarios (2023-2050, tonnes)



Key uncertainties and dependencies

The development of significant export demand for New Zealand hydrogen will depend on several factors, including global demand for hydrogen, the cost competitiveness and pace of development of New Zealand's hydrogen compared to other countries and the ability of New Zealand to secure export partnerships (such as building on its current agreements with Japan[43] and South Korea[44]).

Globally, IRENA's Global Hydrogen Trade Outlook[45] suggests that 25% of global hydrogen will be internationally traded by 2050, equivalent to around 150 million tonnes per annum. If New Zealand were to have the three large plants, it would produce a total of 260 tonnes of hydrogen per annum, equivalent to less than one per cent of the globally traded amount. If New Zealand is able to produce low-cost hydrogen at pace with other exporting countries, then it may be well positioned to supply export demand.

For commentary on the potential cost competitiveness of New Zealand hydrogen, see section 6.6.3.

5.7 Residential and commercial uses

The model includes residential and commercial uses of hydrogen where it displaces natural gas in combustion (e.g., cooking, heating). The modelled uptake is largely driven by whether hydrogen is blended with natural gas and distributed via the existing gas pipelines. Blending is only modelled to occur in 'Accelerated uptake' and 'Energy security and resilience'.

Modelling assumptions – 'Accelerated uptake' and 'Energy security and resilience'

At the time of model development, the Gas Transition Plan has not yet been published, therefore assumptions have been made across the scenarios on whether gas pipeline blending would occur. In

[43] NZ, Japan team up on renewable energy | Beehive.govt.nz
[44] Trade, business and investment focus for visit to South Korea | Beehive.govt.nz
[45] Global Hydrogen Trade Outlook, International Renewable Energy Agency (IRENA)

the modelling, it is assumed that gas blending occurs in 'Accelerated uptake' and 'Energy security and resilience' in 2035 and can tolerate 20% of hydrogen blending volume. Due to the differences in density between hydrogen gas and natural gas, this is equivalent to hydrogen supplying 6.5% of the energy content. The model does not consider a full conversion of the pipeline network to hydrogen.

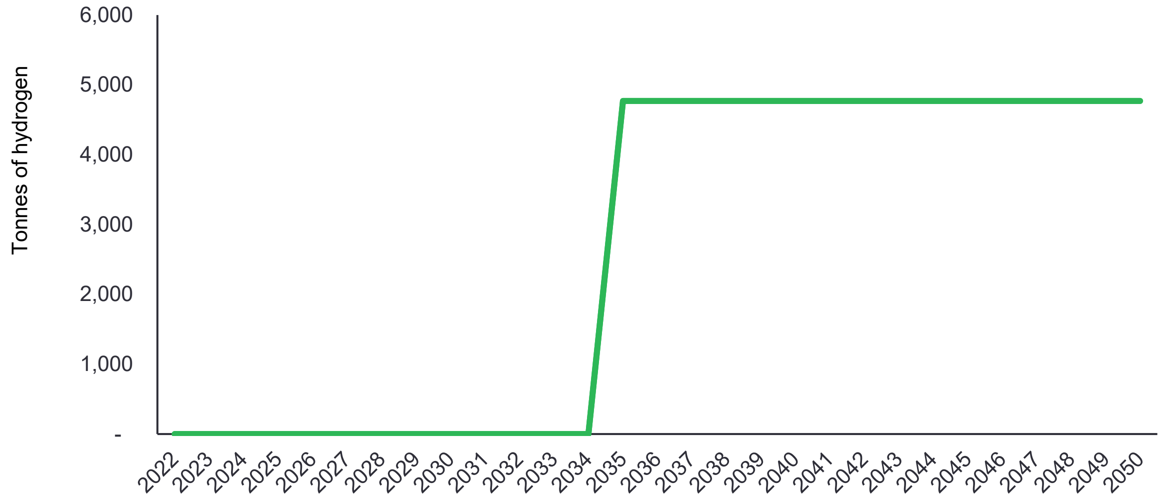
Residential and commercial gas demand is based on the Climate Change Commission's Demonstration Path but with demand levels in 2035 extended out to 2050, rather than following their modelled trend of gas demand declining to zero by 2050, to create long-term demand for gas pipeline blending.

Figure 22 illustrates the demand for hydrogen from residential and commercial uses. Because the base case, 'Export market' and 'Value-add export' do not assume pipeline blending occurs, these scenarios have no demand from this sector.

Modelling outputs – 'Accelerated uptake' and 'Energy security and resilience'

In both 'Accelerated uptake' and 'Energy security and resilience', hydrogen demand from residential and commercial use is small in comparison to other demand sectors, reaching 4,770 tonnes by 2035 through to 2050.

Figure 22: Residential/commercial demand for hydrogen for 'Accelerated uptake' and 'Energy security and resilience' scenarios (2023-2050, tonnes)



Key uncertainties and limitations

The key uncertainty that could materially impact the uptake of hydrogen for residential and commercial use is whether or not hydrogen blending occurs using the existing natural gas infrastructure and to what extent hydrogen is blended over time (e.g. 20% as modelled, or eventual full conversion to 100% hydrogen). If a higher proportion of hydrogen is transported through the natural gas system, then It is also likely that end users will have to replace their existing technology (e.g. heating and cooking appliances) with new technology that is able to tolerate higher proportions of hydrogen. Given New Zealand's highly renewable electricity system, and the current technology readiness of electric heating and cooking technologies, hydrogen uptake in a scenario with higher blending ratios may be more dependent on its cost competitiveness with electric (or biogas) alternatives.

6. Modelled hydrogen production and supply

The following section describes the modelled output of hydrogen demand across each scenario.

6.1 Hydrogen production volume

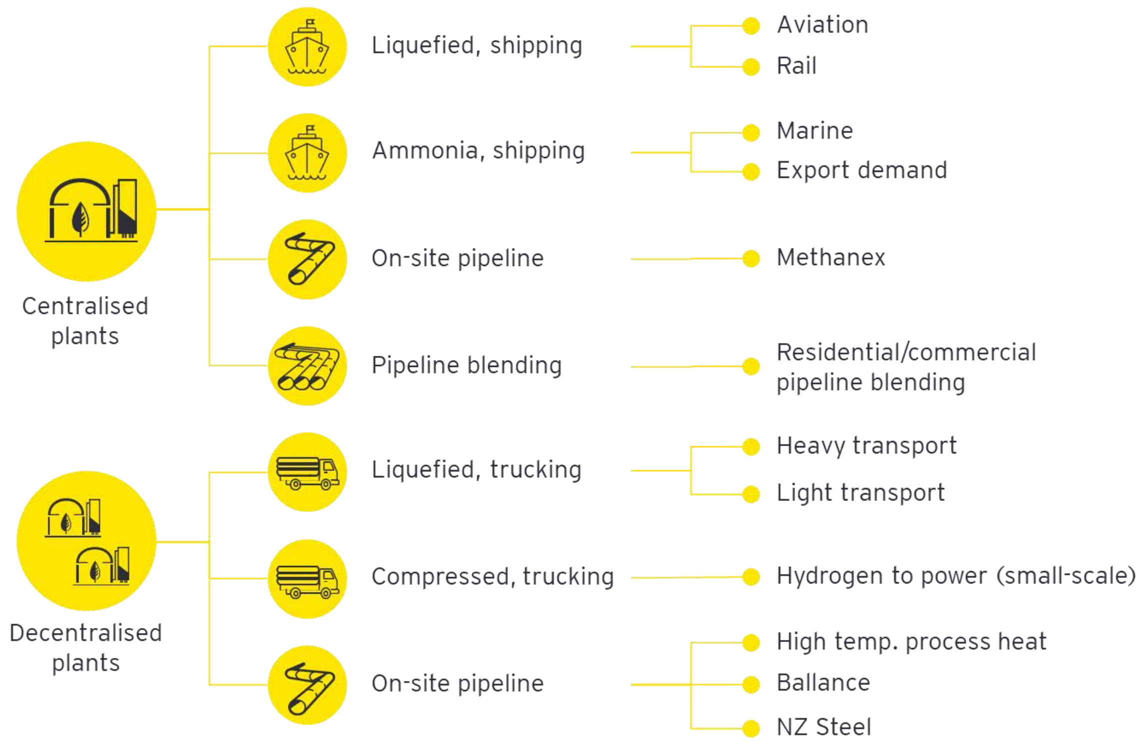
As per the modelling methodology described in section 3, hydrogen production volumes are based on the total demand modelled. In each scenario, we have considered how hydrogen production might be split between large, centralised plants and smaller, decentralised plants spread around the country.

It is expected that centralised plants will likely be in regions such as (but not limited to) Taranaki, Southland or Northland where there is an existing industrial base and infrastructure to enable the distribution of hydrogen. These plants will likely be hundreds of MW In capacity and produce tens of thousands of tonnes of hydrogen annually. It is expected that smaller, decentralised plants will be spread around the country, close to hydrogen demand and be tens of MW in size or smaller. Note that the model does not consider the regional distribution of plants, distribution distances, or specific sizes (MW) for centralised and decentralised plants. These are potential areas for further analysis outside of this model.

Modelling assumptions

To determine the volume of hydrogen production for each plant type, it is assumed that for each demand sector, hydrogen demand is supplied from a particular channel and plant type. For ease of modelling, a 'likely' channel (Figure 23) is assumed but it is possible that each demand sector may receive its hydrogen from multiple channels depending on factors such as proximity to plants, geographical location, and supply contracts. The assumptions are based on our understanding of the hydrogen sector and have been informed by limited consultation with the industry.

Figure 23: Modelled centralised and decentralised production by demand



These assumptions and associated demand curves drive the differences in supply from each plant type. There are also assumed levels of hydrogen energy required for different transformation and distribution processes which are outlined in section B.3.3 of the appendix. This results in total hydrogen production being greater than end-use demand. In this model, it is assumed that the energy for transformation and distribution is delivered by hydrogen however it is possible that electricity or other source can provide the energy for these processes.

Modelling outputs – Base case

The modelling suggests that under the base case, hydrogen production from large, centralised plants is modelled to reach approximately 137,600 tonnes in 2035 and 325,000 tonnes in 2050 while production from smaller, distributed plants would reach approximately 95,200 tonnes in 2035 and 395,900 tonnes in 2050. This means the total supply for hydrogen production will reach approximately 232,800 tonnes in 2035 and 721,000 tonnes in 2050.

Total production is greater than total end demand to account for the energy used for transformation and distribution processes along the hydrogen supply chain. These assumptions are detailed in section B.3.3 of the appendix.

Figure 24: Hydrogen production by plant type in base case (2023-2050, tonnes)

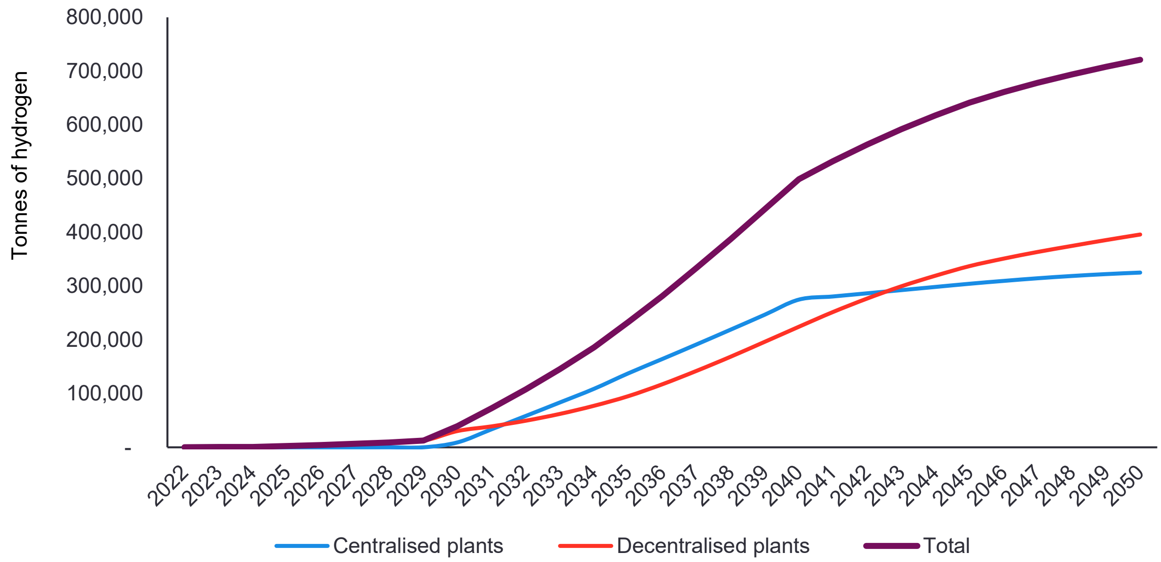


Table 6: Hydrogen supply by plant type (2035 and 2050)

Plant type	2035		2050	
	tonnes	% of total	tonnes	% of total
Centralised	137,622	59%	325,095	45%
Decentralised	95,167	41%	395,899	55%
Total	**232,789**	**100%**	**720,993**	**100%**

Modelling outputs – Alternative scenarios

The following figures illustrate how the build out of centralised and decentralised production of hydrogen varies across the alternative scenarios.

As shown in Figure 25 centralised hydrogen supply almost doubles from the base case scenario under the 'Accelerated uptake' scenario, reaching approximately 620,000 tonnes by 2050. This is mostly driven by the increased and more rapid uptake of hydrogen from Methanex from 2025 which accounts for 56% of all hydrogen demand, and 90% of centralised hydrogen production by 2035 in this scenario.

Under the ‘Export market’ and ‘Value-add export’ scenarios, it is assumed that there are three staggered introductions of export plants resulting in a significant increase in the level of centralised hydrogen supply, reaching approximately 854,600 tonnes and 943,000 tonnes of hydrogen by 2050 respectively. Higher levels of supply required under the ‘Value-add export’ scenario is due to the assumed increase in feedstock in line with long-term GDP growth.

Figure 25: Centralised hydrogen production by scenario (2023-2050, tonnes)

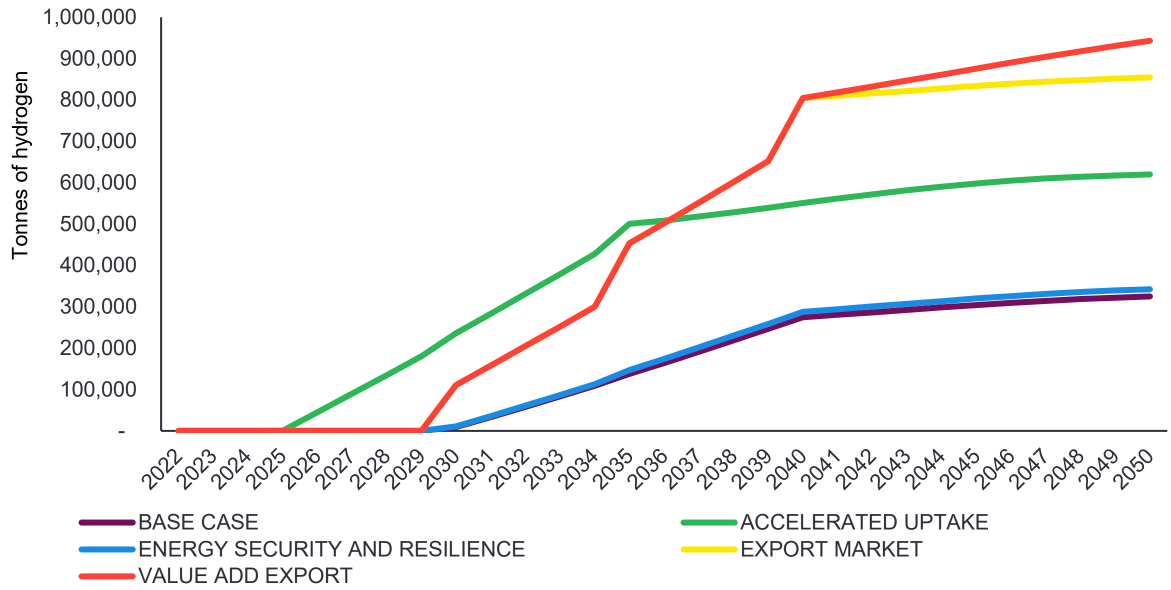


Figure 26 displays varying levels of decentralised hydrogen supply for the alternative scenarios. The modelling shows the largest increase under the ‘Accelerated uptake’ scenario which results in supply reaching approximately 591,700 tonnes or a 49% increase in supply levels on the base case scenario by 2050. This is closely followed by other alternative scenarios, where the modelled supply increases are between 28-48% on the base case. This is a result of greater hydrogen uptake in the transport and process heat sectors.

Figure 26: Decentralised hydrogen production by scenario (2023-2050, tonnes)

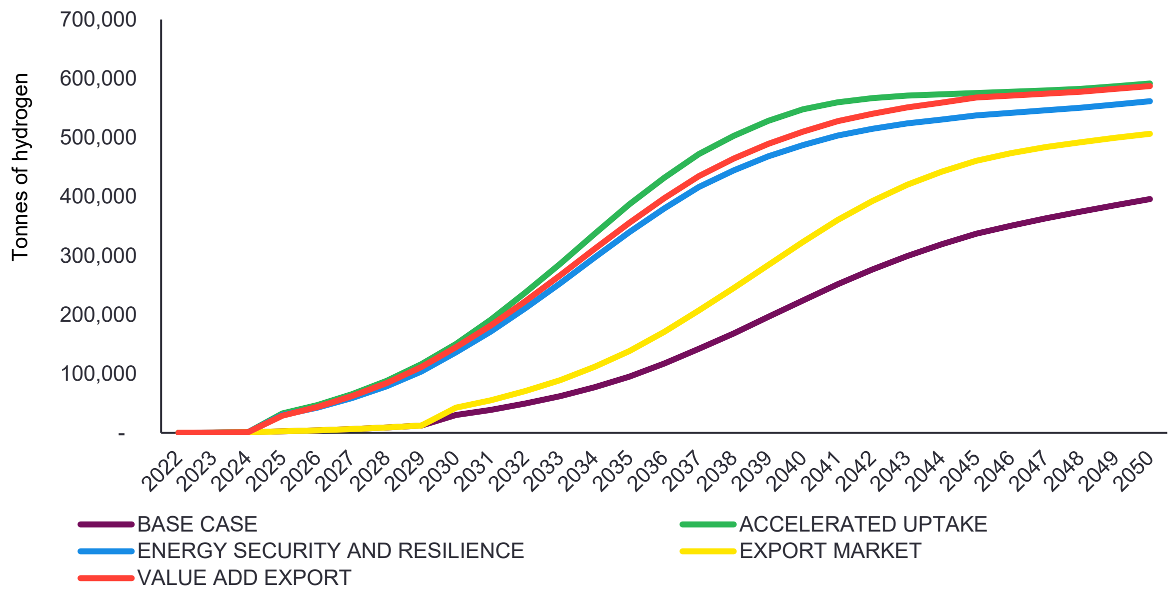


Table 7: Overview of differences in hydrogen production modelling by scenario

Scenario	2035				2050			
	tonnes	+/- Base	Cent %	Decent %	tonnes	+/- Base	Cent %	Decent %
Base case	232,789	+0%	59%	41%	720,993	+0%	45%	55%
Accelerated uptake	887,145	+281%	56%	44%	1,211,722	+68%	51%	49%
Energy security and resilience	486,543	+109%	30%	70%	903,895	+25%	38%	62%
Export market	591,838	+154%	77%	23%	1,360,986	+89%	63%	37%
Value-add export	808,784	+247%	56%	44%	1,530,385	+112%	62%	38%

6.2 Electrolyser capacity

In each scenario, the modelled centralised and decentralised hydrogen production is used to calculate the electrolyser capacity required for each plant type.

Modelling assumptions – Base case and alternative scenarios

The key assumption for determining the electrolyser capacity required in each scenario is the utilisation and efficiency of each plant type.

For centralised plants, it is assumed they are available for 95% of the year. Their efficiency increased from 68% in 2022 to 80% in 2050, based on projections made by IRENA[46]. For decentralised plants, it is assumed they are available for 95% of the year. Their efficiency increased from 50% in 2022 to 80% in 2050, based on projections made by IRENA[47].

For both plant types, and all scenarios except the 'Energy security and resilience' scenario, it is assumed that plants operate with a 90% capacity factor and that the remaining 10% is curtailed electricity demand due to demand response. This changes to 85% and 15% respectively in 'Energy security and resilience' to represent higher support for the electricity system.

It is possible that in the future, plants will be able to operate economically at lower capacity factors due to lower capital and operating costs. This would enable operators running a wind/solar plant and electrolyser to turn off their production for a greater proportion of time and sell their electricity to the grid. This consideration is not included in this model.

Modelling outputs – Base case

In the base case, the modelling shows electrolyser capacity will reach 1.5 GW by 2035 and 4.5 GW by 2050 as shown in Figure 27.

In 2050, approximately 43% of capacity is in centralised plants and 57% is in decentralised plants

A gradual increase in centralised electrolyser capacity is modelled to avoid dictating specific years that plants come online (with the exception of the 'Export market' scenario). In reality, the capacity

[46] Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal, International Renewable Energy Agency (IRENA)
[47] Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal, International Renewable Energy Agency (IRENA)

curve may increase in step changes (e.g., 100s of MW) as large plants come online. Smaller step changes (i.e., 10MW) would be expected for decentralised plants.

Figure 27: Hydrogen electrolyser capacity in base case by plant type (2023-2050, GW)

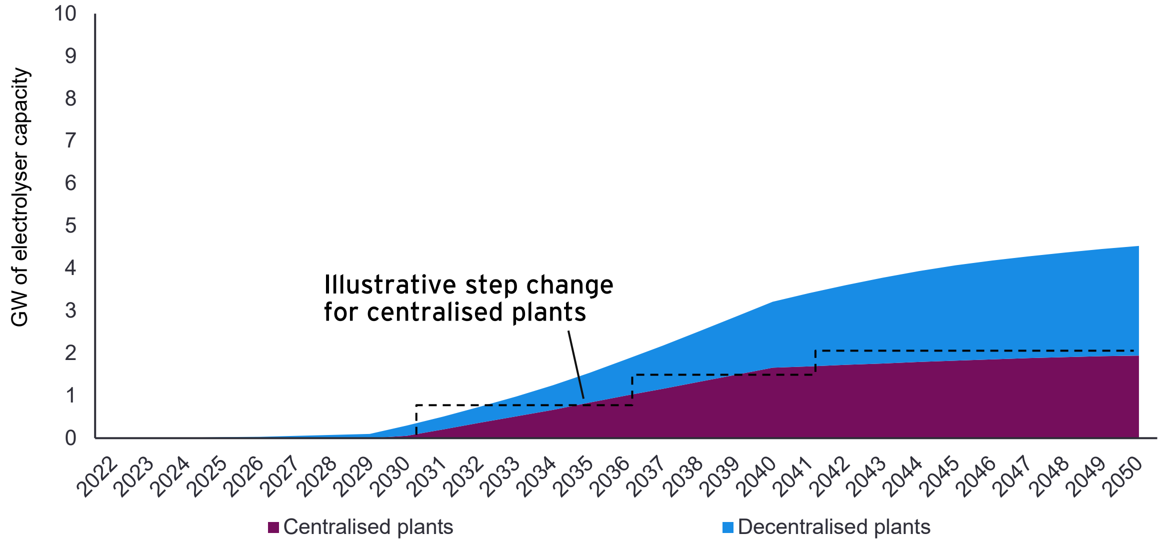


Table 8: Hydrogen electrolyser capacity from base case by plant type (2035 and 2050, GW and % of total)

Plant type	2035		2050	
	GW	% of total	GW	% of total
Centralised	0.8	55%	1.9	43%
Decentralised	0.7	45%	2.6	57%
Total	**1.5**	**100%**	**4.5**	**100%**

Modelling outputs – Alternative scenarios

Movements in the level of hydrogen electrolyser capacity are directly linked to the total hydrogen supply levels. As a result, scenarios with more demand/production have higher electrolyser capacity required, as shown in Figure 28 below.

Under the ‘Energy security and resilience’ scenario, an increased need for demand response from hydrogen production plants is assumed which results in a lower utilisation rate. This means that the ‘Energy security and resilience’ scenario requires a higher capacity of electrolysers to produce the same volume of hydrogen.

Figure 28: Comparison of hydrogen electrolyser capacity by scenario (2023-2050, GW)

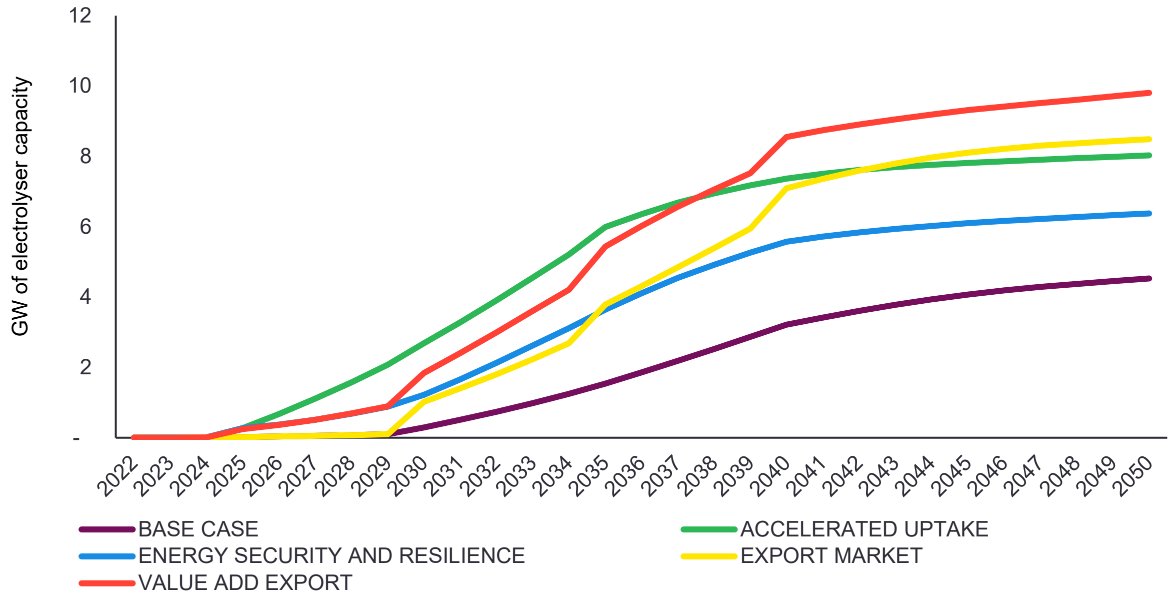


Table 9: Key difference in hydrogen electrolyser capacity between scenarios (2035 and 2050)

Scenario	2035		2050	
	GW	+/- Base case	GW	+/- Base case
Base case	1.5	0%	4.5	0%
Accelerated uptake	6.0	+289%	8.0	+77%
Energy security and resilience	3.6	+136%	6.4	+41%
Export market	3.8	+146%	8.5	+87%
Value-add export	5.4	+253%	9.8	+117%

6.3 Distribution

Total hydrogen supply by distribution type is directly driven by the demand sector make-up of the total supply and the distribution method assumptions as laid out earlier in Figure 23.

Modelling assumptions – Base case and alternative scenarios

Levels of additional hydrogen energy required for different transformation and distribution channels have been assumed, which are outlined below and in section B.3.3 of the appendix. These are high level assumptions based on desktop research. This part of the model is less evolved than other areas and therefore outputs should be considered as directional only.

Modelling outputs – Base case

Under the base case scenario, on-site pipeline distribution consists of 50% of the total supply in 2050. This is because industrial feedstock is modelled as the largest demand sector for hydrogen. Process heat hydrogen demand is also material and assumes that plants are co-located with hydrogen production. Other distribution methods which make up the remaining 50% of the total supply consist of compressed trucking, liquefied trucking, liquefied shipping and ammonia shipping. Compressed trucking volumes are insignificant due to the low demand from hydrogen to power. In reality, it is possible that compressed trucking volumes could be greater due to plant specific needs in sectors such as process heat and transport.

Note that hydrogen supply via blended pipeline is zero under the base case scenario as it is assumed no hydrogen blending for residential and commercial gas users.

Figure 29: Base case hydrogen supply by distribution type (2022-2050, tonnes)

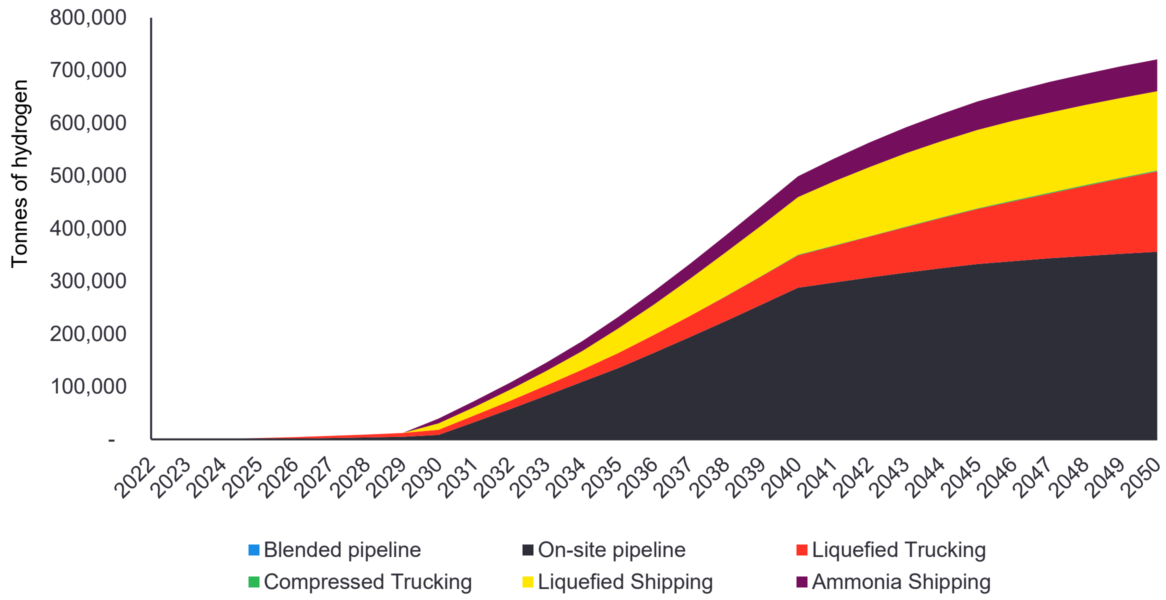


Table 10: Base case hydrogen supply by distribution type (2035 and 2050, tonnes and percentage of total)

Sector	2035		2050	
	tonnes	% of total	tonnes	% of total
Compressed trucking	235	0%	1,830	0%
Liquefied trucking	28,269	12%	152,557	21%
Liquefied shipping	46,892	20%	150,428	21%
Ammonia shipping	21,810	9%	60,210	8%
Blended pipeline	0	0%	0	0%
On-site pipeline (co-located)	135,583	58%	355,968	50%
Total	**232,789**	**100%**	**720,993**	**100%**

Modelling outputs – Alternative scenarios

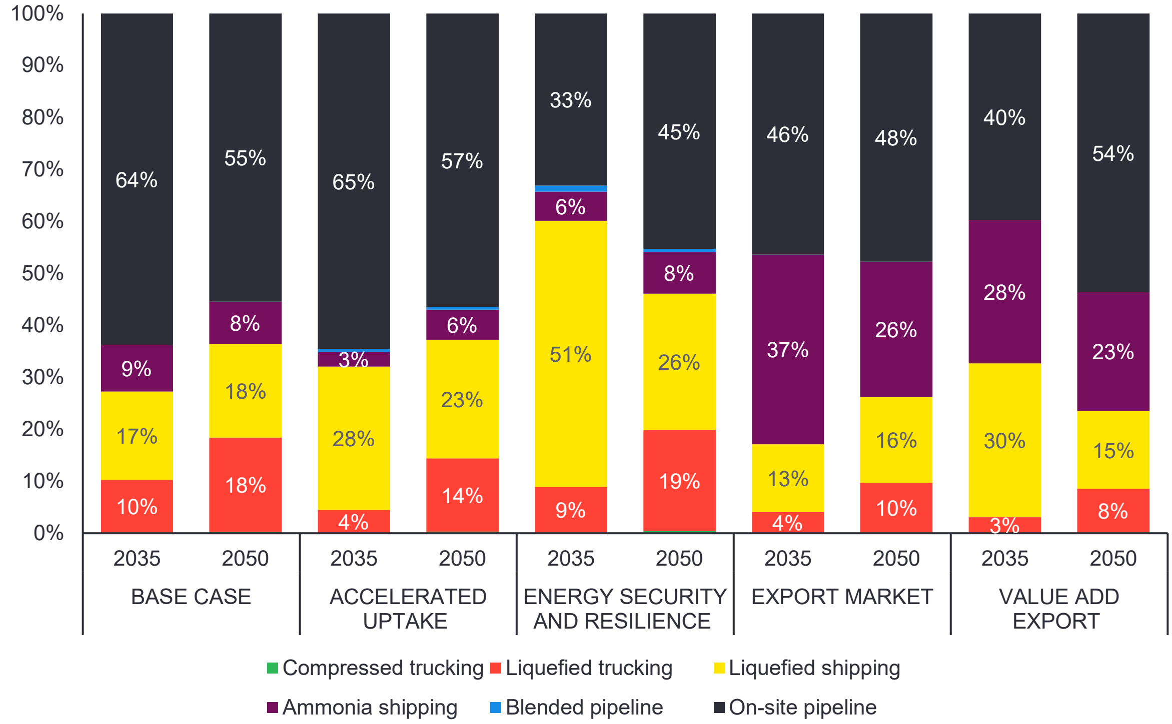
For each of the alternative scenarios, hydrogen supply composition by distribution types will be driven by the changing levels of hydrogen demand for each of the demand sectors. Refer to Figure 30 below for hydrogen supply breakdown by distribution types for each of the scenarios.

Under the 'Accelerated uptake' the hydrogen supply profile by distribution type remains similar to the base case scenario as all demand sectors under this scenario are assumed to have greater and more rapid uptake of hydrogen. The increase in liquefied hydrogen shipping can be attributed to aviation and rail uptake having faster and higher modelled uptake levels.

Under the 'Energy security and resilience', there is a higher proportion of liquefied shipping in the earlier years of the modelled period due to higher and more rapid uptake assumed in the aviation and marine transport sector. Because industrial feedstock uptake levels are modelled to be lower than the 'Accelerated uptake' scenario, there is a smaller proportion of on-site pipeline use.

The chart also illustrates a significant increase in the proportion of hydrogen supply via ammonia shipping under 'Export market' and 'Value-add export' due to the increased export demand. Therefore, the relative proportion of supply through other distribution types is lowered. Ammonia shipping is used in the other scenarios to supply hydrogen to the marine sector.

Figure 30: Hydrogen supply by distribution type and scenario (2035, 2050)



6.4 Water consumption

Water consumption is modelled as it is a key input for hydrogen production and its use will draw on New Zealand's natural resources. Water use is driven by the volume of hydrogen production and is an important consideration in determining the LCOGH. It is assumed that 9 litres of water are required for each kilogram of hydrogen produced.

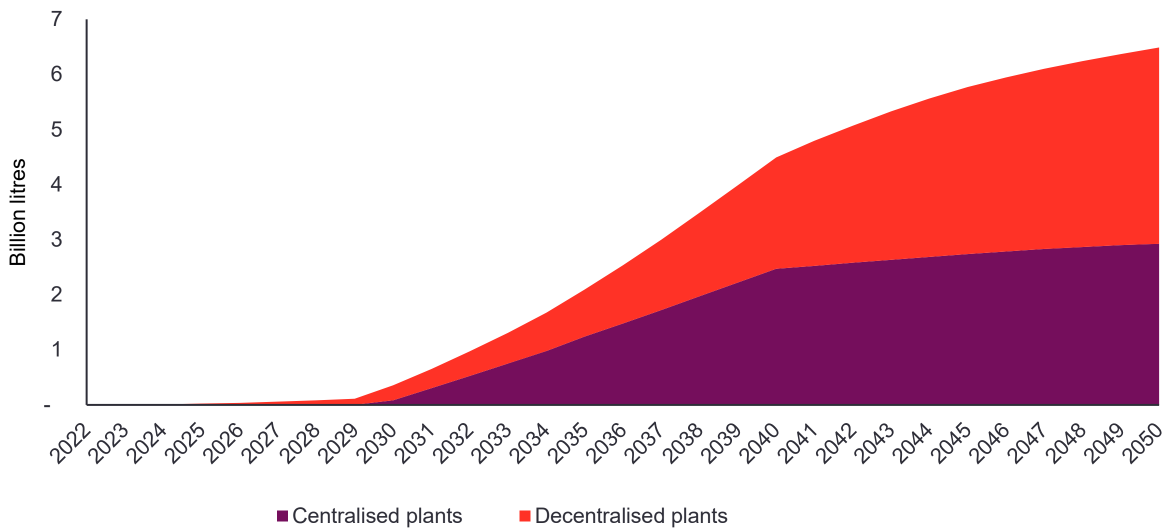
It is out of the scope of this study to consider the cultural and commercial arrangements for procuring such volumes of water. It is, however, important to note that for Māori, water has significant cultural importance. Iwi and Māori have rights and interests in water across the country. Plant developers and operators will need to follow proper consultation and engagement if they wish to access water for hydrogen development.

The type of water that will be used for hydrogen production other than freshwater has not been considered in this model. Desalination of sea water[48] or use of wastewater[49] are also being considered globally.

Modelling outputs – Base case

Figure 31 below illustrates the estimated water consumption from hydrogen production in the base case.

Figure 31: Annual water consumption in base case by hydrogen plant type (2023-2050, billion litres)



In the base case, hydrogen water consumption is modelled to meet 2.1 billion litres annually by 2035 and 6.5 billion litres annually by 2050.

In 2017, New Zealand consents allowed for 7.45 trillion litres of freshwater for irrigation, 2.16 trillion for drinking and 1.3 trillion litres for industrial use[50]. Compared to these figures, the modelled water consumption from hydrogen is equivalent to less than 1% of each of these uses. As another comparison, New Zealand's water bottling industry currently consumes 163 million litres of water annually[51]. By 2035, the modelled water demand from hydrogen is equivalent to over ten times this figure.

Note that while the aggregate effect of hydrogen demand on water is small in comparison to other water uses in New Zealand, water use constraints for specific hydrogen plants may exist in the form of regional water and infrastructure capacity and existing consents and allocations in the area, The modelling does not specify the regions where this water is drawn from, however, generally, it is expected that centralised plants will tend to draw large volumes of water in concentrated areas (e.g. Taranaki, Southland, Northland). Decentralised plants will draw water in smaller volumes distributed across the country.

In their New Zealand Hydrogen Scenarios report[52], Castalia noted that an irrigated dairy farm in New Zealand uses an estimated 712 million litres annually and a large brewery uses an estimated 319 million litres annually. In the modelling, a 300MW centralised plant is expected to use 413

[48] 'Vast majority' of green hydrogen projects may require water desalination, potentially driving up costs | Recharge (rechargenews.com)
[49] Hydrogen cheaply produced from wastewater with new technique | E&T Magazine (theiet.org)
[50] Consented freshwater takes | Stats NZ
[51] Water Bottling (nzbeveragecouncil.org.nz)
[52] New Zealand Hydrogen Scenarios Report June 2022 (mbie.govt.nz)

million litres of water annually, and a 10MW decentralised plant is expected to use 10 million litres of water annually.

Table 11 summarises the total water demand modelled for hydrogen use in 2035 and 2050. The proportion of water demand in the model slowly shifts from centralised to decentralised plants over the forecast period of the model.

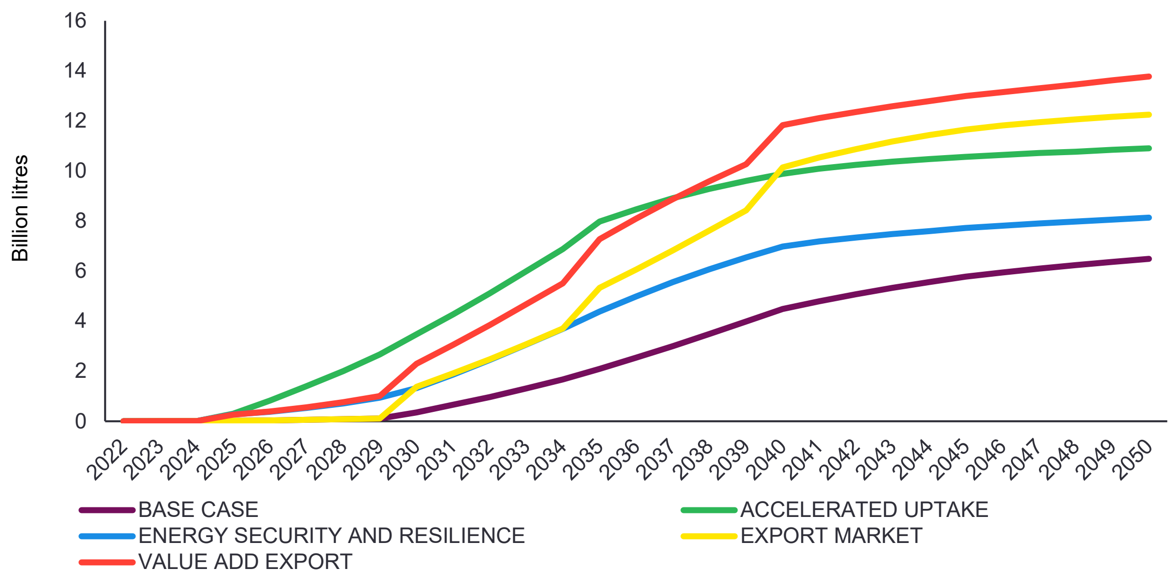
Table 11: Base case annual water consumption

Plant type	2035		2050	
	Billion L	% of total	Billion L	% of total
Centralised	1.2	59%	2.9	45%
Decentralised	0.9	41%	3.6	55%
Total	**2.1**	**100%**	**6.5**	**100%**

Modelling outputs - Alternative scenarios

Figure 32 below illustrates the comparison of water consumption by scenario. As water use is driven by hydrogen production in each scenario, the differences are consistent with that of hydrogen production in each scenario.

Figure 32: Annual water consumption by scenario (2023-2050, billion litres)



As expected, water demand in the 'Value-add export' and 'Export' scenarios is greatest, reaching 13.8 billion litres and 12.2 billion litres by 2050 respectively. While around double than the base case, these values still represent less than 1% of New Zealand's consented freshwater use[53].

Table 12 below summarises the key differences across scenarios.

[53] Consented freshwater takes | Stats NZ

Table 12: Comparison of water consumption across scenarios

Scenario	2035		2050	
	Billion L	+/- Base case	Billion L	+/- Base case
Base case	2.1	0%	6.5	0%
Accelerated uptake	8.0	+281%	10.9	+68%
Energy security and resilience	4.4	+109%	8.1	+25%
Export market	5.3	+154%	12.2	+89%
Value-add export	7.3	+247%	13.8	+112%

6.5 Electricity system implications

Hydrogen production is expected to have material implications for the electricity system. In the following sections, we discuss the modelled electricity demand, potential electricity generation build out required, demand response and additional electricity price considerations.

6.5.1 Electricity demand from hydrogen production

In each scenario, electricity demand from hydrogen production is modelled.

Modelling assumptions – Base case and alternative scenarios

The key assumption for determining electricity demand from hydrogen is the efficiency of the hydrogen electrolysers and the volume of hydrogen produced. Hydrogen plants are modelled to have increasing efficiency as electrolyser technologies improve (from 50-68% in 2022 to 80% in 2050, as discussed in Section 6.2), therefore reducing the amount of electricity required per kilogram of hydrogen over time.

Where electricity is sourced from depends on whether the hydrogen production plant is centralised or decentralised.

To enable us to consider the flexibility of electrolysers and understand the potential magnitude of new renewable build required to supply electricity to these electrolysers, we have modelled different electricity offtake profiles for centralised and decentralised plants.

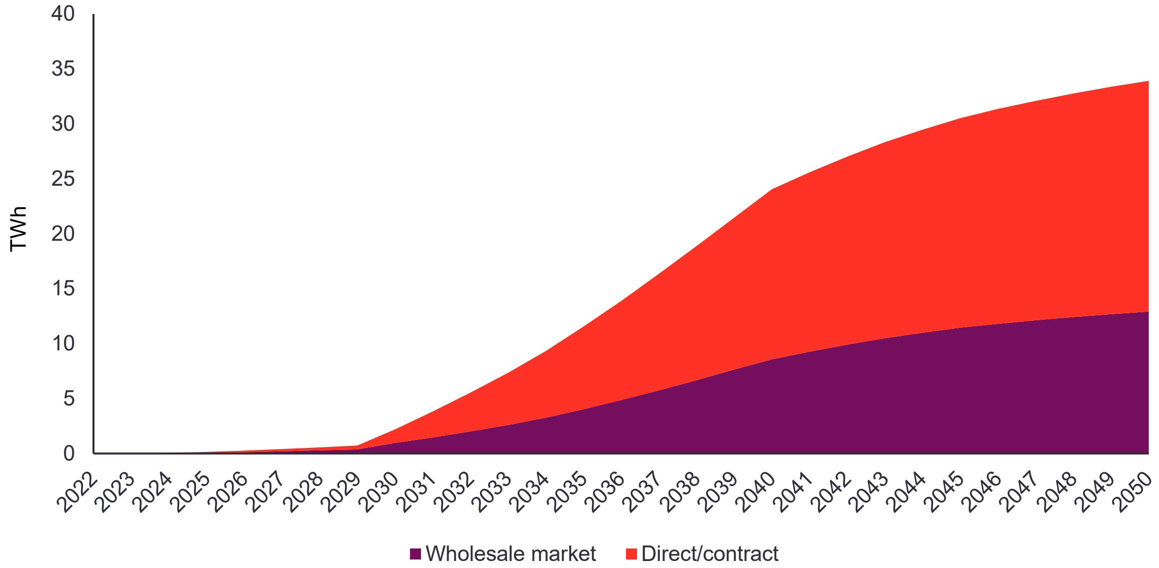
Due to their buying power, it is assumed that large, centralised plants can secure long-term electricity offtake agreements and/or build significant onsite renewable generation to supply 70% of electricity generation for a plant. It is assumed that the remaining 30% of electricity required will be supplied from the wholesale market to accommodate for the intermittency of renewable generation and enable electrolysers to soak up excess renewables on the market. It is also assumed that these plants will be able to curtail demand and divert any on-site or contracted generation to the grid during peak periods to support the network.

Smaller, decentralised plants are assumed to have a mix of electricity supplied from the wholesale market and from direct generation/long-term contracts/Power Purchase Agreements (PPAs). Due to the uncertainty around what this mix will be in the future, it is assumed that there is an even split of wholesale market and direct supply. In practice, some small plants may be able to offtake all electricity from an on-site generation or some from a PPA and the rest from the wholesale market. It is assumed that these plants will also be able to provide demand response during peak periods and may be incentivised to do so in response to high wholesale electricity prices.

Modelling outputs – Base case

As shown in Figure 33 below, in the base case, electricity demand from hydrogen production is modelled to reach 11.5 TWh by 2035 and 33.9 TWh by 2050 (equivalent to approximately 27% and 80% of New Zealand's 2022 electricity demand[54] respectively). We discuss later in section 6.5.3 the potential implications this demand has on the wider electricity demand growth expected across the economy.

Figure 33: Electricity demand from hydrogen demand by electricity source in base case (2023-2050, TWh)



Of this electricity demand, in 2050, approximately 38% is sourced from the wholesale electricity market and 62% is sourced from a direct investment/long-term contract.

Table 13: Electricity demand from hydrogen supply plant type (2035 and 2050, TWh and % of total)

Electricity source	2035		2050	
	TWh	% of total	TWh	% of total
Wholesale market	4.0	35%	12.9	38%
Direct investment/long-term contract	7.5	65%	21.0	62%
Total	**11.5**	**100%**	**33.9**	**100%**

Modelling outputs – Alternative scenarios

Figure 34 below illustrates how electricity consumption from hydrogen production varies across scenarios. As electricity consumption is directly driven by hydrogen production in each scenario, the differences across scenarios are consistent with the differences in hydrogen demand.

[54] Electricity data tables, MBIE.

Figure 34: Total electricity demand from hydrogen by scenario (2023-2050, TWh)

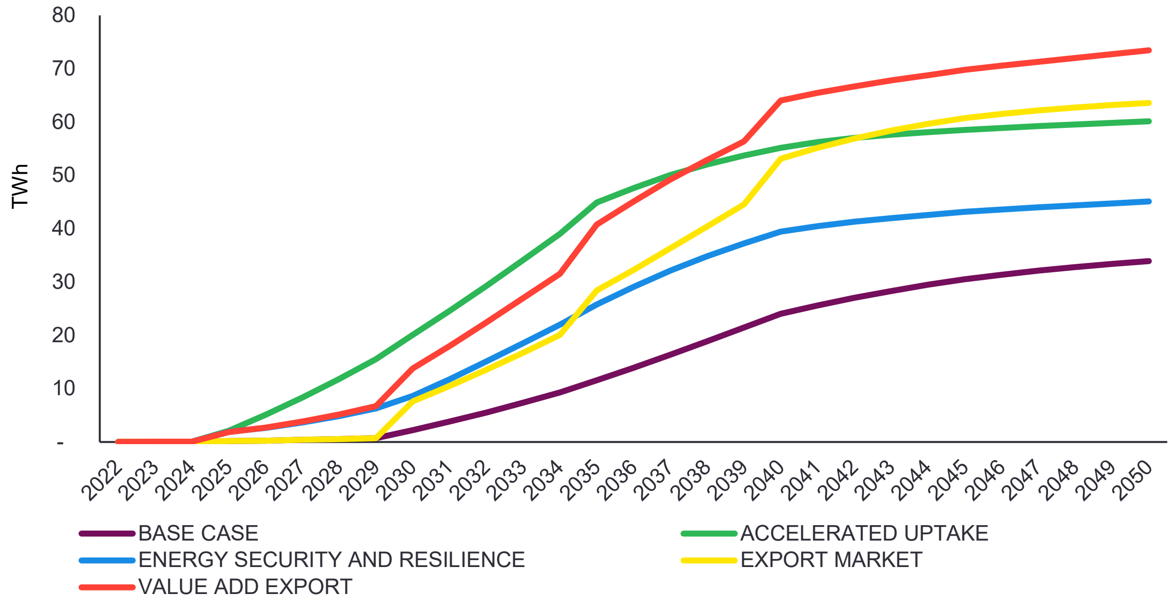
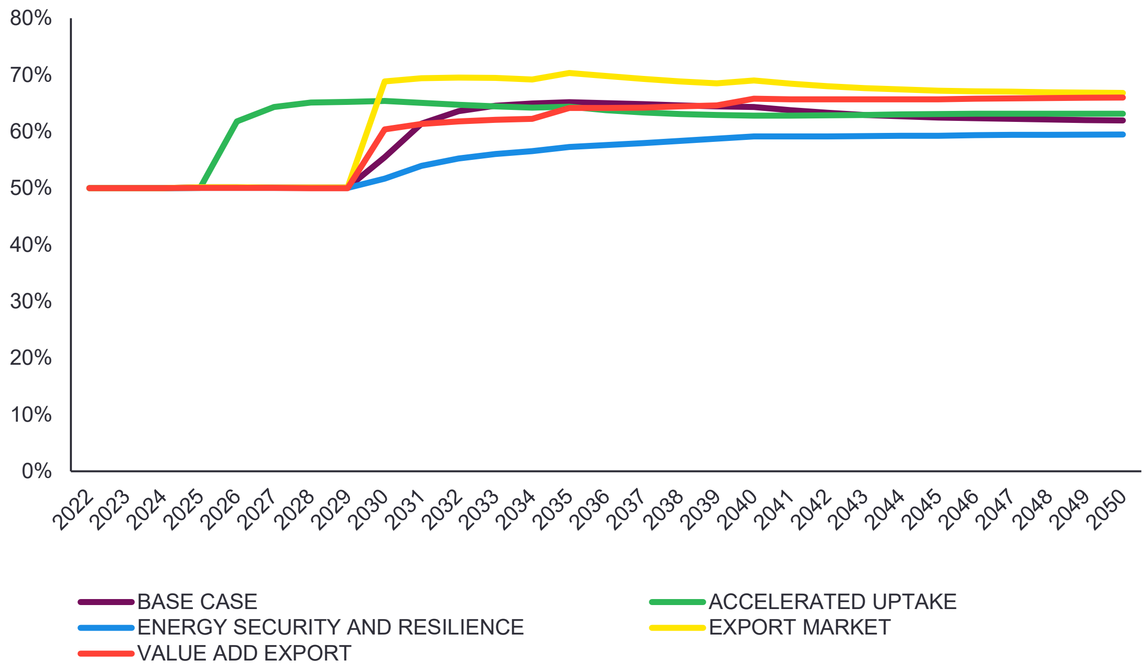


Figure 35 illustrates how scenarios differ in terms of the proportion of electricity that is sourced from direct investment / long-term contracts. The proportion of electricity that is sourced from the wholesale market is calculated as 100% less the proportion sourced from direct investment.

Figure 35: Proportion of electricity sourced from direct investment/long-term contracts by scenario



As evident in Figure 35, all scenarios have at least 50% of their electricity supplied from direct investment/long-term contracts from 2022, rising to 60-70% by 2050. Note that the volatility and fluctuations in the proportion of electricity sourced from direct investments/long-term contracts leading up to 2030 are largely due to there being low levels of demand and production in these early years. Therefore, any growth in demand/production in these years (e.g., from industrial feedstock or different transport sectors) can have a material impact on the proportions. For example, in 'Accelerated uptake', the jump in 2025 can be attributed to Methanex beginning its conversion, and therefore a higher proportion of centralised production coming online. Similarly in 2030, the jump in the base case and 'Energy security and resilience' can be attributed to

Methanex's conversion. For the 'Export market' and 'Value-add export', the jump in 2030 can also be partly attributed to the export plants coming online.

Furthermore, it is important to note that a declining proportion (e.g., 2030 in the base case) does not signal a decline in electricity used, but rather a material increase in electricity consumed from the wholesale market.

As discussed in the previous section, where electricity is sourced from in each scenario is driven by the makeup of centralised and decentralised plants. Centralised plants are modelled to procure over 70% of their electricity from direct investment/long-term contracts whereas this figure is 50% for decentralised plants. Therefore, scenarios with a higher proportion of centralised hydrogen production will procure more electricity from direct investment/long-term contracts. Consequently, 'Export market' and 'Value-add market' scenarios have a higher proportion of electricity sourced from direct investment/long-term contracts. In these scenarios, when the export plants come online, it is evident in the figure that the proportion of electricity from direct investment/long-term contracts increases in that year, then gradually declines as more incremental, decentralised production is built.

Table 14 below summarises the key differences across scenarios.

Table 14: Overview of differences in hydrogen powered electricity generation modelling by scenario

Scenario	2035			2050		
	+/- Base	% from market	% from contract	+/- Base	% from market	% from contract
Base case	0%	35%	65%	0%	38%	62%
Accelerated uptake	+289%	36%	64%	+77%	37%	63%
Energy security and resilience	+123%	43%	57%	+33%	41%	59%
Export market	+146%	30%	70%	+87%	33%	67%
Value-add export	+253%	36%	64%	+117%	34%	66%

6.5.2 Potential demand response capacity

As noted earlier, the modelling assumes that hydrogen production plants have the flexibility and appetite to flex their electricity demand in response to electricity prices or contractual arrangements. The reduced demand modelled is illustrated as potential demand response capacity.

As the model is run on an annual basis, further analysis is required to better understand the demand response dynamic, the commercial attractiveness of this to hydrogen plants and the consequent ability and appetite to support the security of supply on an hourly, daily and seasonal time frame. Other factors such as contractual arrangements (e.g., offtake requirements for export), electricity market rules and incentives and technological feasibility in other areas of the value chain (e.g., local electricity network) may also impact the potential demand response capacity for any given plant.

Modelling assumptions – Base case and alternative scenarios

In the base case, 'Accelerated uptake', 'Export market' and 'Value-add export', it is assumed that hydrogen production plants may curtail demand for approximately 10% of the year (e.g., run at zero capacity for 2.4 hours a day or 36.5 days a year, or run at 50% for 4.8 hours a day on average). The 'Energy security and resilience' scenario assumes that plants may curtail their demand for 15% of the year to represent a higher integration with the energy system and support energy security.

Modelling outputs – Base case and alternative scenarios

Figure 36 below illustrates the difference in demand response capacity by scenario.

Under the base case, the modelling suggests there will be 1.3 TWh of potential demand response annually by 2035 and 3.8 TWh of demand response by 2050.

As with electricity supply, the demand response capacity in each scenario is largely driven by the demand for electricity, therefore all alternative scenarios have a higher demand response capacity than the base case.

Of note is the 'Energy security and resilience' scenario, which has the second highest total demand response capacity, falling just below 'Value-add export', due to its demand response representing a higher level of electrolyser curtailment.

Figure 36: Annual demand response capacity by scenario (2023-2050, TWh)

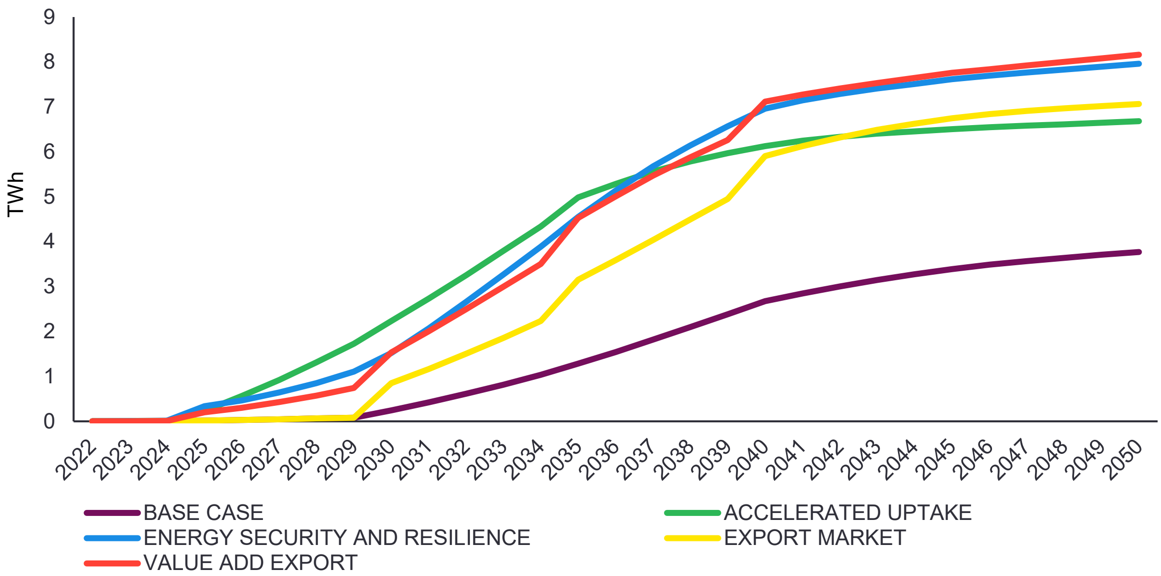


Table 15 below summarises the key differences across scenarios.

Table 15: Comparison of demand response capacity by scenario

Scenario	2035		2050	
	TWh	+/- Base case	TWh	+/- Base case
Base case	1.3	0%	3.8	0%
Accelerated uptake	5.0	+289%	6.7	+77%
Energy security and resilience	4.6	+255%	8.0	+111%
Export market	3.2	+146%	7.1	+87%
Value-add export	4.5	+253%	8.2	+117%

6.5.3 Implied generation investment

Electricity demand and capacity factors of electricity generation technologies have been used to understand the potential build out required of the electricity generation stack. Note that the analysis is limited to the total generation capacity required and excludes modelling of individual generation plants coming online, or the additional network build out required.

Modelling assumptions – Base case and alternative scenarios

To understand the potential magnitude of the electricity generation build out required, four curves are presented to represent a range for the potential generation that would be built depending on technology type.

- Firm capacity: if all generation built can be operated at full capacity
- All onshore wind: if all generation built is wind and operates with a 40% capacity factor
- All solar: if all generation built is solar and operates with a 22% capacity factor
- Mid-point wind and solar: if generation built is split evenly between wind and solar and has an effective capacity factor of 31%. We see this estimate as being closest to the likely outcome due to the mix of solar and wind technologies.

It is important to note that because the modelling was completed on an annual basis, the estimated build out of electricity generation relies on annual electricity values and does not consider time of day of generation (e.g., solar during daylight hours) or accompanying storage technologies (e.g. solar-battery systems). We have also restricted the analysis to wind and solar, which are expected to grow the most in the next three decades. However, other generation technologies such as geothermal, offshore wind are also possible. Further analysis is required to understand the generation stack build out in more detail.

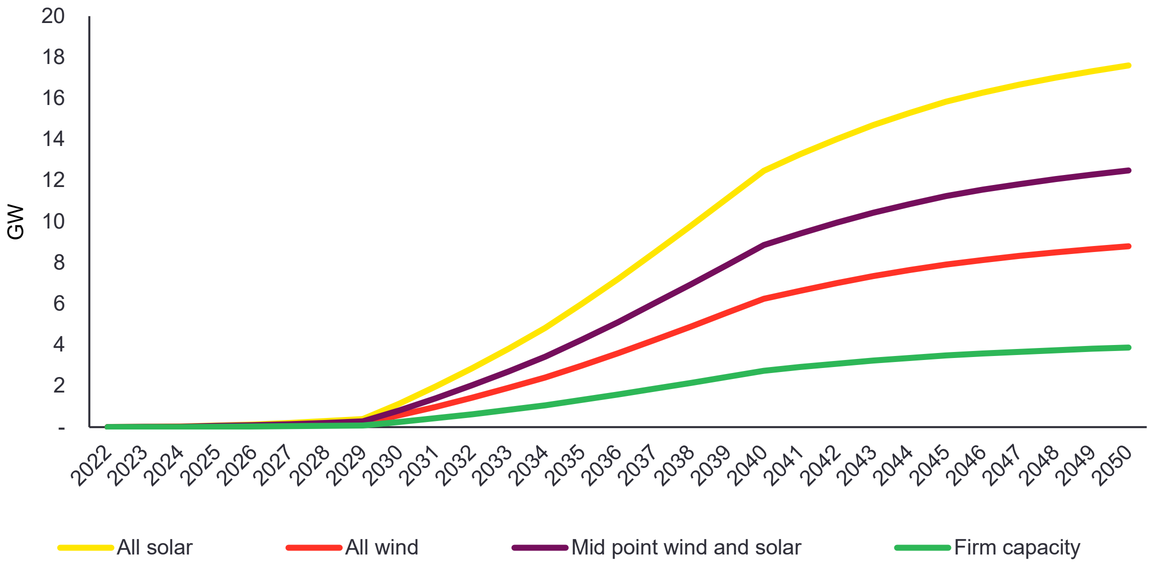
For electricity generation build and capacity factor assumptions, see section B.3.1 of the Appendix.

Modelled outputs and further analysis – Base case

Figure 37 below illustrates the potential electricity generation that would need to be built to support hydrogen production in the base case.

- Firm capacity: if all generation built can be operated at full capacity, then 3.9 GW would be required by 2050
- All onshore wind: if all generation built is wind and operates with a 40% capacity factor then 8.8 GW would be required by 2050
- All solar: if all generation built is solar and operates with a 22% capacity factor then 17.6 GW would be required by 2050
- Mid-point wind and solar: if generation built is split evenly between wind and solar and has an effective capacity factor of 31% then 12.5 GW would be required by 2050.

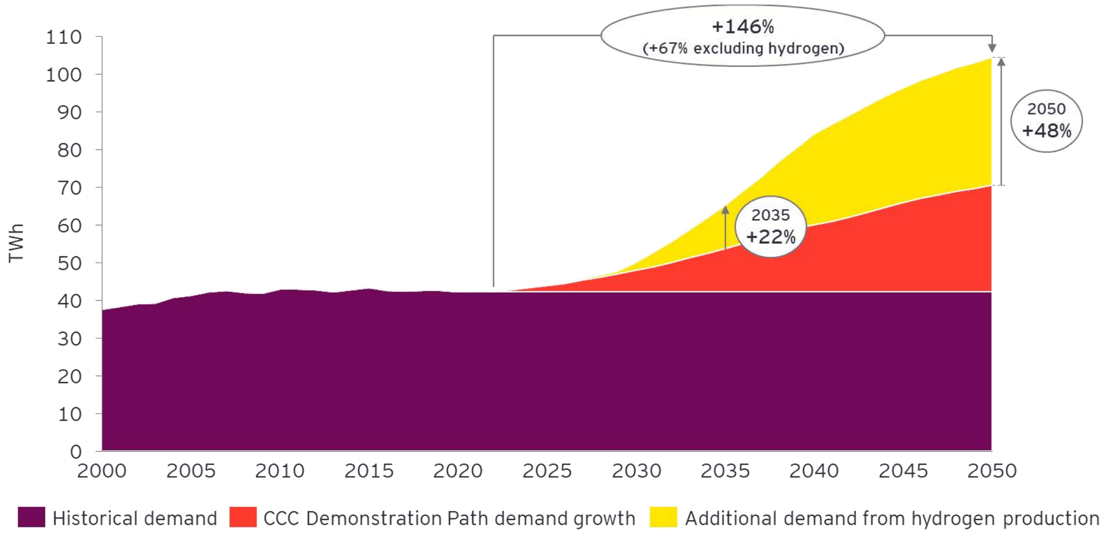
Figure 37: Electricity generation build out breakdown for base case (2023-2050, GW)



If New Zealand were to pursue the build out of a hydrogen supply chain at scale, then the energy industry would have to consider the scale, pace and sequencing of electricity generation and network investment. It is important to consider the build out of the electricity generation required for hydrogen in the context of the wider investment needs of the electricity system required for electrification. This consideration will ensure that the hydrogen supply chain can stimulate and support new electricity generation development without negatively affecting the wider energy transition.

In Figure 38 below, the additional electricity required for hydrogen in the base case is overlayed with the Climate Change Commission's modelled electricity demand (in the scenario where NZAS remains, to be consistent with the modelling). As shown in the figure, the additional demand from hydrogen production in the base case would increase annual electricity demand by 22% in 2035 and 48% in 2050. This would lead to an overall increase in electricity demand from 67% between 2022 and 2050 excluding hydrogen, to an increase of 146% including hydrogen.

Figure 38: Comparison of hydrogen induced electricity demand with the Climate Change Commission's electricity demand growth[55]



[55] Climate Change Commission, NZAS stays scenario.

To meet the growth in demand for hydrogen, the base case modelling suggests New Zealand would need around 12.5GW of new wind and solar generation by 2050. Other forecasts suggest that by 2050, New Zealand would need an additional 10GW+ of electricity generation capacity to support electrification. For example, Transpower's Whakamana i Te Mauri Hiko[56] models +12.6 GW by 2050. BCG's The Future is Electric[57] model's +13.6 GW in Path 1. This means that by 2050, to meet both the needs of electrification and hydrogen, New Zealand's generation stack may need to increase in capacity from around 9GW today to over three times that amount.

Transpower's March 2023 monitoring report[58] suggests there is 30GW of potential generation in the pipeline, which if all realised, could support both electrification and some hydrogen production. However, around 80% of this interest is still in early investigations and may not materialise.

In addition to the scale of the challenge, the scenarios currently show that electricity demand from hydrogen production is modelled to ramp up during the same period in which electricity demand from electrification is expected to grow significantly.

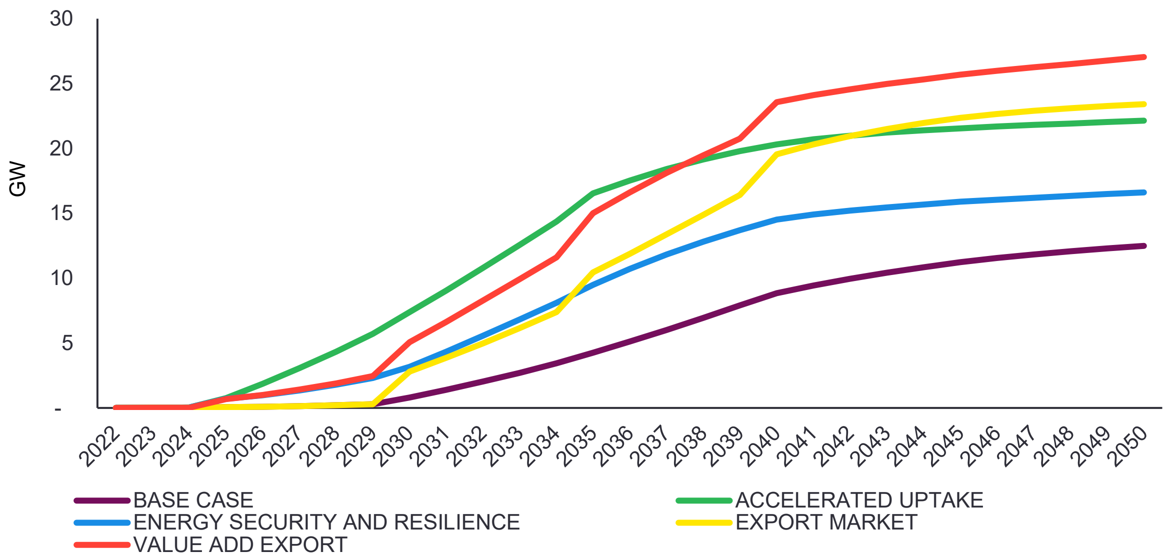
In Whakamana i Te Mauri Hiko, Transpower stated that it would need to build 70 new grid scale connections for both new generation and demand use, and these connections are driven mostly by electrification. This would represent at least 5 new connections each year, a significant increase from previous years. Similarly, to meet the generation required, generation developers are already facing the prospect of building significantly more generation than historically done, requiring a scale up of supply chain and workforce and co-ordination across the industry. This rate of electricity investment would need to increase again to accommodate hydrogen production plants and new electricity generation.

Furthermore, large scale networks and generation plants require long lead times from investigation through to consenting to commissioning. Plants required for generation in ten years are already being considered today.

Modelled outputs - Alternative scenarios

Figure 39 below illustrates the different generation build out modelled in each scenario, using the wind/solar mixed capacity factor.

Figure 39: Required electricity generation capacity by scenario (2035-2050, wind-solar mix, GW)



[56] Whakamana i Te Mauri Hiko, Transpower.
[57] The Future is Electric, BCG.
[58] WiTMH Monitoring Report, March 2023, Transpower.

As with electricity demand, differences across scenarios are largely driven by the different hydrogen demands modelled. Table 16 below summarises the key differences across scenarios

Each alternative scenario represents a higher generation build out requirement compared to the base case, which could amplify the challenges described in the previous section relating to ensuring sufficient and timely investment in new electricity generation can support both hydrogen production and electrification. 'Accelerated uptake' is more so challenging as the generation build ramps earlier than other scenarios, in 2025. Given the long-time frames required to build new generation, this scenario would already need to be in motion.

Table 16: Comparison of electricity generation (wind-solar mix) build out by scenario

Scenario	2035		2050	
	GW	+/- Base case	GW	+/- Base case
Base case	4.3	0%	12.5	0%
Accelerated uptake	16.5	+289%	22.1	+77%
Energy security and resilience	9.5	+123%	16.6	+33%
Export market	10.5	+146%	23.4	+87%
Value-add export	15.0	+253%	27.0	+117%

6.5.4 Electricity price considerations

A concern for pursuing large scale production and export of hydrogen in New Zealand is the potential to increase electricity prices for local electricity users. Due to the limitations of the modelling, we have not modelled the dynamics between the hydrogen and electricity markets and therefore cannot quantify the impacts that the modelled levels of hydrogen production will have on the wholesale electricity price. We expect that hydrogen production will have some effect on the wholesale electricity price depending on the size of the hydrogen market and activity in the wholesale electricity market.

As discussed in section 6.5.1, we have modelled electricity to be sourced from a combination of the wholesale electricity market and new investment. The assumption in the modelling is that wholesale electricity market prices are static and based on the Climate Change Commission's Tiwai stays sensitivity. New generation investment prices are based on the LCOE of new generation consistent with NZ Battery IBC assumptions.

In this section, we discuss the potential impacts that hydrogen can have on the electricity price which are subject to further, more detailed modelling.

Hydrogen production has the potential to put upwards pressure on the wholesale electricity spot price due to it being a large electricity demand.

At the most simplistic level, we expect that if electricity for hydrogen production is sourced from a direct investment in generation or long-term contract such as a Power Purchase Agreement that is in addition to electricity generation that would have been built otherwise, then that electricity procured will have limited impact on wholesale electricity spot prices.

If, however, electricity for hydrogen production is sourced from the wholesale electricity market or is linked to new generation that would have otherwise been built to support growing electricity demand from the rest of the economy, then that electricity may have upwards pressure on wholesale electricity spot price if the total capacity is material. During periods of excess low-cost renewable supply, electricity used for hydrogen production is less likely to put a material upwards pressure on the spot price. The impact on the spot price is likely to be greatest during periods of tight electricity supply.

Given the current conditions in New Zealand's electricity system, it is likely that material electricity demand from hydrogen production will impact electricity prices as the electricity system is already facing challenges in ensuring there is sufficient supply to meet demand. The grid emergency on 9 August 2021 saw a record high New Zealand peak demand and the grid emergency resulted in several power outages to customers and was partly due to insufficient generation being available during a cold evening[59].

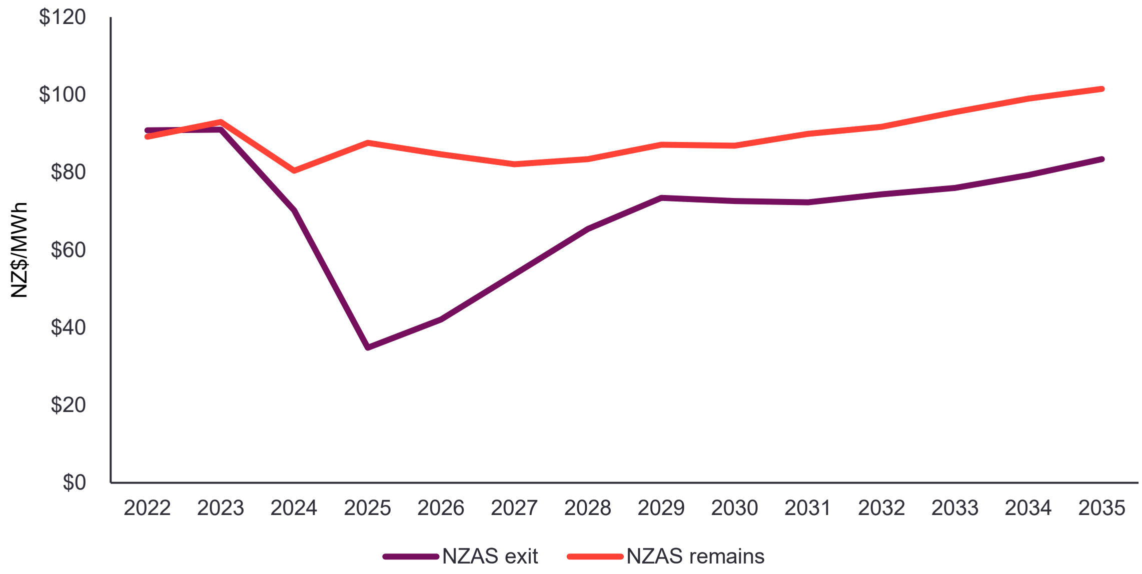
Because New Zealand's generation fleet is already experiencing periods of tight supply, large hydrogen producers would need to incentivise new generation development to avoid exacerbating energy security and resilience issues. If large hydrogen producers procure large amounts of electricity from existing plants or plants that are being built to meet rising demand in other parts of the economy, then this could further strain the system, as well as put upwards pressure on electricity prices.

Furthermore, as discussed in section 6.5.1, the modelling suggests that even with most electricity being sourced from direct investment or long-term contracts, a material amount of electricity (at least 30% in the base case) will still be procured off the wholesale electricity market and can therefore impact price to other consumers.

A similar example of how significant electricity demand can impact the electricity price that is currently being discussed in the New Zealand context is the impact NZAS has on the electricity price to end consumers. NZAS currently consumes 13% (5 TWh) of New Zealand's annual electricity demand. Its current electricity contracts are due to end at the end of 2024. Currently, there are no confirmed plans on its exit.

Figure 40 below illustrates the Climate Change Commission's modelling of wholesale electricity prices in a scenario where NZAS remains and exits.

Figure 40: Climate Change Commission sensitivity analysis of wholesale electricity price and NZAS exit (real 2021)



As shown in the figure, NZAS exiting the market in 2025 would cause a sudden drop in the electricity price due to the excess renewable supply released. From 2029 onwards, prices stabilise

[59] Investigation into electricity supply interruptions of 9 August 2021, Ministry of Business, Innovation & Employment

and the absence of NZAS in the market results in an electricity price that is consistently ~20% below the NZAS remains price.

This suggests that large electricity loads on the system may put upwards pressure on the electricity price and consequently, a large build out of hydrogen production could put upwards pressure on the price if low-cost renewables cannot be built at an adequate pace. Similarly, if hydrogen production creates congestion in certain parts of the electricity transmission network, then this can drive up network costs for that part of the transmission network if additional network investment is required.

Large, centralised plants will also likely require a direct connection to the transmission network to off-take electricity and also inject electricity if built with on-site electricity generation. This can add a significant cost to the hydrogen production plant costs and add to that plant's LCOGH. Smaller, decentralised plants may not require direct connections to the transmission network but may still incur material network costs to connect to their local distribution network.

Further electricity market and generation expansion analysis is required to better understand how the modelled hydrogen production volumes might impact the wider market.

Hydrogen production has the potential to put downward pressure on the wholesale electricity spot price through demand response.

We expect hydrogen plants to be capable of flexing their electricity demand and consequently, hydrogen output, in response to the electricity system's needs. This demand response capability can put downward pressure on electricity prices as it reduces demand in the electricity system, limiting the need to call on high-cost electricity generation (e.g. gas peakers or scarce hydro generation).

The electricity market's recent implementation of real-time pricing[60] and the ongoing flexibility enabling work being completed by industry (e.g. Flex Forum[61] and trials run by various electricity distribution businesses and Transpower) will likely incentivise new plant developments to build in this capability and enable plants to participate in the electricity market.

However, there is the possibility that hydrogen production being linked to global commodity market through exports will make this demand response more expensive and exert upwards pressure on prices.

At the most simplistic level, we expect that if almost all hydrogen produced in New Zealand is consumed domestically then the cost of electricity will be an input cost to hydrogen production and will likely not be impacted by the price of hydrogen.

However, if a significant proportion of hydrogen produced in New Zealand is exported, then there could be implications for the price of electricity. In the event where New Zealand is able to sell its hydrogen at a premium to export markets (e.g., New Zealand hydrogen price increases to match cost of next highest alternative for the country that is importing hydrogen) then the domestic price for hydrogen would also increase. Domestic plants that are not linked to export markets may also increase their prices to match the export plants if it enables them to capture a larger margin.

The impacts of exporting hydrogen on electricity price are likely to depend on the extent of demand response that electrolysers provide to the market. When considering demand response, hydrogen production plants will weigh the value of high electricity input costs against the value of lost export production. If they are receiving a higher price for hydrogen, they may be able to tolerate a higher electricity input price. Therefore, they may also only trigger demand response at a higher electricity price. If plants increase the trigger price for demand response, then they are likely to lower their average demand response capacity over any given period. Because electrolyser plants

[60] Real Time Pricing, Electricity Authority
[61] New Zealand's FlexForum, Ara Ake

would be decreasing the flexibility they are offering in the market during periods of tight demand, this would put upwards pressure on the wholesale electricity market relative to if they provided more demand response capacity.

Another potential impact from exporting significant amounts of hydrogen at a premium price is the negative impact it would have on domestic hydrogen consumers. This is a similar dynamic to dairy products in New Zealand, where the price New Zealand consumers pay is influenced by global dairy commodity prices.

6.6 Levelised cost of green hydrogen (LCOGH)

We have modelled LCOGH under each scenario. When examining the scenarios in terms of LCOGH, there were no significant variations due to the same underlying assumptions.

Generally, across all scenarios, large, centralised plants are modelled to have lower costs per kilogram of hydrogen due to higher plant efficiencies and lower capital and operating costs per unit due to economies of scale. Smaller, decentralised plants are modelled to have higher costs per kilogram of hydrogen due to lower plant efficiencies and higher costs associated with running the plants on a per unit basis.

The only scenario where LCOGH varies is 'Energy security and resilience' where LCOGH is slightly higher due to a lower capacity factor for the electrolysers, and therefore higher capital cost recovery on each kilogram of hydrogen produced. This lower capacity factor is attributed to the electrolysers expected to curtail electricity demand at higher levels than other scenarios to support the electricity system during periods of tight electricity supply.

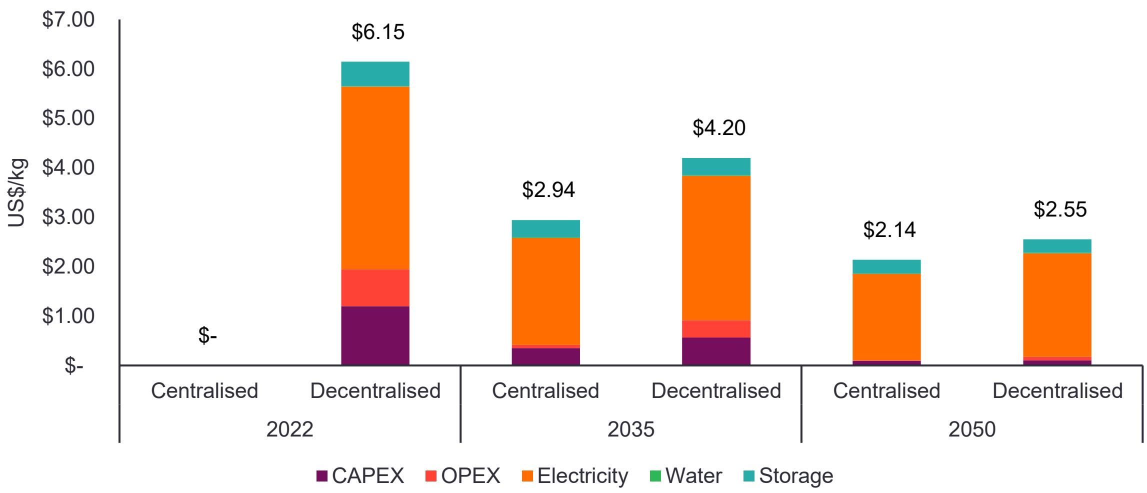
The following sections use the LCOGH in the base case as a basis for further analysis.

For more detail on the specific input costs, refer to section B.3 of the appendix. CAPEX and OPEX costs are sourced from IRENA. Electricity costs are sourced from a combination of the Climate Change Commission and NZ Battery's modelling. Water costs are sourced from Water NZ.

6.6.1 Production cost

Figure 41 below shows incremental LCOGH in the base case in 2022, 2035, and 2050. Note that there is no LCOGH for centralised plants in 2022 because plants of this size are not modelled in that year. Based on the modelling, by 2035, we can expect incremental LCOGH to average US$2.94/kg for centralised plants and US$4.20/kg for decentralised plants. By 2050, incremental LCOGH drops to US$2.14/kg and US$2.55 respectively.

Figure 41: Modelled Incremental LCOGH by plant type (US$/kg)



As evident in Figure 41, electricity input costs make up a significant proportion of the LCOGH and any change in electricity price can have material impacts on the LCOGH. To examine this further, Figure 42 and Figure 43 below show the changes in electricity price can impact LCOGH, assuming all other factors remain constant.

The figures show that if hydrogen plants today were to procure all electricity from the spot market, based on an average spot price from 2018-2023, LCOGH could reach US$5.26/kg for centralised plants and US$8.23/kg for decentralised plants. This is the cost before additional costs associated with any transformation and distribution.

As discussed earlier, the modelling assumes that hydrogen plants procure a significant proportion of the electricity from long-term contracts/direct investment where they may be able to secure low electricity prices. We also expect plants to adopt some level of flexibility and can lower their demand during periods of high wholesale spot prices.

Figure 42: Electricity input cost impact on incremental centralised LCOGH

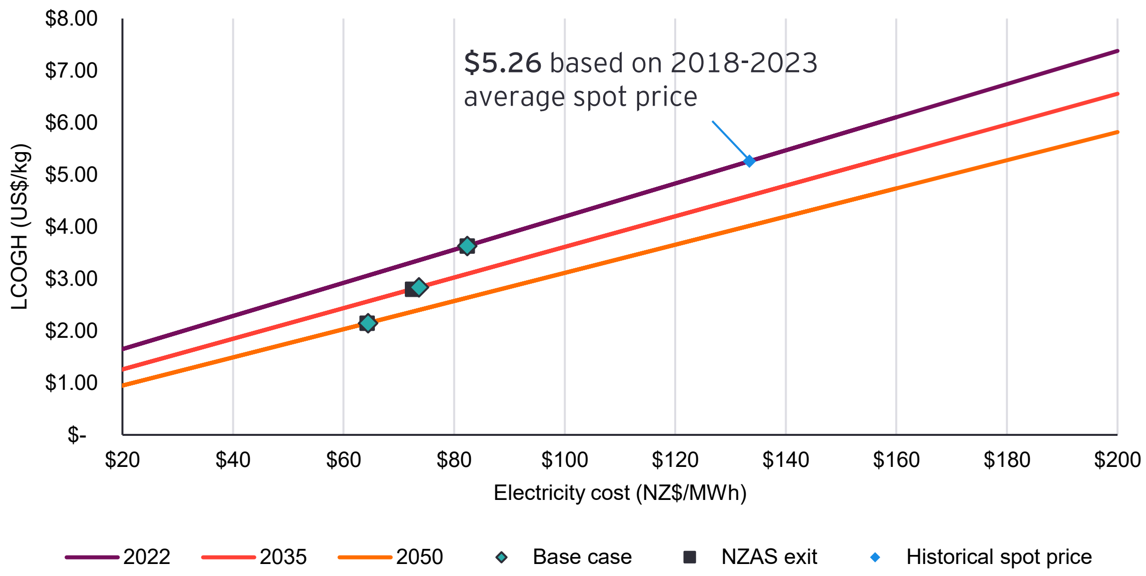
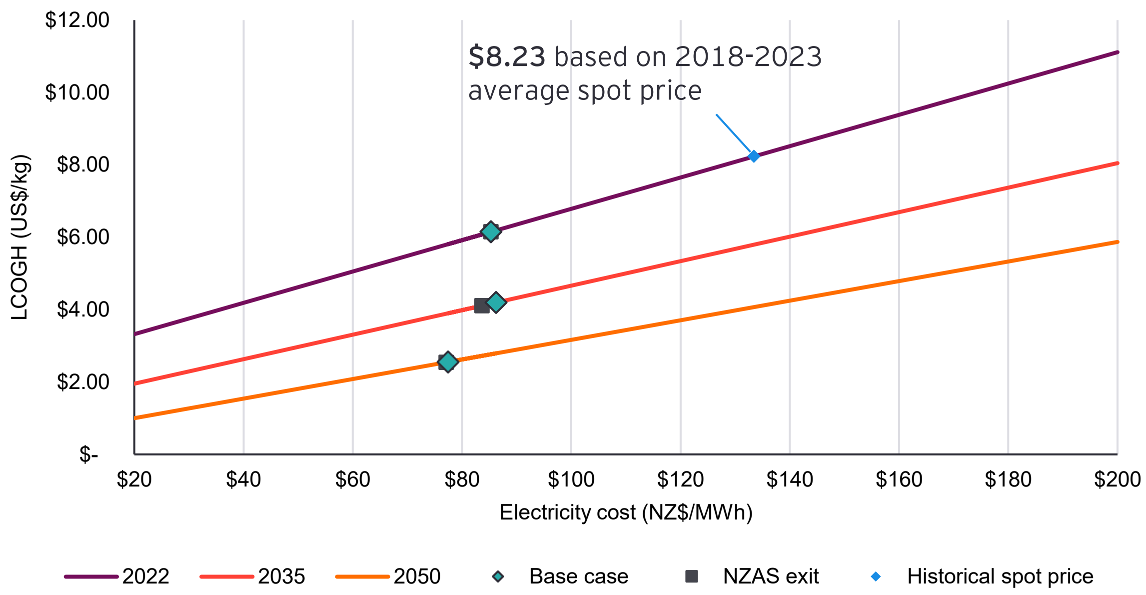


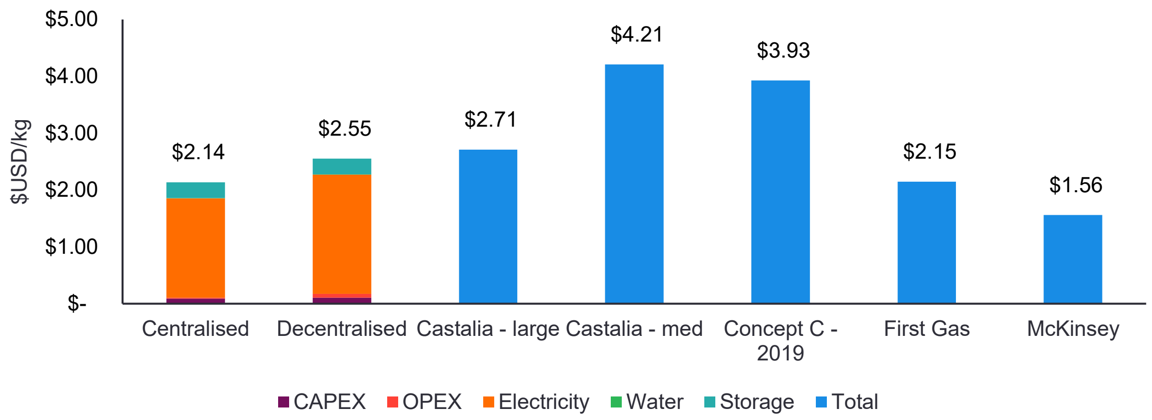
Figure 43: Electricity input cost impact on incremental decentralised LCOGH



The figures also explore the impact that a potential NZAS exit could have on LCOGH. We have used the Climate Change Commission's modelled lower wholesale electricity price for an NZAS exit scenario. As evident in Figure 43, for decentralised plants, this change in price has a limited impact on LCOGH by 2035 and almost no impact by 2050.

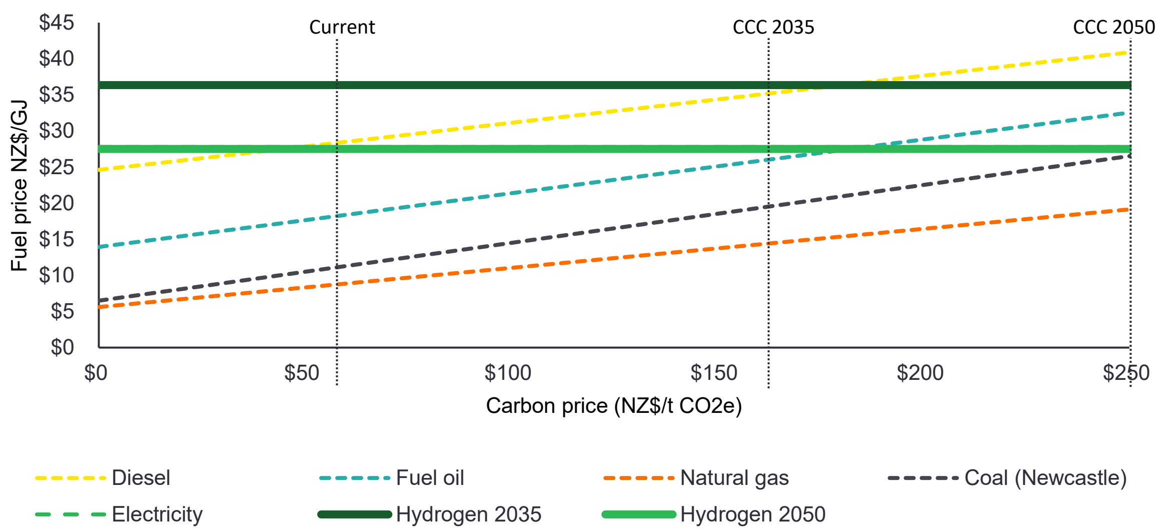
We also compared the modelled LCOGH in 2050 to other analysis completed for New Zealand as shown in Figure 44 below. The modelling sits in the mid-range of LCOGH estimates by 2050. Differences will be due to different assumptions made in modelling, with different electricity prices likely to be the largest driver (as discussed earlier).

Figure 44: Comparison of modelled incremental LCOGH to other NZ analysis (2050)



An important consideration that we have not modelled in detail is when a demand sector may choose to convert to hydrogen as a fuel due to it being commercially attractive. While we have not presented a total cost of ownership comparison for each demand sector, as a starting point for discussion, Figure 45 presents the modelled LCOGH for centralised plants in 2035 and 2050 against current fossil fuel and carbon prices. The fossil fuel figures assume that 2021 fuel prices[62] prevail, except for carbon prices. In the figure, electricity and hydrogen are assumed to be 100% renewable. It is important to note that direct fuel comparisons such as the below do not account for differences in end-use efficiency, which can vary between fuel and application.

Figure 45: Comparison of modelled incremental LCOGH to other fuel types, carbon price and the Climate Change Commission's modelled future carbon price



[62] Energy prices | Ministry of Business, Innovation & Employment (mbie.govt.nz), NCFZ23 | gC Newcastle Coal Dec 2023 Overview | MarketWatch

It is evident in the figure, that hydrogen is likely to become cost competitive with diesel, which is primarily used in transport in the model, on a $/GJ basis once the carbon price reaches above NZ$100/t CO_2-e. However, even with high carbon prices, hydrogen will be more expensive than natural gas and coal on an energy basis.

However, due to the higher efficiency of fuel cells over combustion equipment and the difference in maintenance and operating costs between the two types of equipment, this type of analysis is not likely to define the economic fuel switching point. Each use case has a number of idiosyncrasies that need to be factored in to understand the economics of switching. Full assessment of the total cost of ownership is a more robust predictor of fuel switching than simple fuel price parity.

Furthermore, fuel cost will not be the only driver for businesses choosing to switch to hydrogen from fossil fuels. Other drivers such as regulation (e.g. ban on coal boilers[63]), co-ordinated action (e.g. Hydrogen Consortium and energy precinct at Christchurch Airport[64]), capital funding support and public sentiment will influence switching decisions.

6.6.2 Impact of transformation and distribution costs

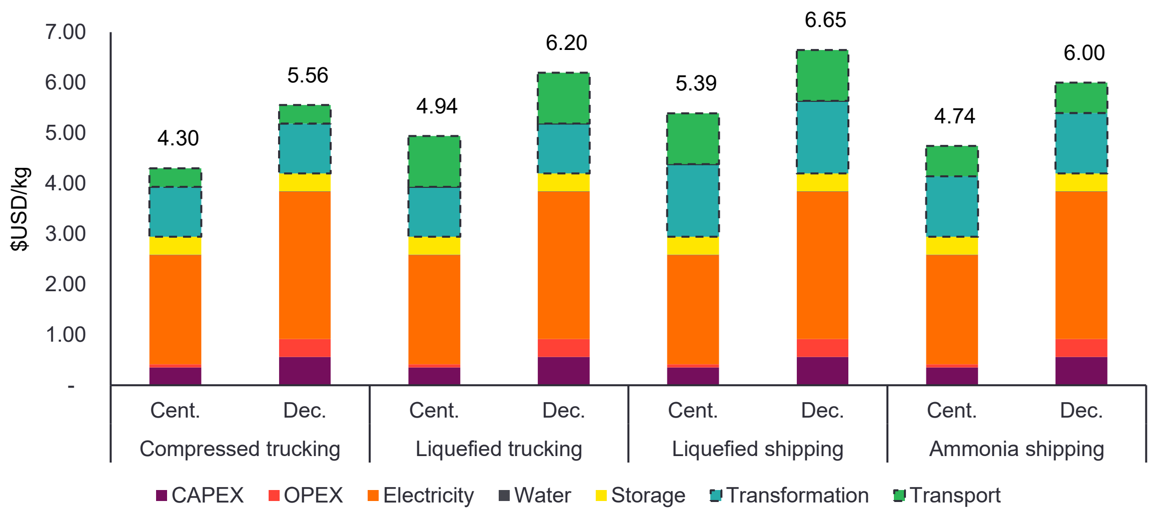
We also assessed the impact costs associated with transforming hydrogen gas into other hydrogen forms and distribution. Figure 46 and Figure 47 below show the LCOGH with the addition of transformation and distribution costs in 2035 and 2050.

Transformation and distribution costs, like electrolyser costs, are expected to fall over time as the technology improves. Assumptions for these costs are detailed in section B.3.3 of the appendix and are based on desktop research. These costs are assumed to include the costs of additional energy required for each process. This part of the model is less evolved than other areas and therefore outputs should be considered as directional only.

The modelling finds that transformation and distribution can add 30% to 80% to the LCOGH in 2035 and 16% to 80% in 2050.

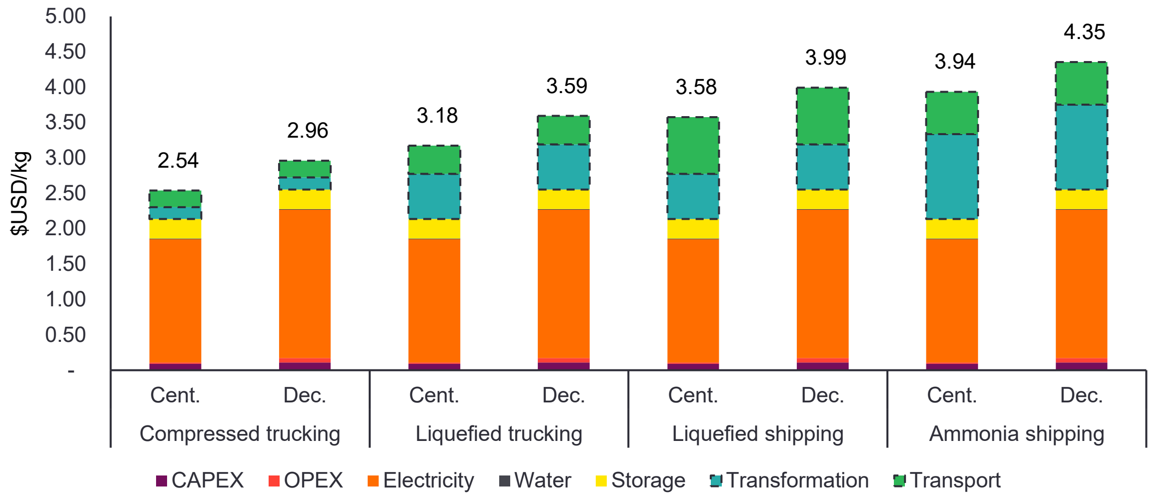
These costs will be closer to the landed cost to end consumers. Note that a profit margin for any aspect of the supply chain has not been assumed, which would add to make the price higher to end consumers.

Figure 46: Transformation and distribution impact on incremental LCOGH (2035)



[63] Government delivers next phase of climate action | Beehive.govt.nz
[64] New consortium to enable zero emission aviation to take off in Aotearoa New Zealand (christchurchairport.co.nz)

Figure 47: Transformation and distribution impact on incremental LCOGH (2050)

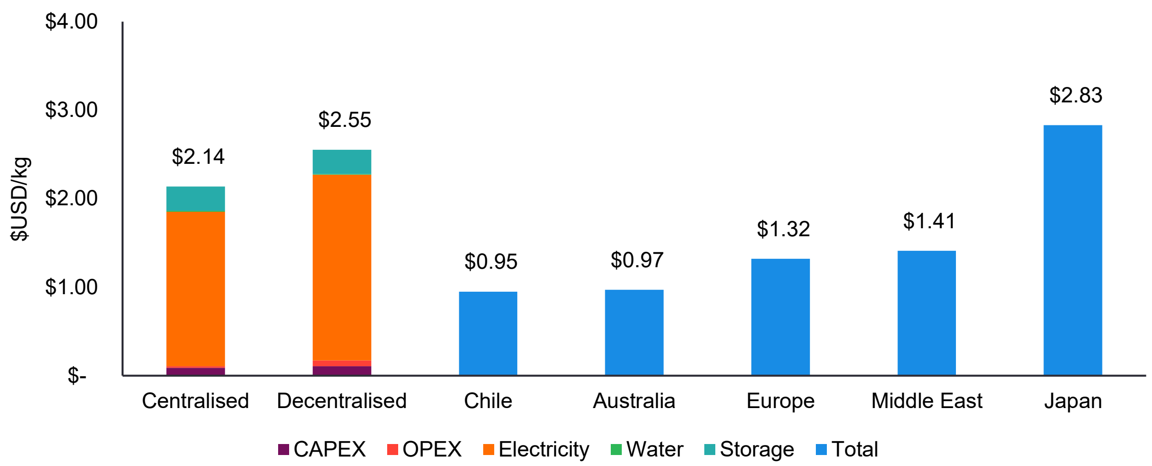


6.6.3 Comparison to global benchmarks

The modelling does not explicitly consider the cost competitiveness of New Zealand's hydrogen for export. However, analysis of the modelled LCOGH suggests that in 2050, New Zealand's hydrogen producers may find it difficult to compete globally due to lower LCOGH in other countries. Figure 48 below compares the modelled New Zealand LCOGH with other countries estimated by IRENA[65]. As evident in the figure, countries such as Australia and Chile are forecast to be able to produce hydrogen at less than US$1/kg. These low costs are primarily driven by low-cost renewable electricity. Australia for example, is modelled by IRENA to produce its hydrogen from 90% solar generation and the remaining from wind. Similarly, Chile is modelled to use 75% solar generation, 20% wind and 5% from other sources.

Based on the modelling, in 2050, electricity input costs in New Zealand need to fall from NZ$65/MWh to NZ$55/MWh for LCOGH to fall below US$2/kg H2 and to NZ$20/MWh for LCOGH to fall to US$1/kg H2. Modelling by NZ Battery suggests that new entrant wind and solar could reach NZ$52-56/MWh (detailed in section B.3.1.3 of the appendix) which suggests that plants that are able to secure this price for all of their hydrogen production could potentially compete globally.

Figure 48: Comparison of modelled 2050 incremental LCOGH with global benchmarks[66]



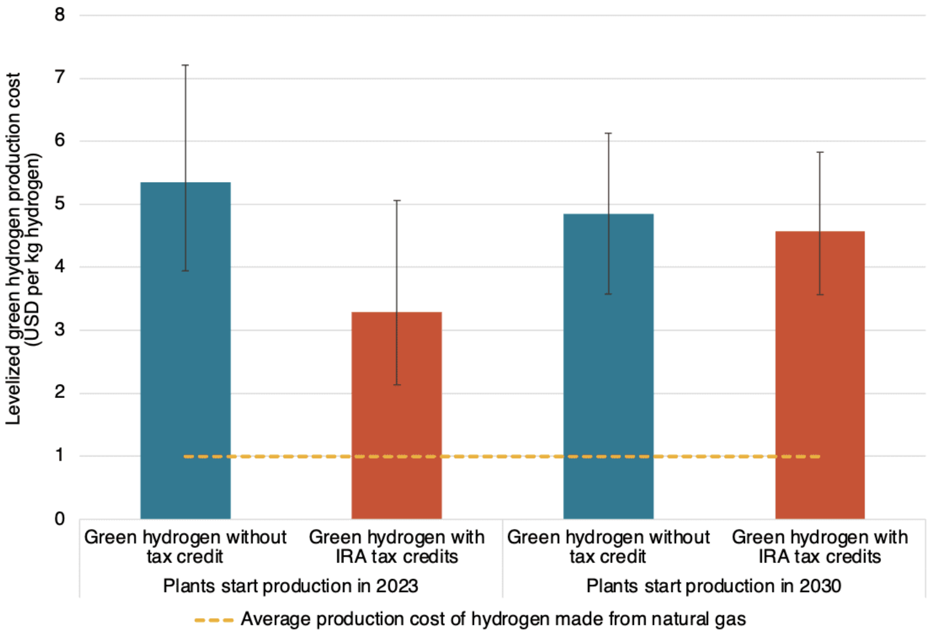
[65] Global hydrogen trade to meet the 1.5°C climate goal: Part III – Green hydrogen cost and potential (irena.org)
[66] Global hydrogen trade to meet the 1.5°C climate goal: Part III – Green hydrogen cost and potential (irena.org)

Global efforts to reduce the cost and increase uptake of green technologies may lower prices even more, further making it difficult for NZ to export cost competitive hydrogen

For example, in 2022, the U.S. introduced the Inflation Reduction Act (IRA), which includes a range of clean energy tax incentives intended to accelerate the deployment of clean energy technologies such as hydrogen.

Analysis by the International Council on Clean Transportation[67] (Figure 49) shows the modelled production cost of green hydrogen with and without IRA tax credits for a new project built in 2023 or 2030. The error bars indicate the possible cost range due to regional variations in renewable resources and uncertainties in electrolyser costs.

Figure 49: Impact of IRA tax credits on USA LCOGH for a new project built in 2023 or 2030



On average, the IRA tax credits for renewable electricity and clean hydrogen can reduce the cost of green hydrogen production by almost half, falling to nearly US$3 per kg of hydrogen for a project starting in 2023.

The modelling suggests that if a new large, centralised plant were built in 2023 in New Zealand, LCOGH would be around US$3.60/kg, 12% higher than the potential cost in the US.

According to the ICCT analysis, the IRA credits' impacts fade steadily after 2023, until they expire in 2032. A project coming online in 2030 would qualify for only three years of tax credits, resulting in a 6% cost reduction compared to the no-credit scenario – around US$4.50/kg. The modelling suggests that if a new large, centralised plant were built in 2030 in New Zealand, LCOGH would be around US$3.30/kg, 27% lower than the potential cost in the US.

67 Can the Inflation Reduction Act unlock a green hydrogen economy? - International Council on Clean Transportation (theicct.org)

7. Modelled outcomes

To understand the impacts that varying levels of hydrogen uptake and supply chain development will have on New Zealand, we have assessed how each scenario performs against three levers:

- **Decarbonisation:** the volume of emissions reduction enabled by hydrogen through fossil fuel displacement and associated contribution towards emissions reductions and renewability targets.
- **Economic development**: The impact of the hydrogen economy on the wider economy in terms of Gross Value Add and employment opportunities. Gross Value Add is used as an indicator for Gross Domestic Product.
- **Energy security and resilience:** The ability of hydrogen to support the reliability of New Zealand's renewable energy supply and reduce reliance on fossil fuel imports. This outcome is measured by the volume of new electricity generation incentivised (assuming most electricity is procured from new generation plants), demand response capacity (assuming most hydrogen plants have flexibility capabilities and commercial arrangements) and liquid fossil fuel displaced by hydrogen use.

Across each of these levers, we have modelled several quantitative indicators that are described in the following sections. The three levers considered here are broad and reach beyond the scope of the hydrogen supply chain. As such, we have also included qualitative discussion on additional considerations that have not been explicitly modelled.

The modelled outcomes are summarised in Table 17 below. For each outcome, scenarios are ranked in performance, where five is the highest performing and one is the lowest performing.

Table 17: Summary of scenario performance against outcomes

Indicator	Base case	Accelerated uptake	Energy security and resilience	Export market	Value-add export
Decarbonisation					
Emissions reduction by 2050 and contribution to final energy consumption	3	5	4	2	1
Economic development					
Gross value- add and employment	1	3	2	4	5
Energy security and resilience					
New generation incentivised	1	3	2	4	5
Demand response capacity	1	2	4	3	5
Liquid fossil fuel volume displaced	3	5	4	3	3

7.1 Enabling decarbonisation

The first outcome lever that we will discuss is decarbonisation and the contribution that the modelled hydrogen production and uptake can potentially make to New Zealand's emissions reduction targets and renewable energy consumption.

New Zealand has set out ambitious emissions reduction targets, as prescribed by the Emissions Budgets (EBs). In May 2022, the Government set the first three emissions budgets (2022-2025, 2026-2030 and 2031-2035), supported by the first Emissions Reduction Plan (ERP)[68].

New Zealand also has two renewable energy targets. The first is that 50% of total final energy consumption (TFEC) is from renewables by 2035 and the second is an aspirational target of 100% renewable electricity by 2030.

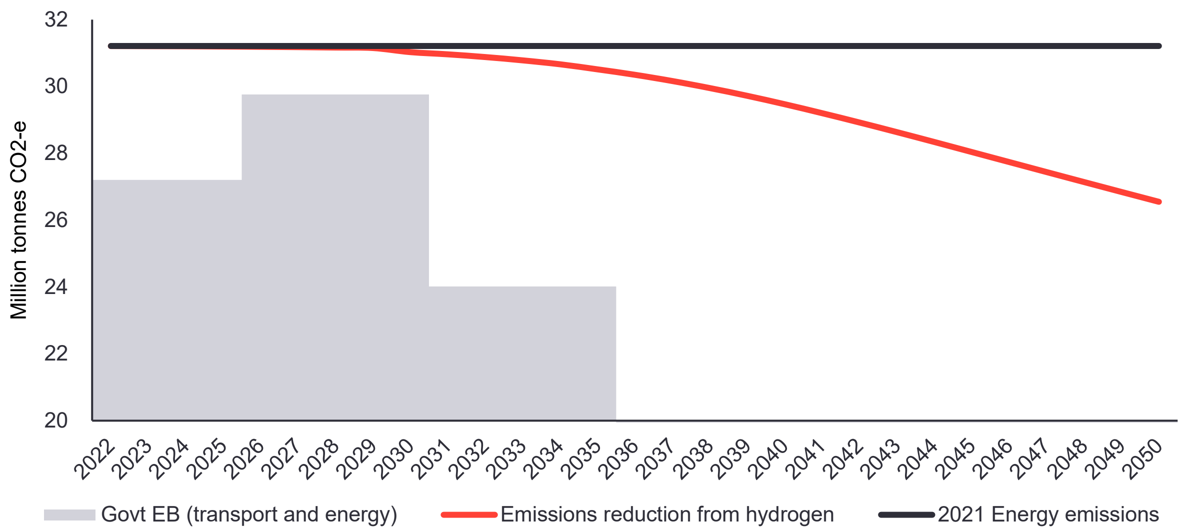
In the following sections, we describe how hydrogen could play a role in helping to meet these goals. It is important to note that the modelling is limited to hydrogen only and does not integrate the potential of electrification or decarbonisation via other fuels such as bioenergy. Therefore, what we present here is indicative but further analysis at a whole energy sector level (e.g. as part of the Energy Strategy) is required to build a more fulsome view.

7.1.1 Direct emissions reductions

7.1.1.1 Base case

Figure 50 illustrates the potential emissions reduction from hydrogen use in the transport and energy sectors in the base case. We have compared these emissions reductions with the 2021 energy emissions (inclusive of transport) and the transport and energy proportions of the emissions budgets set by the government. In 2021, energy (inclusive of transport) made up 41% of New Zealand's gross emissions[69].

Figure 50: Base case hydrogen consumption contribution to emissions reductions (2023-2050, $MtCO_2$-e)



As evident in Figure 50 and Table 18 below, as an energy source for the transport and energy sectors, hydrogen can contribute to an emissions reduction that is equivalent to 2.24% of 2021 energy emissions by 2035 and 14.94% of 2021 energy emissions by 2050.

In the context of New Zealand's target to reach net zero greenhouse gas emissions (except biogenic methane) by 2050, the hydrogen use modelled in the base case is equivalent to 1.4% of 2019's gross long-lived gas emissions by 2035 and 9.6% by 2050. These values are 1.6% and 11.3% respectively when compared to the net emissions (including forestry removals). This is based on the Climate Change Commission's advice[70] which reported that in 2019, total gross long-lived gas emissions were 48.6 Mt CO_2e, and 41.2 Mt CO_2e when including forestry removals.

[68] Emissions budgets and the emissions reduction plan, Ministry for the Environment.
[69] NZ's Interactive Emissions Tracker. Ministry for the Environment
[70] Ināia tonu nei: a low emissions future for Aotearoa (climatecommission.govt.nz)

It is not unexpected that hydrogen contributes a small proportion of energy emissions reductions due to the expectation that electrification will play a significant role in decarbonising the economy. BCG's The Future is Electric[71] suggests that electrifying transport and heat, and increasing renewable electricity, will be the most significant contributors to New Zealand achieving net zero carbon by 2050, delivering an estimated 70% of the gross emissions reductions required to achieve New Zealand's net zero carbon target by 2050.

Table 18: Emissions reductions by sector (2035 and 2050)

Sector	2035		2050	
	Mt CO_2-e	% of 2021	Mt CO_2-e	% of 2021
Transport	0.62	-	4.08	-
High temperature process heat	0.07	-	0.56	-
Power generation	0.00	-	0.02	-
Residential and commercial	0.00	-	0.00	-
Total energy emissions reductions	**0.70**	**2.24%**	**4.66**	**14.94%**

Note that the modelling results presented here exclude emissions from industrial processes and product use, which made up 4.6 million tonnes CO_2-e, or 6% of New Zealand's gross emissions in 2021[72]. These emissions are expected to decrease as hydrogen displaces fossil fuel in industrial feedstock. However, we have not explicitly modelled these emissions reductions due to the complexity of calculating emissions relating to process feedstock. Emissions factors for these processes are not published as intensity is likely to be specific to individual installations[73].

For comparison on the 2021/22 reported emissions for the three main industrial hydrogen users are given in Table 19 below. It should be noted that the NZ Steel and Ballance emissions are process emissions while the Methanex emissions stated are for the end use of the product. Process emissions for Methanex are not reported separately from process heat. Furthermore, all methanol is exported and therefore these emissions do not fall within New Zealand greenhouse gas reporting or emissions budgets considerations.

To give an order of magnitude of the potential contribution of green hydrogen to emissions reduction, we have also shown the percentage of plant throughput using green hydrogen in plant in the base case in 2035 and 2050. It cannot be inferred that the reduction in process emissions will be directly proportional to the percentage of production converted to green hydrogen due to the complexities of each process, however there will likely be significant reductions in these emissions if uptake of green hydrogen took place at these rates as assumed in the scenarios.

71 The Future is Electric, BCG
72 NZ's Interactive Emissions Tracker (environment.govt.nz)
73 Measuring emissions: A guide for organisations: 2022 summary of emission factors | Ministry for the Environment

Table 19: 2021/22 Industrial process emissions from key hydrogen users[74,75]

User	2021/22 emissions	% of production using green hydrogen	
	Mt CO_2-e	2035	2050
NZ Steel	0.04	0%	50%
Ballance	0.59	40%	100%
Methanex	1.86	25%	50%

The results presented here also do not include the potential emissions increase from increased electricity use. We expect that there will be some emissions increase due to the electricity procured from the wholesale electricity market, particularly in the 2020s, given the system is not yet at 100% renewables. As the electricity system transitions to a 100% renewable system, emissions from additional electricity demand are expected to decrease. It is out of scope of this modelling to consider how and when the electricity system will reach 100% renewables.

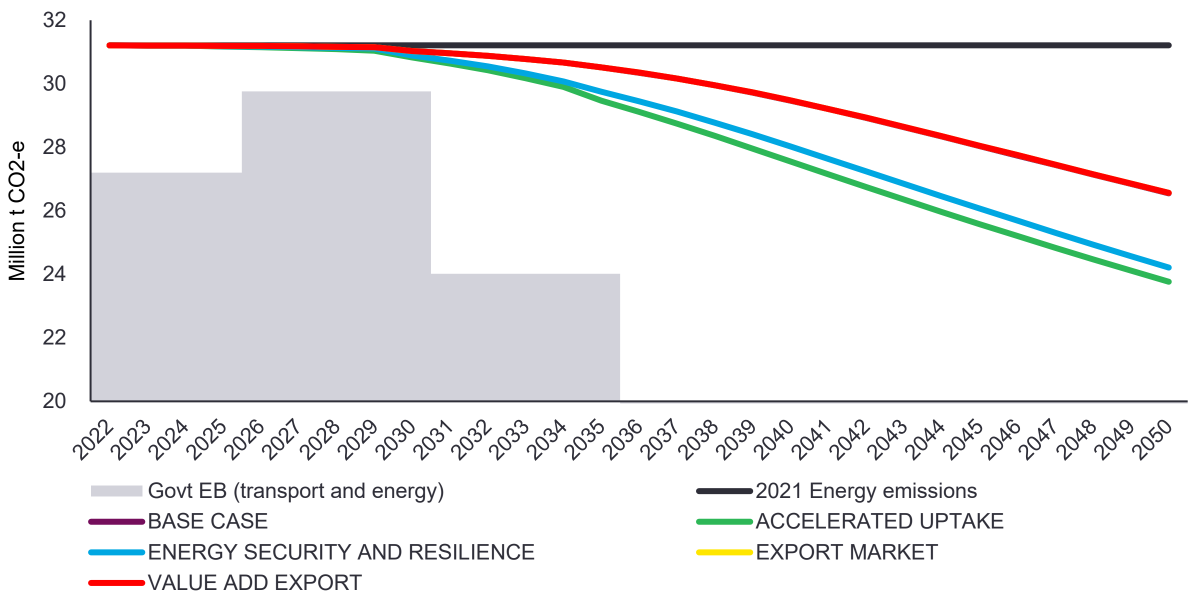
Furthermore, the emissions reductions here also do not consider the embedded emissions and supply chain emissions (e.g. construction) associated with building out the hydrogen ecosystem.

7.1.1.2 Alternative scenarios

Figure 51 illustrates how the scenarios compare in terms of emissions reductions from the energy sector, comparing again to New Zealand's 2021 energy emissions and the emissions budget set by Government.

As expected, 'Accelerated uptake' has the potential to enable the greatest emissions reductions from hydrogen use, followed by 'Energy security and resilience'.

Figure 51: Comparison of total emissions reduction by scenario (2023-2050, $MtCO_2$-e)



[74] ETS Participants Emissions Report 2021 FINAL (epa.govt.nz)

[75] Note that NZ Steel emission are reported under industrial process emissions, Ballance emission are reported under agricultural emissions and Methanex is reported as a removal as methanol is exported. No process emissions are reported for Methanex. The analysis presented shows the emissions of the final methanol product as it is used. These emissions are outside New Zealand greenhouse gas reporting and emissions budgets.

Table 20 below summarises the key values for each scenario and their relative ranking according to emissions reductions enabled, where five is the highest performing and one is the lowest performing.

The base case, 'Export market and 'Value-add export' are all consistent in the emissions reductions enabled due to the same uptake assumptions across the transport and energy use sectors. However, 'Export market' and 'Value-add export' have been ranked two and one respectively, due to the increased electricity demand for the production of exported hydrogen/value-add commodities, which would increase energy emissions while the grid is not yet 100% renewable.

Table 20: Key differences in emission reduction for all scenarios (2035-2050)

Scenario	2035		2050		Ranking
	Total Mt CO2-e	% of 2021	Total Mt CO2-e	% of 2021	
Base case	0.70	2.2%	4.66	14.9%	3
Accelerated uptake	1.74	5.6%	7.45	23.9%	5
Energy security and resilience	1.46	4.7%	7.00	22.4%	4
Export market	0.70	2.2%	4.65	14.9%	2
Value-add export	0.70	2.2%	4.65	14.9%	1

7.1.2 Contribution to final energy consumption

As part of understanding the potential hydrogen can play in decarbonising New Zealand's economy, we are also seeking to understand the potential contribution hydrogen can make towards New Zealand's total final energy consumption (TFEC). The higher the proportion of energy that green hydrogen can provide to TFEC, the greater the contribution hydrogen can make towards New Zealand's targets for renewable energy use.

As noted earlier, this model considers hydrogen in isolation and does not model the dynamics between the build out of other energy systems (e.g. electricity, bioenergy). Therefore, we have not attempted to model the TFEC by fuel across the economy out to 2035 and 2050. This type of exercise is more likely appropriate as part of the Energy Strategy.

Instead, to provide an indicator of the potential contribution hydrogen can make to TFEC, we have compared the energy supplied by hydrogen in the scenarios with Transpower's estimated TFEC in 2035 and 2050 in Whakamana i Te Mauri Hiko, which assumes high levels of electrification, and does not comprehensively model hydrogen uptake. Transpower's TFEC includes energy demand delivered by geothermal, coal, gas, biofuel, oil and electricity.[76]

Figure 52 below compares the energy delivered by hydrogen in the base case with Transpower's estimate for 2035 and 2050. Under the base case, hydrogen delivers 2 TWh of energy in 2035 and 9.5TWh in 2050. This is equivalent to 5.8% of Transpower's modelled TFEC of 151 TWh in 2035 and 8% of 120 TWh in 2050. If Transpower's 2035 estimate holds true, and if hydrogen is assumed

[76] Whakamana i Te Mauri Hiko, Transpower

to be produced from renewable resources, then hydrogen has the potential to contribute 1.3% towards the government target of 50% of total final energy consumption coming from renewable sources by 2035.

As shown in Table 21 below, hydrogen energy is equivalent to a larger proportion of Transpower's TFEC in 'Accelerated uptake' and 'Energy security and resilience' due to higher uptake in the transport and energy sectors.

Figure 52 also shows the modelled potential increase in TFEC due to growth in electricity demand from hydrogen production that supplies hydrogen for feedstock. Under the base case, the additional electricity required is equivalent to an increase in Transpower's TFEC by 6% in 2035 and 20% in 2050. This is higher in 'Accelerated uptake, 'Export market' and 'Value-add export' scenarios where more electricity is required for industrial feedstock. Because hydrogen is used as a feedstock as opposed to energy supply, this does not result in an increase in hydrogen's contribution to TFEC.

It is important to note that fossil fuels that are used as industrial feedstock are not included in TFEC because they are used directly as a feedstock, rather than requiring additional energy to transform them into a usable form. In the case of green hydrogen however, energy is required for the electrolysis process to create hydrogen before it can be used as a feedstock. This additional energy required increases the overall TFEC.

Figure 52: Comparison of hydrogen energy supply and additional electricity generation required with Transpower's Whakamana i Te Mauri Hiko total final energy consumption estimate in base case (2035, 2050)

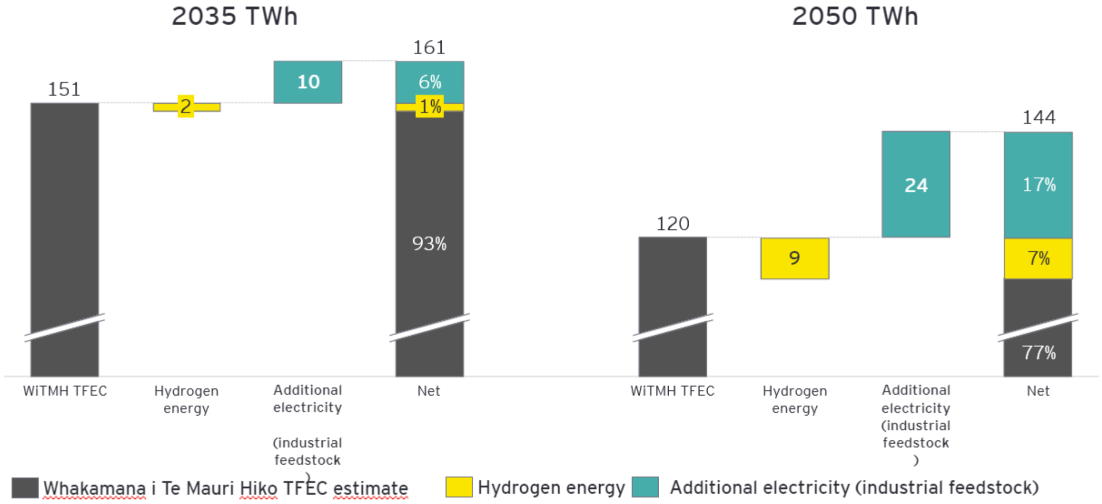


Table 21 below summarises the key values for each scenario and how scenarios rank against each other, with five being the most positive contribution to TFEC and one being the least.

Table 21: Overview of differences in hydrogen energy supply compared to Transpower's total final energy consumption by scenario (2035 and 2050)

Scenario	2035	2050	

	% of WiTMH est.	% of WiTMH + new electricity	% of WiTMH est.	% of WiTMH + new electricity	Ranking
Base case	1.2%	1.1%	7.9%	6.6%	3
Accelerated uptake	2.6%	2.1%	11.2%	8.0%	5
Energy security and resilience	1.7%	1.5%	9.4%	7.3%	4
Export market	1.2%	1.0%	7.9%	5.4%	2
Value-add export	1.2%	0.9%	7.9%	5.2%	1

7.2 Supporting economic development

As a result of the modelled hydrogen production and consumption in the New Zealand market, the analysis shows there will be a substantial contribution to New Zealand's economic development. It is important to note that the modelling of economic development has been completed using a high-level input-output method to illustrate the directional impact hydrogen can have. Further analysis, such as through a broader cost-benefit analysis or at region specific levels, is required to build a more detailed and nuanced view of the economic potential.

Furthermore, it is worth noting that hydrogen investment from commercial entities will not be the only driver of economic development. Other strategic dependencies such as targeted regional development or international export relationships could influence the level and direction of economic development at national and regional levels. These are outside the scope of this modelling but may be considered by the wider Hydrogen Roadmap.

In the model, economic impact is measured in two main areas:

- Gross value-add as an indicator for GDP
- Employment effect

To assess these impacts, the total contribution of hydrogen activity in New Zealand is considered as the sum of direct effect (i.e., those activities directly related to the hydrogen projects' construction and operation) and indirect effect (i.e., the industry activity required to support the direct investments). Investment is derived from the total volume of hydrogen demand at the end use, multiplied by the LCOGH at the plant, and distribution and transformation costs. It is assumed that 70% of the hydrogen spend will be in New Zealand and the remaining 30% will be overseas (e.g. to suppliers).

There is an inherent challenge in attempting to model the flow on impacts of the hydrogen industry since the industry is not yet well established in New Zealand and there is limited data to draw on. The following upstream industries are modelled based on their likely importance to the hydrogen industry:

- Electricity generation and on-selling
- Electricity transmission and distribution
- Gas supply and Water supply
- Construction services
- Machinery and equipment wholesaling

- Other manufacturing

Input-Output table limitations

We have used Input-Output tables (IO tables) to measure the impact of hydrogen investment and spending on the wider economy. The assumptions included in this section have been developed using materials and assumptions from Stats NZ. The IO tables include the following limitations:

- **Aggregation**: IO tables are often aggregated to a high level, which means that the details of specific industries or activities within those industries may not be captured. This can limit the accuracy of the model when attempting to simulate the behaviour of specific industries.

- **Static nature**: IO tables are static in nature and do not capture the dynamic nature of an economy. They reflect the relationships between sectors based on a single period, and do not reflect changes in production and consumption patterns over time. This can limit the usefulness of the model in forecasting future economic scenarios.

- **Assumptions**: IO tables rely on certain assumptions about the interrelationships between sectors, which may not always be accurate. For example, they assume that the production process is linear and that inputs are fully consumed in the production of outputs, which may not always be the case. These assumptions can limit the accuracy of the model in capturing the complexity of real-world economic systems.

- **Geographical limitations**: IO tables are typically constructed at a national level, which means that they may not capture the nuances of regional economies or the impacts of international trade. This can limit the usefulness of the model in simulating the impacts of regional economic policies or global economic shocks.

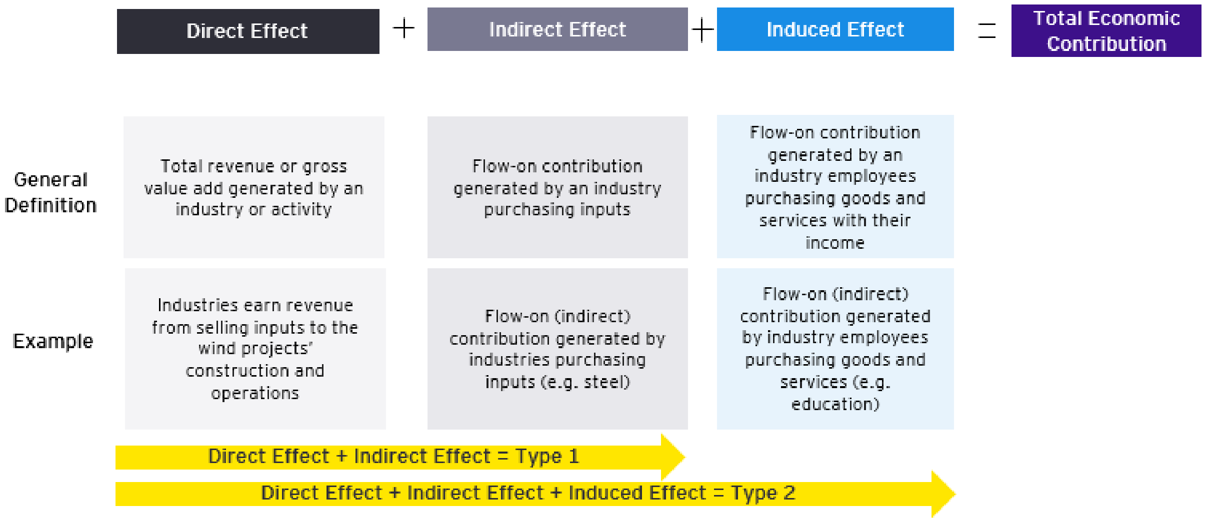
- **Limited scope**: IO tables only consider monetary transactions between sectors and do not account for non-monetary factors such as environmental impacts or social welfare. This can limit the usefulness of the model in simulating the broader impacts of economic policies.

Overall, IO tables can be a valuable tool for modelling economic systems, but they should be used in conjunction with other methods and approaches to provide a more complete picture of an economy. Careful consideration of their limitations is necessary to ensure that the model is accurate and useful for the intended purpose.

As with the rest of the modelling, all values included in this section of the report do not consider the impacts of inflation and discounting. Further details on the assumptions made for the economic contribution and development section of this report can be found in Appendix B.

Our outputs predominantly show the 'Type 1' effects of hydrogen spending in New Zealand. 'Type 1' effect looks at inter industry effects and does not consider the induced effect (also known as consumption effect). 'Type 2' effects which include induced effects have not been considered in the modelled outcomes as inclusion of the consumption effect is regarded as overly optimistic and potentially unrealistic. Figure 53 below elaborates on the definitions of these terms.

Figure 53: Defining economic contribution



7.2.1 Gross value-add

Gross value-add is commonly used estimate for the market value of goods and services produced, after deducting the cost of goods and services used. It incorporates the sum of all wages, income and profits generated. In this report, we are using gross value-add as an indicator for the potential GDP that the hydrogen economy can contribute to New Zealand. GDP can be derived from value-add by adjusting for government taxes and subsidies. The modelling excludes consideration of indirect taxes (such as levies on goods and services) and therefore a value for GDP has not been provided.

Throughout this report, all numbers cited are in 'gross' terms. When reporting value-add figures, it is considered best practice to specify the period for which the value-add figure applies.

Figure 54 below illustrates the value-add effect that hydrogen investment has on the economy. The value effect has phases of rapid growth taking place between 2030-2040. Furthermore, CAPEX spending will be a higher proportion of spending in the earlier years before OPEX spending dominates in the years post 2040.

Under the base case, modelled value-add enabled by hydrogen reaches NZ$0.8 billion by 2035 and NZ$2.2 billion by 2050. The base case has the lowest value-add growth compared to the other scenarios. The 'Value-add export' scenario has the highest growth, reaching NZ$2.9 billion by 2035 and NZ$4.6 billion by 2050.

Figure 54: Gross value-add from domestic hydrogen economy by scenario (2023-2050, NZ$ billion)

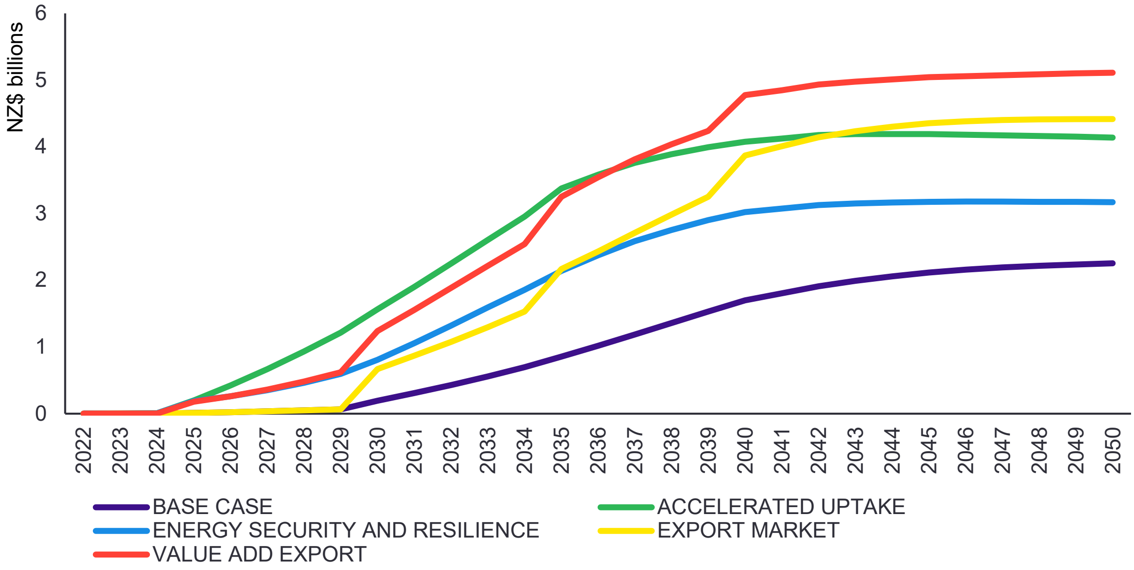


Table 22 summarises the value-add effect for each scenario. Scenarios are ranked in order of the value enabled by 2050, with five being the highest performing and one being the lowest performing.

Table 22: Comparison of value-add effect across scenarios

Scenario	2035		2050		Ranking
	Value effect ($b)	+/- Base case	Value effect ($b)	+/- Base case	
Base case	0.9	0%	2.3	0%	1
Accelerated uptake	3.4	296%	4.1	84%	3
Energy security and resilience	2.1	151%	3.2	41%	2
Export market	2.2	154%	4.4	96%	4
Value-add export	3.3	281%	5.1	127%	5

7.2.2 Hydrogen production related capital spending

To achieve the hydrogen supply targets needed to service domestic and potential export demand in New Zealand under each scenario, significant capital expenditure in hydrogen production plants and distribution channels is required. Through the modelling, the capital spend for production plants is estimated based on the assumed capital costs of electrolyser systems and the balance of plant. Due to the limited modelling of the different hydrogen distribution channels, estimates of capital spend for hydrogen transformation and distribution in the scenarios are unavailable.

Electrolyser system costs are assumed to fall from US$1000/kW in 2022 to US$200/kW in 2050 for centralised plants. For decentralised plants, these fall from US$1400/kW to US$200/kW over the same period. These costs are based on analysis completed by IRENA. Capital costs relating to the balance of plant are assumed to be +20% of electrolyser costs for centralised plants, and +15% for decentralised plants.

Table 23 shows the cumulative total capital costs for hydrogen production plants up to the years 2035 and 2050, based on the modelled electrolyser capacity required. Note that in the model, capital costs are assumed to be recovered over the 20-year lifetime of the plant through the CAPEX component of the levelized cost of green hydrogen. Note that the costs below are not discounted to present value.

Table 23: Cumulative hydrogen plant CAPEX by scenario (2035 and 2050)

Scenario	Total production plant CAPEX ($m)	
	2022-2035	2022-2035
Base case	1,492	3,386
Accelerated uptake	6,227	7,664
Energy security and resilience	4,069	5,922
Export market	3,401	6,436
Value-add export	5,498	8,217

7.2.3 Employment created or supported

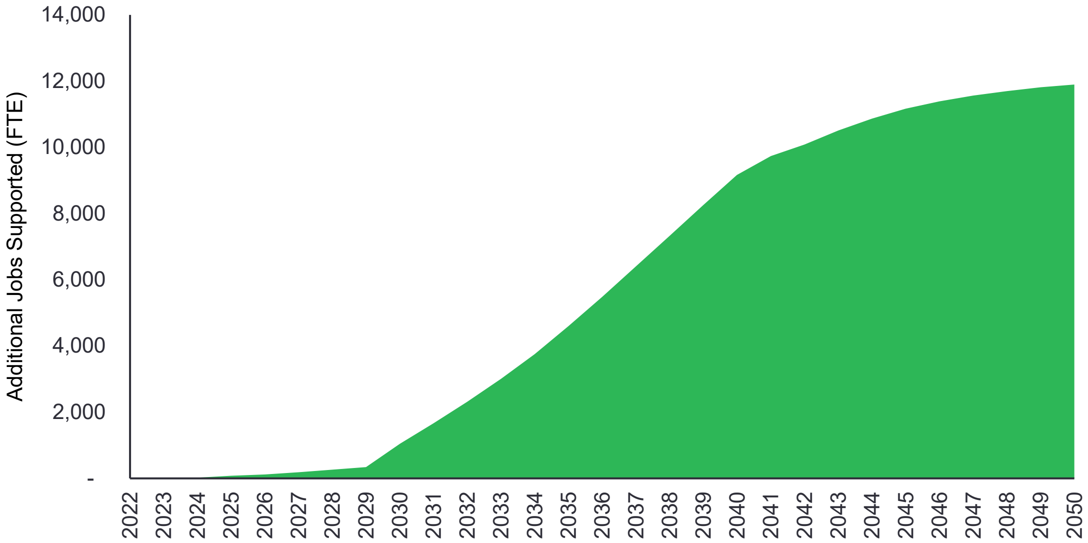
The employment effect presented in this report represents the gross employment demand that would arise in New Zealand as a result of hydrogen production and consumption. In other words, these employment estimates help us to understand the overall job opportunities that flow from the modelled hydrogen investment. The jobs numbers in this report are estimates based on sector employment multipliers applied to the hydrogen investment value. Therefore, the actual number of workers directly employed by the hydrogen industry may differ from these estimates.

Figure 55 illustrates that hydrogen spending in the model is expected to be steady and sizeable enabler of employment in the New Zealand economy. The figure illustrates the level of employment in each year that is supported by spending in the hydrogen sector. The figure shows that in the base case, there will be approximately 4,600 jobs supported the energy sector by 2035, increasing to 11,900 in 2050. By comparison, McKinsey's The New Zealand Hydrogen Opportunity[77] suggests that the South Island's Green Hydrogen economy could support 4,000-7,000 ongoing jobs by 2030.

It should be noted that the figure shows the level of employment as at each year. For example, the modelling output does not suggest that there are 11,900 new jobs from the total domestic spend from investments into hydrogen in 2050, rather there are 11,900 jobs in 2050 that are supported by the total spend in the hydrogen sector. Note that we are unable to model the duration of the new jobs created due to the limitations of this model.

[77] The New Zealand Hydrogen Opportunity, McKinsey & Company for Meridian Energy (Meridian) and Contact Energy (Contact)

Figure 55: Base case impact on employment (2023-2050, full time equivalents)



One key limitation of the IO table is that its assumption of an unconstrained supply of labour (i.e., there are sufficiently skilled people willing and able to work in the hydrogen industry at the prevailing wage rate). This assumption does not take into consideration changing unemployment rates and the overall availability of the domestic workforce, which can affect actual labour supply. At present, the unemployment rate is at 3.4%, as of Q1 2023, which is sitting far below the natural rate of unemployment.[78] For additional labour to be compelled to switch jobs or enter the workforce, it is likely that the hydrogen industry will need to offer higher wages than the market is receiving.

Figure 56 illustrates the difference in jobs supported by the hydrogen economy in each scenario. As employment impact is a direct function of hydrogen spend and the output multipliers have remained constant across scenarios, the profile of the employment effect for the alternative scenarios are similar to those of total hydrogen spend. It is important to note that in scenarios with export spending, the employment figures may be overstated due to employment being unlikely to scale with increased production.

As depicted in Figure 56 the base case profile illustrates a more gradual growth in the number of jobs in the hydrogen sector as compared to scenarios such as 'Accelerated uptake' or 'Value-add export' market. A challenge for all scenarios, but is more pronounced in the higher uptake scenarios, will be the ability for the workforce associated with hydrogen to scale (either via training or sourcing overseas) in time.

[78] https://www.stats.govt.nz/indicators/unemployment-rate/

Figure 56: Comparison of impact on employment by scenarios (2023-2050, full time equivalents)

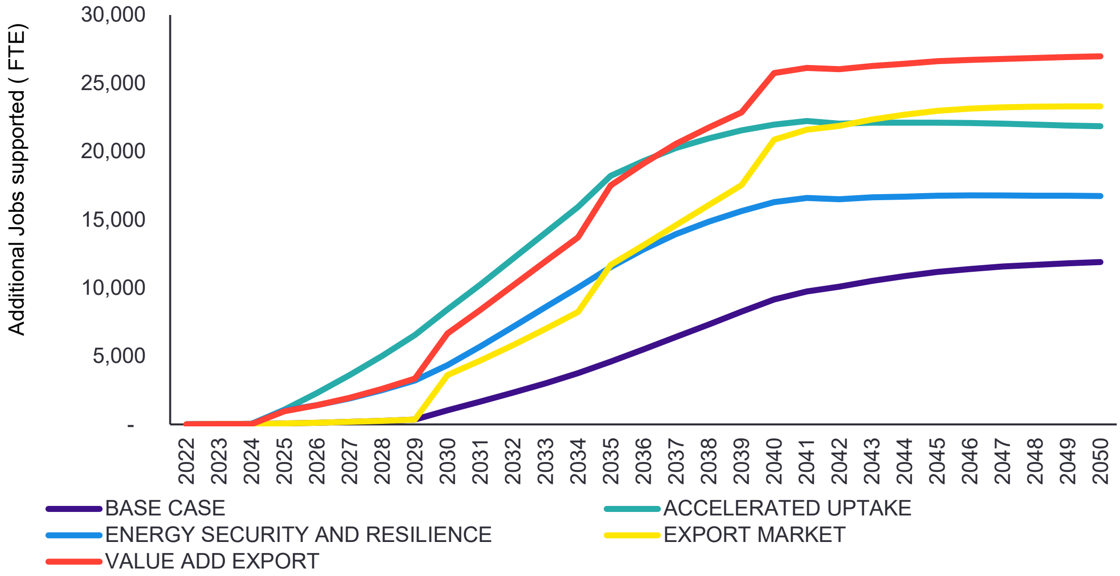


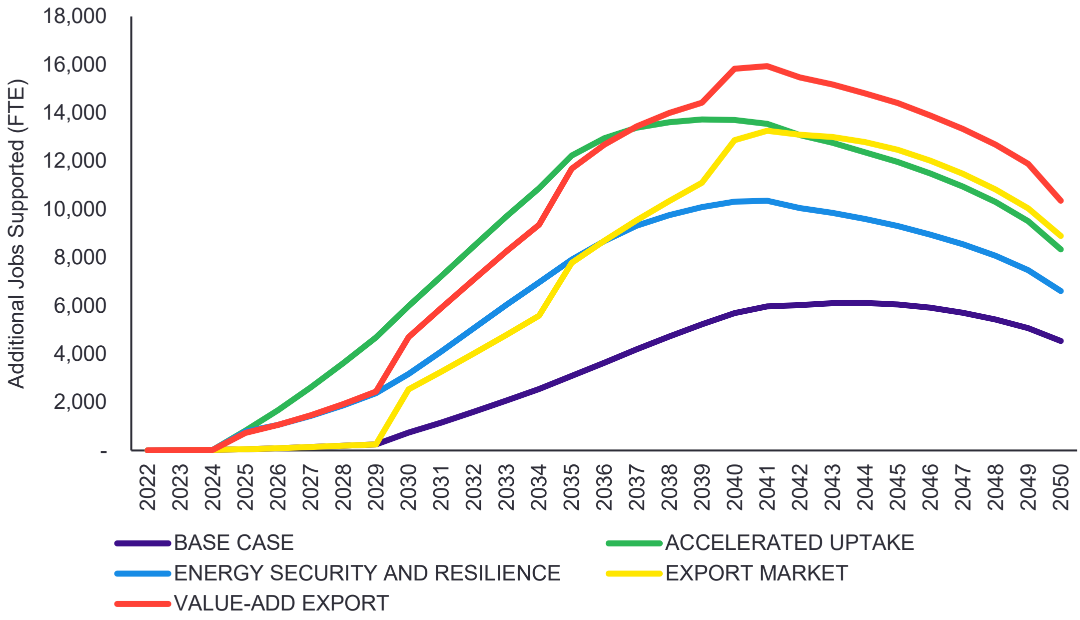
Table 24 summarises the employment impact for each scenario. Scenarios are ranked in order of the employment supported by 2050, with five being the highest, and one being the lowest.

Table 24: Difference in impact on employment by scenario (2035 and 2050)

Scenario	2035		2050		Ranking
	Employment (FTEs)	+/- Base case	Employment (FTEs)	+/- Base case	
Base case	4,603	0%	11,896	0%	5
Accelerated uptake	18,209	296%	21,845	84%	3
Energy security and resilience	11,532	151%	16,727	41%	4
Export market	11,689	154%	23,296	96%	2
Value-add export	17,520	281%	26,974	127%	1

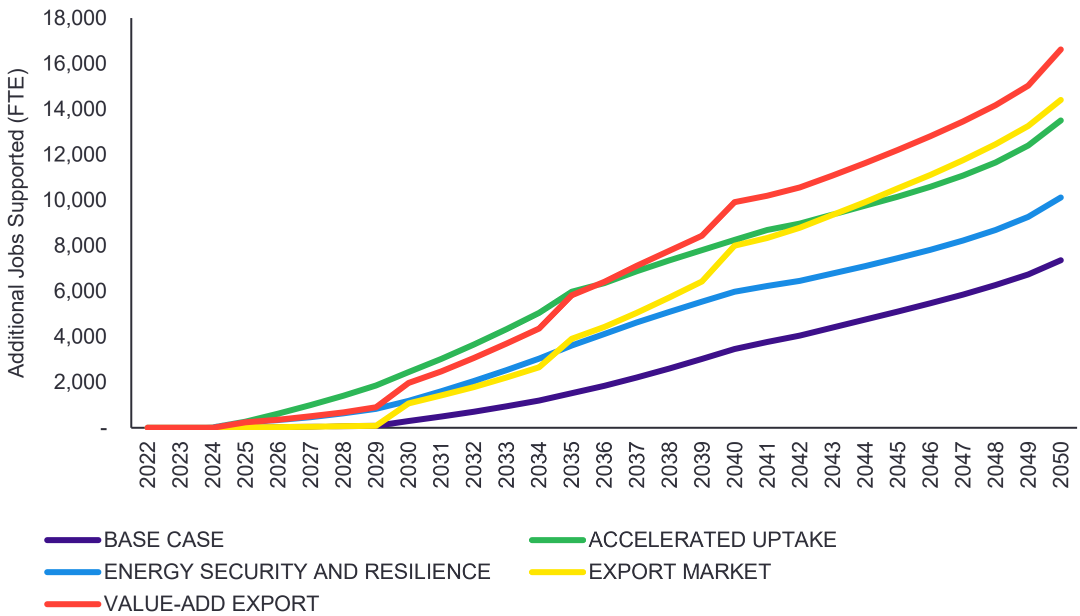
We have also considered the employment relating to capital expenditure and operating expenditure, to represent the employment relating to constructing and running the hydrogen ecosystem. Figure 57 shows the increase in supported jobs that arise from capital spending that spans from 2024 and peaks in around the late 2030s and early 2040s in all scenarios. As the hydrogen industry matures, the rate at which hydrogen facilities are being built slows down. A lot of this slow down can be attributed to the larger industrial feedstock conversion projects having completed conversion to green hydrogen.

Figure 57: Capital spending (CAPEX) impact on employment by scenario (2023-2050, full time equivalents)



The model outputs show employment from operating the hydrogen ecosystem increasing linearly as more hydrogen facilities and plants come online, as shown in Figure 58 below. Jobs arising from operating spending are expected to be of long-term nature, particularly given that hydrogen plants are expected to have useful lives of 20 years.

Figure 58: Operational spending (OPEX) impact on employment for by scenario (2023-2050, full time equivalents)



The spikes observed in years 2030, 2035, and 2040 in the 'Export market' and 'Value-add export' scenarios are a result of the limitations of IO modelling and are not intended to suggest that there will be an influx of jobs in 2040 that will not exist in 2041. In reality, we would expect that these spikes are smoothed across the time period.

Table 25 below reports CAPEX as the main source of spending in 2035 across all scenarios while OPEX forms the main source of spending in 2050. This table gives insight as to how spending from CAPEX to OPEX changes throughout the uptake of hydrogen in New Zealand.

Table 25: Difference in impact on CAPEX and OPEX employment by scenario (2035 and 2050)

Scenario	2035		2050	
	Employment (CAPEX)	Employment (OPEX)	Employment (CAPEX)	Employment (OPEX)
Base case	3,090	1,513	4,537	7,360
Accelerated uptake	12,232	5,977	8,343	13,502
Energy security and resilience	7,913	3,619	6,610	10,117
Export market	7,778	3,911	8,892	14,404
Value-add export	11,693	5,827	10,353	16,621

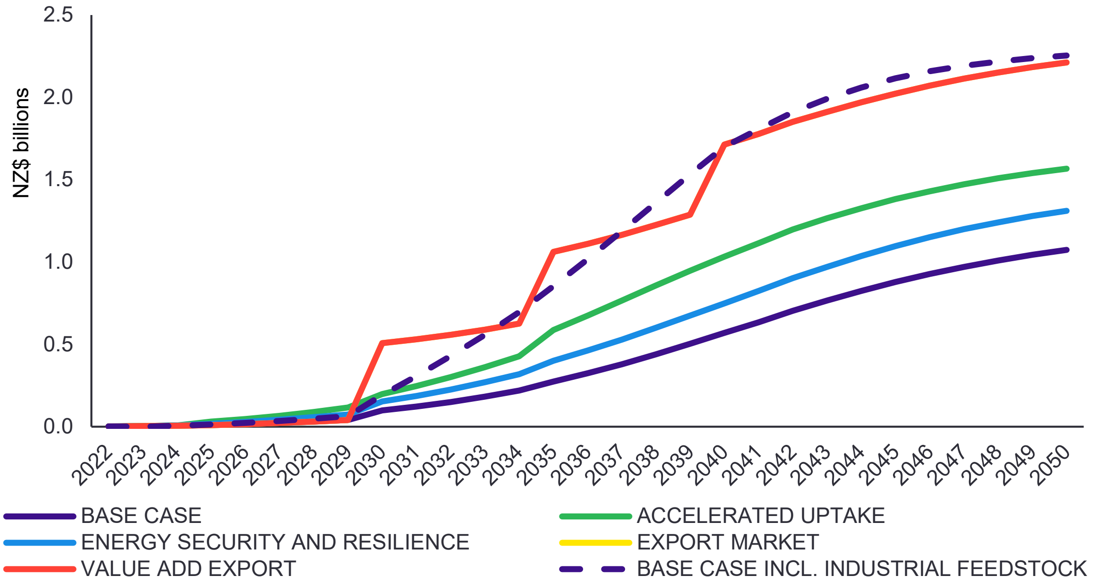
7.2.4 Economic outcomes excluding the impact of industrial feedstock

Due to the material impact that modelled industrial feedstock can have on the outcomes modelled, we have also considered the economic outcomes of using and producing hydrogen for energy end uses only. This helps to provide some understanding of the outcomes enabled if New Zealand focused more on developing hydrogen for energy use and less as an industrial feedstock.

7.2.4.1 Gross value-add

Figure 59 below shows the gross value add enabled by the hydrogen sector in each scenario if all industrial sector demand and associated hydrogen supply was set to zero. The figure also includes the base case including the impact of industrial feedstock as a reference point. As evident in the figure, the impact of industrial feedstock is material and its exclusion results in a gross value add that is $0.3 billion in 2035 and $1.1 billion in 2050 in the base case, equivalent to 68% and 54% lower than the base case with industrial feedstock included. The alternative scenarios also all result in lower gross value add, largely driven by the significantly lower hydrogen demand and production resulting from the exclusion of industrial feedstock.

Figure 59: Gross value-add from domestic hydrogen economy excluding impact of industrial feedstock by scenario (2023-2050, NZ$ billion)



The table below summarises the differences in the value-add effect across the scenarios based on whether the impact of industrial feedstock is included or excluded.

Table 26: Comparison of value-add effect and impact of industrial feedstock across scenarios

Scenario	2035, NZ$ billions			2050, NZ$ billions		
	Including industrial feedstock	Excluding industrial feedstock	% difference	Including industrial feedstock	Excluding industrial feedstock	% difference
Base case	0.9	0.3	-68%	2.3	1.1	-52%
Accelerated uptake	3.4	0.6	-83%	4.1	1.6	-62%
Energy security and resilience	2.1	0.4	-81%	3.2	1.3	-59%
Export market	2.2	1.1	-51%	4.4	2.2	-50%
Value-add export	3.3	1.1	-67%	5.1	2.2	-57%

7.2.4.2 Hydrogen production related capital spending

The table below shows the difference between cumulative total capital costs for hydrogen production plants up to the years 2035 and 2050 between scenarios if industrial feedstock is included and excluded. Excluding the impact of industrial feedstock results in modelled capital spend of $470 million by 2035 and $1,400 million by 2050 in the base case, equivalent to 69% and 58% lower than the base case with industrial feedstock included.

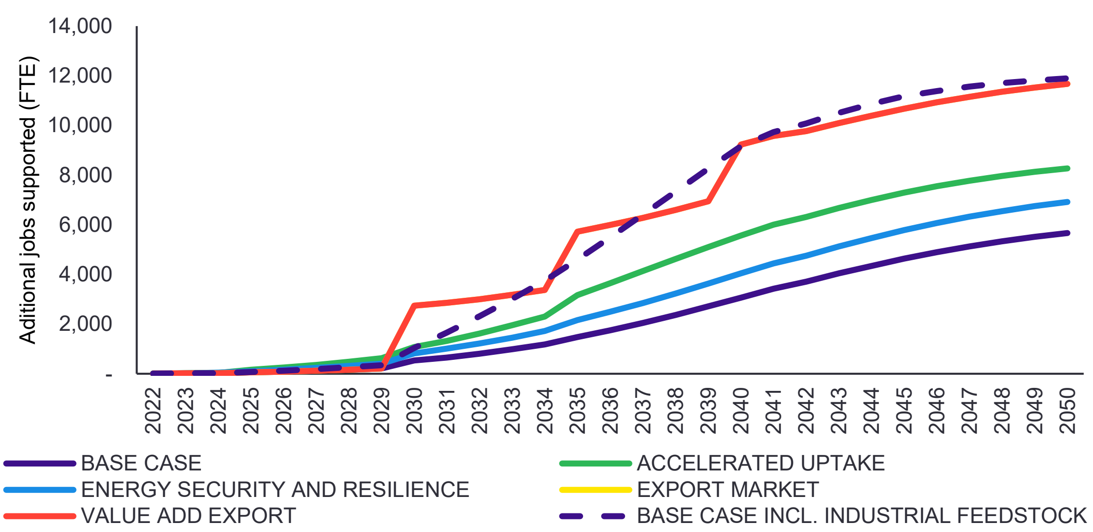
Table 27: Cumulative hydrogen plant CAPEX by impact of industrial feedstock and scenario (2035 and 2050)

Scenario	2022-2035, NZ$ millions			2022-2050, NZ$ millions		
	Including industrial feedstock	Excluding industrial feedstock	% difference	Including industrial feedstock	Excluding industrial feedstock	% difference
Base case	1,492	468	-69%	3,386	1,406	-58%
Accelerated uptake	6,227	1,035	-83%	7,664	2,243	-71%
Energy security and resilience	4,069	731	-82%	5,922	1,872	-68%
Export market	3,401	1,472	-57%	6,436	2,742	-57%
Value-add export	5,498	1,472	-73%	8,217	2,742	-67%

7.2.4.3 Employment created or supported

Figure 60Figure 59 below shows the employment levels supported by the hydrogen sector in each scenario if all industrial sector demand and associated hydrogen supply was set to zero. The figure also includes the base case including the impact of industrial feedstock as a reference point. As evident in the figure, excluding the impact of industrial feedstock results in modelled employment of 1,500 FTEs in 2035 and 5,700 FTEs in 2050 in the base case, equivalent to 68% and 54% lower than the base case with industrial feedstock included. The alternative scenarios also all result in lower employment levels.

Figure 60: Comparison of impact on employment excluding impact of industrial feedstock by scenario (2023-2050, full time equivalents)



The table below summarises the differences in employment across the scenarios based on whether the impact of industrial feedstock is included or excluded.

Table 28: Comparison of employment and impact of industrial feedstock across scenarios

Scenario	2035, FTEs			2050, FTEs		
	Including industrial feedstock	Excluding industrial feedstock	% difference	Including industrial feedstock	Excluding industrial feedstock	% difference
Base case	4,603	1,475	-68%	11,896	5,667	-52%
Accelerated uptake	18,209	3,162	-83%	21,845	8,270	-62%
Energy security and resilience	11,532	2,158	-81%	16,727	6,919	-59%
Export market	11,689	5,720	-51%	23,296	11,674	-50%
Value-add export	17,520	5,720	-67%	26,974	11,674	-57%

7.3 Supporting energy security and resilience

The third lever that each scenario is assessed against is hydrogen's impact on New Zealand's energy security and resilience. In this section, we consider the implications of hydrogen in New Zealand on both the electricity system and energy imports.

7.3.1 Stimulating new electricity investment

As discussed earlier in this report, significant growth in domestic hydrogen production will require significant volumes of renewable electricity. In New Zealand, challenges are already emerging surrounding the availability of electricity generation during times of high demand. In its Winter Review Paper[79] the System Operator noted in the past decade, the ten largest peak demands all occurred in 2021 and 2022, with six out of ten occurring in 2022. The grid emergency on 9 August 2021 saw a record high New Zealand peak demand. The 9 August 2021 grid emergency resulted in several power outages to customers and was partly due to insufficient generation being available during a cold evening[80].

Because New Zealand's generation fleet is already experiencing periods of tight supply, large hydrogen producers would need to incentivise new generation development to avoid exacerbating energy security and resilience issues. If large hydrogen producers procure large amounts of electricity from existing plants, then this could further strain the system, as well as put upwards pressure on electricity prices.

Currently in New Zealand, while there is a significant pipeline of potential new generation plants, some sources have cited uncertainty in demand (and therefore revenue and cost recovery) as inhibitors for progressing with generation development[81]. This is where hydrogen production plants can play a positive role in supporting the build out of generation. As a large electricity demand user, plants can engage in long-term contracts (e.g., Power Purchase Agreements) that help to underwrite and de-risk electricity plant investment. Alternatively, hydrogen plant developers can choose to invest in their own on-site electricity generation plant.

As discussed in section 6.5.3, at a system level, the staging of new electricity generation development would have to consider the additional electricity required for meeting the country's electricity needs from electrification and ensure that hydrogen demand for electricity does not negatively impact New Zealand's electrification efforts. A potential benefit that the material

[79] Winter Review Paper, System Operator, Transpower
[80] Investigation into electricity supply interruptions of 9 August 2021, Ministry of Business, Innovation & Employment
[81] New Zealand 2023 Energy Policy Review, International Energy Agency.

increases of generation build linked to hydrogen plants is that it can contribute to building the momentum and electricity supply chain required to build the ramp in electricity generation.

More analysis is required to understand the dynamic between electricity generation demand from electrification and hydrogen over time to create a more nuanced view on the impact that hydrogen production can have on the electricity system.
On the basis that hydrogen producers procure generation largely from new generation, scenarios are ranked by the volume of new generation incentivised, as discussed in section 6.5.3, with five being the highest performing and one being the lowest performing. Table 29 summarises the new electricity investment under each scenario.

Table 29: New generation investment driven by hydrogen production by scenario

Scenario	GW of new generation by 2035 (wind/solar mid-point)	GW of new generation by 2050 (wind/solar mid-point)	Ranking
Base case	4.3	12.5	1
Accelerated uptake	16.5	22.1	3
Energy security and resilience	9.5	16.6	2
Export market	10.5	23.4	4
Value-add export	15.0	27.0	5

7.3.2 Providing electricity system flexibility

Having a flexible electricity system that can adjust to unexpected increases/decreases in demand and supply is another aspect of energy security and resilience that we consider.

It is expected that hydrogen plants may be capable of flexing their electricity demand and consequently, hydrogen output, in response to the electricity system's needs. Research shows that with technologies such as polymer electrolyte membrane (PEM) electrolysers[82], this is a plausible technology for offering flexibility. As large demand loads with flexibility capabilities, hydrogen plants are able to increase the overall electricity system's flexibility through demand response, as discussed in section 6.5.2. Without flexibility, large amounts of hydrogen production capacity are likely to have a detrimental effect on energy security and resilience, adding to already constrained networks and tight supply situations.

In practice, demand response, or flexibility more broadly, can be in the form of a plant decreasing its take of electricity from the grid and/or a plant, that is co-located with new generation, decreasing its take of electricity from its own generation, and that generation being injected into the grid during periods of tight supply and to support the country's security of supply. Depending on the commercial arrangements, plants can support security of supply during peak periods (curtailing demand for hours at a time) or during dry years (weeks at a time).

The electricity market's recent implementation of real-time pricing[83] and the ongoing flexibility enabling work being completed by industry (e.g. Flex Forum[84] and trials run by various electricity distribution businesses and Transpower) will likely incentivise new plant developments to build in this capability.

On the basis that hydrogen producers build flexibility into their plant, scenarios can be ranked against the volume of demand response capacity they provide, as summarised in Table 30 below.

[82] Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal (irena.org)
[83] Real Time Pricing, Electricity Authority
[84] New Zealand's FlexForum, Ara Ake

Due to the annual nature of this model, we have not developed a detailed understanding of how these flexibility services will play out at an hourly or day-to-day time period. Instead, as discussed in Section 6.5.1, an average plant capacity factor is assumed that accounts for some curtailed demand due to demand response. More analysis is required at an electricity system and market level to understand the likely volume and value of these flexibility services.

Table 30 summarises the demand response capacity in each scenario. Scenarios are ranked in order of the demand response enabled by 2050, with five being the highest performing, and one being the lowest performing.

Table 30: Potential demand response capacity enabled by hydrogen production by scenario

Scenario	Demand response by 2035 (TWh)	Demand response by 2050 (TWh)	Ranking
Base case	1.3	3.8	1
Accelerated uptake	5.0	6.7	2
Energy security and resilience	4.6	8.0	4
Export market	3.2	7.1	3
Value-add export	4.5	8.2	5

7.3.3 Reduction in energy imports

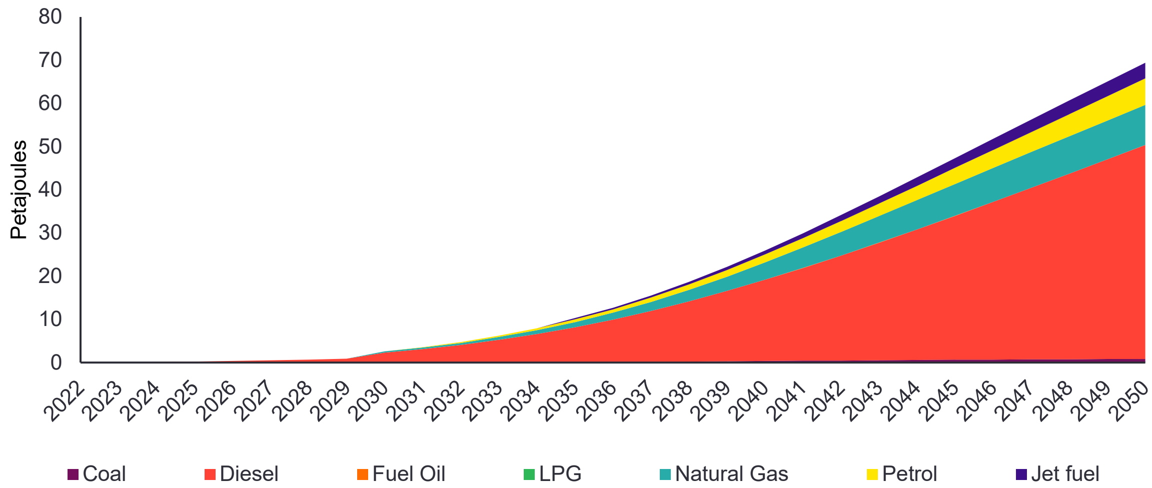
The build out of hydrogen production and hydrogen consumption in New Zealand is expected to have significant impacts on the nation's ability to reduce its reliance on energy imports. To understand the potential that hydrogen can play in this area, the volume of fossil fuel energy and liquid fuel imports that are displaced have been approximated by the increase in hydrogen demand.

Base case modelling outputs

As represented in Figure 61 hydrogen uptake under the base case scenario results in displacement of approximately 69.40 Petajoules of fossil fuel energy consumption in New Zealand by 2050. This is equivalent to approximately 19% of total consumer energy delivered by fossil fuels in 2021 as reported in the MBIE Energy Balance Tables.[85]

[85] Energy Balance Tables, MBIE

Figure 61: Base case breakdown of fossil fuel displaced by hydrogen (2023-2050, petajoules)



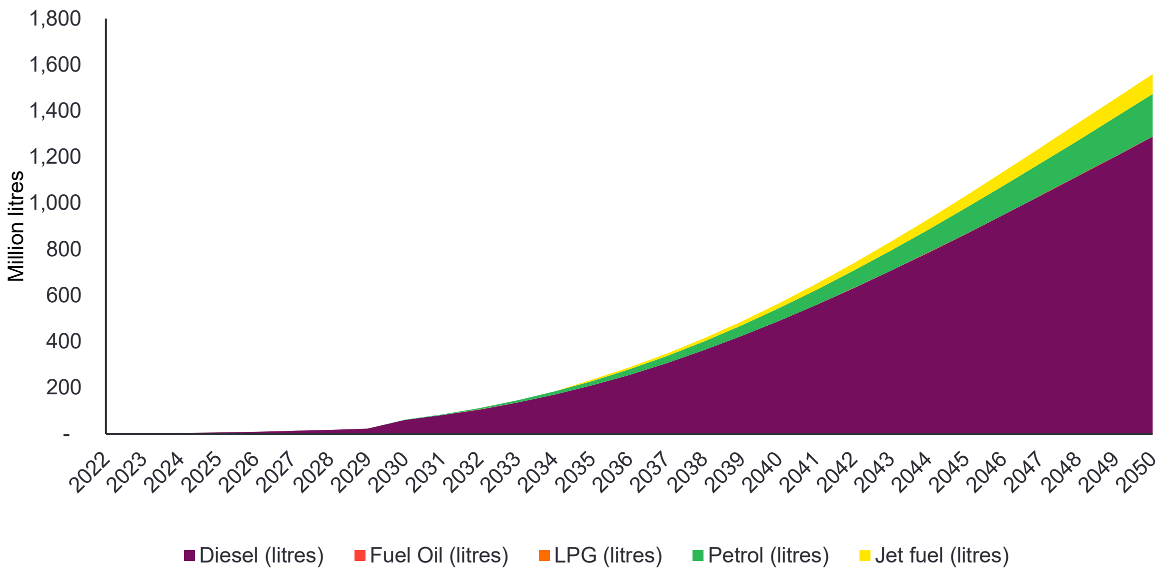
As shown in Table 31, the displacement of diesel and natural gas represents approximately 84% of all fossil fuel displacement by hydrogen under the base case scenario. Diesel is displaced largely in the transport demand sector and natural gas is largely displaced in the process heat sectors.

Table 31: Base case breakdown of fossil fuel displaced by hydrogen by type (2035 and 2050)

Fuel type	2035		2050	
	PJ	% of total	PJ	% of total
Diesel	8.07	79%	49.55	71%
Natural gas	1.19	12%	9.26	13%
Jet fuel	0.29	3%	3.61	5%
Petrol	0.62	6%	6.13	9%
Coal	0.10	1%	0.81	1%
Fuel oil	0.00	0%	0.04	0%
Total	10.28	100%	69.40	100%

Figure 62 focuses on total liquid fossil fuel displacement. This focus allows examination of New Zealand's ability to reduce its reliance on imported energy as all liquid fossil fuels consumed in New Zealand today are imported. As a result of the modelling, transport has been identified to be the largest contributor to the displacement of liquid fossil fuels - with diesel comprising 83% of all liquid fossil fuels displaced in 2050.

Figure 62: Liquid fossil fuel displaced by type (2023-2050, million litres)



Modelled total liquid fossil fuel displacement under the base case reaches approximately 1,559.6 million litres, equivalent to around 9.81 million barrels of liquid fossil fuels displaced by 2050. This represents approximately 17.8% of New Zealand's imported liquid fuel in 2022 per MBIE's reporting.[86]

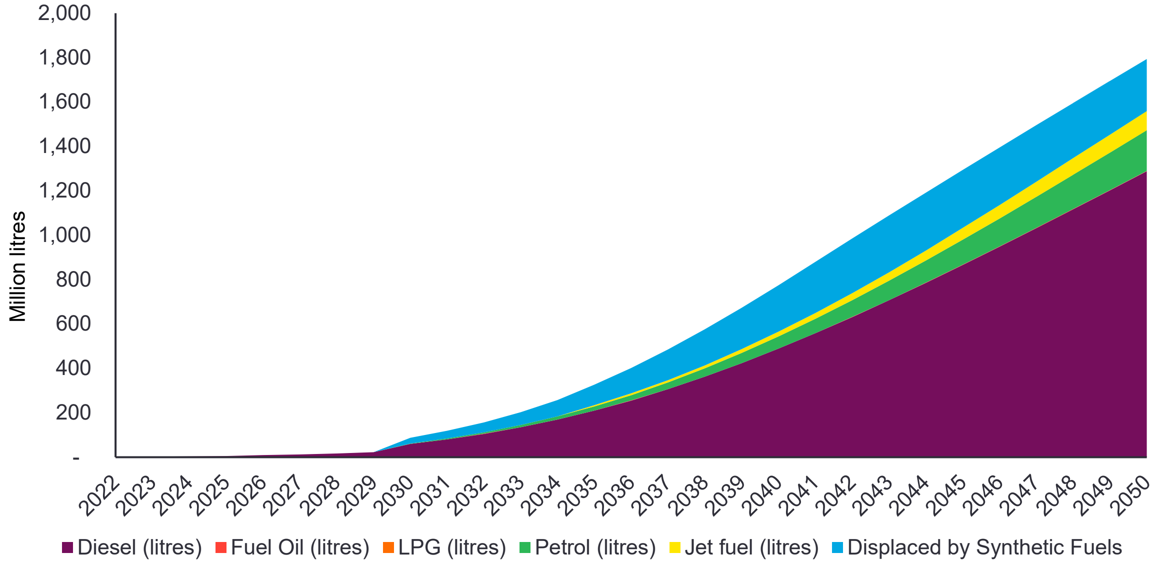
Table 32: Total liquid fossil fuel displaced for base case by type (2035 and 2050)

Fuel type	2035		2050	
	Million L	% of total	Million L	% of total
Diesel	209.9	89.3%	1,288.3	82.6%
Jet fuel	6.6	2.8%	86.3	5.5%
Petrol	18.5	7.9%	184.0	11.8%
Fuel oil	0.1	0.1%	1.0	0.1%
TOTAL	235.1	100 %	1559.6	100%

This model does not consider the distribution of synthetic fuels produced by hydrogen from industrial feedstock demand (see Appendix B) for use in other demand sectors. In the synthetic fuels sector, it is estimated that approximately 1.47 million barrels of synthetic fuel would be created. If this synthetic fuel were to be distributed into domestic demand sectors (i.e. transport) it could further displace 234 million litres of fossil fuels by 2050. Total liquid fossil fuel displacement from the distribution of synthetic fuels is illustrated in Figure 63 below.

[86] Oil statistics, MBIE

Figure 63: Liquid fossil fuel displaced including displacement from synthetic fuel distribution (2023-2050, million litres)



Across the various alternative scenarios modelled, there are considerable increases in the level of fossil fuel energy displacement in comparison to the base case scenario as a result of the increased and more rapid uptake of hydrogen.

As displayed in Figure 64 fossil fuel energy displacement reaches approximately 111 petajoules in the 'Accelerated uptake' scenario and 103 petajoules in the 'Energy security and resilience' scenario by 2050 which represents an additional displacement of 6% and 4% respectively of New Zealand's total fossil fuel consumption in 2022[87]. The increase in fossil fuel displacement under 'Energy security and resilience' is attributable to the higher uptake in transport demand, and a greater increase in displacement under 'Accelerated uptake' scenario is attributable to higher uptake in both transport and process heat demand.

Fuel displacement in 'Export market' and 'Value-add export' scenarios are modelled to be consistent with the base case.

[87] Energy Balance Tables, MBIE

Figure 64: Comparison of total fossil fuel energy displaced for all scenarios (2023-2050, petajoules)

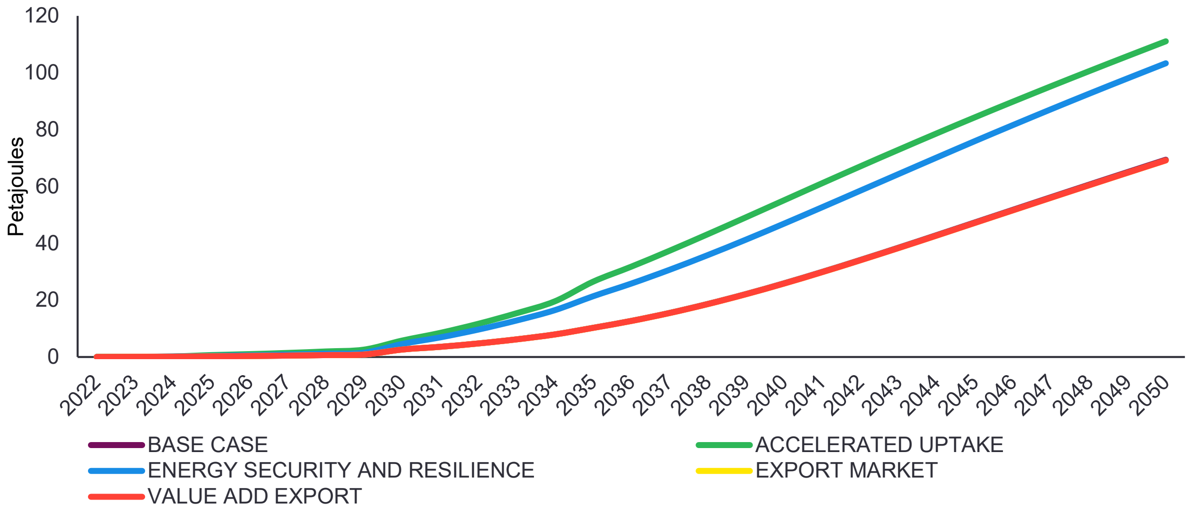


Table 33 summarises the key differences in fossil fuel energy displacement by scenario and ranks the scenarios, with five being the highest performing and one being the lowest performing.

Table 33: Key differences of fossil fuel energy displaced between scenarios (2035 and 2050)

Scenario	2035		2050		Ranking
	PJ displaced	+/- Base case	PJ displaced	+/- Base case	
Base case	10.3	0%	69.4	0%	3
Accelerated uptake	26.5	+157.8%	111.1	+60%	5
Energy security and resilience	21.4	+107.9%	103.3	+48.9%	4
Export market	10.2	0%	69.2	0%	3
Value-add export	10.2	0%	69.2	0%	3

The drivers of differences in liquid fossil fuel displacement between the alternative scenarios and the base case scenario are consistent with drivers for the fossil fuel energy displaced by scenario as displayed in Figure 65.

Figure 65: Comparison of total liquid fossil fuel displaced by scenario (2023-2050, million litres)

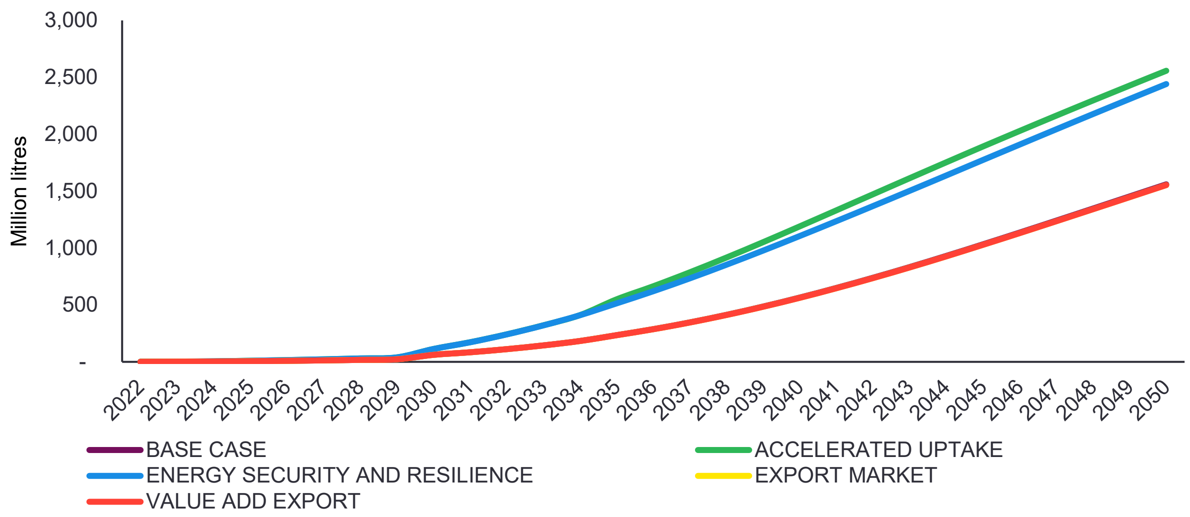


Table 34 summarises the key differences in liquid fuel displacement by scenario and ranks the scenarios, with five being the highest performing and one being the lowest performing.

Table 34: Key differences between total liquid fossil fuel displaced by scenario (2023-2050)

Scenario	2035		2050		Ranking
	Million L displaced	+/- Base case	Million L displaced	+/- Base case	
Base case	235.1	0%	1,559.6	0%	3
Accelerated uptake	549.6	+134%	2,557.6	+64%	5
Energy security and resilience	514.1	+119%	2,440.7	+56%	4
Export market	234.3	0%	1,553.2	0%	3
Value-add export	234.3	0%	1,553.2	0%	3

7.3.4 Energy outcomes excluding the impact of industrial feedstock

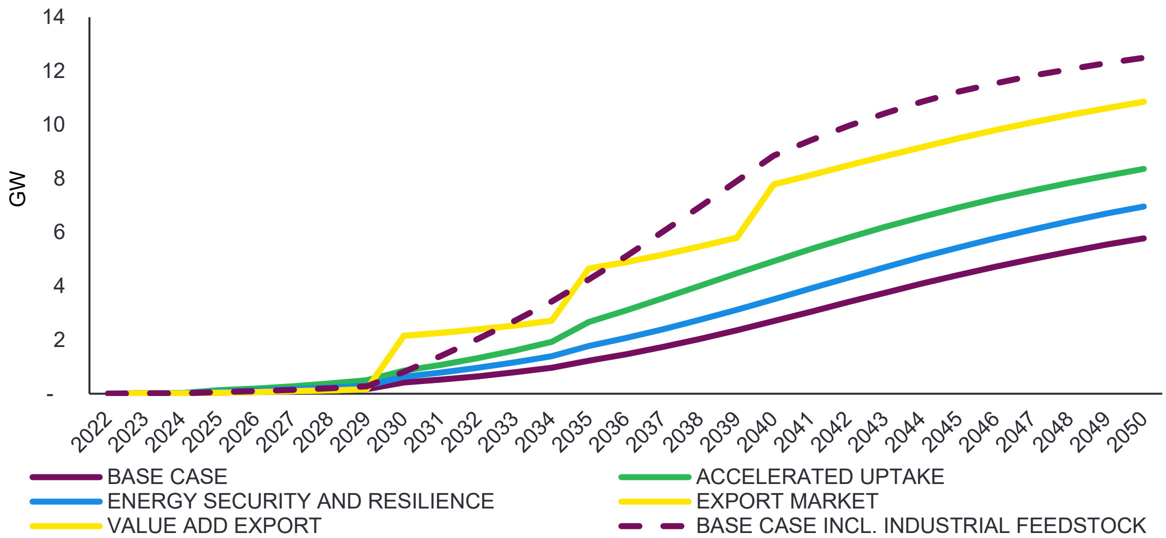
Due to the material impact that modelled industrial feedstock can have on the outcomes modelled, we have also considered the energy security and resilience outcomes of using and producing hydrogen for energy end uses only. This helps to provide some understanding of the outcomes enabled if New Zealand focused more on developing hydrogen for energy use and less as an industrial feedstock.

We have not presented additional analysis on energy imports due to this measure already excluding industrial feedstock.

7.3.4.1 Electricity investment

Figure 66 below shows the modelled new electricity generation investment required in each scenario if all industrial sector demand and associated hydrogen supply was set to zero. The figure also includes the base case including the impact of industrial feedstock as a reference point. As evident in the figure, excluding the impact of industrial feedstock results in a modelled generation build out of 1.2 GW in 2035 and 5.8 GW in 2050 in the base case, equivalent to 72% and 54% lower than the base case with industrial feedstock included. The alternative scenarios also all result in lower build out levels driven by lower electricity demand from lower levels of hydrogen production.

Figure 66: Required electricity generation capacity excluding impact of industrial feedstock by scenario (2035-2050, wind-solar mix, GW)



The table below summarises the differences in the electricity generation required across the scenarios based on whether the impact of industrial feedstock is included or excluded.

Table 35: Comparison of electricity generation capacity and impact of industrial feedstock across scenarios

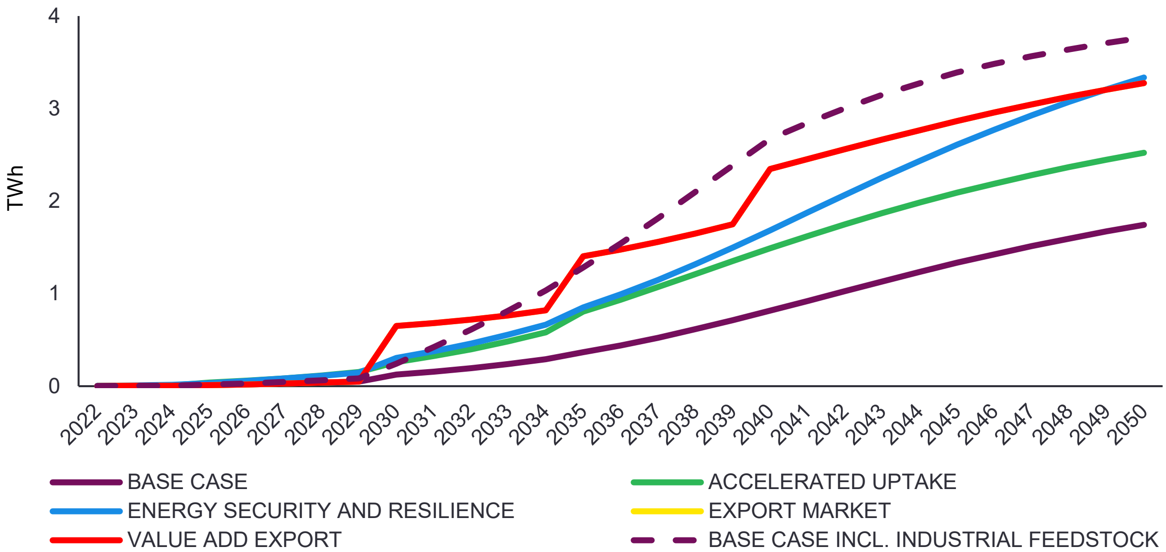
Scenario	2035, GW			2050, GW		
	Including industrial feedstock	Excluding industrial feedstock	% difference	Including industrial feedstock	Excluding industrial feedstock	% difference
Base case	4.3	1.2	-72%	12.5	5.8	-54%
Accelerated uptake	16.5	2.7	-84%	22.1	8.4	-62%

Energy security and resilience	9.5	1.8	-81%	16.6	7.0	-58%
Export market	10.5	4.7	-55%	23.4	10.9	-53%
Value-add export	15.0	4.7	-69%	27.0	10.9	-60%

7.3.4.2 Electricity system flexibility

Figure 67 below shows the modelled demand response capacity in each scenario if all industrial sector demand and associated hydrogen supply was set to zero. The figure also includes the base case including the impact of industrial feedstock as a reference point. As evident in the figure, excluding the impact of industrial feedstock results in a potential demand response capacity of 0.4 TWh in 2035 and 1.7 TWh in 2050 in the base case, equivalent to 69% and 55% lower than the base case with industrial feedstock included. The alternative scenarios also all result in lower demand response levels, driven by lower modelled electrolyser capacity due to lower hydrogen demand.

Figure 67: Annual demand response capacity excluding impact of industrial feedstock by scenario (2023-2050, TWh)



The table below summarises the differences in the potential demand response across the scenarios based on whether the impact of industrial feedstock is included or excluded.

Table 36: Comparison of potential demand response capacity and impact of industrial feedstock across scenarios

Scenario	2035, TWh			2050, TWh		
	Including industrial feedstock	Excluding industrial feedstock	% difference	Including industrial feedstock	Excluding industrial feedstock	% difference
Base case	1.3	0.4	-69%	3.8	1.7	-55%
Accelerated uptake	5.0	0.8	--84%	6.7	2.5	-63%

Energy security and resilience	4.6	0.9	80%	8.0	3.3	-59%
Export market	3.2	1.4	-56%	7.1	3.3	-53%
Value-add export	4.5	1.4	-69%	8.2	3.3	-60%

8. Potential next steps

This model was commissioned to provide analysis that provides a range of outputs intended to aid the government in understanding how the build out of hydrogen production and demand might unfold and identify gaps that could be addressed via policy interventions. As stated throughout this report, there are several limitations to this model that need to be considered when interpreting these outcomes, as discussed in section 3.

Limitations of the modelling include the uncertainty of future technology uptake, limited modelling of the dynamic relationship between hydrogen and electricity markets, limited import and export considerations and the use of Input-Output tables to measure the impact of hydrogen spending on the wider economy. Furthermore, the assumptions used in this model are based on the current understanding of hydrogen, desktop research and some consultation with industry, and can be improved upon as the sector engages with the Interim Hydrogen Roadmap.

Taking these limitations into account, the model strives to cover the full scope of the economy at a macro level and establishes the foundation for more exhaustive economic and technical studies into the potential of hydrogen. To build on this work, further analysis and modelling could be completed such as:

- Developing a market equilibrium model and industry specific total cost of ownership models to better understand how and when industries might switch to green hydrogen
- Spatial studies of hydrogen demand and supply to better understand the regional impacts and feasibility of hydrogen uptake
- Electricity market modelling to better understand the dynamic relationship between electricity demand from hydrogen production, wholesale electricity prices and the generation build out required
- More detailed policy impact assessments to test potential future policy options.

Appendix A Scenario descriptions

During the scenario and model development phase of this work, we held several workshops with MBIE energy policy teams to better understand the varying expectations of the role that hydrogen could play in New Zealand's energy future. We also held a workshop and sought offline feedback from Hydrogen Council members to explore various scenarios and key assumptions in the model.

The following sections describe the guiding narrative for each scenario considered in this model.

Figure 68: Modelled scenarios and key differences relative to base case

	Base case	Accelerated uptake	Energy security and resilience	Export market	Value-add export
Hydrogen demand	Driven mostly by industrial feedstock and heavy transport	Uptake across domestic demand sectors higher and faster	Uptake across domestic demand sectors higher	Increased demand from export plants	Increased demand from export plants and industrial feedstock
Hydrogen supply	Production focused in decentralised plants Some centralised production	Production focused in decentralised plants Some centralised production	Production focused in decentralised plants Some centralised production	Production focused in centralised plants Some decentralised production	Production focused in centralised plants Some decentralised production
Intended outcomes	Lower performance against decarbonisation, energy security and resilience and economic development Lower risk to electrification	Highest emissions reduction potential	Higher displacement of liquid fossil fuels and increased support for electricity system	High economic value	Highest economic value

A.1 Base case

New Zealand recognises that hydrogen will be an important low carbon energy source for hard-to-abate sectors alongside alternative fuels such as bioenergy.

Due to uncertainties in technology development, New Zealand waits for global technologies to become commercially available and viable in the country. Efforts are not made to position New Zealand as a world leader in hydrogen production.

The build out of the hydrogen supply chain is largely driven by private, commercial players. Some individual, large suppliers have pursued export partnerships but most of the hydrogen produced in New Zealand is consumed domestically.

The intended outcome of this scenario is that the hydrogen supports the decarbonisation of energy uses/industrial feedstock where it is more cost-efficient than alternatives.

A.2 Accelerated uptake

As in the base case, New Zealand recognises that hydrogen will be an important low carbon energy source to help decarbonise hard-to-abate sectors. In this scenario, there is a consensus that uptake of hydrogen needs to be accelerated for decarbonisation objectives.

As a result of the intent to accelerate hydrogen uptake throughout the nation, hydrogen production businesses are able to scale at a pace much faster than in the base case. As in the base case, some individual, large suppliers have pursued export partnerships but most of the hydrogen produced in New Zealand is consumed domestically.

Moreover, increased domestic demand for hydrogen is also brought forward, with most of the increase in demand observed in hard-to-abate sectors.

The intended outcome of this scenario is that hydrogen use drives emissions reductions sooner than in the base case and plays a larger role in supporting New Zealand to meet its decarbonisation targets.

A.3 Energy security and resilience

In this scenario, the hydrogen supply chain has been developed with the purpose of supporting New Zealand's energy security and resilience, as well as decarbonisation.

Geopolitical factors have created risks for New Zealand's ability to import liquid fuels and other energy sources. Therefore, hydrogen production has been promoted to reduce reliance on imports.

In recognition of the impact hydrogen production plants can have on the electricity system, production plants are developed to complement the intermittency of renewable generation, as well as providing flexibility services and support to the electricity networks. There is also emphasis on supporting new renewable generation build.

On the demand side, hydrogen is used directly or as an input to green fuels that displace the need for some imported fuels, enabling New Zealand's energy independence.

The intended outcome of this scenario is that New Zealand is able to better withstand global shocks and geopolitical tensions that might impact energy imports. Decarbonisation is achieved as a secondary objective.

A.4 Export market

In this scenario, New Zealand pursues the development of a domestic supply chain with the aim of not only decarbonising the economy, but also developing a significant export sector.

The supply chain is built up to provide enough hydrogen supply to meet the needs of New Zealand's hard-to-abate sectors, where hydrogen is the most economic low carbon fuel, as well as demand from exports. Excess hydrogen is exported.

Production plants are located close to export terminals (e.g., Southland, Taranaki) and powered by dedicated renewable generation plants to mitigate electricity price impacts on domestic users.

The intended outcome of this scenario is that New Zealand's hydrogen is cost competitive globally and export revenue from hydrogen provides material economic benefit to the country. Locally, users benefit from lower hydrogen prices than in the base case due to the economies of scale that the hydrogen production market gains from targeting exports.

A.5 Value-add export market

In this scenario, New Zealand has put significant effort towards building up the hydrogen supply chain and industries where hydrogen is a green substitute for feedstocks such as fossil gas. This scenario builds on scenario four.

As in scenario four, the supply chain is built up to provide enough hydrogen supply to meet the needs of New Zealand's hard-to-abate sectors. In addition to meeting decarbonisation needs, hydrogen is used an input fuel to industrial processes domestically. New Zealand becomes a hub for exporting value-added green hydrogen products such as ammonia, steel and synthetic fuels.

Production plants are located close to export terminals and industrial processing plants that use hydrogen. Significant investment has also been made in growing these industries.

The intended outcome of this scenario is that New Zealand's export revenue from hydrogen products is significant. This scenario provides the largest economic benefit to the country.

Appendix B Model assumptions

The purpose of this appendix is to provide an outline of the assumptions underlying the hydrogen model developed by EY. This appendix includes the following sections:

- An overview of the modelling scope and approach to contextualize and clarify the rationale behind the assumptions.
- Modelling assumptions and data sources for:
  - General modelling assumptions
  - Demand-side assumptions
  - Supply-side assumptions
  - Conversion rates
  - Economic benefit assumptions
  - Energy resilience and carbon emissions reductions assumptions

B.1 General assumptions

The following section provides an overview of the general assumptions that are used across the model.

B.1.1 Gross domestic product (GDP)

GDP figures from the Climate Change Commission's scenarios have been adopted [88]. GDP growth trajectory is used as a baseline to inform sector growth trajectories. A growth rate is derived from the table below using linear interpolation in the economic model. We discuss later in this assumptions book how trajectories might vary across drivers and scenarios.

Table 37: Gross domestic product

Parameter	Unit	2022	2035	2050
Real GDP	2009/10 $ billion	256.92	346.99	435.47

B.1.2 Population numbers

The 50th percentile of Statistics New Zealand projections[89] have been used. Population numbers do not deviate between scenarios. A growth rate is derived from the table below using linear interpolation in the economic model.

Table 38: Population

Parameter	Unit	2022	2035	2050
Population	Count	5,128,900	5,642,100	6,132,400

[88] Scenarios dataset for the Commission's 2021 Final Advice (output from ENZ model), Climate Change Commission
[89] National population projections: 2022(base)-2073 , Stats NZ

B.1.3 Monetary rates and conversions

Monetary rates do not vary between scenarios. Treasury's discount rate of 5%[90] has been used.

Table 39: Monetary rates and conversions

Parameter	Unit	Value
Exchange rate[91]	USD to NZD	0.65
Discount rate	%	5

B.1.4 Carbon prices

The Climate Change Commission's Demonstration Path carbon prices[92] have been used and do not vary between scenarios.

Table 40: Carbon price

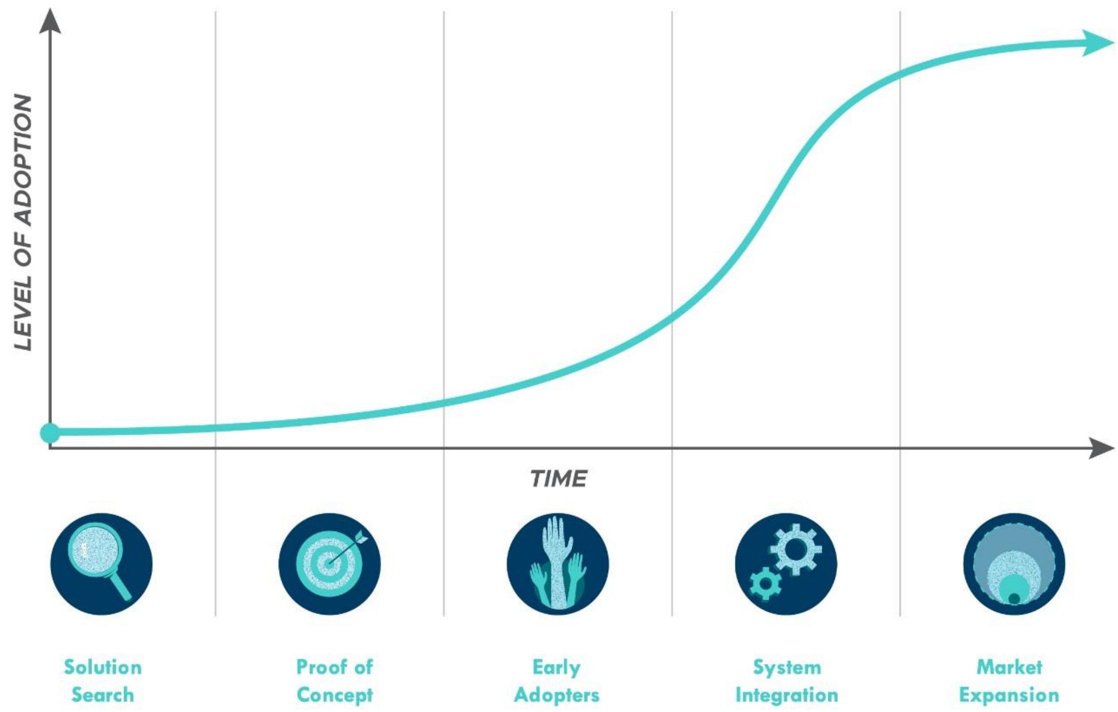
Parameter	Unit	2022	2035	2050
Carbon price	NZD/t CO_2-e	$52	$160	$250

B.1.5 Uncertain technologies

There are several hydrogen technologies that are still in early stages of development. The lack of data and certainty around their widescale deployment makes modelling uptake out to 2050 difficult. The approach for constructing the uptake curve involved utilising an 's' curve model of adoption. This generic curve maps a path between early adoption and significant uptake of a technology.

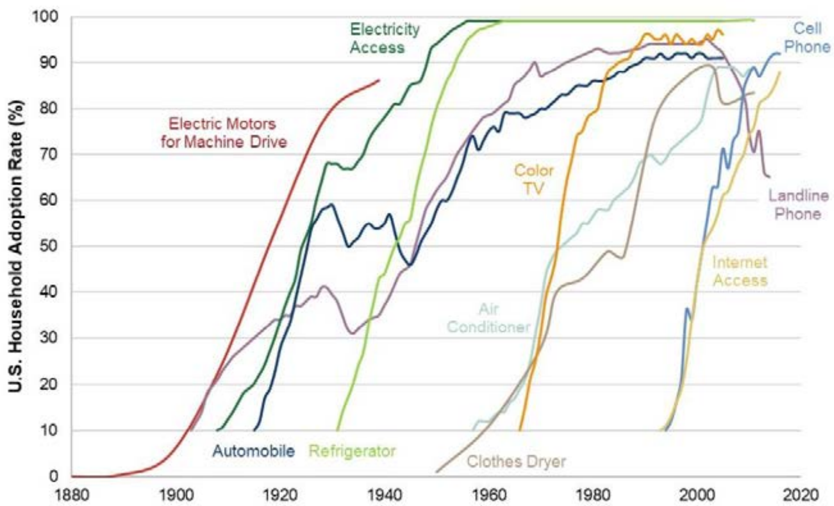
[90] Discount Rates, Treasury
[91] Scenarios dataset for the Commission's 2021 Final Advice (output from ENZ model), Climate Change Commission
[92] Scenarios dataset for the Commission's 2021 Final Advice (output from ENZ model), Climate Change Commission

Figure 69: Illustration of 's' curve[93]



The use of an 's' curve is based on the observation that technology adoption has typically followed an 's' curve shape, as shown in Figure 67 below. As evident in the figure, the duration that a technology can move from early adoption to plateau varies by technology. Where there is limited data available on the potential shape of the 's' curve for a hydrogen technology, assumptions use datapoints from existing projects to estimate the likely year that the technology is expected to become commercially available in New Zealand, the likely year that uptake in New Zealand materially ramps up and the estimated proportion of energy or feedstock demand in 2050 that is delivered by hydrogen.

Figure 70: Examples of historical 's' curves for technologies[94]



[93] Harnessing the Power of 's' Curves – Rocky Mountain Institute.

[94] Role of Electric Vehicles in the U.S. Power Sector Transition: A System-level Perspective, National Renewable Energy Laboratory (NREL)

B.2 Demand assumptions

The following section provides an overview of the assumptions that are used to model demand for hydrogen.

B.2.1 Industrial feedstock

B.2.1.1 Ballance

Ballance is one of New Zealand's largest producers and consumers of hydrogen and use 31,000 tonnes of hydrogen annually as feedstock in the manufacturing of ammonia. They currently produce hydrogen via Steam Methane Reformation.

The Kapuni site uses 7-7.5PJ of natural gas annually.[95]

- **53%** is used as a feedstock in the manufacture of Ammonia and Urea. 150,000 tonnes of Ammonia is produced per year and over 99% is converted to 265,000 tonnes a year of Urea (one third of New Zealand's demand).
- **20%** of natural gas is used for high temperature heat (600°C) in the reformer to crack natural gas. Waste heat is used elsewhere in the process.
- **14%** of natural gas is used to power three large compressors.
- **9%** of natural gas is used for steam raising and electricity generation from a cogeneration plant.

Using the natural gas feedstock and steam methane reformation, Ballance produces and uses 31,000 tonnes of hydrogen annually. Over 99% of this is used in the production ammonia and then converted to urea.

According to Ballance, green hydrogen production can displace natural gas used for feedstock and reforming. Ballance have partnered with Hiringa Energy to develop a green hydrogen plant at Ballance's Kapuni site. Green hydrogen is set to be available from the plant in Q3 2024 and will displace 7,000 tonnes of imported Urea.

The underlying assumption is that the Ballance green hydrogen project will go ahead and from Q3 2024 the plant will consume 818 tonnes of green hydrogen a year based on the proportion of imported urea that is displaced.

The following table outlines the assumptions in regard to Ballance.

[95] Submission on: "A vision for hydrogen in New Zealand" Green paper, Ballance Agri-Nutrients Limited

Table 41: Assumptions by scenarios

Scenario	Unit
Base case	Demand for green hydrogen increases from 2025, displaces 100% of natural gas for feedstock by 2050
Accelerated uptake	Demand for green hydrogen increases from 2025, displaces 100% of natural gas for feedstock by 2040. From 2040 output of plant increases in line with GDP growth and displaces imported Urea.
Energy security and resilience	No change from base case
Export	No change from base case
Value-add export	Demand for green hydrogen increases from 2025, displaces 100% of natural gas for feedstock by 2030, from 2030 output of plant increases. By 2040, plant produces enough Urea to displace all of New Zealand's demand. From 2045, output increases in line with GDP for Urea export

B.2.1.2 New Zealand Steel (NZ Steel)

It is assumed that NZ Steel will continue operating in New Zealand and will seek to decarbonise their processes in line with the country's net zero carbon ambitions. As per the assumptions in the Climate Change Commission's modelling, steel production activity in the future is modelled as constant at an average of 2015-2019 levels.[96]

NZ Steel is actively supporting and collaborating with tertiary institutions who are investigating alternative hydrogen-based iron reductant processes.[97] In steel making, hydrogen is an alternative to using coal to produce direct reduced iron from iron sand and reduces or eliminates the CO2 emissions resulting from the ironmaking process.

Additionally, NZ Steel uses a significant amount of hydrogen in the metal coating and treatment process. They have signed an agreement with BOC for supply of green hydrogen which will displace 300 t of CO_2 per year[98]. At an average carbon intensity for hydrogen from steam methane reformation of 10 g CO_2/g H2[99], this implies current green hydrogen consumption of 30 tonnes per year. However, information is not publicly available on the amount of hydrogen used at Glenbrook currently. We have therefore not been able to calculate hydrogen demand from the current coating process and potential for green hydrogen to displace this usage.

For conversion of the iron production process, hydrogen requirements are estimated at 50 kg of hydrogen per tonne of steel[100]. This metric is used to calculate hydrogen demand from a converted steel mill. It is currently estimated that NZ produces 670,000 tonnes of steel per year.

In May 2023, the Government and NZ Steel announced that they are co-investing in an electric arc furnace to replace the existing steelmaking furnace and two of the four coal-fuelled kilns. With this investment, NZ Steel plans to reduce its steel production from iron ore and increase its production from scrap steel recycling, producing at least 50% of its steel from scrap metal before 2030[101,102]. Based on this announcement, it is assumed that the remaining 50% of the steel produced by NZ Steel will use a hydrogen-based iron reductant process over time, resulting in 16,750,000 kg of annual hydrogen demand once fully converted. It is possible that NZ Steel will increase its production from scrap steel beyond 50% and is incentivised to do so through incentive payments

96 ENZ assumptions and inputs for the Commission's 2021 final advice, Climate Change Commission
97 Feedback on the Climate Change Commission's 2021 Draft Advice for Consultation, New Zealand Steel
98 BOC to supply 'green' carbon-free hydrogen to NZ Steel at Glenbrook, NZ Herald
99 Hydrogen Supply - Analysis - IEA, International Energy Agency
100 The potential of hydrogen for decarbonising steel production, European Parliamentary Research Service
101 NZ's biggest ever emissions reduction project unveiled | Beehive.govt.nz
102 Govt helps NZ Steel reduce the Glenbrook steel mill's carbon footprint | interest.co.nz

from the government, however the extent of this is uncertain and therefore have not been considered in the model[103].

The following table outlines the assumptions in regard to NZ Steel.

Table 42: Assumptions by scenarios

Scenario	Unit
Base case	NZ Steel successfully converts 50% of its Glenbrook plant to use hydrogen by 2045. A linear growth in green hydrogen demand is modelled from 2035 to 2045 to reflect a gradual commissioning.
Accelerated uptake	Commissioning brought forward to 2040
Energy security and resilience	No change from base case
Export	No change from base case
Value-add export	After 2045, steel output and hydrogen demand increase in line with GDP

B.2.1.3 Methanex

It is assumed that Methanex will continue operating in New Zealand and will seek to decarbonise their processes in line with the country's net zero carbon ambitions.

"With global demand for methanol growing, the Methanex business strategy is to continue to add production capacity around the world to meet this need" [104]

In 2023, Methanex (global) intends to conduct a technical and economic feasibility study of using green hydrogen at existing plants to produce methanol with a lower carbon intensity.

Current NZ production capacity is 2.4 Mtpa of methanol. Methanex uses 45% of NZ's gas production (or around 85 PJ of gas). Around 70% of this gas is used as process feedstock[105]. Hydrogen is produced from the natural gas feedstock as part of the methanol production process. This process also produces CO_2 which then also becomes a feedstock for methanol production. Given the composition of methanol (CH_3OH) a source of carbon is required which makes it difficult to remove methane from the process.

However, e-methanol production is being developed where green hydrogen can be combined with CO2 (either from waste CO2 or direct air capture). Based on available research, 93,750 tonnes of hydrogen will be required to produce 500,000 tonnes of e-methanol[106]. This figure is used to forecast hydrogen demand based on the plant capacity and this ratio of hydrogen input to methanol output.

The following table outlines the assumptions in regard to Methanex.

[103] NZ's biggest ever emissions reduction project unveiled | Beehive.govt.nz
[104] Feedback of Methanex New Zealand ("Methanex") to Climate action for Aotearoa 2021 Draft, Methanex New Zealand
[105] Submission: Process Heat in New Zealand: Opportunities and Barriers to lowering emissions, Methanex New Zealand
[106] Rufer, A. Quantitative Design of a New e-Methanol Production Process, Energies December 2022

Table 43: Assumptions by scenarios

Scenario	Unit
Base case	Methanex successfully converts 50% of its Taranaki plants to use hydrogen by 2040. A linear growth in green hydrogen demand is modelled from 2030 to 2040 to reflect a gradual commissioning.
Accelerated uptake	Methanex accelerates conversion of 100% of its Taranaki plants to use hydrogen by 2035. A linear growth in green hydrogen demand is modelled from 2025 to 2035 to reflect a gradual commissioning.
Energy security and resilience	No change from base case
Export	No change from base case
Value-add export	After 2040, methanol output and hydrogen demand increase in line with GDP

B.2.1.4 Synthetic fuels

Hydrogen demand for synthetic fuels is forecast to grow significantly over the coming decades to address emissions from hard to abate sectors. The term hydrogen-based fuels refer to the following fuels:

- Green methanol
- Ammonia
- Biofuels and e-fuels
- Sustainable Aviation Fuel (SAF)

This section considers demand for these fuels within NZ and potential for export in some scenarios.

However, it should be noted that transformation to ammonia is likely to a key method of preparing hydrogen for export. Demand for export ammonia is considered in the export section regardless of end use while in this section we consider synthetic fuel demand.

IEA NZE scenario projects that 5.6 mb/d of hydrogen-based fuels will be required in 2050 or 16% of global liquid fuel demand[107]. This level of production will require 118 Mt of hydrogen[108] or 57.73 kg H_2 per barrel of liquid fuel.

The Climate Change Commission's projection of liquid fuel demand[109] has been used as this takes into account reduced liquid fuel demand due to electrification of transport.

Table 44: Liquid fuel conversion

Parameter	Conversion Factor
PJ to Litres	26,000,000[110]
Barrels to Litres	159 litres[111]

[107] World Energy Outlook 2022 (Table 7.1), International Energy Agency
[108] World Energy Outlook 2022 (Table A.27), International Energy Agency
[109] Scenarios dataset for the Commission's 2021 Final Advice (output from ENZ model), Climate Change Commission
[110] Liquid Fuel Use in New Zealand November 2008, Ministry of Business, Innovation and Employment
[111] Unit Converter, International Energy Agency

Table 45: Climate Change Commission liquid fuel demand[112]

Parameter	Unit	2022	2035	2050
Liquid Fuel	PJ	361.4	274.0	116.8

The Climate Change Commission's demonstration path assumptions include yearly liquid fuel demand forecast until 2050. The same demand levels have been assumed.

Table 46: Hydrogen demand for synthetic fuel production by scenario

Scenario	Beginning of early adoption	Height of rapid growth	2050 Uptake
Base case	2030	2040	8% of PJ
Accelerated uptake	2025	2035	16% of PJ
Energy security and resilience	As per Accelerated uptake case		
Export	No change from base case		
Value-add export	As per Accelerated uptake case with growth of oil demand in line with GDP from 2030		

B.2.2 Transport

The following section provides an overview of the assumptions that are used to model transport demand for hydrogen.

B.2.2.1 Heavy transport

Fuel cell trucks and buses

Due to hydrogen fuel cell trucks and buses already being deployed in New Zealand, and the plans in place by Hiringa Energy (and partners) to develop a nationwide refuelling network, it is assumed that fuel cell electric vehicle (FCEV) uptake for heavy vehicles will commence within the next five years.

For the purposes of this model, the assumptions are informed by New Zealand's heavy vehicle fleet composition and age data from the Ministry of Transport to determine the annual fleet retirement (replacement) and additional vehicles for the forecast period. The Climate Change Commission's Current Policy Reference fleet composition has been used to determine an average annual growth rate of heavy vehicles and therefore the additional vehicles required each year. The average fuel requirement for both buses and trucks are sourced from Castalia's modelling.

[112] Scenarios dataset for the Commission's 2021 Final Advice (output from ENZ model), Climate Change Commission

Table 47: Heavy transport fleet assumptions

Parameter	Unit	Value
Number of buses (2021)	#	11,412
Bus fleet growth rate	% YoY	2.5
Buses average km travelled p.a.	km	45,180
Number of trucks (2021)	#	161,004
Truck fleet growth rate	% YoY	0.3
Trucks average km travelled p.a.	km	44,235
Average fuel requirement (both buses and trucks)	Kg H_2/km	0.08

The IEA's Net Zero Emissions by 2050 (NZE) Scenario[113] has been used to inform the expected proportion of new vehicles sales that will be FCEV by 2050 in the Accelerated uptake scenario. The IEA's NZE scenario shows a pathway for the global energy sector to achieve net zero CO_2 emissions by 2030 and 2050, with advanced economies reaching net zero emissions in advance of others. It requires effort beyond the current global pledges, making it similar in uptake levels to the Accelerated uptake scenario. The base case is therefore modelled to have slower and lower uptake of hydrogen. For the 'Energy security and resilience' scenario, since transport energy relies on imported fuels, its modelled uptake is that same as 'Accelerated uptake'.

Table 48: Proportion of new vehicles entering fleet that are likely to be FCEV

Scenario	Vehicle Type	Beginning of early adoption	Height of rapid growth	Maximum Uptake by 2050
Base case	Bus	2022	2035	20%
	Trucks	2022	2035	20%
Accelerated uptake	Bus	2022	2035	30%
	Trucks	2022	2035	30%
Energy security and resilience	Bus	Same as Accelerated uptake scenario		
	Heavy truck			
Export	Bus	Same as base case		
	Heavy truck			
Value-add export	Bus	Same as base case		
	Heavy truck			

Hydrogen hybrid diesel trucks and buses

Following HW Richardson's announcement on the planned uptake of hydrogen hybrid diesel trucks, we have considered the likelihood of conversion of heavy vehicles to hydrogen hybrid.

For hydrogen-diesel hybrid uptake in the heavy transport sector, it is assumed that 20% of new trucks and buses of any weight entering the fleet that isn't already FCEV will be hydrogen-diesel

113 Net Zero by 2050 - A Roadmap for the Global Energy Sector, International Energy Agency

hybrids by 2050. This assumption is based on the IEA's modelling that suggests by 2050, 60% of new heavy vehicles entering the fleet will likely be battery electric. Therefore, if 20% of vehicles are likely to be FCEV, there remains 20% of the new entrant vehicles that may run on fossil fuels. These are the vehicles assumed to be hydrogen-diesel hybrids. [114]

It is assumed that for hybrid vehicles, the amount of energy consumed remains the same as the existing fleet per km and have assumed 40% of the energy is provided by hydrogen.[115]

Table 49: Proportion of the non-FCEV fleet that are likely to be hybrid

Scenario	Beginning of early adoption	Height of rapid growth	Maximum Uptake by 2050
Base Case	2025	2035	20%
Accelerated uptake	2025	2030	20%
Energy security and resilience	Same as Accelerated uptake scenario		
Export	Same as base case		
Value-add export	Same as base case		

B.2.2.2 Light transport

It is assumed hydrogen FCEV uptake will be unlikely for light passenger vehicles due to the suitability and availability of BEV with the expectation that this will continue in the future. Therefore, the model does not include hydrogen demand from light passenger vehicles.

Areas where hydrogen is assumed to have an advantage are in off-road or remote light vehicles and commercial vehicles such as utility vehicles (utes). For the purposes of this model, New Zealand's light commercial vehicle fleet composition and age data from the Ministry of Transport have been used to determine the annual fleet retirement (replacement) and additional vehicles for the forecast period. The Climate Change Commission's Current Policy Reference fleet composition has been used to determine an average annual growth rate of light commercial vehicles and the additional vehicles required each year.

It is assumed that a proportion of these replacements and additions to the fleet will be hydrogen fuel cell vehicles.

When determining the avoided fossil fuel use and carbon emissions, it is assumed that the 2021 proportion of petrol and diesel light commercial vehicles to be held constant throughout the forecast period and applied an average kilometre travelled per annum.

[114] World Energy Outlook 2022 (Figure 3.14), International Energy Agency
[115] Fleets – Hydra Energy, Hydra Energy

Table 50: Light commercial vehicle fleet composition data[116]

Parameter	Unit	Value
Number of light commercial vehicles (2021)	#	713,857
Light vehicle number growth	% YoY	0.8%
Light commercial vehicles average age	Years	12.75
Proportion of Petrol LCVs	%	21.5
Proportion of Diesel LCVs	%	78.5
Average kilometres travelled p.a. (2021)	km	13,000
Hydrogen consumption rate	kg H_2/100km	0.815[117]

The IEA's Net Zero Emissions by 2050 (NZE) Scenario[118] has been used to inform the expected proportion of new vehicles sales that will be hydrogen by 2030 and 2050 in the 'Accelerated uptake' scenario and 'Energy security and resilience' scenario. The IEA suggests that 10% of new light vehicles entering the fleet in 2050 will be hydrogen fuel cell. Given that New Zealand's light commercial fleet makes up 16% of light vehicles, this would suggest that approximately two thirds of light commercial vehicles entering the fleet in 2050 would be hydrogen (approximately 67%). It would be expected that the remaining commercial vehicles would be electric. The base case is assumed to have half of the uptake expected under the Accelerated uptake scenario.

Table 51: Proportion of new light commercial vehicles entering fleet that are likely to be hydrogen FCEV

Scenario	Beginning of early adoption	Height of rapid growth	Maximum uptake by 2050
Base Case	2030	2040	33.33%
Accelerated uptake	2030	2035	66.66%
Energy security and resilience	Same as Accelerated uptake scenario		
Export	Same as base case scenario		
Value-add export	Same as base case scenario		

B.2.2.3 Rail

The following baseline assumptions for rail energy demand have been made based on the EECA's End Use Database[119]. For freight fuel demand, 2021 figures have been used for 2022 assumptions. For passenger rail fuel demand, an average of 2017-2019 demand has been used for 2022 assumptions. This is because over 2020-2021, passenger rail experienced a significant downturn due to COVID-19 restrictions and recovery.

Some rail in New Zealand has already been electrified, and the proportions are reflected in the table below.

[116] Fleet statistics, Ministry of Transport

[117] Research on Hydrogen Consumption and Driving Range of Hydrogen Fuel Cell Vehicle under the CLTC-P Condition, World Electric Vehicle Journal (vehicle mounted hydrogen supply consumption test)

[118] Net Zero by 2050 - A Roadmap for the Global Energy Sector, International Energy Agency

[119] Energy End Use Database, Energy Efficiency and Conservation Authority

Table 52: Baseline assumptions for rail energy demand

Parameter	Unit	Value
Passenger rail fuel demand (2022)	PJ	0.340 (0.125 / 37% diesel, 0.215 / 63% electricity)
Passenger rail fuel demand growth	% YoY	Consistent with population growth
Freight rail fuel demand (2022)	PJ	1.650 (1.620 / 98% diesel, 0.030 / 2% electricity)
Freight rail fuel demand growth	% YoY	Consistent with GDP growth
Diesel Engine	Efficiency rate (%)	50% (based on typical diesel engine efficiency)
Hydrogen Fuel Cell Engine[120]	Efficiency rate (%)	50%

The IEA's Net Zero Emissions by 2050 (NZE) Scenario[121] has been used to inform the expected hydrogen uptake in each scenario. Note that it is assumed that rail will experience significant levels of electrification.[122]

Table 53: Rail demand for hydrogen by scenario

Scenario	Sector Group	Beginning of early adoption	Height of rapid growth	2050 Uptake
Base case	Passenger rail	2025	2040	2% of useful energy
	Freight rail	2025	2040	2% of useful energy
Accelerated uptake	Passenger rail	2025	2035	3% of useful energy
	Freight rail	2025	2035	3% of useful energy
Energy security and resilience	Passenger rail	2025	2035	3% of useful energy
	Freight rail	2025	2035	3% of useful energy
Export	Passenger rail	No change from base case		
	Freight rail			
Value-add export	Passenger rail	No change from base case		
	Freight rail			

B.2.2.4 Marine

It is assumed marine vessels will eventually use hydrogen, ammonia, or methanol as a fuel of choice.

120 A review of hydrogen technologies and engineering solutions for railway vehicle design and operations, Railway Engineering Science
121 Net Zero by 2050 - A Roadmap for the Global Energy Sector, International Energy Agency
122 The New Zealand Rail Plan, Ministry of Transport

The following baseline assumptions for marine energy demand have been made based on the CCC's Current Policy Reference. It is assumed that in the absence of fuel switching, all demand would be delivered through a fossil-based fuel such as diesel.

Table 54: Baseline energy demand assumptions for marine

Parameter	Unit	Value
Domestic marine fuel demand (2022)	PJ	4.5
Domestic marine fuel demand growth	% YoY	-0.8
International marine fuel demand (2022)	PJ	14.7
International marine fuel demand growth	% YoY	-1.2

The IEA's Net Zero Emissions by 2050 (NZE) Scenario[123] has been used to inform the expected proportion of energy that will be supplied by hydrogen (or hydrogen derived fuel) by 2050 in the Accelerated uptake scenario. The IEA estimates that ~60% of energy demand from shipping will be supplied by hydrogen or Ammonia in 2050, up from 0% in 2020 and 10% in 2030.

In each scenario, modelled hydrogen uptake is based on the following assumptions.

Table 55: Marine demand for hydrogen by scenario

Scenario	Sector Group	Beginning of early adoption	Height of rapid growth	2050 Uptake
Base case	Domestic marine	2030	2040	50% of PJ
	International marine	2030	2040	50% of PJ
Accelerated uptake	Domestic marine	2030	2040	60% of PJ
	International marine	2030	2040	60% of PJ
Energy security and resilience	Domestic marine	2030	2040	60% of PJ
	International marine	2030	2040	60% of PJ
Export	Domestic marine	No change from base case		
	International marine			
Value-add export	Domestic marine	No change from base case		
	International marine			

B.2.2.5 Aviation

The following baseline assumptions for aviation energy demand have been made based on the CCC's Current Policy Reference. It is assumed that in the absence of fuel switching, all demand would be delivered through a fossil-based jet fuel. A conservative average efficiency for a jet fuel combustion engine has been assumed. We acknowledge that aircraft engine efficiency varies by the stage of flight, type of plant, weather, and several other factors. Choosing a high efficiency for the jet fuel combustion engine increases the useful energy required and the amount of hydrogen demand eventually calculated when the FCEV efficiency factor is applied.

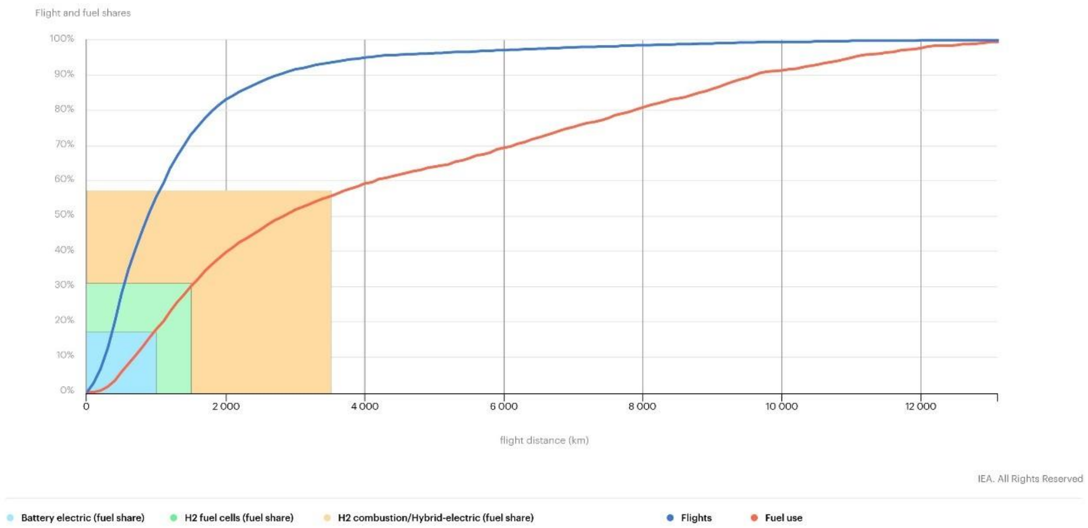
123 Net Zero by 2050 - A Roadmap for the Global Energy Sector, International Energy Agency

Table 56: Baseline assumptions for aviation energy demand

Parameter	Unit	Value
Domestic jet fuel demand (2022)	Useful energy (PJ)	14.1
Domestic jet fuel demand growth	% YoY	0.9
Jet fuel combustion engine	Efficiency rate (%)	50%
Hydrogen fuel cell engine[124]	Efficiency rate (%)	60%
Hydrogen fuel content for hydrogen combustion hybrid-electric engine	% of input energy	50%

It is assumed that for aviation, hydrogen, electric or electric hybrid aircraft will be used for domestic flights, while sustainable aviation fuel (that may use hydrogen as a feedstock) will become the fuel (s) of choice for international flights. [125] As international aviation is likely to use sustainable aviation fuel (SAF), the modelling only considers domestic aviation. The proportions in the chart below have been used to inform the proportion of energy demand supplied by hydrogen in 2050 in the Accelerated uptake scenario. For the 'H2 combustion/Hybrid-electric' category, it is assumed that 50% of this energy is supplied by hydrogen and 50% is supplied by electricity.

Figure 71: Flight and fuel shares (IEA)



In each scenario, hydrogen uptake is modelled based on the following assumptions.

[124] GAES project: Potential Benefits of Fuel Cell Usage in the Aviation Context, EuroControl Experimental Centre
[125] Aviation – Analysis - IEA, International Energy Agency

Table 57: Aviation demand for hydrogen by scenario

Scenario	Sector Group	Beginning of early adoption	Height of rapid growth	2050 Uptake
Base case	Domestic aviation – Fuel cell planes	2035	2045	15% of useful energy
	Domestic aviation - Hybrid	2035	2045	25% of input PJ
Accelerated uptake	Domestic aviation – Fuel cell planes	2035	2040	30% of useful energy
	Domestic aviation - Hybrid	2035	2040	50% of input PJ
Energy security and resilience	Domestic aviation	No change from base case		
Export	Domestic aviation	No change from base case		
Value-add export	Domestic aviation	No change from base case		

B.2.3 Process heat

We have considered the likelihood of hydrogen considerations across various process heat sector groups as set out by EECA's Energy End Use Database. Based on the considerations in table below, it is expected that hydrogen uptake is most likely in high temperature heat (>300°C) applications and therefore the model does not consider hydrogen uptake in other process heat sectors.

Table 58: Hydrogen considerations across process heat sectors

Sector Group	Hydrogen uptake considerations
Cooling	Likely to be electrified and not feasible for hydrogen uptake
High Temperature Heat (>300°C)	Hydrogen uptake will be feasible and likely to be a carbon emission reducing option, likely to be significantly more expensive than fossil fuel applications in initial uptake
Intermediate Heat (100-300°C)	Likely to be electrified or decarbonised through biomass and not feasible for hydrogen uptake
Low Temperature Heat (<100°C)	Likely to be electrified and not feasible for hydrogen uptake

Table 59: Base case hydrogen uptake assumptions for high temperature heat applications

Parameter	Unit	Value
High Temperature Heat (>300°C) energy demand from fossil fuels	TJ	38.6
High Temperature Heat (>300°C) energy demand growth	% YoY	Consistent with GDP growth

Hydrogen application in high temperature heat may eventuate in the form of hydrogen, ammonia, or methanol. For this study modelled expected hydrogen uptake will likely provide a lower bound on hydrogen demand due to avoided energy losses from converting to methanol or ammonia.

The IEA's Net Zero Emissions by 2050 (NZE) Scenario[126] has been used to inform the expected proportion of energy that will be supplied by hydrogen (or hydrogen derived fuel) by 2050 in the Accelerated uptake scenario. The IEA estimates that ~25% of energy demand from process heat will be supplied by hydrogen in 2050.

Table 60: Base case hydrogen uptake assumptions for high temperature heat applications

Scenario	Beginning of Early Adoption	Height of Rapid Growth	2050 Uptake
Base case	2030	2040	20%
Accelerated uptake	2025	2035	25%
Energy security and resilience	No change from base case		
Export	No change from base case		
Export value-add	No change from base case		

B.2.4 Hydrogen to power

It is assumed in the modelling that hydrogen-to-power is only used in off-grid instances such as back-up generators or as a small, distributed energy resource.

The stationary motive power energy profile from EECA's Energy End Use Database has been used as a baseline for generation demand of this nature and model a growth in demand based on population growth.

Table 61: Base case hydrogen uptake assumptions for small scale electricity generation from hydrogen

Parameter	Unit	Value
Stationary motive power fuel demand (2021)	TJ	18,835
Stationary motive power fuel demand growth	% YoY	Consistent with population growth

In each scenario, modelled hydrogen uptake is based on the following assumptions. Note that uptake proportions are low due to stationary motive power encompassing a broad range of energy use (e.g., motors) beyond small scale generation.

Table 62: Hydrogen uptake assumptions for high temperature heat applications

Scenario	Beginning of early adoption	Height of rapid growth	2050 Uptake
Base case	2025	2040	5% of PJ
Accelerated uptake	2025	2040	10% of PJ
Energy security and resilience	2025	2040	10% of PJ
Export	No change from base case		
Value-add export	No change from base case		

[126] Net Zero by 2050 - A Roadmap for the Global Energy Sector, International Energy Agency

Hydrogen to power applications used in large scale, grid connected generators have not been modelled due to end-to-end efficiencies being significantly lower than other generation or grid support technologies and therefore unattractive in the New Zealand market.[127] It is recognised that hydrogen production will provide some level of demand response for either dry year or peak periods. These assumptions are discussed later in Section B.3.1.2.

B.2.5 Export demand

Assumptions have been made around whether New Zealand would develop plants to supply hydrogen for export. It is assumed that exporting hydrogen will be most feasible in ammonia form due to readily available shipping technology. Hence all export demand modelled will be converted to ammonia.

To model export demand, three large plants are modelled to come online, similar in size to Meridian's proposed Southern Green Hydrogen Project. Each plant is 600MW in capacity and produces 88,250 tonnes of hydrogen demand per annum for ammonia production

The following table outlines the years in which these plants come online in each scenario.

Table 63: Export demand by scenarios

Scenario	Plant 1 Online	Plant 2 Online	Plant 3 Online
Base case	No export demand under this scenario		
Accelerated uptake	No change from base case		
Energy security and resilience	No change from base case		
Export	2030	2035	2040
Value-add export	2030	2035	2040

We have not attempted to size the full potential of New Zealand's export market beyond three large plants. This scale of development will have an impact on New Zealand's electricity sector but expect that hydrogen exports would serve a small proportion of the growing global demand.

IRENA's Global Hydrogen Trade Outlook[128] suggests that 25% of global hydrogen will be traded by 2050, equivalent to around 150 million tonnes per annum. If New Zealand were to have the three large plants, it would produce a total of 260 kilo tonnes of hydrogen per annum, equivalent to less than one per cent of the global traded amount.

B.2.6 Gas pipeline blending

Hydrogen demand for gas pipeline blending will be based on supporting residential and commercial demand for gas without switching of appliances. Work on gas appliances has shown that domestic/commercial appliances will likely operate at blending rates of up to 20% by volume. Due to the different energy densities of hydrogen and methane, this equates to a blend of around 6% on an energy basis.

Natural gas demand projections from the Climate Change Commission's Demonstration Path have been considered, which assumes that electrification in these sectors is significant and will uses these as the basis for the analysis.

[127] The New Zealand Hydrogen Opportunity, McKinsey & Company for Meridian Energy (Meridian) and Contact Energy (Contact)
[128] Global Hydrogen Trade Outlook, International Renewable Energy Agency (IRENA)

It is assumed that blended hydrogen is transported via the existing gas network as pipelines are able to tolerate the 20% by volume blending.

It is not assumed that there will be 100% conversion of pipelines to hydrogen.

Table 64: Climate Change Commission projection of residential and commercial gas demand[129]

Parameter	Unit	2022	2035	2050
Commercial	PJ	8.4	4.0	0.0
Residential	PJ	7.0	4.8	0.0

The following table shows how these assumptions vary by alternative scenario.

Table 65: Residential and commercial demand by scenario

Scenario	Unit
Base case	No blending of hydrogen
Accelerated uptake	Blending starts in 2035 and hydrogen is blended at 20% by volume for residential and commercial demand only. The CCC demand in 2035 is extended to 2050.
Energy security and resilience	As per Accelerated uptake case
Export	As per base case
Value-add export	As per base case

B.3 Supply assumptions

The following section provides an overview of key assumptions that are used to model demand for hydrogen.

B.3.1 Hydrogen production

B.3.1.1 Electrolyser plants

It is assumed that the electrolyser technology utilised in New Zealand will align with international developments. Given its current maturity and ability to provide fast response flexibility, all electrolyser units are assumed to be of the Proton Exchange Membrane (PEM) technology.

Furthermore, the electrolyser assumptions listed below remain consistent across all scenarios considered in this study.

Capital costs and efficiency estimates have been derived from IRENA[130], which provides a range for electrolyser system costs and plant efficiencies. For the purposes of this analysis, the upper bound has been utilised for decentralized plants, whereas the mid-range figure has been used for centralised costs, taking into account that larger plants can achieve economies of scale. The lower bound for centralised plants has not been used to be conservative. An additional balance of plant cost is assumed based on Castalia's modelling.

129 https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.climatecommission.govt.nz%2Fpublic%2FInaia-tonu-nei-a-low-emissions-future-for-Aotearoa%2FModelling-files%2FScenarios-dataset-2021-final-advice.xlsx&wdOrigin=BROWSELINK

130 Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal, International Renewable Energy Agency (IRENA)

Table 66: Centralised and decentralised plant assumptions

Parameter	Unit	Plant type	2022	2035	2050
Electrolyser CAPEX[131]	US$/kW	Centralised	1000	-	200
		Decentralised	1400	-	200
Efficiency	%	Centralised	68	-	80
		Decentralised	50	-	80
Balance of plant CAPEX	% of Electrolyser CAPEX	Centralised	15	15	15
		Decentralised	20	20	20
Annual OPEX	% of Total CAPEX	Centralised	1.5	1.5	1.5
		Decentralised	5	5	5
Availability	% of year in operation	Centralised	95	95	95
		Decentralised	95	95	95
Lifetime	Years	Both	20	20	20

B.3.1.2 Electricity demand profile and demand response

Due to the nature of this model, we are unable to model the hourly demand profile of electrolysers for electricity and the consequent hourly impacts on the grid, electricity spot price and additional renewable generation build required.

To enable us to consider the flexibility of electrolysers and understand the potential magnitude of new renewable build required to supply electricity to these electrolysers, different electricity offtake profiles for centralised and decentralised plants have been assumed. These assumptions are described and reflected in the table below.

Due to their buying power, it is assumed that large, centralised plants can secure long-term electricity offtake agreements and/or build significant onsite renewable generation to supply most electricity generation for a plant. It is assumed that a small amount of grid electricity will supply electricity to the plant to accommodate for the intermittency of renewable generation. It is also assumed that these plants will be able to curtail demand and divert generation to the grid during peak periods to support the network.

Smaller, decentralised plants are assumed to have a mix of electricity supplied from the grid and from direct generation/Power Purchase Agreements (PPAs). Due to the uncertainty around what this mix will be in the future, an even split of grid and direct supply is assumed. In practice, some small plants may be able to offtake all electricity from on-site generation or some from a PPA and the rest from the grid. It is assumed that these plants will also be able to provide demand response during peak periods and may be incentivised to do so in response to high wholesale electricity prices.

The proportion of demand response is used as an input for calculating the potential demand response capacity enabled by hydrogen electrolysers.

Table 67: Electricity supply and demand response by plant type assumptions

Parameter	Unit	Centralised	Decentralised
Proportion of time that electricity is supplied from the grid/wholesale electricity spot market	%	20	45
Proportion of time that electricity is supplied from direct connect and/or PPA	%	70	45
Proportion of time that electricity consumption is zero due to demand response	%	10	10

[131] Electrolysers – Analysis - IEA, International Energy Agency

Capacity factor	%	90	90

Table 68: Assumptions by alternative scenarios

Scenario	Unit
Accelerated uptake	No change
Energy security and resilience	Increased demand response requirement for both centralised and decentralised plants result in the proportion of time that electrolysers consume no electricity increasing to 15%. For both plant types, capacity factor reduces to 85%.
Export	No change
Value-add export	No change

B.3.1.3 Electricity price

It is assumed that the electricity price from either the wholesale spot market, or direct investments/PPAs will not change between scenarios. The input electricity price for a centralised or decentralised plant is a weighted average according to the following prices and the proportion of electricity supply sources described earlier.

Table 69: Wholesale electricity spot price assumptions

Parameter	Unit	2022	2035	2050
Wholesale spot price (NZAS remains)[132]	NZ$/MWh	90.6	109.0	100.9
Wholesale spot price (NZAS exits)[133]	NZ$/MWh	90.6	103.8	100.2

It is assumed that NZAS will continue operating in New Zealand. However, due to the current uncertainty of the future operation of NZAS in New Zealand, a sensitivity analysis for the base scenario to test how the outputs might change if NZAS exits the market has been considered. The primary assumption changed is the electricity price.

It is assumed that any new generation built to supply electricity to a hydrogen electrolyser will be wind and/or solar. While it is possible that some offshore wind generation may be built alongside hydrogen production, particularly in locations such as Taranaki, offshore wind has been excluded in the model due to its high cost compared to solar and onshore wind.

As discussed earlier, due to the nature of this model, there is limited ability to model an hourly electricity demand and supply characteristics, which limits the ability to optimize wind and solar generation with the electrolysers. For the purposes of this model and to avoid the need to specify when particular electricity generation plants need to be built, the mid-point capacity factors and levelized cost of energy for solar and wind have been used, as shown in the tables below. The capacity factor is used to inform the level of new renewable generation build required to support hydrogen production.

The following capacity factor assumptions are taken from the NZ Battery Indicative Business Case modelling.

[132] Modelling and data - Tiwai stays with certainty sensitivity, Climate Change Commission. Includes wholesale energy price, and fixed and variable charges for commercial users.
[133] Modelling and data - Demonstration Path, Climate Change Commission. Includes wholesale energy price, and fixed and variable charges for commercial users.

Table 70: Electricity generation capacity factor assumptions

Parameter	Unit	Value
Solar capacity factor	%	22
Onshore wind capacity factor	%	40
Solar-wind midpoint	%	31

The following electricity price assumptions are taken from the modelled LCOE in the NZ Battery Indicative Business Case.

Table 71: Direct generation investment or power purchase agreement electricity price assumptions

Parameter	Unit	2022	2035	2050
Solar	NZ$/MWh	99	71	56
Onshore wind	NZ$/MWh	61	56	52
Solar-wind midpoint (used in model)	NZ$/MWh	80	63.5	54

B.3.2 On-site storage

It is assumed that plants will have sufficient storage to enable short-term demand response for peaking services. This storage will add to the levelized cost of hydrogen for that plant.

Concept Consulting's assumed storage price from their Hydrogen in New Zealand Report 2[134] is used, as shown in the table below.

Table 72: Storage assumptions

Parameter	Unit	2020	2040	2050
Storage	NZ$/kg H_2	0.5	0.35	0.275

B.3.3 Distribution

B.3.3.1 Hydrogen supply channels

For each demand sector it is assumed that hydrogen demand is supplied from a particular channel and plant type. For ease of modelling, a 'likely' channel has been assumed, but it is possible that each demand sector may receive their hydrogen from multiple channels depending on factors such as proximity to plants, geographical location, and supply contracts.

Table 73: Mapping of demand sectors to supply channels

Demand sector	Sub-sector	Form of hydrogen	Distribution and storage channel	Plant type
Transport	Heavy	Hydrogen gas (FCEV)	Liquefied, trucking	Decentralised
	Light	Hydrogen gas (FCEV)	Liquefied, trucking	Decentralised
	Aviation	Hydrogen gas (FCEV)	Liquefied, shipping	Centralised
	Rail	Hydrogen gas (FCEV)	Liquefied, shipping	Centralised

[134] Hydrogen in New Zealand Report 2 Analysis, Concept Consulting Group Ltd

Demand sector	Sub-sector	Form of hydrogen	Distribution and storage channel	Plant type
	Marine	Ammonia	Shipping	Centralised
High temperature process heat	-	Hydrogen gas	On-site pipeline	Decentralised
Power generation	-	Hydrogen gas (FCEV)	Compressed, trucking	Decentralised
Industrial feedstock	Ammonia (Ballance)	Hydrogen gas	On-site pipeline	Decentralised
	NZ Steel	Hydrogen gas	On-site pipeline	Decentralised
	Methanex	Hydrogen gas	On-site pipeline	Centralised
Residential and commercial	-	Blended hydrogen gas with natural gas	Pipeline blending	Centralised
Export demand	-	Ammonia	Shipping	Centralised

B.3.3.2 Liquid hydrogen by truck

The following table outlines the assumptions for the additional hydrogen energy required during transformation and transportation, and the average additional cost for these processes. These assumptions are held constant across the modelled timeframe and across scenarios.

Hydrogen transformation energy assumptions are sourced from the IEA's Global Hydrogen Review[135] and assume that the energy required for transformation and transport are from hydrogen. It is possible that this energy can be sourced from electricity. Cost assumptions for the liquefaction process are based on Castalia's modelling. Transport costs are sourced from IRENA[136] based on small scale (10 tonne/d) transport of hydrogen up to 1,000 km.

Table 74: Base case hydrogen compression assumptions

Parameter	Unit	Value
Additional hydrogen energy required for liquefaction	%	20
Additional hydrogen energy required for transport	%	10
Additional hydrogen energy required for gasification	%	1
Average additional cost per kg H_2 for liquefaction (2022)	US$/kg H_2	1.5
Reduction in additional cost for liquefaction	YoY %	3
Average additional cost per kg H_2 for transport (2022)	US$/kg H_2	1.5
Average additional cost per kg H_2 for transport (2050)	US$/kg H_2	0.4

B.3.3.3 Compressed hydrogen gas by truck

The following table outlines the assumptions for the costs of transformation and transportation, and the average additional cost for these processes. These assumptions are held constant across the modelled timeframe and across scenarios.

[135] Global Hydrogen Review 2022, International Energy Agency

[136] Global hydrogen trade to meet the 1.5°C climate goal: Part II - Technology review of hydrogen carriers, International Renewable Energy Agency

Assumptions for the compression process are based on Castalia's modelling. Transport costs have been sourced from IRENA[137] based on small scale trucking less than 1000 km.

Table 75: Hydrogen Compression Assumptions

Parameter	Unit	Value
Average additional cost per kg H_2 for compression	US$/kg H_2	0.4
Reduction in additional cost for compression	YoY %	3
Average additional cost per kg H_2 for transport	US$/kg H_2	0.55
Reduction in additional cost for transport	YoY %	3

B.3.3.4 Liquid hydrogen by ship

The following table outlines the assumptions for the additional hydrogen energy required for transformation and transportation, and the average additional cost for these processes. These assumptions are held constant across the modelled timeframe and across scenarios.

Hydrogen transformation energy assumptions have been sourced from IRENA's report Global Hydrogen Trade to Meet the 1.5°C Climate Goal[138] and assume that the energy required for transformation and transport are from hydrogen. It is possible that this energy can be sourced from electricity. Transformation cost assumptions are based on Castalia's detailed modelling. Transport costs have been sourced from IRENA[139] based on shipping 1,000-10,000 kms.

Table 76: Liquid hydrogen shipping assumptions

Parameter	Unit	Value
Additional hydrogen energy required for liquefaction	%	20
Additional hydrogen energy required for transport	%	9
Additional hydrogen energy required for gasification	%	1
Average additional cost per kg H_2 for liquefaction (2022)	US$/kg H_2	1.5
Reduction in additional cost for liquefaction	YoY %	3
Average additional cost per kg H_2 for transport (2022)	US$/kg H_2	2
Average additional cost per kg H_2 for transport (2050)	US$/kg H_2	0.8

B.3.3.5 Ammonia by ship

The following table outlines the assumptions for the additional hydrogen energy required for transformation and transportation, and the average additional cost for these processes. These assumptions are held constant across the modelled timeframe and across scenarios.

Hydrogen transformation energy assumptions have been sourced from IRENA's report Global Hydrogen Trade to Meet the 1.5°C Climate Goal[140] and the IEA's Global Hydrogen Review 2022[141] and assume that the energy required for transformation and transport are from hydrogen. It is possible that this energy can be sourced from electricity. Transport costs have been sourced from

[137] Global hydrogen trade to meet the 1.5°C climate goal: Part II – Technology review of hydrogen carrier, International Renewable Energy Agency
[138] Global hydrogen trade to meet the 1.5°C climate goal: Part II – Technology review of hydrogen carriers, International Renewable Energy Agency
[139] Global hydrogen trade to meet the 1.5°C climate goal: Part II – Technology review of hydrogen carriers, International Renewable Energy Agency
[140] Global hydrogen trade to meet the 1.5°C climate goal: Part II – Technology review of hydrogen carriers, International Renewable Energy Agency
[141] Global Hydrogen Review 2022, IEA.

McKinsey's study for Meridian's Southern Green Hydrogen project[142]. Because ammonia production and shipping are already mature processes, these costs have been constant across the modelling years.

Table 77: Ammonia shipping assumptions

Parameter	Unit	Value
Additional hydrogen energy required for ammonia synthesis	%	13
Additional hydrogen energy required for shipping	%	2
Average additional cost per kg H_2 for transformation	US$/kg H_2	1.2
Average additional cost per kg H_2 for transport	US$/kg H_2	0.6

B.3.4 Water

It is assumed that the cost of water is the average non-residential water cost across New Zealand, as per Water New Zealand[143].

Table 78: Cost of Water Assumptions

Parameter	Unit	Value
Cost of water	NZ$/m^3	1.72
Water input to H_2[144]	Litres/kg H_2	9

B.4 Economic outcomes

Input-Output tables (IO tables) have been used to measure the impact of hydrogen investment and spending on the wider economy. The assumptions included in this section have been developed using materials and assumptions from Stats NZ[145].

B.4.1 Economic outcomes assumptions

In economics, IO tables are a quantitative measure of the interdependencies between different sectors of an economy. They show the relationships between industries, the goods, and services they produce, and who uses them. To inform the analysis an IO table has been derived from Stats NZ IO tables.

The IO tables have considered the following macroeconomic effects:

- The total New Zealand based spending on hydrogen
- The output effect from hydrogen spending
- The value effect from hydrogen spending
- The employment effect from hydrogen spending

It is assumed that the following industries will be influenced by hydrogen spending:

[142] The New Zealand Hydrogen Opportunity, McKinsey & Company for Meridian Energy (Meridian) and Contact Energy (Contact)
[143] Customer Focus : Water New Zealand, Water New Zealand
[144] Global hydrogen trade to meet the 1.5°C climate goal: Part III – Green hydrogen cost and potential, International Renewable Energy Agency (IRENA)
[145] National accounts input-output tables: Year ended March 2020, Stats NZ

- Machinery and equipment wholesaling
- Construction services
- Gas supply and water supply
- Electricity transmission and distribution
- Electricity generation and on-selling
- Other manufacturing

In the model, it is assumed that 100% of operational expenditure (OPEX) would be allocated domestically, whereas a portion of capital expenditure (CAPEX) would be spent internationally to acquire technology and materials. Consequently, it is estimated that 70% of total expenditure related to hydrogen production would be channelled into the domestic economy. This allocation was subsequently applied to the economic multipliers presented in Table 72.

The model considers both the direct and type one effects from hydrogen spending within the New Zealand economy. In economics, direct effects refer to the immediate impacts of investment/spending on a particular industry. Indirect impacts are those that result from interdependencies between industries or sectors in the economy. Indirect effects arise when spending on one industry cause change in the production, employment, or income of other industries that supply goods and services. Type one effects are the combination of direct and indirect impacts.

B.4.2 Economic multipliers

The following economic multipliers have been derived from the Stats NZ IO tables. As specified above, it is assumed that these industries are the most likely to incur additional upstream demand from increased hydrogen spending.

Table 79: Economic multipliers

	Output multipliers		Value-added multipliers		Employment years multipliers	
Industry	Direct	Type I	Direct	Type I	Direct	Type I
Other manufacturing	1.00	1.74	0.38	0.70	3.87	6.26
Electricity generation and on-selling	1.00	2.63	0.27	0.92	0.36	2.49
Electricity transmission and distribution	1.00	1.74	0.62	0.94	0.94	2.64
Gas supply and Water supply	1.00	2.12	0.41	0.91	0.66	2.52
Construction services	1.00	1.88	0.41	0.78	3.50	6.34
Machinery and equipment wholesaling	1.00	1.65	0.56	0.88	4.22	6.67

B.5 Energy resilience and carbon emissions reduction assumptions

To measure energy security resilience and carbon emissions reduction, the analysis considers how domestic hydrogen production displaces imported fossil fuels. The following table outlines which fuels have been assumed to be displaced for each hydrogen demand. The quantity of displaced fuel and the number of emissions from that fuel based on the emissions factors in section have been used to estimate the energy resilience/carbon emission reduction benefits of each scenario.

Table 80: Fossil fuel displacement assumptions

Demand sector	Sub-sector	Fossil Fuel Displaced
Transport	Heavy	Diesel
	Light	Diesel
	Aviation	Jet A1
	Rail	Diesel
	Marine	Diesel
High temperature process heat	North Island gas users	Natural gas
	Other process heat	Coal, Diesel, Fuel Oil, LPG
Power generation	-	
Industrial feedstock	Ammonia (Ballance)	Natural gas
	NZ Steel	Natural gas, Coal
	Methanex	Natural gas
Residential and commercial	-	Natural gas
Export demand	-	

B.6 Conversion Rates

The following tables show the assumptions for energy, commodity, and hydrogen conversion rates used in the modelling calculations. These conversion rates have been sourced from several sources, particularly the U.S. Energy Information Administration[146] and the Ministry for the Environment[147].

Table 81: Volumetric energy density

Parameter	Unit	Value
Natural Gas	MJ/m^3	38.85
Hydrogen	MJ/m^3	10.80
Coal	PJ/short tons	50,000
Diesel	Litres/PJ	26,000,000
Electricity	kWh/PJ	278,000,000
Natural Gas	PJ/m^3	26,000,000
Petrol	PJ/litres	30,000,000
Jet Kerosene / Jet A1	MJ/litres	46.29

Table 82: Carbon emissions coefficient by fuel type

Parameter	Unit	Value
Coal	t CO2/TJ	89.13
Diesel	t CO2/TJ	69.31
Electricity	t CO2/kWh	0.00012
Oil	t CO2/TJ	73.59
LPG	t CO2/TJ	60.43
Natural Gas	t CO2/TJ	53.96

[146] Energy conversion calculators, U.S. Energy Information Administration (EIA)
[147] Measuring emissions: A guide for organisations: 2022 summary of emission factors, Ministry for the Environment

Parameter	Unit	Value
Petrol	t CO2/TJ	66.70
Wood	t CO2/TJ	89.47

Table 83: General conversion rates

Parameter	Unit	Value
MWh per PJ	#	277,778
Hydrogen Kg per MWh	#	30.03
Water - m^3 to litres	#	0.001
PJ to TJ	#	1,000
PJ to MJ	#	1,000,000,000

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