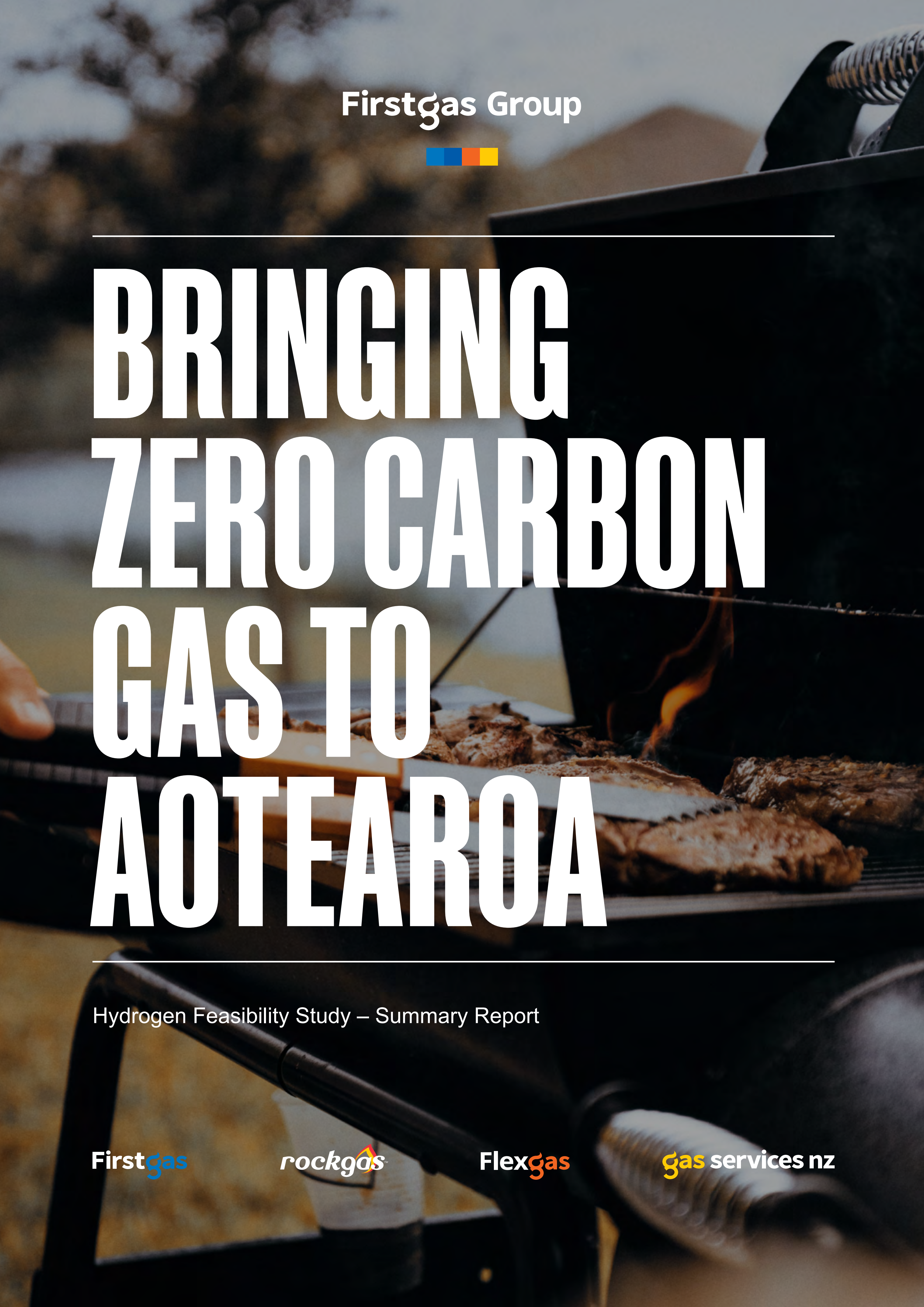

Firstgas Group

# BRINGING ZERO CARBON GAS TO AOTEAROA

Hydrogen Feasibility Study – Summary Report

Firstgas rockgas Flexgas gas services nz

# I OREA TE TUATARA KA PUTA KI WAHO

*– Ta Hirini Moko Mead*

*Translation:*

*The Tuatara comes out before it is too late.*
*A problem is solved by continuing to find solutions.*

# FOREWORD

Every day Firstgas Group supplies the energy needs of 430,000 New Zealanders. Our pipelines generate jobs and value for New Zealand by supporting the meat, dairy, steel, petrochemicals and pulp and paper sectors. We are committed to ensuring we play our role in providing energy to New Zealanders in a zero carbon world and see hydrogen as an exciting prospect to unlock low-carbon solutions for future industry, transport and heating needs.

## FIRSTGAS GROUP IS BRINGING ZERO CARBON GASES TO AOTEAROA...

As a member of the Climate Leader's Coalition, Firstgas Group has committed to reducing our scope 1 and 2 emissions by 30% by 2030. We are doing this by making improvements to our compressor fleet, which is our largest source of emissions by far. This includes investigating the use of zero carbon gases like hydrogen as a fuel for gas compression.

For over two years, Firstgas has had a dedicated workstream investigating low carbon gases, such as hydrogen, biogas, and bioLPG. Developing these technologies will help us provide low emissions options for our customers in the future, while retaining the benefits of gas provided via existing pipeline networks in New Zealand.

This study is the first step in a programme of work we will be undertaking to prove that our pipelines can be converted to hydrogen and to make that conversion happen. This study helps us get clarity over what we need to do to ensure that our networks can transport hydrogen as demand ramps up over the coming years and informs our next steps in this programme.

Our customers and stakeholders need to be part of New Zealand's journey towards zero carbon gases. We're pleased to say that they have had a lot of input into this study. They have helped us scope the scenarios for conversion, providing their valuable time and expertise.

We'd like to thank all of those involved to date. We will call on you again as this is just the start.

We have also been fortunate enough to have the support of the Government which contributed 50% of the funding required for this study, through the Provincial Development Unit. This backing from the Government has been invaluable in supporting the study and helping us connect with government stakeholders.

## OUR GOAL: 30% REDUCTION IN EMISSIONS BY 2030...

I'm excited to be presenting this report to you as I see this work as crucial in setting Firstgas Group up for the future. The Firstgas Group team is a bright bunch of individuals with a huge amount of passion for supplying New Zealand with energy. The opportunities to decarbonise our gas networks are simply too big to ignore We're up for the challenge presented in this report and we want to have you alongside us.

## NGĀ MIHI NUI
## PAUL GOODEVE

Firstgas Group

# CONTENTS

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# 01 EXECUTIVE SUMMARY

Firstgas Group supports the decarbonisation of New Zealand's energy sector. As a member of the Climate Leader's Coalition, we are committed to leading the decarbonisation of New Zealand's gas networks with low emissions technology and to provide our customers with zero carbon gas.

We see transitioning to lower emitting gases as an essential step in New Zealand's decarbonisation. That's why we have a dedicated programme of work to investigate zero carbon gas options, such as hydrogen, biogas, and bioLPG. We believe that New Zealand's energy future will be a combination of renewable electricity and zero carbon gases that can meet all of our varied energy needs; from vehicles, to homes, to restaurants, to steel production, to electricity generation at peak times supported by large scale, long-term energy storage.

## ...GIVING NZ A RANGE OF RENEWABLE ENERGY CHOICES...

This study has progressed our understanding of how Firstgas Group can prepare for hydrogen use as part of New Zealand's energy future. The work allows us to confirm the feasibility of converting Firstgas pipelines to hydrogen — initially as a blend, and then to 100% in the future if required. We have gained a better understanding of the likely challenges in this conversion process and have designed an indicative programme of future work for converting the gas network.

This study builds on technical and economic modelling work carried out overseas and considers this work in the New Zealand context. Figure 1 below summarises the hydrogen pipeline feasibility study process and intended future sequencing of hydrogen trials and blending within the gas network.

**We've investigated what New Zealand's hydrogen future could look like and how our network can play its part.**

This study concludes that the use of the existing gas pipeline network to transport hydrogen throughout the North Island is technically feasible and can make a valuable contribution to carbon emissions reductions. This report also describes further steps that need to be taken to progress towards the introduction of hydrogen into the natural gas network later this decade, with more detail provided in the full study report.

The future role of hydrogen in New Zealand's economy and the potential future demand for hydrogen were investigated through three distinct scenarios, each representing a variation of a decarbonised New Zealand energy sector by 2050. These scenarios are outlined in Figure 2 and are described in detail in the full study report.

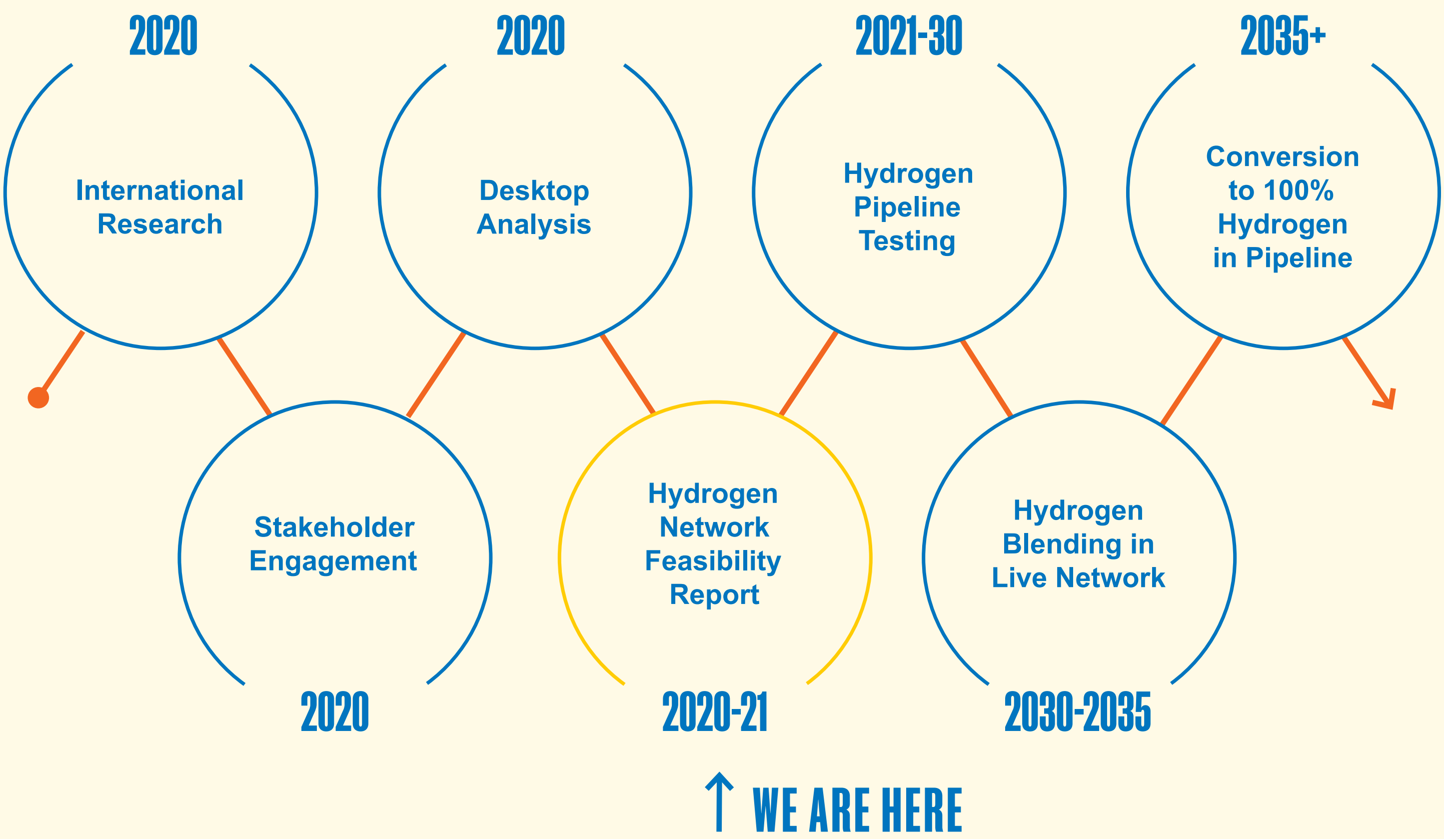



Figure 1: Firstgas hydrogen network trial and conversion stages

## OUR ENERGY SCENARIOS

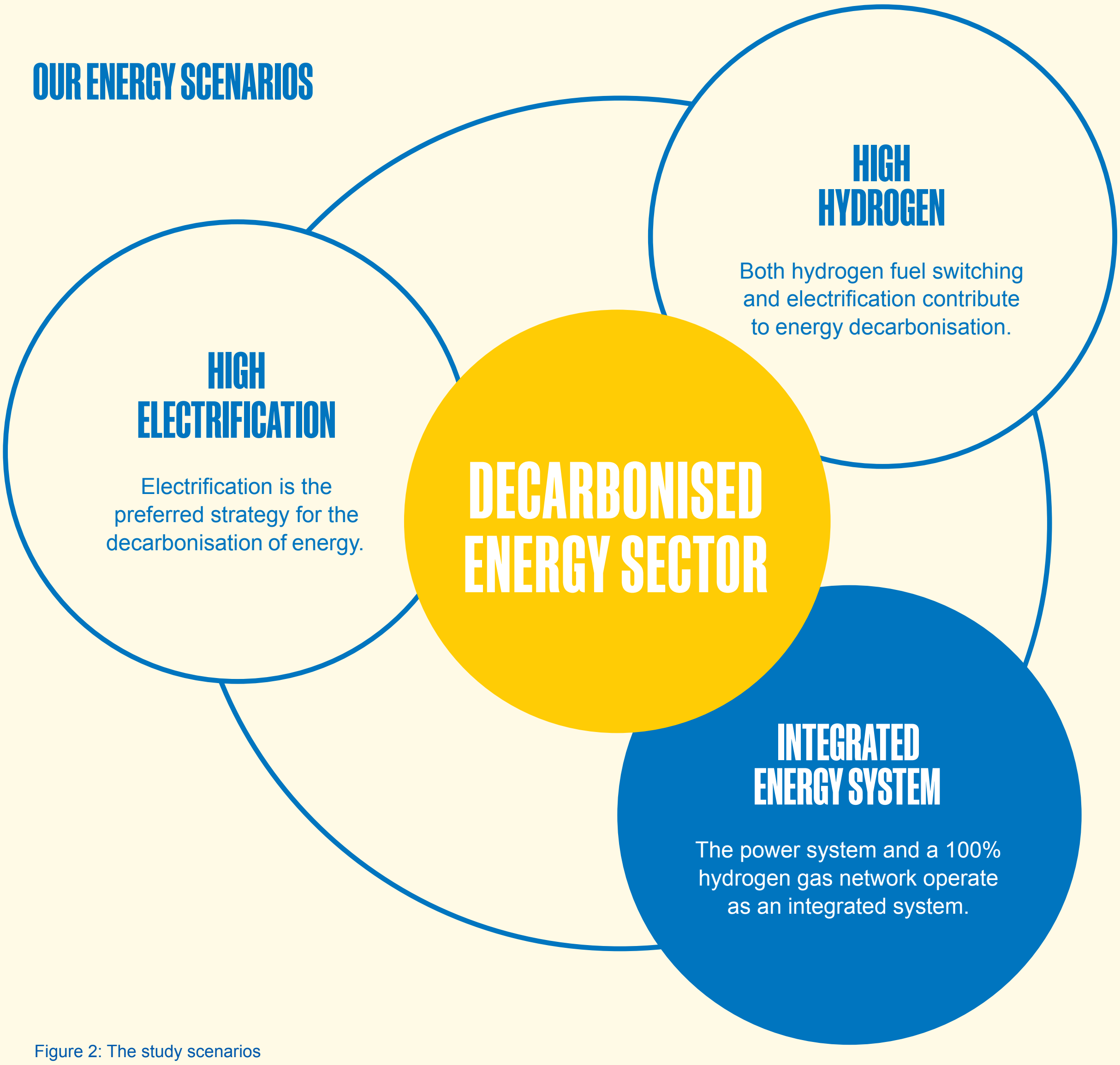



Figure 2: The study scenarios

The scenarios are based on a set of assumptions around future government support and policies for the decarbonisation of energy, as well as the role of customer choice, which will influence the type of low-carbon fuels and technologies that will prevail in the coming decades.

All of the scenarios used in this study are based on the assumption that hydrogen demand is met entirely with green hydrogen. While other zero carbon sources of hydrogen may emerge over the time frames considered in this report (such as blue hydrogen which involves capturing and storing the carbon created by reforming natural gas into hydrogen), this report has focused on a green hydrogen pathway for New Zealand.

**In the context of these scenarios, the study considers:**

— How and why the gas network might be used to transport hydrogen

— The suitability of the materials that the current network is constructed from to transport hydrogen to energy users

— The capacity of the network to transfer the quantities of hydrogen to the areas where it will be required, including how the network may need to be re-configured and;

— The cost of generating green hydrogen and the changes required to allow transportation and use of natural gas/hydrogen blends and hydrogen.

The results presented in this summary report focus on the Integrated Energy System scenario, which was selected as the focus of the analysis in the full study report. The implementation of this scenario has the potential to bring the greatest economic and operational benefits for New Zealand's energy

## A RANGE OF ENERGY CHOICES GIVES NZ THE BEST ECONOMIC BENEFIT

future and has a wide range of implications for the use of gas infrastructure. Since this scenario requires the most significant changes to the existing gas network to accommodate energy needs, being ready for this scenario will set us up well to manage the transportation of hydrogen in other scenarios.

**Hydrogen can play a significant role in decarbonising New Zealand's integrated energy system.**

The study identifies the potential for hydrogen to decarbonise high temperature process heat and heavy transport, and to provide an energy storage vector that supports a 100% renewable electricity system. These uses are sometimes referred to as generating 'hard to abate' sources of emissions because the direct use of renewable electricity does not provide a realistic option for reducing emissions. The potential roles for hydrogen within the energy system are shown in Figure 3.

Maximizing the use of hydrogen in these applications delivers significant carbon reductions. The study estimates that hydrogen would contribute 8 Mt $CO_2$/yr of emissions reductions in 2050 from a baseline of energy sector emissions of 32 Mt $CO_2$/yr in 2018 – removing one quarter of New Zealand's energy system emissions. Other emissions reductions of 6 Mt $CO_2$/yr come from reduced demand (energy efficiency), 11 Mt $CO_2$/yr from direct electrification and 5 Mt $CO_2$/yr from bioenergy.

## ACHIEVING 2050 GOAL REQUIRES ZERO CARBON GAS, RENEWABLE ELECTRICITY AND A DECREASE IN ENERGY DEMAND

The switch from coal, oil and natural gas to hydrogen, renewable electricity and biofuels, together with the overall reduction in energy demand, results in near zero energy sector emissions in 2050, as shown in Figure 4.

## HYDROGEN'S ROLE IN DECARBONISING OUR ENERGY


Figure 3: How hydrogen supports a 100% renewable electricity system

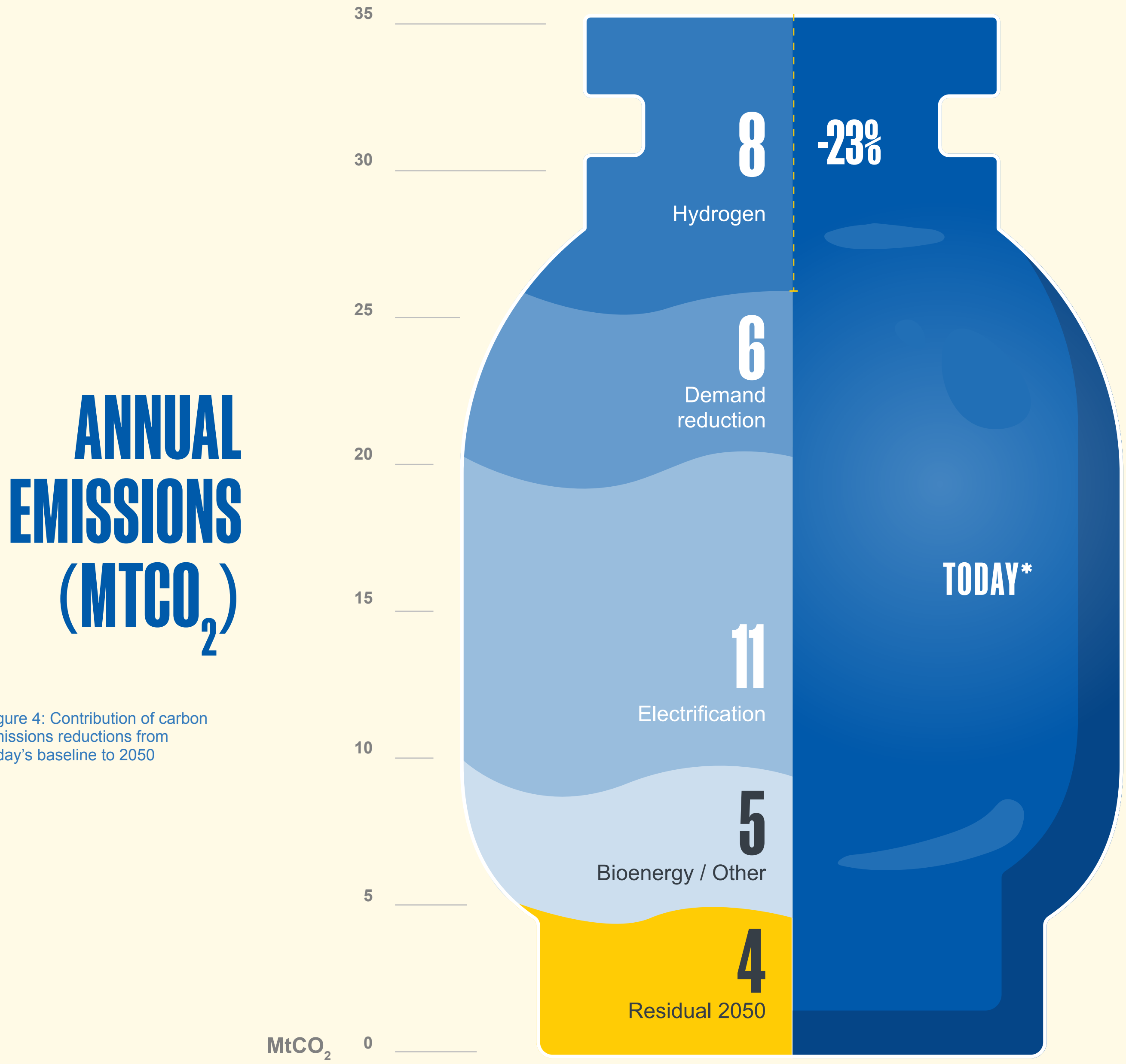



Figure 4: Contribution of carbon emissions reductions from today's baseline to 2050

*Excludes agricultural, land use, forestry and waste emissions

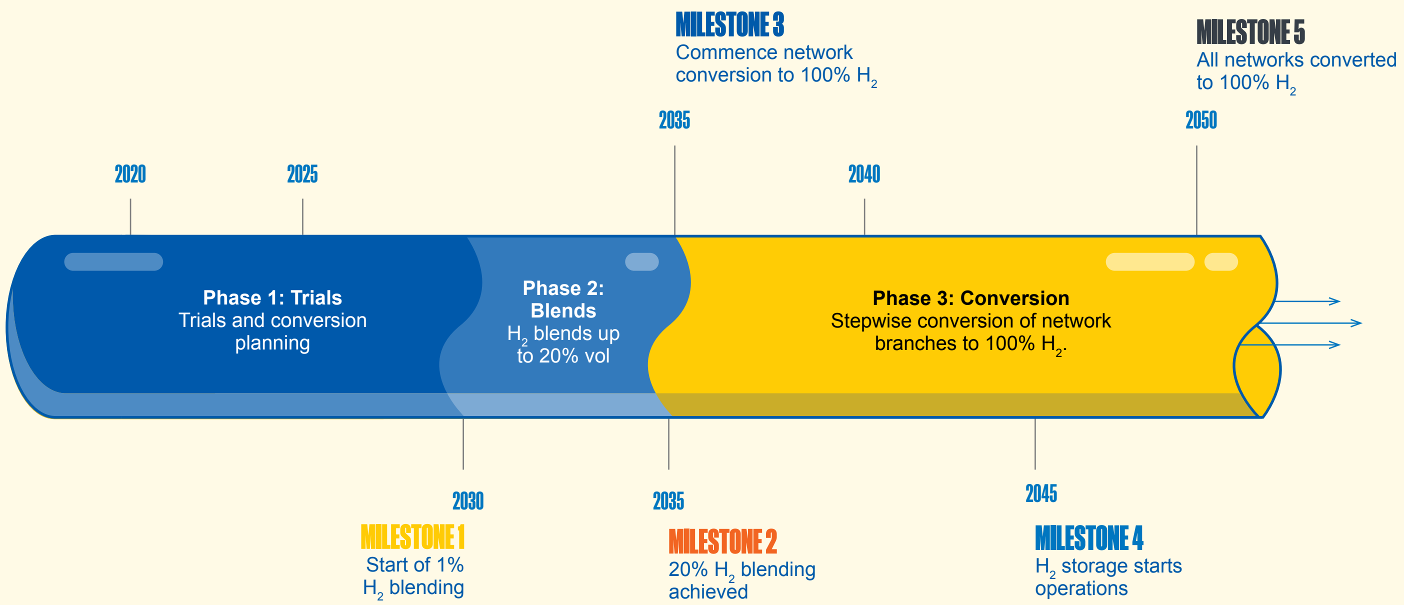



Figure 5: Indicative hydrogen conversion strategy timeline

# ANNUAL HYDROGEN DEMAND PROJECTION

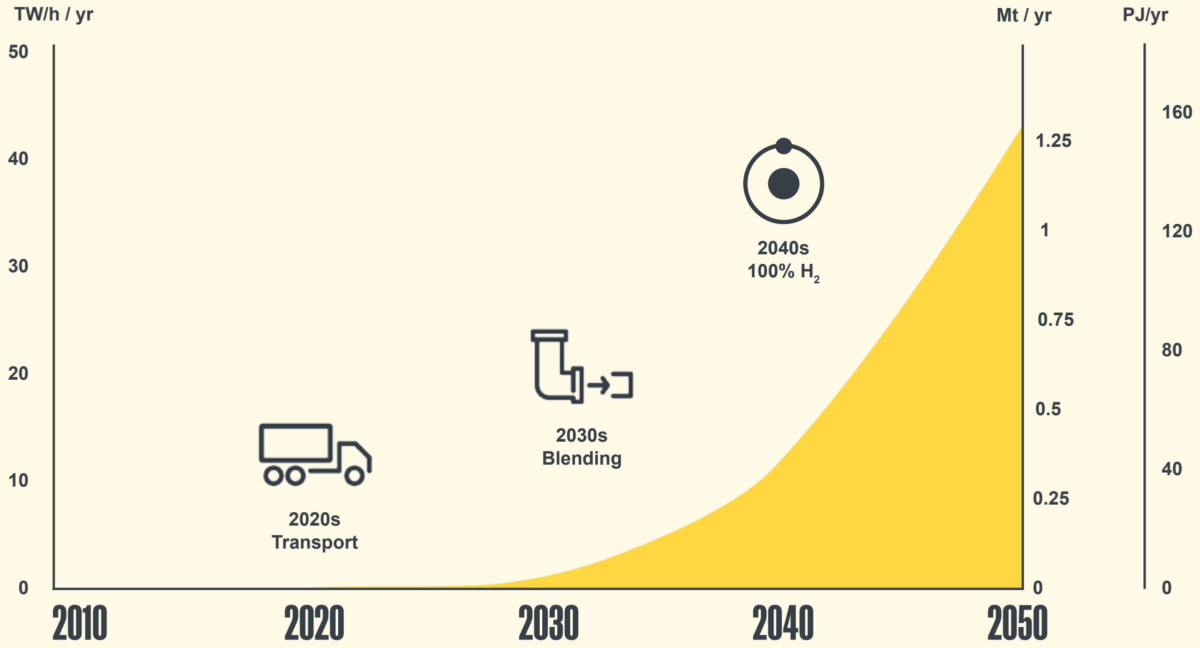



Figure 6: Projection of annual hydrogen demand

The expected cost of hydrogen is within the range of expected costs for other fuels—but higher than most energy costs incurred today. The study estimates the cost of producing hydrogen will fall to $3.26/kg in 2050 ($98/MWh or $27/GJ). This compares with a likely range of conventional natural gas prices between $8/GJ and $30/GJ (including carbon prices of between $25/t$CO_2$e and $200/t $CO_2$e).

Using the existing Firstgas network to transport hydrogen improves its overall economics by avoiding the need to compress hydrogen for transport in a tube trailer or make a chemical conversion (e.g. ammonia) to transport hydrogen as a liquid[1]. These steps both incur additional penalties in terms of energy losses and additional costs. Pipeline transportation also avoids truck movements and therefore has safety advantages and is a more environmentally friendly method of transporting energy.

Network connections also provide the ability to optimise the value of hydrogen production by combining other (potentially high value) uses of hydrogen such as heavy transport, export production and industrial use with the ability to feed the surplus hydrogen produced into gas networks. Used in this way, gas network connections enhance the economic viability of hydrogen production as part of multi-use hydrogen 'hubs', rather than relying on a single use case for hydrogen.

## FIRSTGAS GROUP TARGET IS A 20% BLEND OF HYDROGEN STARTING 2030 WITH 100% STARTING 2035

1 *https://www.iea.org/reports/the-future-of-hydrogen*

**We have sufficient network capacity and a viable strategy for converting the networks to hydrogen blends and then 100% hydrogen.**

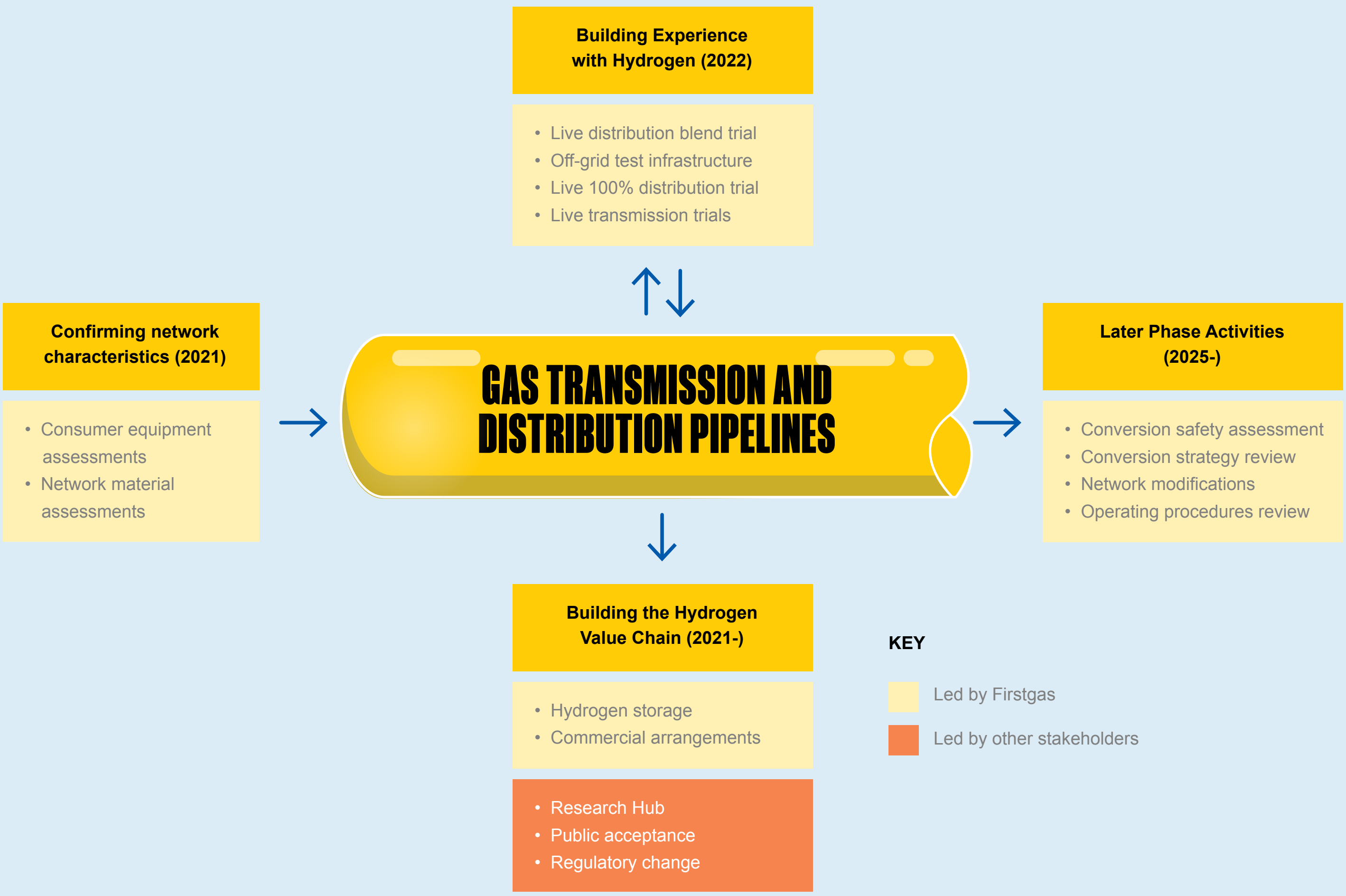
The study modelled demand growth in hydrogen increasing from an initial transport load that builds in the 2020s, with blending into the gas network starting at scale from 2030. This work suggests that the network could be 20% hydrogen by 2035, with a move to full hydrogen by 2050 supported by large scale storage of hydrogen in Taranaki to provide inter-seasonal and inter-year flexibility for the energy system. Starting 2035 the network would be progressively converted to 100% hydrogen from the end of the network back to Taranaki as hydrogen demand grows. Working inwards in this manner means we could keep supplying natural gas to users in Taranaki as hydrogen demand grows.

We've shown this indicative conversion time line in Figure 5. This is a good start to show what's possible, but it is important to bear in mind that other sequences and timings are possible that might meet other energy system needs. For example, if hydrogen storage was required to support a fully renewable electricity grid from an earlier date then this would be feasible and may change the dates for progressing other elements of the conversion strategy.

## NZ CAN ACCESS BLENDED ZERO CARBON GAS THROUGH MOST EXISTING NETWORKS AND APPLIANCES

To understand if our assets can facilitate the level of hydrogen demand estimated, the study explored whether our gas networks could deliver the energy and volume of hydrogen required safely – within pressure, flow and velocity limits. The study found that the transmission system (long distance, high pressure gas transportation

Figure 7: Hydrogen programme focus areas



network) has enough capacity to transport the projected energy demand as either a blend of hydrogen in natural gas, or entirely as hydrogen gas, with minimal capacity reinforcement.

However, Firstgas will need to change the configuration of our compressors as compression will be needed in different locations, since hydrogen production will be distributed across the network. Changing compressors is likely to occur during the already programmed renewal of our assets prior to network conversion to hydrogen. The introduction of hydrogen also creates potential for reduced pipeline compression needs (with associated capex and opex savings), since electrolysers can likely inject hydrogen at pressure across the network.

The study also modelled a typical low-pressure gas distribution network (localised, lower pressure gas transportation network), and found that distribution networks are likely to be able to deliver enough hydrogen blends and 100% hydrogen for projected demands, with some reinforcement required. The cost of the modifications over all distribution networks is projected to be in order of $270 million over the coming 30 years. While this expenditure is significant, the Firstgas Distribution Asset Management Plan already projects $100 million of capital expenditure over the next 10 years with similar (or greater) levels of investment planned on the other gas distribution systems owned by Vector and Powerco. Investments to enable hydrogen could be incorporated into the existing asset renewal programme to manage consumer cost impacts.

**We think that much of the Firstgas network will be capable of transporting hydrogen blends and hydrogen without replacement.**

The study assessed the typical components of our transmission network for likely risks when operating with hydrogen blends or 100% hydrogen. This assessment was made based on the current state of international research. At this point we have

## HYDROGEN CAN BE PRODUCED ANYWHERE, SUPPORTING LOCAL ECONOMIES

identified some issues. The key issue of hydrogen embrittlement of high-strength steel potentially applies to around one third of our transmission network. This and other issues are being actively investigated in overseas research programmes. We therefore expect that some of these technical issues are likely to be resolved as more work is done on gas pipelines overseas and by the forward Firstgas research, development and demonstration (RD&D) programme set out in this summary report.

Of particular relevance here in New Zealand is the body of work being undertaken by the Future Fuels Cooperative Research Centre (FFCRC) in Australia. The FFCRC consists of a combination of

## HYDROGEN CAN BE STORED AT SCALE, MEANING LESS INVESTMENT TO PRODUCE

industry experts, government representatives and academic researchers to cover multiple streams of technical evidencing required to decarbonise Australia's energy networks using hydrogen and biomethane. Their RP3 Network lifecycle management programme is a 30+ topic research stream focusing on quantifying and combating key issues of equipment material compatibility and performance under hydrogen service. A key focus of this research is the issue of hydrogen embrittlement and the FFCRC is setting up large scale research test facilities to test the effect of hydrogen on transmission pipeline material. Firstgas is a member of the Australian Pipeline

## FIRSTGAS GROUP IS LEADING THE WAY BY STAYING ABREAST OF INTERNATIONAL DEVELOPMENTS AND LEADING NZ INDUSTRY

and Gas Association (APGA) who partly fund the FFCRC, which allows us to participate in this research programme and access the findings of the work. We aim to leverage this connection to ensure that we can both influence the direction of the programme and potentially provide representative samples of existing pipeline materials for testing.

**Hydrogen production opportunities are large and dispersed across the Firstgas network.**

The Firstgas network is designed to transport gas from Taranaki to users across the North Island. Hydrogen changes that dynamic as hydrogen can be produced across the island. This means that the compressors will work in a different way and gas will potentially flow in different directions. Also, as the study assumes that electrolysers will discharge at high pressure into the network, the Firstgas compressors will have less work to do – saving on operating expenditure. This distribution of electrolysers across the network provides the opportunity to develop hydrogen economy hubs across the regions to take advantage of this infrastructure.

The build-out of electrolysers estimated in the study is significant. Hydrogen demand in 2050 is projected to be 42 TWh and this will need 8.5 GW

*2 Equivalent to approximately 2,000m$^3$/hr or 178 tonnes$H_2$/hr production capacity.*
*3 https://www.nationalgrid.com/uk/gas-transmission/insight-and-innovation/transmission-innovation/futuregrid*

of electrolyser capacity[2] and use 50 TWh of electricity. This would require the addition of around 28 GW of electricity generation capacity by 2050. While this is more that the new generation capacity required in Transpower's Whakamana i Te Mauri Hiko report, our study also encompasses greater decarbonisation as more energy requirements are decarbonised, particularly in high temperature process heat and heavy transport. Importantly, the required generation investment to produce hydrogen is less than if all energy end uses are electrified (which the study estimates would require 32 GW of new generation capacity). This is because hydrogen enables energy to be stored at scale, storing hydrogen produced off-peak for use during peak demand periods.

Our consultants estimate the cost to build the electrolyser capacity at around $3.3 billion by 2035, with an additional cost of $11.6 billion from 2035 to 2050. We view this as the upper bound of electricity generation and electrolyser build out to produce large amounts of hydrogen. However, many of the hydrogen storage and energy system integration benefits would still be realised with lower levels of electricity generation and hydrogen production.

**Our results set a good foundation to define the forward programme.**

To prove reliable and safe operation of our pipeline networks with hydrogen, we need to regularly review worldwide research and adopt results where practicable. Some of this work, like the HyNTS programme currently underway in the United Kingdom[3], involves removing components of their network from service and testing them for hydrogen blends and 100% hydrogen in an off-grid facility. These programmes will give us a realistic view on the likely performance of our similar network componentry of a similar age. There will be gaps, which will need to be addressed by New Zealand specific research and demonstration. While many of our components are similar to overseas networks, they may not be identical or the operating conditions may differ. To successfully convert our pipeline networks, a programme of activities will need to be undertaken. Some of these activities are directly related to assuring the components of our network work with hydrogen.

Others relate to equipment owned by third parties or the need to set up appropriate commercial and regulatory regimes. We see Firstgas Group as the natural leader for work relating directly to our network assets, but think that other stakeholders are best placed to lead hydrogen-related work in the wider energy sector. The work programme is set out in Figure 7.

## FIRSTGAS INTENDS TO START WORK STRAIGHT AWAY

### Consumer equipment assessments:

01

Preparing a full inventory of appliances connected to our networks and those of other network operators to understand RD&D and conversion requirements.

### Materials assessments:

02

Undertaking a detailed materials assessment of our networks and those of other network operators to understand RD&D and conversion requirements.

### Live distribution blend trial planning:

03

Final network selection and execution of a hydrogen blend in a live network.

### Hydrogen storage scoping work:

04

Building understanding of the options for storing hydrogen at various scales, the maturity of these options and the RD&D required to mature the technologies.

### Commercial arrangements scoping work:

05

Developing an understanding of changes to commercial arrangements that will be needed to introduce hydrogen blends into the network post trials.

Alongside this work, we will also actively monitor the progress being made on gas network trials overseas and will incorporate the findings of that work (as applicable) into our programme. We will also continue to participate in the Australian FFCRC programme through our membership of APGA.

**We would like to see other parties working on the following as a priority:**

- **Establishing a research hub:** providing a central clearing house for international research to allow this to be quickly understood and assimilated by stakeholders.
- **Reviews of the regulatory regime:** end to end assessment of all potential regulatory barriers to hydrogen uptake and an action plan to create a facilitative regime.
- **Building public acceptance:** providing impartial, factual information to the public about the potential uses of hydrogen, safety impacts and how it will impact them.

# THIS STUDY IS A GOOD FIRST STEP

When launching this study, we said we believed realising a hydrogen economy will be a collaborative effort. Our findings support this view. We see the role of Firstgas Group as facilitating the programme to convert the gas network to hydrogen, while others can join us in developing other parts of the hydrogen ecosystem.


This collaboration will ensure New Zealand is well placed to roll out hydrogen as a part of its approach to energy sector decarbonisation.

# ACKNOWLEDGEMENTS

**This study was 50% funded by Government investment managed by the Provincial Development Unit (PDU). We would like to thank the Provincial Development Unit for their support in furthering this very important work.**

**We would like to acknowledge the members of our governance group who gave their time to support this study:**

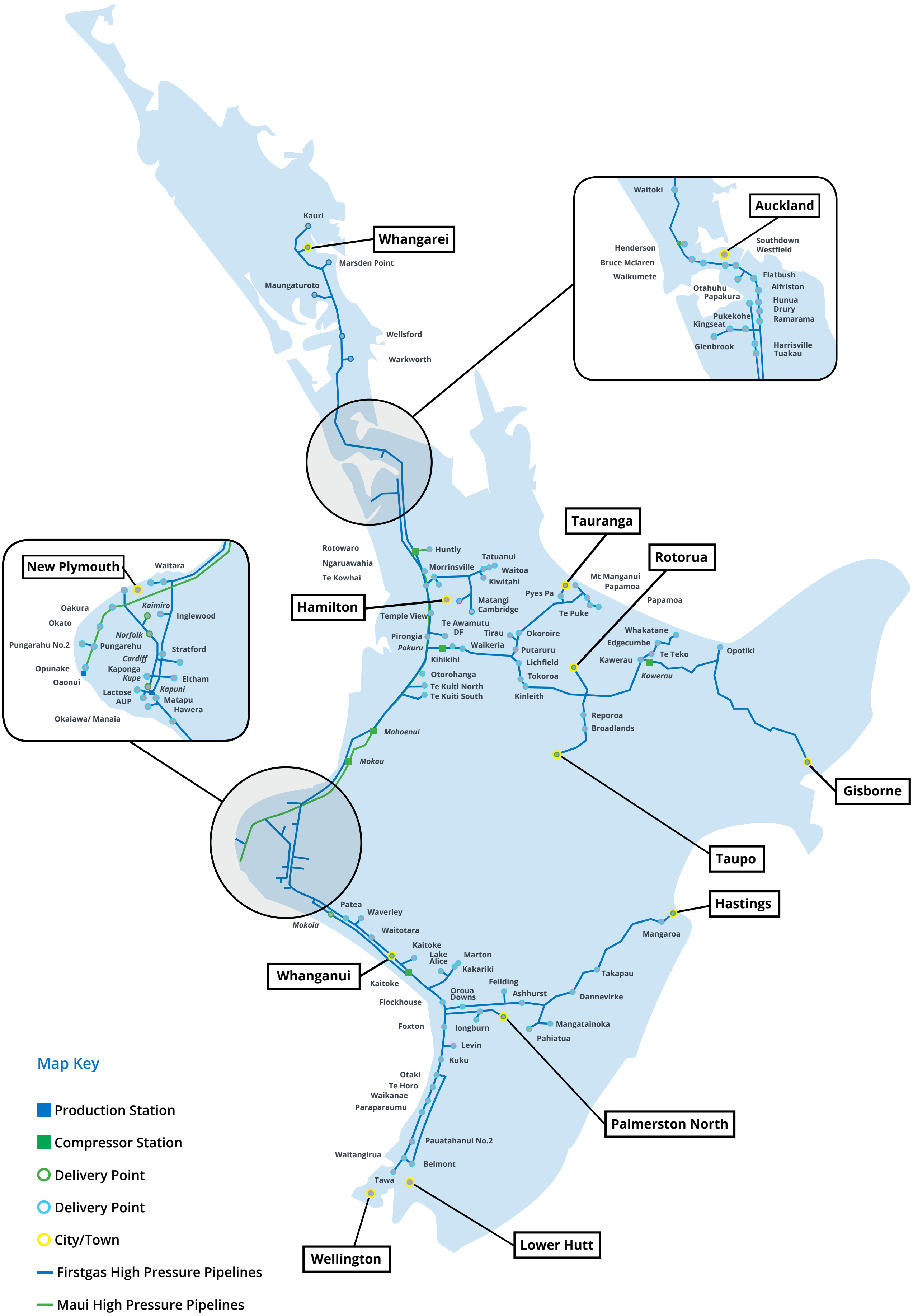
- **Bridget Sullivan, Provincial Development Unit**
- **Dr Linda Wright, NZ Hydrogen Council**
- **Pam Walklin, National New Energy Development Centre Establishment**

We would also like to acknowledge the support of all our workshop attendees and interviewees.

Special thanks also to Dr Megan Woods, Minister of Energy and Resources for her support of this study. Finally, we would like to acknowledge the assistance of the following organisations in the preparation of this report:

- **Ara Ake**
- **Beca**
- **Business Energy Council**
- **Callaghan Innovation**
- **Commerce Commission**
- **Concept Consulting**
- **Contact Energy**
- **Elemental Group**
- **Energy Efficiency and Conservation Authority**
- **EHL Solutions**
- **Fonterra**
- **Gas Industry Company**
- **Genesis Energy**
- **GNS**
- **Halcyon Power**
- **Hiringa Energy**
- **Hyundai NZ**
- **JGP Ltd**
- **MacDiarmid Institute**
- **Major Gas Users Group**
- **Methanex NZ**
- **Ministry for Business Innovation and Employment**
- **Mitsubishi NZ**
- **Nova Energy**
- **Office of the Minister for Energy and Resources**
- **Obayashi Corporation**
- **Refining NZ**
- **Standards NZ**
- **PowerCo**
- **Transpower**
- **Venture Taranaki**
- **Victoria University Wellington**
- **Worksafe NZ**
- **Worley**
- **Z Energy**

# FIRST GAS TRANSMISSION NETWORK MAP



# 02 INTRODUCTION

In May 2019, Firstgas Group announced our intention to explore how hydrogen might be used in our existing gas pipeline networks as part of a low carbon energy system in New Zealand. This report and the accompanying technical study from Aqua Consultants and Element Energy, document the work completed to establish and inform our trial programme.

# 2.1 ABOUT OUR CONSULTANTS

Element Energy is a low carbon energy economics consultant firm based in London. They have significant experience in the analysis of hydrogen projects and are involved in the Hy4Heat study[4] and the Gigastack project[5] among a wide range of work they have done for public and private sector clients throughout Europe. This economic expertise is complemented by the practical engineering expertise provided by Aqua Consultants. Aqua have been integral to numerous UK gas transmission innovation projects in the hydrogen and new energy space, such as the Leeds H21 project[6].

# 2.2 FOCUS OF THIS WORK

The focus of this work is to better understand how existing natural gas infrastructure might be used to transport hydrogen from where it is produced to where it is required.

While natural gas today provides over 20% of New Zealand's primary energy supply[7], hydrogen has the potential to decarbonise more parts of the economy than are currently fuelled by natural gas, such as vehicles like trucks, trains, ferries and planes. To stimulate discussion on the role of hydrogen in New Zealand's zero carbon future, the Government released its Vision for Hydrogen in New Zealand Green Paper in 2019.[8]

The study Firstgas has commissioned aims to help improve our understanding on how pipeline infrastructure can help realise this vision. Firstgas' extensive pipeline network in the North Island reaches all major centres. This creates the opportunity for existing infrastructure to play a substantial role in decarbonising New Zealand's energy system through:

- Storage in our pipeline network to support intraday/daily and weekly energy flexibility;
- Connection to large scale hydrogen storage for seasonal flexibility;
- Low-cost transportation of hydrogen as a transport fuel;
- Systems to manage specification, measurement and gas safety;
- Commercial chain of custody between hydrogen producers and users;
- Enabling 'hard to treat' industrial users the ability to decarbonise by providing zero emission gas to their site; and
- Management of hydrogen blends prior to 100% hydrogen operations commencing.

# 2.3 STUDY PROCESS

This work could not have happened without the input of Firstgas' stakeholders. We began in early March 2020 with a series of workshops and interviews in Wellington and New Plymouth. This allowed our study team to understand more about the NZ energy system and source data for the study. We interviewed over 40 individuals across 14 organisations over a week to kick off the study. A further 30 people from 15 organisations attended two, four-hour long workshops in Wellington and New Plymouth.

We also held stakeholder events for around 180 people to further engage with potential sources of information and users.

The study team took this information away to develop the hydrogen scenarios. We set up further meetings with other stakeholders focused on specific topics. This allowed for ground-truthing of the scenarios and testing of their robustness. Following on from this work we set to work modelling these scenarios from an economic and physical perspective to understand the implications of introducing hydrogen into the system.

It was intended that further stakeholder workshops were to be held during the course of the study. Unfortunately, due to COVID-19 the team were unable to return to NZ following their initial visit. However, they were able to complete the study with only limited delays.

*4 https://www.hy4heat.info/*
*5 https://gigastack.co.uk/*
*6 https://www.h21.green/projects/*
*7 Gas Industry Company, 2016, NZ Gas Story, p6. https://www.gasindustry.co.nz/about-the-industry/nz-gas story/document/5806*
*8 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/a-vision-for hydrogen-in-new-zealand/*

## 2.4 REPORT STRUCTURE

This report is set out with the following sections:

- Future hydrogen demand – how we think hydrogen could be used in a decarbonised New Zealand economy.
- Future hydrogen supply – how we think hydrogen could be supplied and the implications for the electricity and water sectors.
- Network conversion strategy – how we could roll out hydrogen to our networks based on our views of future hydrogen supply and demand.
- Technical feasibility – what we think we will need to test to undertake conversion of the network.
- Our next steps – what we will need to test, who we need to engage with and what we should investigate first.

This summary report highlights the key elements of the full study report, which can be found on our website **www.firstgas.co.nz**

We invite you to contact us if there is something you would like to know more about. Please contact:

**comms@firstgasgroup.co.nz**

# 03 FUTURE HYDROGEN DEMAND

The study considered three scenarios for the potential future demand for hydrogen - each representing a variation of a decarbonised New Zealand energy sector by 2050.

The scenarios are based on a set of assumptions around future government support and policies for the decarbonisation of energy, as well as the role of customer choice, which will influence the type of low-carbon fuels and technologies that will prevail in the coming decades.

All of the scenarios used in this study are based on the assumption that hydrogen demand is met entirely with green hydrogen. While other zero carbon sources of hydrogen may emerge over the time frames considered in this report (such as blue hydrogen which involves capturing and storing the carbon created from reforming natural gas into hydrogen), this report has focused on a green hydrogen pathway for New Zealand.

In this summary report we present the results of the Integrated Energy System scenario, which assumes that Government policy and network economics drive the integration of the power and gas sectors to deliver a balanced low carbon energy supply system. In this scenario, surplus renewable power is stored as hydrogen and used for industrial and transport needs, as well as being reconverted to power when required to support the grid.

This scenario was chosen as the focal point for our work since it has wide ranging impacts on the use of the gas pipeline system. If we are prepared for that scenario to play out, then we believe we can confidently facilitate the use of hydrogen under other plausible scenarios. This scenario also performed best when assessed against the World Energy Council's Energy Trilemma objectives – delivering on energy security, energy equity and environmental sustainability outcomes.[9] This section provides an overview of energy demand under this scenario, the main uses and possible costs of hydrogen over the 30-year time frame analysed and summarises the resulting carbon emissions from the energy sector in this scenario.

## 3.1 ENERGY DEMAND IN 2050

Hydrogen is expected to largely replace natural gas demand in most sectors by 2050. It will also replace a large portion of fossil fuels utilised in transport, especially for heavy vehicles. Additionally, hydrogen is expected to be able to replace coal in the steelmaking process and for dry-year storage. Natural gas demand to produce

### OUR ENERGY SCENARIOS

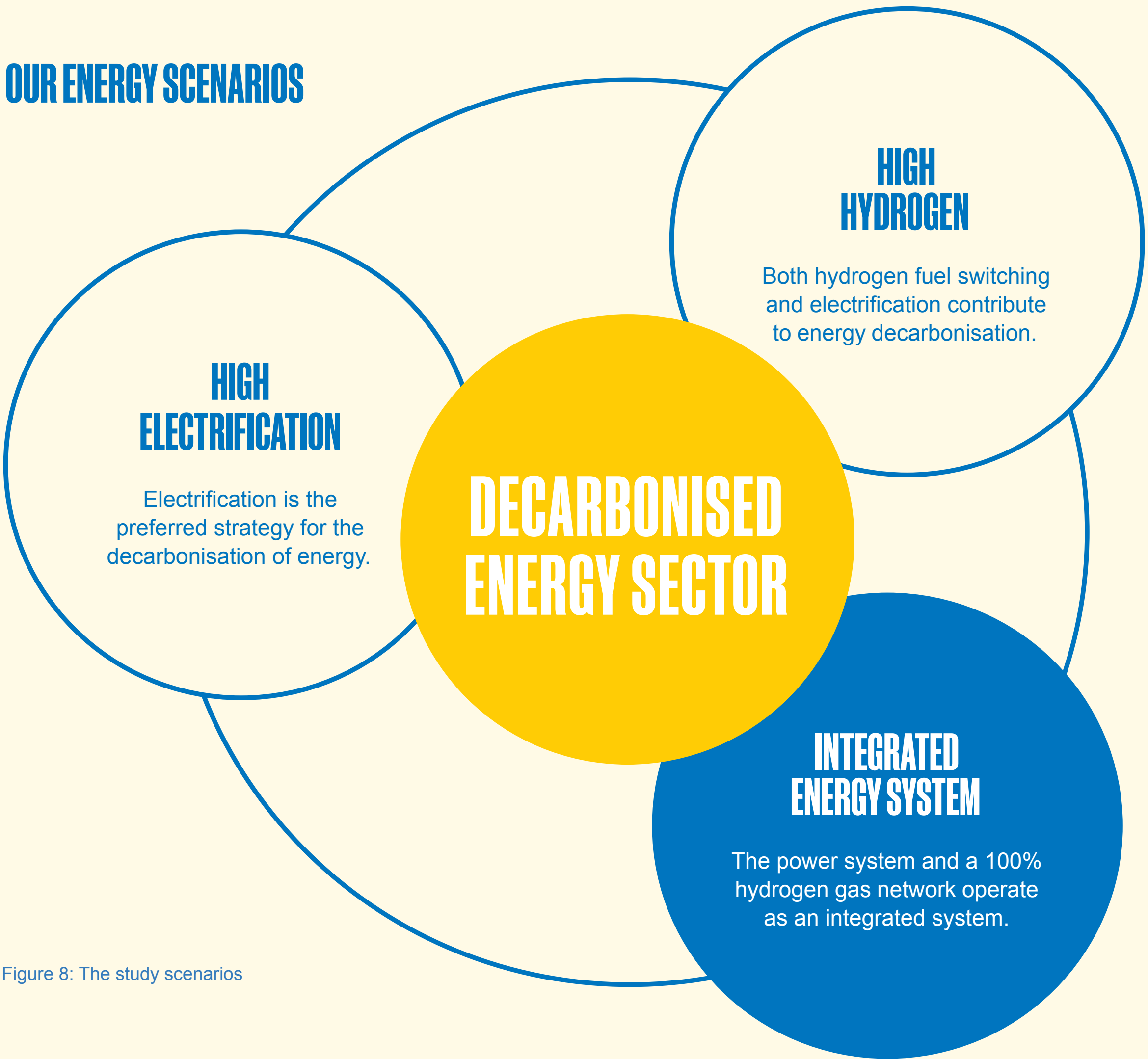



Figure 8: The study scenarios

9 *https://trilemma.worldenergy.org/*

methanol in New Zealand is not replaced by hydrogen, due to the reliance on a large source of $CO_2$ to be used as feedstock in the chemical processes involved. More detailed information on our assumptions on fuel switching is reported in the appendices of the full study report.

A comparison of the energy demand and fuel mix in 2020 and 2050 in the study is provided in Figure 9. This shows final energy consumed by sector. The demand for hydrogen and natural gas in this scenario is summarised in Table 1 below.

In this scenario, fossil fuels are replaced by electrification and conversion to hydrogen in relatively equal proportions. In fact, as a result of the similar expected cost of electricity and hydrogen, we expect the two energy vectors to be used according to their technical suitability and assume they are complementary and interchangeable.

**HYDROGEN COMPLEMENTS AND EXTENDS ELECTRIFICATION**

## 3.2 GROWTH IN HYDROGEN DEMAND PRIOR TO 2050

The increase in hydrogen demand is assumed to follow the following order:

- Transport demand commencing in the early 2020s – commencing with a network of hydrogen refuelling stations. Electrolysers will be built at refuelling stations connected by road tanker. The network of refuelling will grow as the hydrogen fleet grows in size. These locations will be close to transport infrastructure and will act as hubs – not only serving onsite hydrogen refuellers for vehicles travelling on the highways, but also generating hydrogen to be distributed by road tanker to a network of smaller refuelling sites.

- From the early 2030s blending of gas into the gas network is assumed – reaching 20% by 2035.

Table 1: Demand for hydrogen and natural gas

| Sector | Fuel type | Demand | | Comments |
|---|---|---|---|---|
| | | 2020 | 2050 | |
| Energy | Natural gas | **24 TWh** (85 PJ) | **9 TWh** (32 PJ) | **Significant reduction** from 2020: Remaining demand predominantly in methanol production |
| | Hydrogen | **0 TWh** | **40 TWh** (143 PJ) | **New supply** across all sectors |
| Process feedstock | Natural gas | **14 TWh** (51 PJ) | **14 TWh** (51 PJ) | **Largely unchanged from 2020**. Demand from methanol and urea production |
| | Hydrogen | **0 TWh** | **1.2 TWh** (4.3 PJ) | **New supply** for iron reduction at Glenbrook Steel Mill |
| Electricity generation | Natural gas | **11 TWh** (41 PJ) | **0 TWh** | **Natural gas** CCGTs replaced by renewable generation |
| | Hydrogen | **0 TWh** | **0.16 TWh** (0.6 PJ) | **Hydrogen gas turbines** supplement renewable generation |

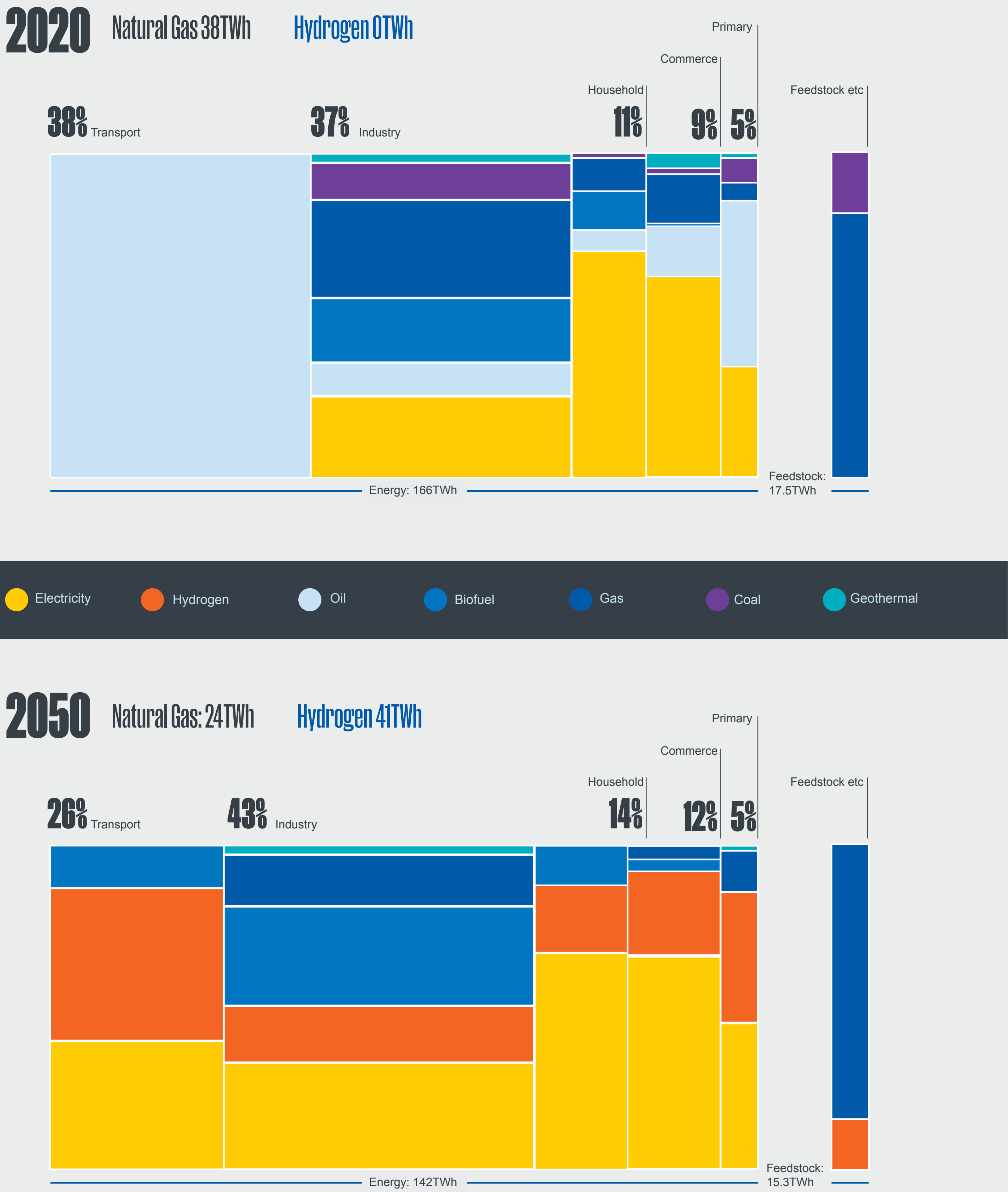



Figure 9: Final energy demand by fuel in 2020 and 2050

- Starting in 2035 the gas network will be converted sequentially to 100% hydrogen and there will be large scale storage of hydrogen available (assumed to be operational from 2045). Hydrogen demand from users connected to the gas grid in 2050 will account for roughly 50% of overall hydrogen demand in New Zealand.

The growth in total hydrogen demand over the period from 2020 to 2050 is shown in Figure 10.

## 3.3 HIGH-LEVEL ECONOMIC ASSESSMENT OF HYDROGEN DEMAND

The study developed a detailed economic assessment to evaluate the role of hydrogen in New Zealand's energy system from an economic perspective. This work included estimating the costs of infrastructure conversion and operating hydrogen production facilities to develop indicative hydrogen resource costs.

The results of this economic analysis are presented in Figure 11. The largest contributor to the cost of hydrogen is the cost of electricity, followed by capex and opex costs of the electrolysers used to produce hydrogen. "Other" costs including the cost of implementation and operation of the inter-seasonal storage and the cost of water for the electrolysers are relatively minor in comparison.

The forecast of the 2050 electricity costs for dedicated renewables is $61 /MWh (real terms 2020), which is based on the long run marginal cost of wind generation. The study assumes that using a mixed supply and allowing hydrogen to be generated to storage from renewable spill through the grid, reduces the 2050 electricity cost for hydrogen by 10% to $55 NZ$/MWh (real terms 2020).

The study also compares expected hydrogen costs with other studies and with estimated future costs of natural gas (which is the alternative fuel in many cases). This analysis is shown in Figure 12. These comparisons suggest that the future hydrogen costs used in the work, fall within

## ANNUAL HYDROGEN DEMAND PROJECTION

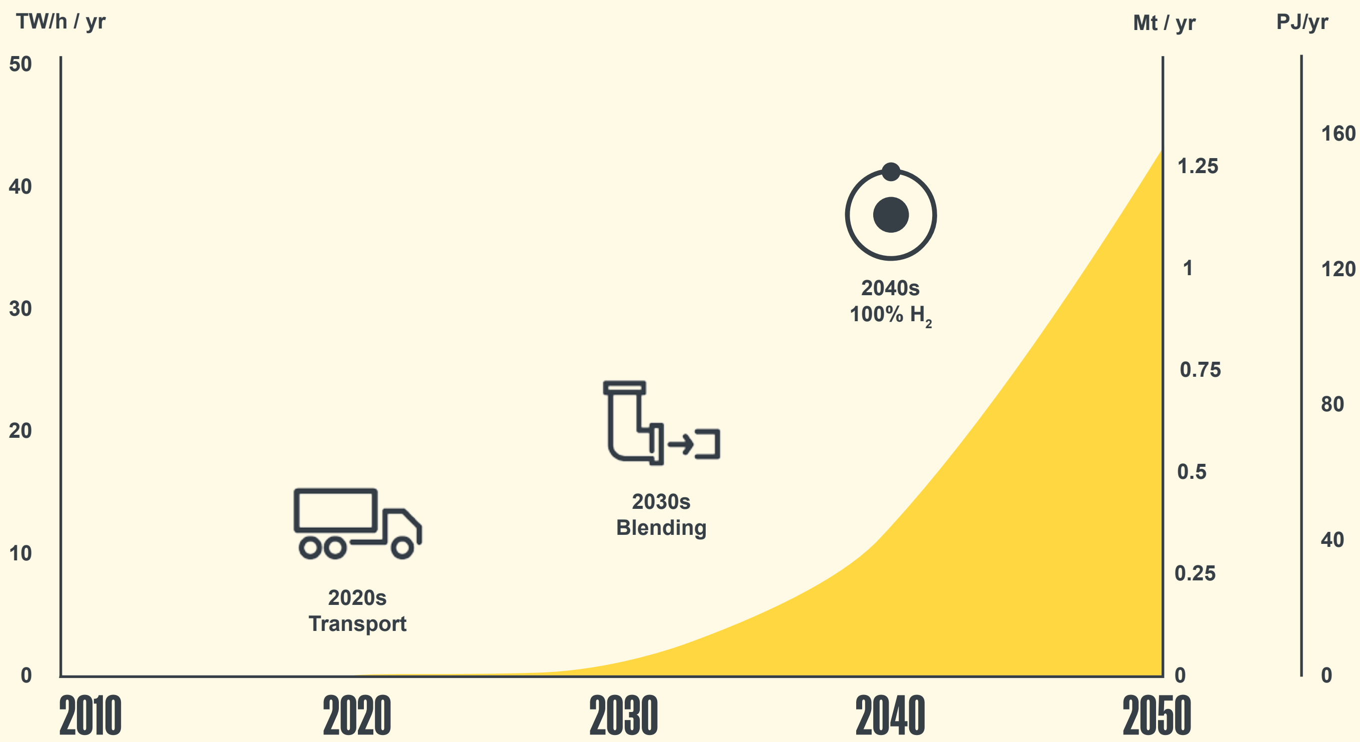



Figure 10: Projection of annual hydrogen demand

the range of other studies, being higher than those used for the Australia Hydrogen Roadmap but lower than Castalia's work for MBIE on hydrogen costs in New Zealand. The analysis also suggests that hydrogen would be a lower-cost option than natural gas in a high gas cost scenario – where wholesale gas costs $19.50/GJ and the carbon price increased to $200/t$CO_2$.

The purpose of these estimates is not to predict the future price of hydrogen. Since large-scale hydrogen production and distribution is not yet commonplace around the world, costs are expected to decline over coming decades – although the rate and level of those cost decreases is highly uncertain. The purpose of estimating these costs for this work is to demonstrate that expected costs are within the range that would support the deployment of hydrogen at scale.

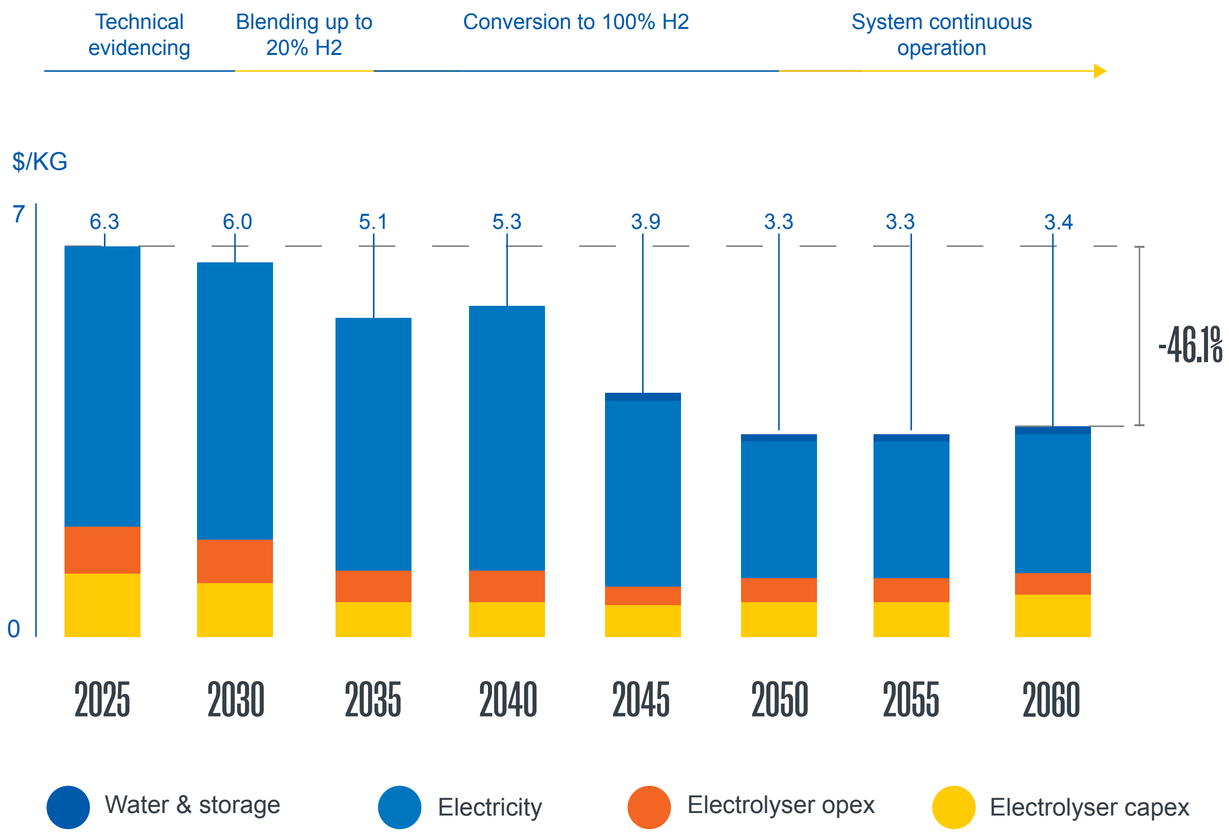



Figure 11: Annual hydrogen cost in NZ$/kg

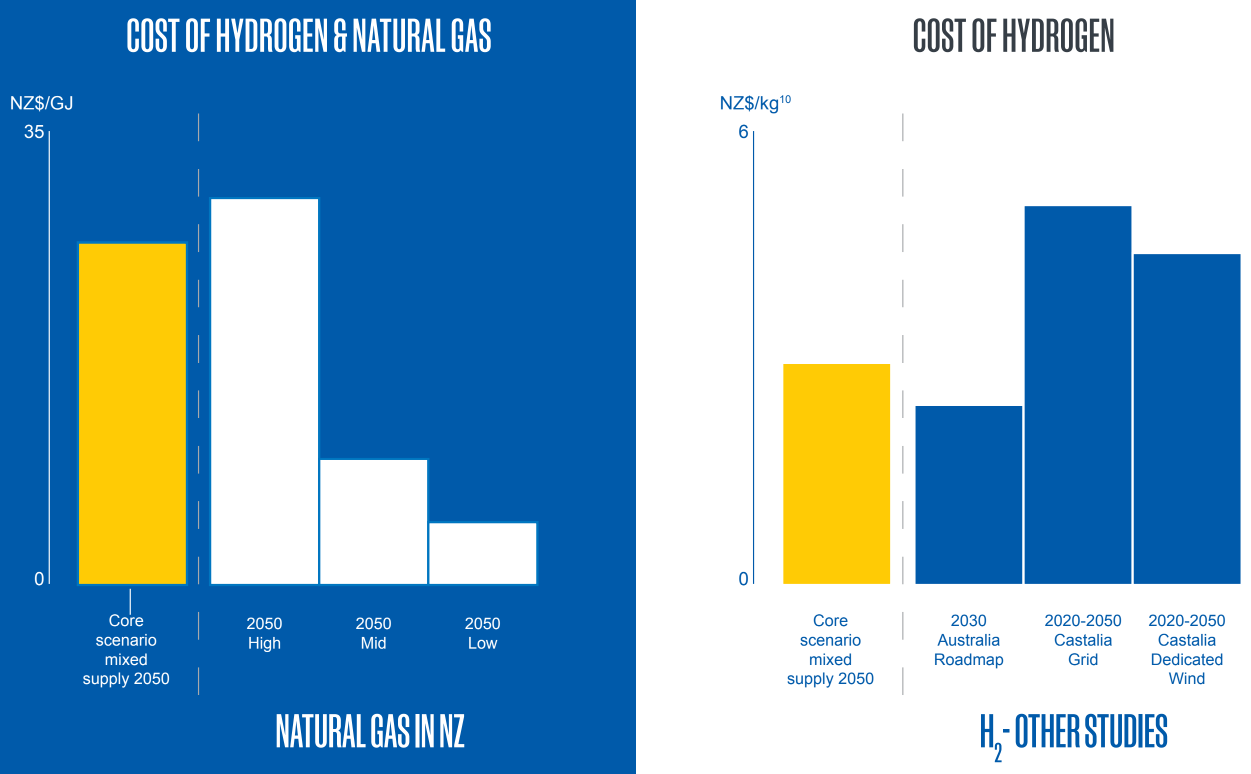



Figure 12 Cost of hydrogen compared with other studies and natural gas estimates

# 3.4 ENERGY SECTOR CARBON EMISSIONS IN 2050

The impact on carbon emissions with the shift in the fuel mix is shown in Figure 13. The switch from coal, oil and natural gas to hydrogen, renewable electricity and increased use of biofuels, together with overall demand reduction, results in energy sector emissions being reduced to near zero and a small amount of residual emissions in 2050, attributable to remaining natural gas use in the industry sector.

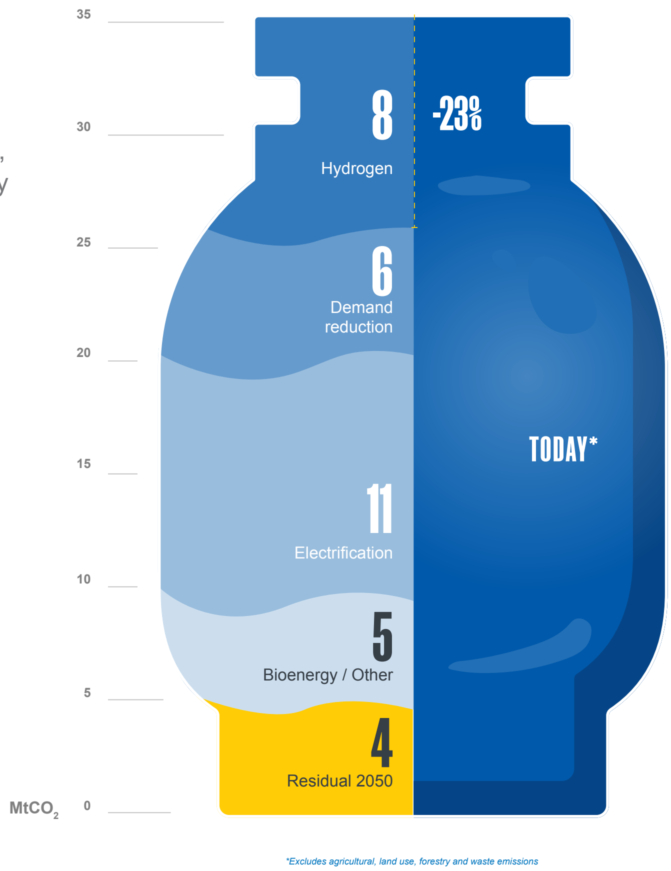



Figure 13: Contribution of carbon emissions reduction from today's baseline to 2050

*10 Exchange rate of NZD/AUD of 1.1*

# 04 PROJECTIONS AND IMPLICATIONS OF HYDROGEN SUPPLY

Ramping up hydrogen production capacity to meet the hydrogen demands estimated in the study will present a significant challenge and investment requirement. In this section we consider the hydrogen production infrastructure required to meet the demand, based on the assumption that all hydrogen demand is met with green hydrogen. We also outline how this interacts with the electricity system and impacts on water usage.

# 4.1 HYDROGEN SUPPLY SOURCES

To assess the hydrogen production requirements, the study developed an hourly model of hydrogen and electricity supply and demand out to 2050. If hydrogen is produced via electrolysis, a key consideration for the supply infrastructure will be to ensure there is adequate renewable electricity available to meet the electrolyser demand, while also meeting the anticipated growth of electricity demand across the economy.

Based on projected hydrogen demand, the hourly model allowed estimation of the following:

- Required electrolyser capacity
- Required hydrogen storage
- Electricity demand due to hydrogen production
- Electricity generated from hydrogen
- Water usage

We assume that renewable energy spilled at times of low electricity demand will be used to make hydrogen which is stored for later use. This increases the capacity factor of the electrolyser and the renewable generation and reduces the production capacity required for both hydrogen and electricity. Both these factors reduce the cost of hydrogen and electricity.

The operation of the large-scale storage to meet demand alongside hydrogen production is shown in Figure 15 overleaf for three time-scales: over the year, over the peak demand month and during the peak day. These graphs demonstrate how hydrogen is contributing to our energy system flexibility.

The electrolyser capacity will be built up over time as the hydrogen demand increases. The total electrolyser capacity reaches 8.5 GW (178 tonnes$H_2$/hr) by 2050 as shown in Figure 14 alongside average utilisation. The build is relatively slow over the period to 2035 as hydrogen is only present in the network at up to a maximum 20% blend. It increases more rapidly in the decade to 2050 as the network converts fully to hydrogen supply. The impact of the large-scale storage coming online in 2045 can be seen by the sharp increase in electrolyser utilisation.

Compared to the current global electrolyser market of around 150 MW, this clearly represents a very significant electrolyser build programme. However, multiple recent market studies forecast a rapid ramp-up in the electrolyser market, with a gigawatt per year market expected to develop in the 2020-2025 period, hence gigawatt-scale installed capacity by 2050 in New Zealand is not unreasonable.[12]

## ELECTROLYSER CAPACITY AND UTILISATION

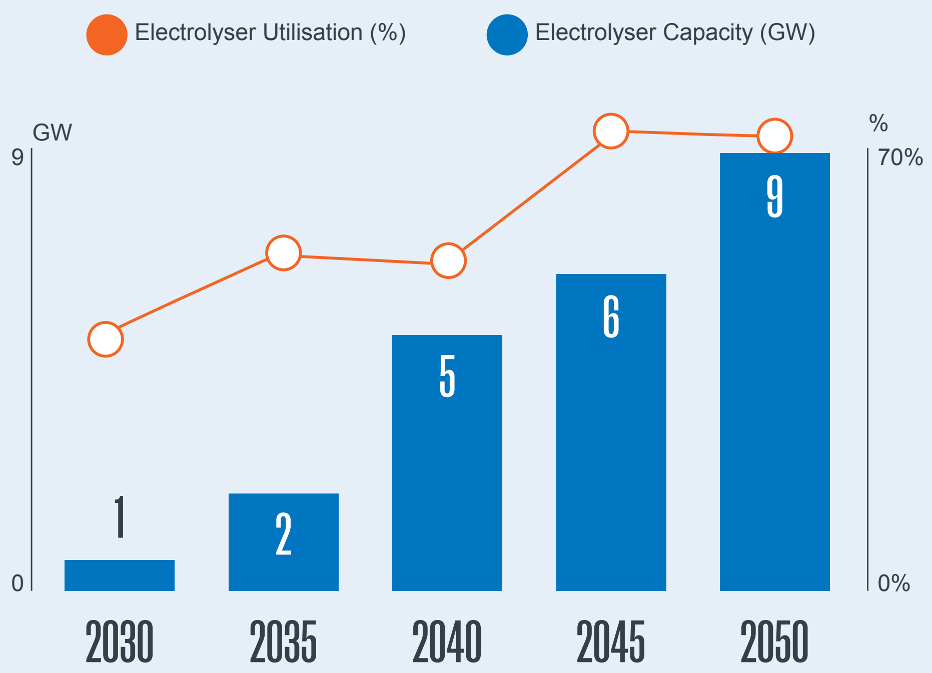



Figure 14: Build-up of electrolyser capacity and utilisation of the installed capacity

12 *https://publications.jrc.ec.europa.eu/repository/bitstream/JRC115958/kjna29695enn.pdf*

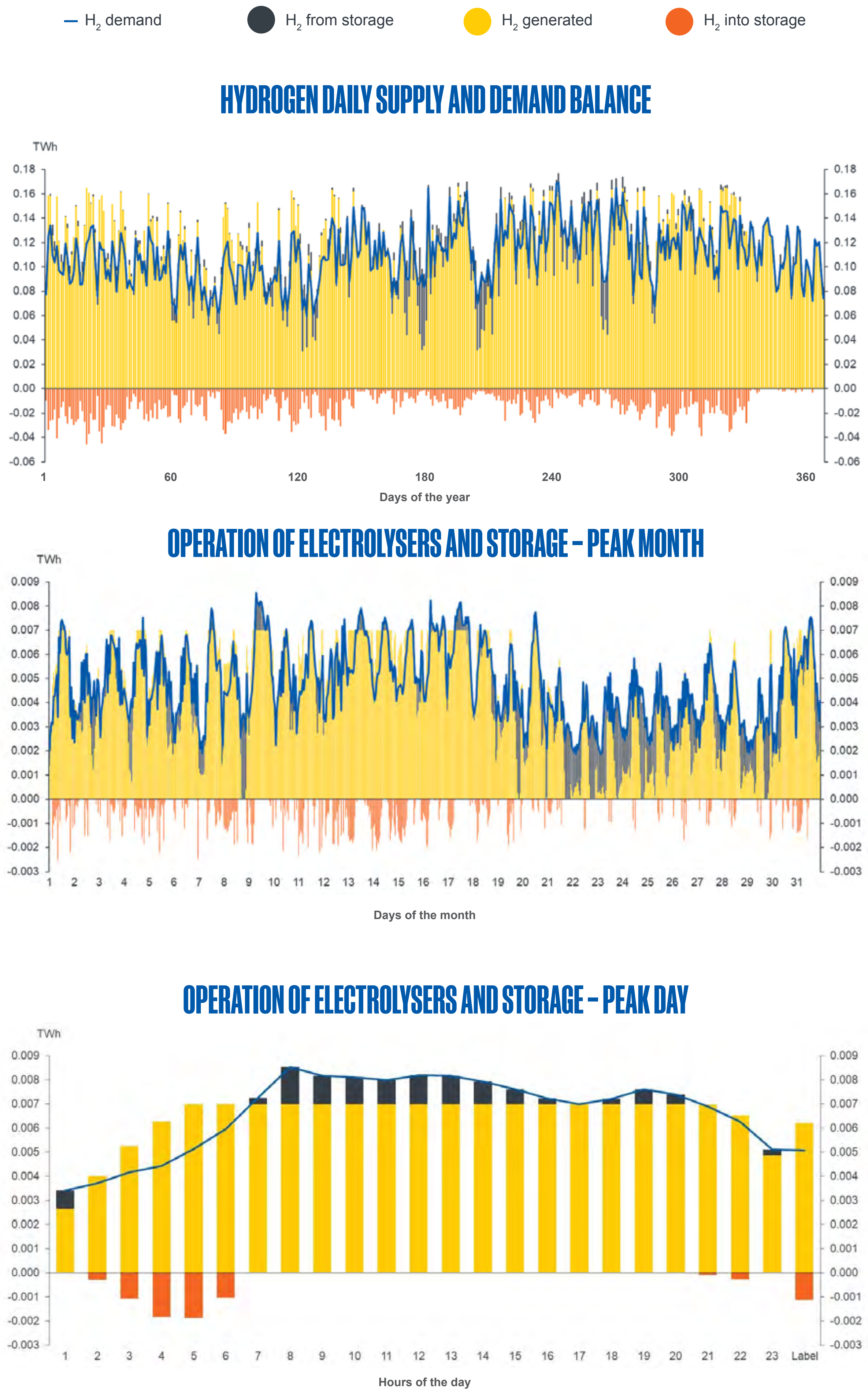



Figure 15: Hydrogen production by electrolysers and operation of storage to meet demand – annual, peak month and peak day timescales

The large-scale hydrogen storage facility required is assumed to be located in Taranaki using a depleted oil and gas reservoir. The rate of withdrawal required to meet modelled demand is 4 GW (15 TJ/h), which has been applied as a cap on the maximum rate at which hydrogen can be fed into the network from the large-scale store. This is larger than the current capacity at the Ahuroa gas storage facility of 2.7TJ/h.

Hydrogen storage has been sized at 5TWh (18PJ) such that hydrogen can be used to generate electricity to meet peak power sector demands and to provide dry year resilience. Increasing the storage volume beyond this level delivers diminishing returns in terms of improving electrolyser utilisation and minimising the renewable generation capacity required in the system. The variation in the level of hydrogen in storage over the year is shown in Figure 16 below for an average year and a dry year (we assume in both cases that the store is 50% full at the start of the year). The hydrogen store is not fully depleted during the winter period even in a dry year, despite a rapid draw-down on the stored hydrogen.

The study assumes that supply of hydrogen will develop in step with the demand created in different sectors as they develop:

- Transport demand commencing in the early 2020s. Electrolysers will be built at re-fuelling stations connected by road tanker. The network of refuelling stations will grow as the hydrogen fleet grows in size. (these locations are shown in the left panel of Figure 17). This proposed network of refuelling hubs has been supported by discussions with Hiringa Energy on the likely distribution of hydrogen demand in the transport sector.

- From the early 2030s we assume blending of gas into the gas network – reaching 20% by 2035. It is assumed that the locations of the electrolysers would build on the hydrogen transport infrastructure (as shown in the middle panel of Figure 17).

- From 2040 parts of the gas network will be 100% hydrogen. The electrolysers used in the blended network will remain in place and be supplemented to form the network in the right-hand panel of Figure 17. This assumes large scale storage of hydrogen in Taranaki.

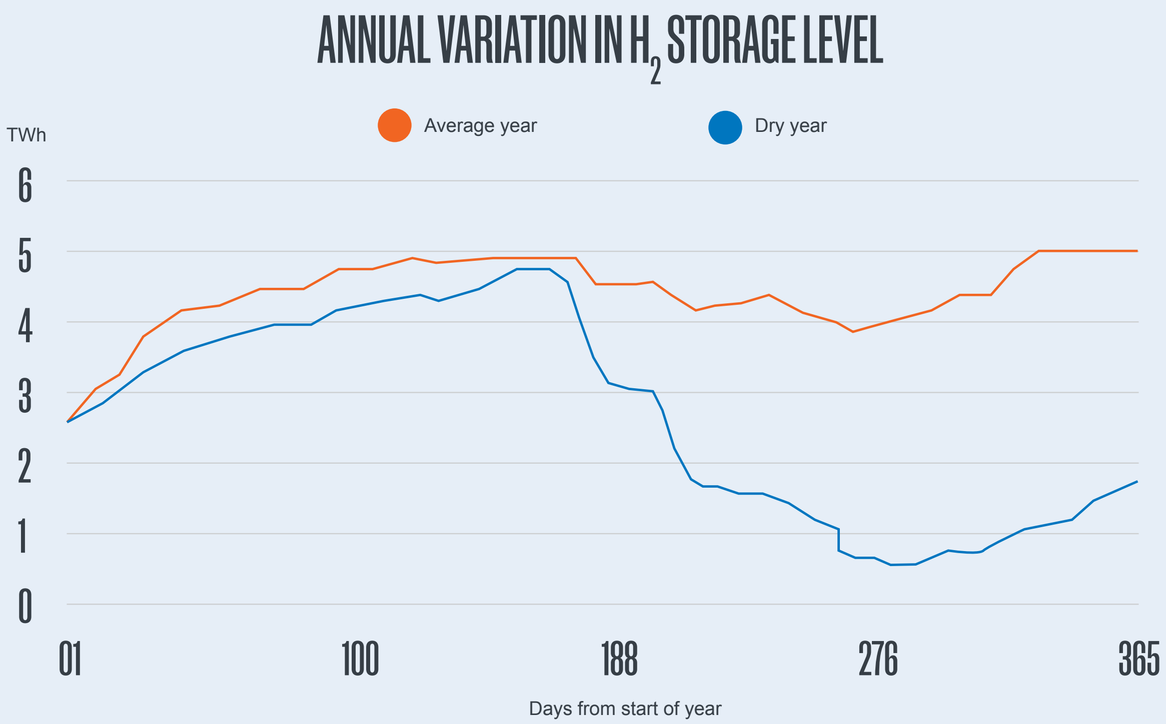
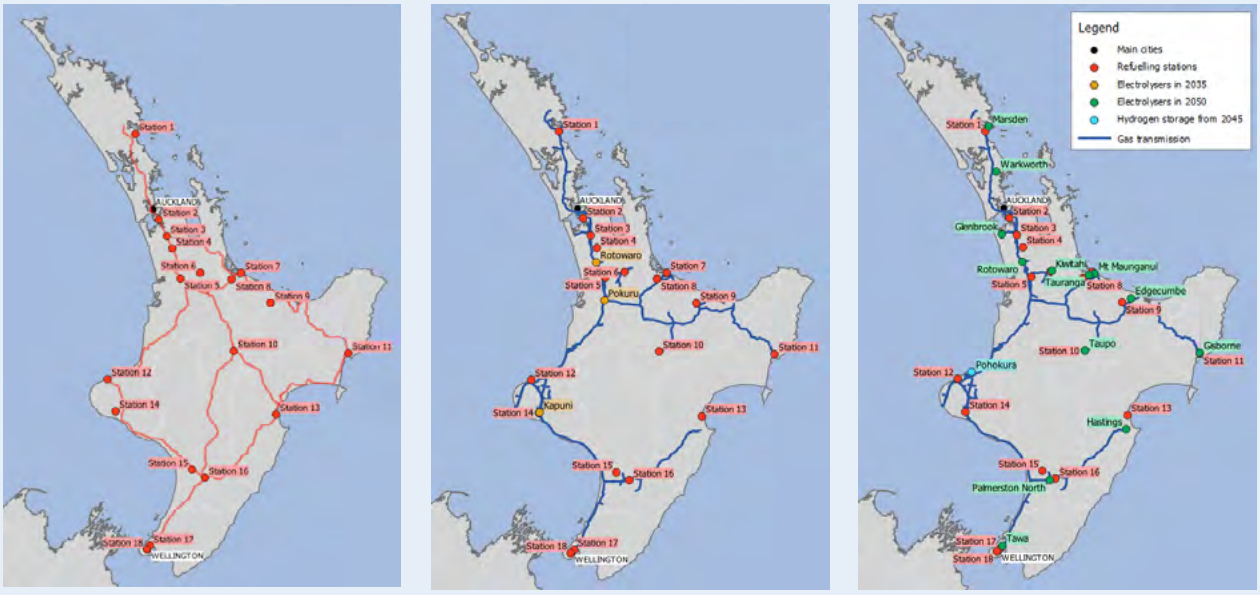



Figure 16 Variation of large-scale storage under average and dry year conditions




**Refuelling station 'hub' locations – sites for onsite electrolysers to meet transport demands.**

**Electrolyser locations in 2035 – additional sites for injection of hydrogen into the transmission network (20 vol% hydrogen blend).**

**Electrolysers and hydrogen storage in 2050 – locations of electrolyser plant and large-scale storage to feed the 100% $H_2$ network.**

Figure 17 Locations of refuelling stations and electrolyser sites

Electrolyser locations have been determined to ensure that the peak demands on the gas network can be met without encountering any network constraints, such as unacceptable pressure drops. The study assumes that the electrolysers installed for grid injection will produce hydrogen at high pressure, enabling injection into the transmission network without additional compression. The injection of hydrogen at high pressure at dispersed locations around the network is expected to have a beneficial impact on the requirement for pipeline network compressors. Additional compressor stations will still be required, but the duty on the compressors should be reduced potentially resulting in reduced operating costs compared to the current natural gas network.

## 4.2 ELECTRICITY SYSTEM IMPACTS OF HYDROGEN SUPPLY

The study modelled the interactions between the hydrogen production system and the electricity system using a supply and demand model, which includes an hourly representation of supply and demand for both hydrogen and electricity over the period to 2050. The electricity supply and demand model incorporates electricity required for electrolysis (the hydrogen sector demand) and electricity demand across other sectors of the New Zealand economy, including domestic, commercial, industrial and transport demands. Electricity demand in these non-hydrogen sectors (collectively referred to as the power sector) is based on the growth projections in the Whakamana i Te Mauri Hiko (WiTMH) report, modified to reflect the impact of hydrogen penetration into the sectors where hydrogen and electricity compete, for example transport and heating.

The supply and demand model was used to assess the electricity generation capacity required to meet total electricity demand as the demand for hydrogen ramps up, in particular the capacity of new renewable generation such as wind and solar. Annual 2050 hydrogen and electricity demand is shown in Table 2. The electricity demand is similar to that in the WiTMH 'Mobilise to Decarbonise' and 'Tiwai Exit' scenarios.

Table 2 2050 hydrogen and electricity demand

| | Demand in 2050 (TWh) |
|---|---|
| Hydrogen | 41.5 |
| Electricity* | 63.2 |

*Excludes demand for hydrogen production through electrolysis

The study includes a relatively limited use of bioenergy and some industrial gas use in 2050, but no other fossil fuels remain in the energy mix (petrol and diesel in the transport sector is entirely replaced by electricity and hydrogen).

In line with WiTMH, the study represents a significant increase in electricity demand compared to today - requiring growth in the electricity generation capacity and phasing out of fossil fuel generation with renewable generating capacity. Production of hydrogen via electrolysis results in a significant additional demand for electricity, on top of the growth in power sector demand. The growth in overall New Zealand electricity demand is shown in Figure 18, with demand from electrolysers accounting for just under half (44%) of New Zealand's total electricity demand in 2050.

To meet this rapid growth in electricity demand whilst also decarbonising the power sector will require a significant increase in renewable generation capacity. The generation capacity required is shown in Figure 19. The capacities of hydro and geothermal generation are taken from the Whakamana i Te Mauri Hiko (WiTMH) report projections with the capacity of wind, solar and other generating plant then sized to meet the power sector demand before the additional wind and solar capacity required to meet the hydrogen sector demand is calculated. 'Other' generating capacity includes fossil fuel plant in the earlier years, that are assumed to be retired over the period to 2050 and dispatchable renewable generation (such as biomass) after that point. In this analysis there is no requirement for 'Other' generating capacity in 2050, as the peaks in power sector demand can be met by hydrogen-fuelled generating plant.

The capacity of renewable electricity generation required to meet the combined power and hydrogen sector demand is large – 18 GW of wind and 13.5 GW of solar by 2050. However, the required generating capacity is less than would be needed if all energy uses were directly electrified.

This is because hydrogen storage allows use wind and solar plant more efficiently in two ways:

- Generating hydrogen at times when wind and solar are available but there is no electricity demand stores energy that would otherwise have been wasted and increases utilisation of the generation plant
- Generating electricity using hydrogen at times of peak demand reduces the requirement for additional wind and solar generation capacity to cover peak times.

## ANNUAL ELECTRICITY DEMAND (TWh/Y)

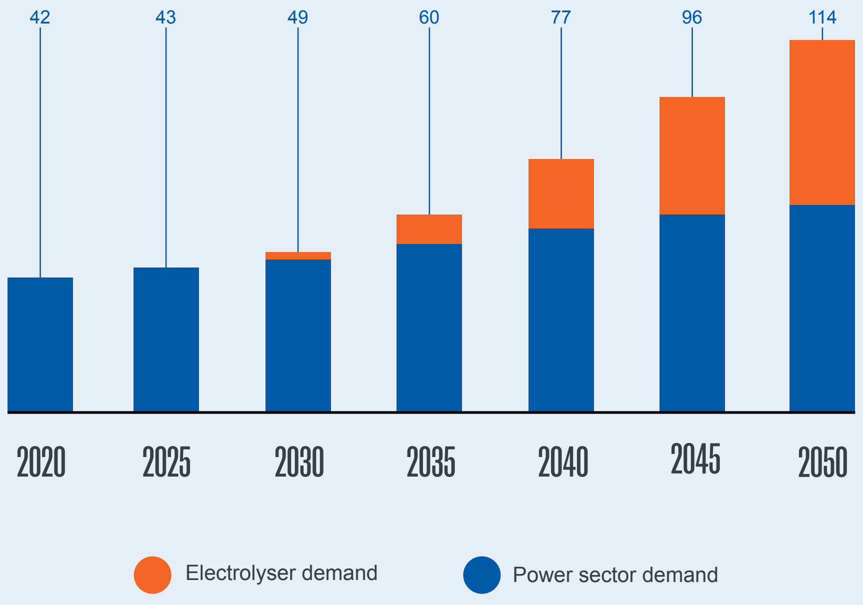



Figure 18 Growth of total electricity demand

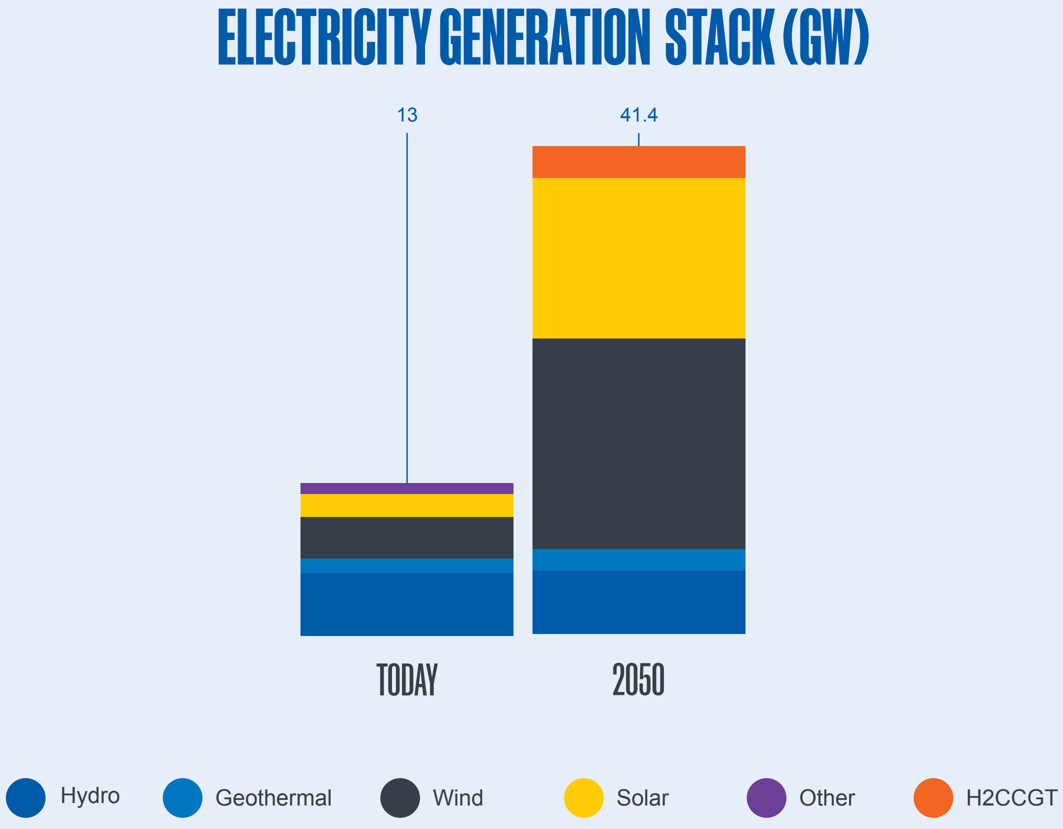



Figure 19 Installed electricity generation capacity today and in 2050

The amount of generation capacity required is significantly larger than the generation capacity forecasts in the WiTMH report. This is because our study includes a significantly larger final energy demand, which is supplied either directly or by hydrogen generated by electrolysis. The additional final energy demand comes from greater penetration of hydrogen in the transport sector (particularly heavy duty vehicles), hydrogen demand in the industrial sector, as well as switching of residential and commercial heating demands from natural gas to hydrogen. This results in greater decarbonisation of energy compared with the WiTMH study.

Typically, the WiTMH projections include a certain amount of annual demand that is met by generating capacity labelled as 'Other' or 'Firming' capacity, but the generation technology is not identified. As further renewable generation capacity is built to meet hydrogen sector demand, the output of this plant could be available to meet coincident peak power sector demands, displacing 'Other' and 'Firming' capacity in the generating stack. At times of surplus generation from the power sector, for example overnight when electricity demands are lower, the electrolysers will run to produce hydrogen.

The study also considers further coupling between the power and hydrogen sectors, particularly once a large-scale hydrogen storage facility is available. Here hydrogen is used to generate electricity via hydrogen-fuelled thermal plant, such as combined-cycle gas turbines (CCGT), at times of peak power sector demand. These could be new plants or the conversion of existing plant. As shown in Figure 19 generation by hydrogen CCGTs can meet all peaking plant requirements in the power sector in 2050 (the hydrogen CCGT capacity required in 2050 reaches 2.75 GW in order to meet peak power sector demands). Large-scale hydrogen storage and hydrogen CCGTs could play a further beneficial role in the energy system by contributing toward the management of dry year risk.

WiTMH estimates the dry year risk to be a shortfall of available generation of around 8 TWh compared to power sector demand over the winter period. The study modelled the dry year as a 20% reduction of the inflows from rainfall into the lakes, which corresponds to approximately a 5 TWh reduction of available hydro generation over the winter. The results show that a combination of additional renewable generating capacity and hydrogen CCGTs could potentially fully address the dry year issue. This requires additional hydrogen CCGTs capacity of 8.2 GW which would allow the storage shown in Figure 16, to be and replenished in the following year. The study has

# ANNUAL WATER CONSUMPTION

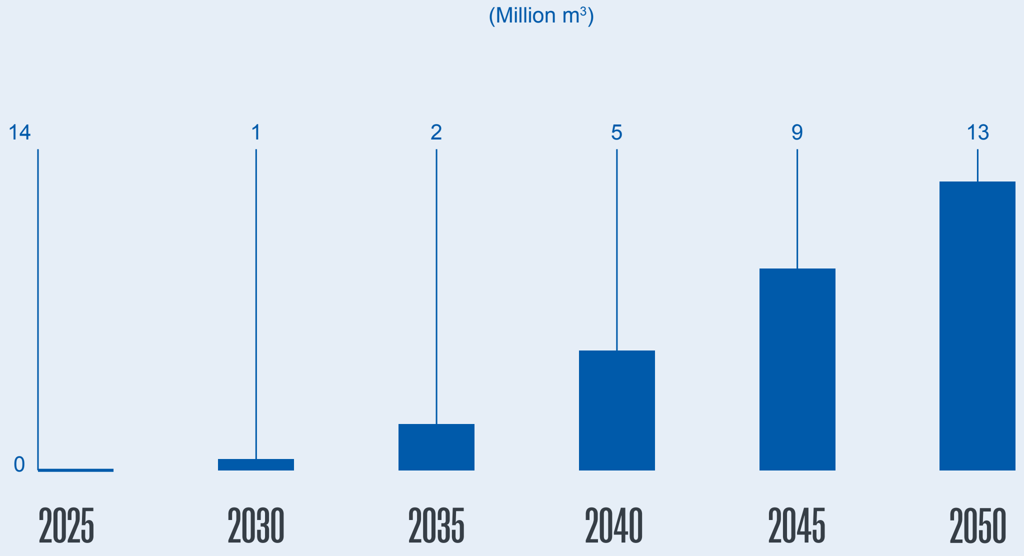



Figure 20: Annual water consumption for electrolysis

not modelled additional storage in the electricity system as it was not necessary. Successive dry years have also not been modelled.

## 4.3 WATER CONSUMPTION FROM HYDROGEN SUPPLY

Water demand for the operation of Polymer Electrolyte Membrane (PEM) electrolysers is around 12 litres of potable water per kg of hydrogen, although this figure could be higher when using non-potable water. The water demand required for the electrolysis of hydrogen is shown in Figure 20, with annual demand increasing up to 13 million cubic metres of water per annum by 2050.

By comparison, annual water demand of 13 million cubic metres is equivalent to:

- 2/3 of the current freshwater demand of the city of Hamilton, or
- 8% of the current freshwater demand of the city of Auckland, or
- ~0.1% of the current national maximum freshwater demand allocation for all sectors[13].

Using treated water reduces demand and efficiency of the process as highly purity water is required by the electrolyser. Water use efficiency is likely to improve in the future and the use of brackish and salt water is being developed. This will reduce and avoid conflict over water usage.

13 https://www.waternz.org.nz/Category?Action=View&Category_id=1001

# 05 TECHNICAL FEASIBILITY & REGULATORY ASSESSMENT

We need to understand how hydrogen and hydrogen blends will work for our customers and networks. This study shows the work we need to do.

To convert gas networks to operate on a hydrogen blend and ultimately 100% hydrogen, we need to understand and develop:

- The ability for gas consumers to safely operate their equipment on blends of hydrogen and natural gas and adapt to safe operation on 100% hydrogen;
- The ability of all components of our gas transmission network and all gas distribution networks to safely handle a blend of hydrogen and 100% hydrogen and deliver enough energy to meet demand;
- A conversion strategy that minimises impacts on consumers; and
- Regulatory changes to allow the conversion to hydrogen blends, and ultimately 100% hydrogen operations.

This section outlines the work done in the study as a preliminary assessment. While more work is required, it's a good initial step that informs our future work programme and the actions other stakeholders can take to realise New Zealand's hydrogen vision.

## 5.1 CONSUMER EQUIPMENT

While we have some knowledge of the equipment connected to our networks, it is not complete. Research to date shows that most appliances (from boilers to home cooking) will not be affected by blends of hydrogen up to 20%. However, existing appliances will not operate with 100% hydrogen and will therefore need to be replaced as part of the conversion strategy. We anticipate that most equipment will be able to be replaced in its natural retirement cycle as we convert the network to 100% hydrogen. Our role is to understand what equipment is connected to gas networks today and how it will be affected by the introduction of hydrogen. We've included that in our programme.

## 5.2 NETWORK CAPACITY AND MATERIALS

Based on the assessment of capacity, network components and the conversion strategy outlined in section 5.3, a list was developed of the required changes to the transmission and distribution networks shown in table 3 and table 4.The study's key finding is that the transmission system (long distance, high pressure gas transportation network) has enough capacity to transport the projected energy demand as either a blend of hydrogen in natural gas, or entirely as hydrogen gas, with minimal capacity reinforcement. However, there will need to be changes to the compressor configuration. It is likely these changes can occur during the already programmed renewal of assets, prior to the network conversion to hydrogen. A typical distribution network (localised, lower pressure gas transportation network) was also modelled, and it was found that these networks are likely to be able to deliver enough hydrogen blends and 100% hydrogen for projected demands, with only minor reinforcements.

In terms of the materials assessment, current research shows that HDPE components will be compatible with hydrogen usage. However, there is still work to do on the compatibility of steel components – particularly in relation to hydrogen embrittlement. Fortunately, there is a large RD&D work programme ongoing globally to address this issue and preliminary findings are encouraging. This is covered in more detail in Section 6 and our accompanying full study report.

Table 3 Transmission network component changes

| TRANSMISSION NETWORK | | | |
|---|---|---|---|
| COMPONENT | | CHANGES FOR 20% BLEND | CHANGES FOR 100% HYDROGEN |
| **Pipelines** | Pipeline materials (X52 grade steel and below) | No changes identified (based on current global RD&D)<br>May require reduced MAOP for high strength steels (approximately 30% of existing network) [14] | No changes identified (based on current global RD&D)<br>May require reduced MAOP for high strength steels |
| **Compression** | Reciprocating compressors | Compression at Mahoenui no longer required (reduction of 3 compressor units)<br>Modifications required to electrical equipment in hazardous areas (IECEx) | Compression at Kawerau, Mahoenui, Mokau and Kaitoke (reduction of 11 compressor units) no longer required<br>Modifications required to electrical equipment in hazardous areas (IECEx) |
| **Valves** | Mainline valves | No changes identified | Modifications may be required to mitigate hydrogen embrittlement and impact of hydrogen on soft seals (subject to the outcome of RD&D programmes) |
| **Pressure reduction at delivery point** | Pressure reduction stream components at delivery points | No changes identified | Replacement of regulators, modifications to soft seals in slam-shut valves (subject to the outcome of RD&D programmes) |
| **Pig launcher/ receiver stations** | Pig launchers / receivers and associated pipework | No changes identified | No changes identified |
| **Metering** | Mixture of ultrasonic, turbine and orifice plate meters | Recalibration required on all meter types<br>Electrical equipment in hazardous areas may need to be changed (IECEx) | Recalibration required on all meter types<br>Replacement of meters not suitable for pure hydrogen<br>Electrical equipment in hazardous areas may need to be changed (IECEx) |

*14 High strength steel pipelines (grades above X52) are more susceptible to hydrogen embrittlement and are the key focus area for Firstgas Group*

Table 4 Distribution network components changes

| DISTRIBUTION NETWORK | | | |
|---|---|---|---|
| COMPONENT | | CHANGES FOR 20% BLEND | CHANGES FOR 100% HYDROGEN |
| **Pipelines** | Metallic mains / PE mains | No changes identified | Our modelling showed that 34km of reinforcement would be requires for the Hamilton distribution network. Extrapolating this for other networks We estimate a total of 400km of reinforcement will be required to deliver enough energy |
| **Valves** | Isolation valves | No changes identified | No additional valves identified. Potential modifications to soft seals if research proves them unsuitable for pure hydrogen We expect that this will be replicated in other networks |
| **Pressure reduction** | District Regulator Stations (DRSs) | Electrical equipment in hazardous areas may need changing to be compliant (IECEx) | Our modelling shows that an additional 9 DRSs will be required on the Hamilton distribution network. Extrapolating this for other networks would create a need for 32 additional DRSs (41 in total) Pressure regulators may need to be replaced with hydrogen compatible units Electrical equipment in hazardous areas may need changing to be compliant (IECEx) We expect that this will be replicated in other networks |
| **Meters** | Connected customers - mixture of ultrasonic, turbine and bellow meters | Recalibration required on all meter types | Recalibration required on meter types recertified for 100% hydrogen Replacement of meters identified as unsuitable following completion of RD&D programmes Electrical equipment in hazardous areas (IECEx) We expect that this will be replicated in other networks |

# 5.3 CONVERSION STRATEGY

The study developed the conversion strategy shown in Figure 21 based on the growth in hydrogen demand laid out in Section 3.2. The key phases of the strategy are:

- Transport demand for hydrogen commencing in the early 2020s;
- Hydrogen blending into the network from the early 2030s – reaching 20% by 2035; and
- 100% hydrogen and large-scale storage of hydrogen from 2035

## 5.3.1 BLENDED NETWORK PRIOR TO 2035

To deliver the hydrogen required to meet the 20% blend, hydrogen production would be required at the following locations:

- Kapuni (south Taranaki)
- Pokuru (near Te Awamutu)
- Rotowaro (near Huntly)

Details of the electrolyser capacity and duties are detailed in section 4.1. To accommodate the existing power generation at Huntly power station, and major hydrogen sensitive consumers (such as Methanex) during the initial transition, a section of the transmission network will remain on natural gas. The 20% blended network and hydrogen injection points are shown in Figure 22.


Figure 22: Map of 20% blend conversion area

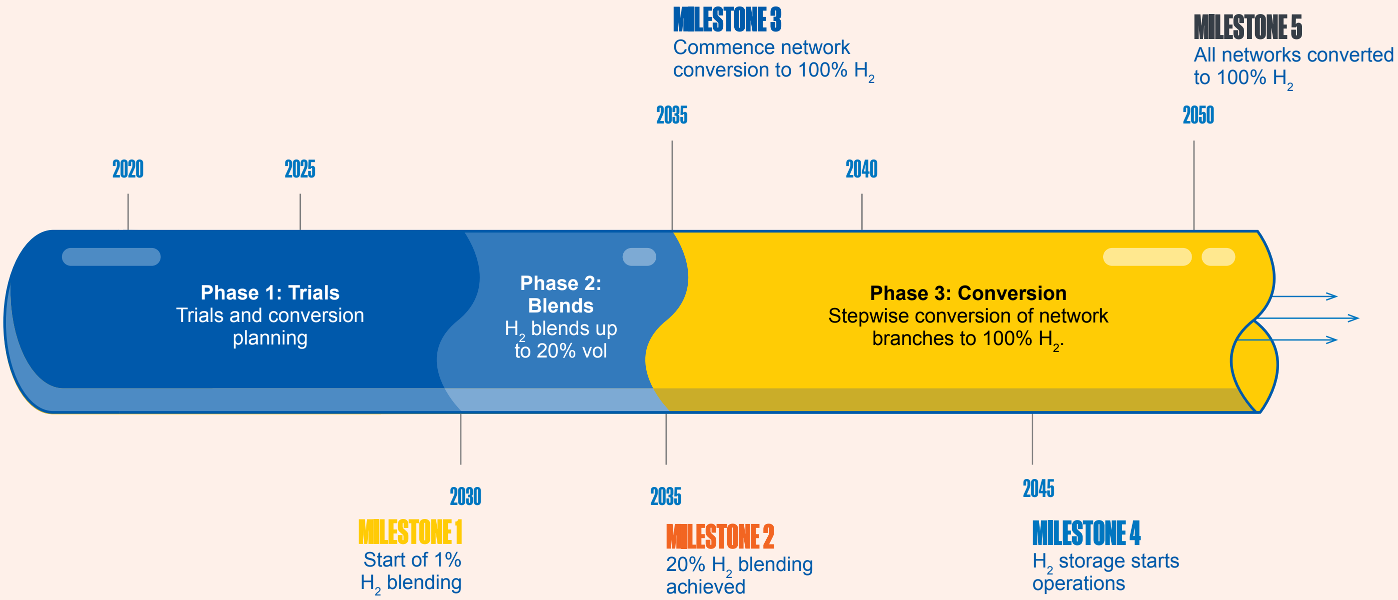



Figure 21: Conversion strategy timeline

## 5.3.2 CONVERSION TO 100% HYDROGEN NETWORK

A conceptual conversion strategy to move from a 20% hydrogen gas blends to a 100% hydrogen network was developed in the study. This entails converting isolated sections of the network from blended gas to 100% hydrogen. Pure hydrogen is fed from the electrolyser located at the extremity of the isolated section, whilst the remainder of the network is fed with a hydrogen blend, fed from the main transmission network. This process is repeated sub-section by sub-section until the entire isolated section is fully converted. Once each isolated section is fully converted the next section is isolated for conversion working towards Taranaki as this is the source of gas for New Zealand. This will be the final area for conversion.

The study estimates that conversion of the entire network from blends to pure hydrogen will take approximately 15 years, starting in 2035. The time taken to convert each individual section will depend on the network configuration, location of isolation valves and customer equipment replacements within the conversion area and will require detailed conversion plans to be developed.

Figure 23 demonstrates a sequential process of how the network could be converted from blends to a 100% hydrogen.

A detailed conversion strategy will need to be developed for each section to accommodate conversion of each section to a 100% hydrogen network. The switch from hydrogen blends to a 100% hydrogen network will require extensive customer consultation and coordination to ensure minimal impact on consumers.

## 5.4 REGULATORY ASSESSMENT

Alongside changes to the network to allow injection 20% hydrogen blend or 100% hydrogen, there will need to be changes to our regulations. A high-level assessment of the regulations involved in gas production, transportation and use has been undertaken to understand the relevant regulation and the requirement for change.

The study did not attempt to design the required change but was limited to identifying where the current regulation may not accommodate hydrogen or hydrogen blends. A summary of the analysis is given in Table 5 while a broader discussion of the policy and regulatory framework is given in the appendices of the full study report. We understand that others may be undertaking work in this area and this work complements those assessments.

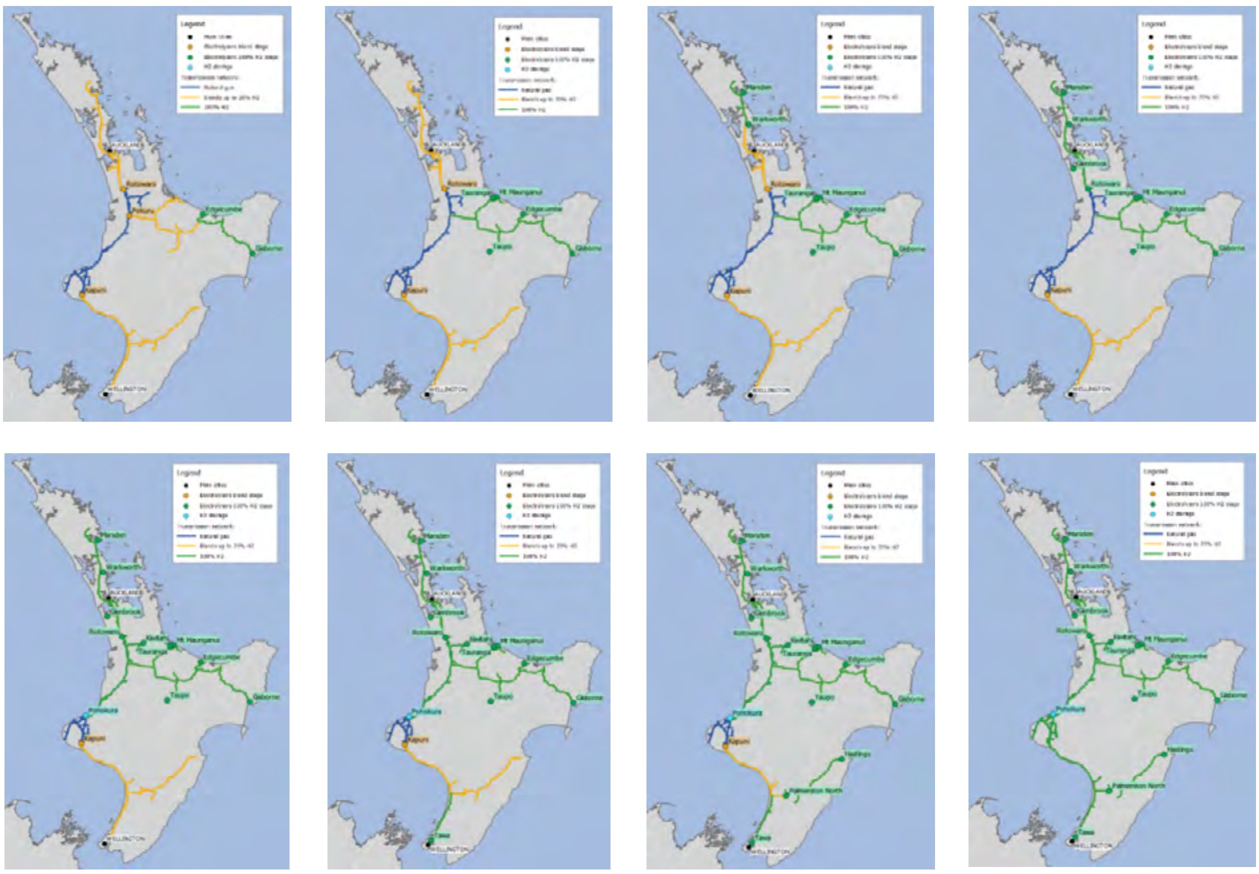


Figure 23: Conversion of the network from 20% blend to 100% hydrogen

Table 5: Relevant New Zealand Gas Regulations and potential areas for change

| LEGISLATION /REGULATION AND OBJECTIVES | REQUIREMENT FOR AMENDMENTS |
|---|---|
| **The Gas Act (1992)** | As the key piece of legislation providing for regulation of the gas industry in New Zealand, the Gas Act will need to be reviewed and potentially amended to ensure it legislates appropriately for the production, transport, supply and use of hydrogen and hydrogen blends.[15] |
| **Gas (Safety and Measurement) Regulations 2010**<br>These Regulations set out responsibilities and obligations for the safe supply of gas | Will require review and potentially amendment to ensure the regulations are applicable to the supply of hydrogen and safety and certification of hydrogen appliances. |
| **Health and Safety at Work Act 2015**<br>This Act covers hazardous activities, workplaces and facilities. | Gas sector-related regulations introduced under the Health and Safety at Work Act or its predecessors will require review and potential amendments to ensure they adequately cover the production, injection, transportation and use of hydrogen and hydrogen blends. |
| **Hazardous Substances and New Organisms Act 1996**<br>This Act covers storage and use of gas containers. | The provisions of this Act would apply to hydrogen, as they do to gas, as a flammable and potentially hazardous substance. The Act will require review and potential amendments to ensure the provisions adequately cover the use of hydrogen and hydrogen blends and remain consistent with the safety requirements of the Gas Act (including any amendments relating to hydrogen production, supply and use). |
| **Gas (Levy of Industry Participants) Regulations 2020**<br>These Regulations allow Gas Industry Co to collect levies from the gas industry to fund its work. GIC costs are met through a combination of levies applied to wholesale and retail participants, and market fees associated with the ongoing administration of specified rules and regulations. | The transition of the gas networks to supply hydrogen may involve new industry participants, not covered by the current regulations. Amendments may be required to ensure the scope of the regulations include all potential participants in the hydrogen supply chain. |
| **Gas (Downstream Reconciliation) Rules 2008**<br>These Rules superseded the Reconciliation Code and provide a set of uniform processes to enable the fair, efficient, and reliable allocation and reconciliation of downstream gas quantities. | The Gas (Downstream Reconciliation) Rules will require review and potential amendments to ensure they adequately account for changes to direction of gas flows in a fully hydrogen or blended gas system. For example, increased injection of gas into the downstream network, gas mixtures in the network (differing CV) and deblending may necessitate changes to procedures for allocation and reconciliation of gas quantities. |

*15 A review of the Gas Act was completed in 2020: https://www.mbie.govt.nz/have-your-say/amending-the-gas-act/*

| LEGISLATION / REGULATION AND OBJECTIVES | REQUIREMENT FOR AMENDMENTS |
|---|---|
| **Gas (Switching Arrangements) Rules 2008**<br>These Rules codified existing arrangements that enable consumers to choose, and alternate efficiently between competing retailers through a centralised Gas Registry that stores key consumer information. | Switching rules may not be affected by changes to the gas supplied. |
| **Gas Governance (Compliance) Regulations 2008**<br>These Regulations establish compliance processes and roles, including the Market Administrator, an Independent Investigator and a Rulings Panel, and allow for rules and regulations to be monitored and enforced to ensure the integrity of markets. | The Gas Governance (Compliance) Regulations will require review and potential amendments to ensure that they remain up-to-date given potential amendments to the rules and regulations that they govern. |
| **Gas Governance (Critical Contingency Management) Regulations 2008**<br>The purpose of these Regulations is to achieve the effective management of critical gas outages and other security of supply contingencies without compromising long-term security of supply. | Review and potential amendments required to ensure gas outages and security of supply contingencies can be effectively managed, given the changes to flows in the network, potential increase in number of producers (including increased supply variability) and injection points and the potential for large-scale hydrogen storage. |
| **Retail Gas Contracts Oversight Scheme**<br>Ensure retailers' supply contracts with small consumers are in the long-term best interests of those consumers. | Requires review to determine whether amendments are required to cover the supply of hydrogen and hydrogen blends. |
| **Gas Distribution Contracts Oversight Scheme**<br>Principles for contract arrangements between gas distributors and retailers, including an assessment regime by independent assessors | Requires review to determine whether amendments are required to cover the supply of hydrogen and hydrogen blends. |

# 06 NEXT STEPS FOR NZ HYDROGEN GAS NETWORK

This section sets out our hydrogen trial roadmap. It is based on a detailed assessment of the global research, development and demonstration (RD&D) landscape by our consultants, which is outlined in the full study report. We reviewed this programme and have developed the focus areas in Figure 24, which match our ambition to move quickly on the hydrogen opportunity for New Zealand.

# 6.1 CONFIRMING NETWORK CHARACTERISTICS

While we know a lot about our networks, we don't know everything about the pipelines, equipment and appliances connected to all of the gas networks in New Zealand. We need to catalogue all the equipment and pipes on the networks to understand:

- The risks associated with introducing hydrogen as a blend or pure hydrogen
- Whether the equipment or pipeline is covered by an RD&D programme overseas
- Whether we need to test the equipment or pipeline in New Zealand
- How we can manage the introduction of hydrogen for customers and other networks.

In preparing the inventory of equipment connected to gas networks in New Zealand, we will draw on the lessons learned from the same exercise recently conducted in Australia through the FFCRC. That work divided user equipment into categories based on international experience operating on blends of hydrogen and natural gas and found that only a small number of equipment types (metallurgical furnaces, glass furnaces, and methane reforming equipment) had no documented hydrogen experience.

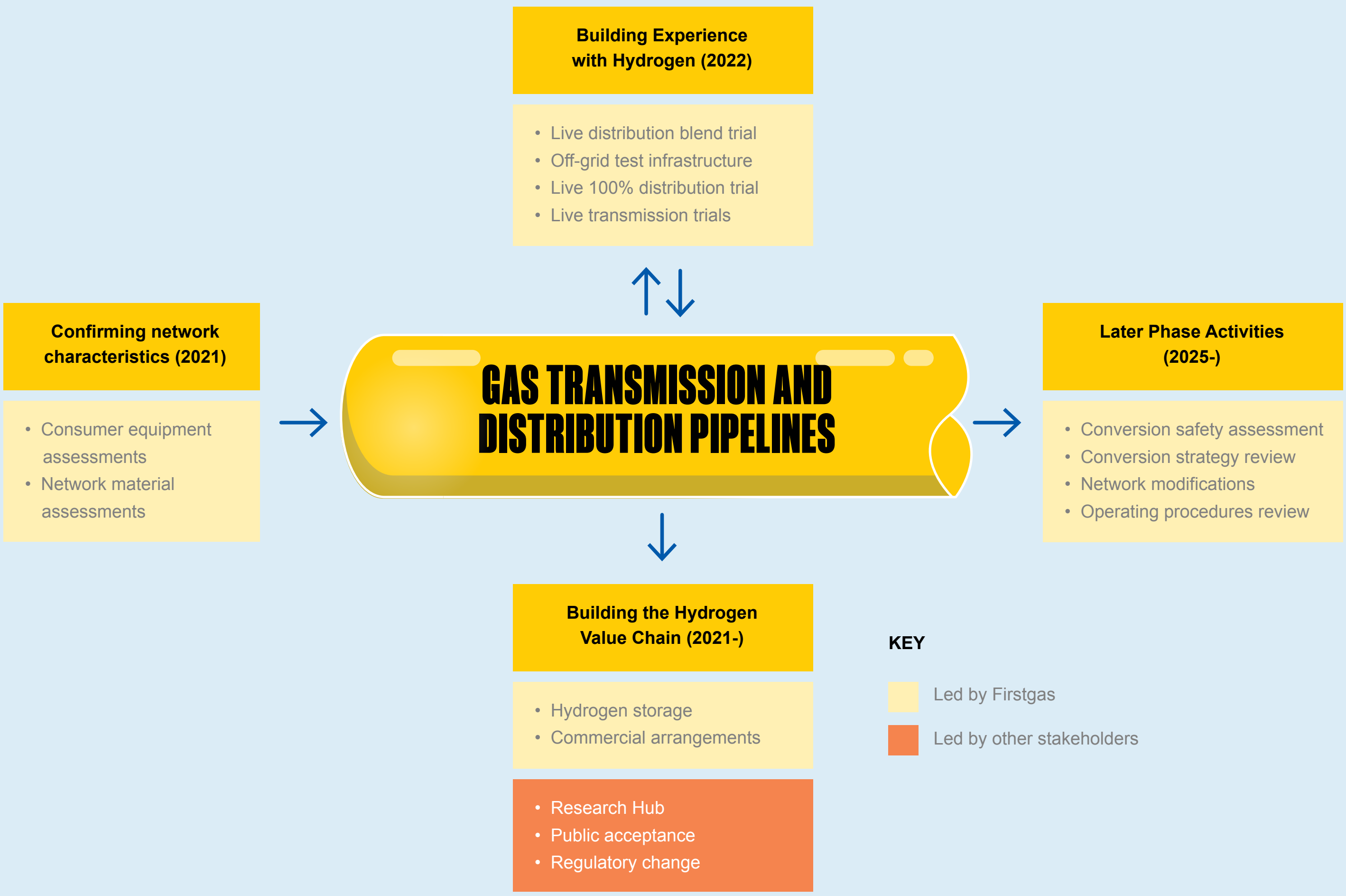



Figure 24: Hydrogen programme focus areas

16 *https://www.futurefuelscrc.com/program_area/compatibility-of-end-user-equipment-with-future-fuels-rp1-4/*

| | POTENTIAL PARTNERS | INFORMED STAKEHOLDERS | TIMING |
|---|---|---|---|
| **PROJECT 1** Consumer equipment assessment | PowerCo<br>Vector<br>GasNet<br>Nova | Retailers<br>Large Users<br>GIC<br>Appliance Manufacturers | Q3/4 2021 |
| **PROJECT 2** Pipeline materials assessment | PowerCo<br>Vector<br>GasNet<br>Nova | Ara Ake<br>Research groups (FFCRC) | Q3/4 2021 |

Firstgas will lead this work but we will need to partner with other network operators. We want to begin straight away to gather information to shape our RD&D programme.

## 6.2 BUILDING EXPERIENCE WITH HYDROGEN

The second focus area for our programme is to build experience dealing with hydrogen on our network. We know from overseas that trials of hydrogen blends on distribution networks can be deployed rapidly. These trials and demonstration projects act to build confidence in hydrogen, build demand for hydrogen and serve as a practical example for regulations and safety assessments. We want to select a distribution network that is blend ready (or nearly blend ready) to start building that experience. We would start with a small amount of hydrogen (1% by volume) and build to 20% by volume over the trial. We aim to kick design off in Q3 2021.

From selecting the network and doing the trial we'll learn a lot about what we need to test in an off-grid setting. This will help us scope and build our off-grid testing infrastructure for the transmission and distribution networks. The other input to our off-grid R&D will be the results of other trials overseas. For transmission pipelines many of these studies will have results in 2023. Consequently, we'll be able to start building the distribution trial infrastructure from 2022 and transmission trial infrastructure from late 2023.

Following a successful live distribution trial and successful off-grid testing of distribution components we'll move to a trial of 100% hydrogen in a distribution network. As this will involve changing out appliances this will take longer and we'll be able to start planning this in 2022.

Our live transmission trials are a longer-term programme as we need to wait for the results of overseas RD&D and our own off-grid testing. We anticipate this would start after 2023.

| | POTENTIAL PARTNERS | INFORMED STAKEHOLDERS | TIMING |
|---|---|---|---|
| **PROJECT 1** Live distribution blend trial | PowerCo<br>Vector<br>GasNet<br>Nova | Connected consumers<br>Worksafe<br>GIC | Q3/4 2021 |
| **PROJECT 2** Off-grid test infrastructure | PowerCo<br>Vector<br>GasNet<br>Nova | Worksafe<br>GIC | 2022+ |
| **PROJECT 3** Live 100% hydrogen distribution trial | PowerCo<br>Vector<br>GasNet<br>Nova | Worksafe<br>GIC | 2022+ |
| **PROJECT 4** Live transmission trials | PowerCo<br>Vector<br>GasNet<br>Nova | Worksafe<br>GIC | 2023+ |

## 6.3 BUILDING THE HYDROGEN VALUE CHAIN

Alongside projects on our network, there is significant work to do to support the development of a hydrogen economy. Some of the initiatives in this space can be progressed by Firstgas, while other stakeholders will need to take the lead on others.

Through our work we've discovered that storage is critical for leveraging the benefits of hydrogen in our energy system. Different types of storage suit different applications – large scale geological storage can help with inter-seasonal variations in the supply/demand balance, while pipelines, tanks and bottles can assist with shorter term fluctuations. We intend to undertake a scoping study that defines which technologies are right for which applications and what the barriers are to adopting these technologies. We think this will be helpful for researchers in identifying future research that will move forward hydrogen in New Zealand. We plan to undertake this study in Q2/3 2021.

We also think there is a gap in our thinking around commercial arrangements for transporting and using hydrogen and hydrogen blends in our network. For example, if we have a blend of hydrogen and natural gas in our network produced by two different parties and consumed by a single consumer, we need to be able to measure and bill that consumption given the different costs of the two products. We will undertake an initial study to scope this issue and set out a programme of work for consultation with industry to see who is best to lead this work in the future. We will undertake this work in Q2/3 2021.

Alongside our programme of work we have identified the following projects that would assist in developing the hydrogen economy in New Zealand.

- **Research Hub** –We think that providing high quality, open-access analysis of the application global RD&D to New Zealand is a priority. We think it should be hosted outside Firstgas to maximise access to information.
- **Public acceptance** –Firstgas will naturally engage with stakeholders where there is a direct change to gas supply, but we think others are best placed to provide impartial information to the public of the potential changes to their energy system. We think government agencies are best placed to undertake this.
- **Regulatory change** – We undertook a high-level review in this study to identify gaps. However, a full review, led by regulators will be required to assess and agree changes to legislation and regulation. This work should be prioritised as we will need to understand the likely regulatory landscape as we develop our testing regime and prior to establishing our conversion strategy and safety assessment.

| | POTENTIAL PARTNERS | INFORMED STAKEHOLDERS | TIMING |
|---|---|---|---|
| **PROJECT 1** Hydrogen storage | PowerCo<br>Vector<br>GasNet<br>Nova | Worksafe<br>GIC | Q2/3 2021 |
| **PROJECT 2** Commercial arrangements | – | Gas users and shippers<br>GIC | Q2/3 2021 |

# 6.4 LATER PHASE ACTIVITIES

In the previous sections we've outlined the activities that we will start straight away. Our study also identified a number of other activities that will need to happen prior to network conversion. We anticipate that these will commence from 2025 and their shape and timing will depend on the findings of our work and industry developments between now and then.

- **Conversion safety assessment** – Firstgas will need to lead the development of the end-to-end risk assessment for the network to prepare for hydrogen conversion. This work will need to be informed by early work on regulatory change, our trial results and the consumer equipment assessment work.
- **Network capacity assessment** – we will need to revise our capacity assessment prior the final conversion strategy to ensure we have the right capacity as the development of the hydrogen economy differs from the scenarios modelled in the study.
- **Conversion strategy** – This work will require engagement with stakeholders and will need to consider the consumer equipment assessment work and the results of trial activities.
- **Network modifications** – Firstgas will be able to scope the required network modifications once we have undertaken trials, end user assessments and understand the conversion strategy.
- **Operating procedures** – Firstgas will need to develop revised operating procedures for the network once network modifications and a conversion strategy have been defined.

It's important to note that the conversion safety assessment is the final safety assessment prior to progressing with conversion of the network. Naturally, we'll be undertaking safety assessments as part of live trial and testing work in consultation with our regulators. This will help inform the conversion safety assessment and build absolute confidence in the approach.

# 07 APPENDIX

# UNIT CONVERSIONS

| Useful conversions |
|---|
| 1 PJ = 277.8 GWh |
| 1 PJ = 8.33 kt $H_2$ |
| 1 TWh = 3.6 PJ |
| 1 TWh = 30.03 kt $H_2$ |
| 1 kg $H_2$ = 120 MJ (LHV) |
| 1 kg $H_2$ = 33.33 kWh (LHV) |

| Orders of magnitude |
|---|
| peta (P) = $10^{15}$ |
| tera (T) = $10^{12}$ |
| giga (G) = $10^{9}$ |
| mega (M) = $10^{6}$ |
| kilo (k) = $10^{3}$ |

Note : All prices included in this document are expressed in real NZ$ prices for the year 2020.

# GLOSSARY

| | |
|---|---|
| **AGPA** | Australian Pipelines and Gas Association |
| **CCGT** | Combined-Cycle Gas Turbine |
| **Capex** | Capital Expenditure - The expenditure used to create new or upgrade existing physical assets in the network, as well as Non network assets, e.g. IT or facilities |
| **CCS** | Carbon Capture and Storage |
| **DRS** | District Regulator Stations |
| **FC** | Fuel Cell |
| **FCEV** | Fuel Cell Electric Vehicle |
| **FFCRC** | Future Fuels Cooperative Research Centre |
| **GIC** | Gas Industry Company – New Zealand's gas industry co-regulatory body |
| **GJ** | Gigajoule (unit of energy). $10^9$ Joules = 1,000 MJ |
| **GW** | Gigawatt (unit of power). $10^9$ watts = 1,000 MW |
| **GWh** | Gigawatt hour (unit of energy). $10^9$ watt hours = 1,000 MWh |
| **IECEx** | International Electrotechnical Commission System for Certification to Standards Relating to Equipment for Use in Explosive Atmospheres |
| **kg** | Kilogram |
| **kt** | Kilotonne |
| **LHV** | Lower Heating Value |
| **MAOP** | Maximum Allowable Operating Pressure |
| **MBIE** | Ministry of Business, Innovation and Employment |
| **MJ** | Megajoule (unit of energy). $10^6$ Joules = 1,000,000 J |
| **MW** | Megawatt (unit of power). $10^6$ watts = 1,000,000 W |
| **MWh** | Megawatt hour (unit of energy). $10^6$ watt hours = 1,000,000 Wh |
| **Opex** | Operational Expenditure – Ongoing costs directly associated with running the gas transmission system. This includes costs both directly related to the network (e.g. routine and corrective maintenance, service interruptions/incidents, land management) |
| **PE** | Polyethylene |
| **PEM** | Polymer Electrolyte Membrane |
| **PJ** | Petajoule (unit of energy). $10^{15}$ Joules = 1,000 TJ |
| **RD&D** | Research, Development and Demonstration |
| **SMR** | Steam Methane Reforming |
| **SOI** | Statement of Intent |
| **TJ** | Terajoule (unit of energy) = $10^{12}$ Joules |
| **TWh** | Terawatt hour (unit of energy). $10^{12}$ watt hours = 1,000 GWh |
| **WiTMH** | Whakamana i Te Mauri Hiko |
| **yr** | Year |

Firstgas Group

# THANK YOU

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