GAS INFRASTRUCTURE FUTURES IN A NET ZERO NEW ZEALAND

REPORT PREPARED FOR FIRST GAS AND POWERCO

DECEMBER 2018

:vivideconomics › Firstgas POWERCO

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COMPANY PROFILE

Vivid Economics is a leading strategic economics consultancy with global reach. We strive to create lasting value for our clients, both in government and the private sector, and for society at large.

We are a premier consultant in the policy-commerce interface and resource- and environment-intensive sectors, where we advise on the most critical and complex policy and commercial questions facing clients around the world. The success we bring to our clients reflects a strong partnership culture, solid foundation of skills and analytical assets, and close cooperation with a large network of contacts across key organisations.

CONTACT US

Vivid Economics Limited, 163 Eversholt Street, London NW1 1BU, United Kingdom

+44 (0)844 8000 254 • enquiries@videconomics.com

EXECUTIVE SUMMARY

Executive summary

The climate change policy landscape in New Zealand is rapidly changing.

In October 2017, one day after forming government, Prime Minister Jacinda Ardern committed to making climate change a top priority, introducing a zero carbon act and setting a net zero target by 2050. In the same month, the Government announced plans to raise the renewables target to 100% of electricity generation by 2035. In June 2018, National Party Leader Simon Bridges pledged support for a cross-party climate commission. The Zero Carbon Bill, out for consultation at the time of writing, is expected to be legislated mid-2019.

These changes have implications for natural gas and gas infrastructure. Currently, New Zealand's 185 PJ of gas consumption is split roughly evenly across electricity, industry and in the manufacture of products to be exported. A small but growing amount of gas is also used for household and commercial heating.

New climate change commitments from government are likely to continue to see less gas, and more renewables, used in electricity. In other sectors that use coal, there may be a switch towards gas.

The future for gas is therefore uncertain, but these uncertainties are important to understand. Given the vital role that gas and its infrastructure play in the New Zealand economy (providing around 20% of New Zealand's primary energy supply), it is crucial to understand the options for gas in the changing policy environment. Our approach to uncertainty involves the analysis of scenarios which describe internally consistent pictures of the future. The similarities and differences between scenarios help identify strategies, trade-offs and possible perverse outcomes.

Owing to this uncertainty, there is value in keeping options on the table, particularly for 'hard-to-treat' sectors. In some areas of the economy, it is likely that options exist to reduce emissions – such as

passenger vehicles, where electric vehicles are almost certainly the low-cost path. In these areas, it is possible for New Zealand to commit to a strategy now, and for customers to invest, and government and business to guide decisions towards the necessary infrastructure development. However, in other areas ('hard-to-treat' sectors), the preferred approach is far from clear. In these areas, there is value in preserving the opportunity to deploy different solutions as understanding and technology evolves. These parts of the economy may require new technologies or offsetting actions (e.g. forestry) to achieve net zero emissions.

To explore these possibilities, we design three net zero scenarios that span the range of plausible outcomes. In all scenarios, the consumption of gas falls, by between 40% and 100% in 2050 depending on the scenario. Scenarios differ in two ways (reflecting the two key uncertainties):

- The extent to which it is possible to offset emissions; and
- The extent to which it is possible to decarbonise the gas flowing within the pipeline infrastructure.

"In some areas of the economy, it is likely that options exist to reduce emissions – such as passenger vehicles, where electric vehicles are almost certainly the low-cost path"

In our central scenario, *Diversified Mix*, natural gas use reduces substantially, but the pipeline infrastructure continues to play a vital role in meeting energy needs. Gas is directed towards the three parts of the energy system where it is difficult to substitute with renewables (hard-to-treat sectors): electricity peaks, industrial heat, and the production of industrial products, largely for export. The remaining emissions are offset through forests, which are around 0.5 Mha larger than the other scenarios.

Our other two scenarios assume that the use of forestry becomes challenging and as a result the energy system has to decarbonise fully in order to meet the net zero 2050 target:

- Rather than using gas, *All-Electric* considers a substantial overbuild of renewable generation to meet electricity demand peaks. This comes at a high cost and there are inefficiencies in the use of infrastructure (i.e. renewable generation assets are underutilised and all existing gas pipelines are decommissioned).
- In contrast, *Green Gas* seeks to maximise the use of gas infrastructure through the production of renewable hydrogen – an energy carrier that can be stored, and therefore can be used to address the hard-to-treat sectors. Hydrogen production is also high cost, as there are substantial inefficiencies associated with using electricity to generate hydrogen.

Use of gas and gas infrastructure differs significantly between scenarios. In the Diversified Mix scenario, gas use decreases from 185 PJ in 2015 to 107 PJ in 2050. In the Green Gas scenario, the use of gas could increase to around 220 PJ as green gas replaces both current use of natural gas, and current use of coal. In the All-Electric scenario, natural gas use is phased out as it is displaced with electricity. Gas consumption and utilisation of gas infrastructure in the three scenarios are described in Table 1.

Affordability differs between scenarios, and a decision now to completely decarbonise using electricity would risk unnecessary costs. The total annual cost of meeting the net zero target could be around \$3.8–4.6 billion, equivalent to 0.9–1.0% of national income if forestry is used to offset residual gas emissions (expressed differently, the annual cost could be around \$1,700 per household, with incomes projected to rise around 35% over this period). However, this cost could rise to \$6.2–7.2 billion, equivalent to around 1.4–1.6% of national income (or around \$2,700 per household), if hydrogen or electrification is needed to address hard-to-treat sectors.

Furthermore, the cost of the electrification approach could be higher than using hydrogen to achieve net zero emissions; if innovation in hydrogen technologies outpaces innovation in electrification technologies, then ruling out this option could reduce the affordability of meeting the net zero target.

A shift to hydrogen could also offer additional advantages over electrification. First, it could offer opportunities for New Zealand to produce hydrogen for export, and potentially provide a source of revenue to Government. Second, the development of a hydrogen export sector could also offer solutions to address New Zealand's unique dry year problem, with surplus hydrogen exported during normal years and used domestically to generate electricity during dry years.

It is therefore a policy and commercial priority to carry out further investigation into the costs and technical potential of forestry, hydrogen and electrification options in New Zealand. Greater certainty over the relative potential for hydrogen and electrification to address GHG emissions in hard-to-treat sectors is needed before long-term decisions can be made on the role of gas infrastructure in meeting the net zero emissions target. Further research over the short- to medium-term should include:

- A comprehensive study on the impacts of large-scale afforestation in New Zealand. This should consider economic, environmental, and social impacts, and examine the risks of 'tipping points' where small additional increases in afforestation might create large impacts on economies, ecosystems and communities.

"The development of a hydrogen export sector could also offer solutions to address New Zealand's unique dry year problem, with surplus hydrogen exported during normal years and used domestically to generate electricity during dry years"

- A techno-economic assessment of the potential for hydrogen and electrification options in New Zealand. This should cover the main hydrogen and electrification options to address winter peaking in electricity generation, intermediate- and high-temperature industrial heat, and hard-to-treat residential and commercial heat. It should also consider New Zealand's specific circumstances, particularly with respect to its intermediate and high-temperature heat needs across industrial sectors. Subsequently, or in parallel, hydrogen blending trials such as those carried out in Australia and the UK can strengthen the evidence base for the technical and economic feasibility of wider deployment.
- A feasibility assessment of carbon capture and storage (CCS) in New Zealand. A full feasibility assessment of CCS in New Zealand. This should cover the environmental and economic aspects, including the availability of suitable storage sites, operational safety and long-term integrity of CO_2 storage, the risks arising from New Zealand's high levels of tectonic activity, and the costs of developing a transport and storage infrastructure for CO_2.

The situation will continue to change. Given the evolving and detailed nature of this work, it was vital to engage across government, business and the public. We thank stakeholders for their contributions and look forward to continued discussions in the fast-moving net zero New Zealand debate.

Figure 1: Affordability differs significantly between scenarios

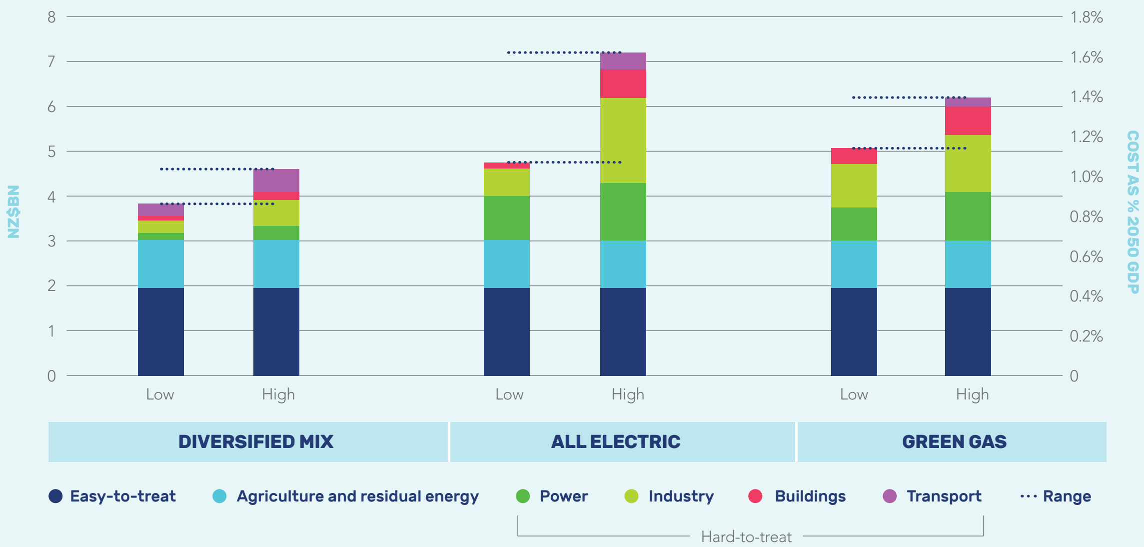


Table 1: Overall gas use and pipeline throughput in the Diversified Mix, Green Gas and All-Electric scenarios

		DIVERSIFIED MIX	ALL-ELECTRIC	GREEN GAS
	2015*	**2050**		
Gas use by sector (PJ)				
Electricity generation	56	35	0	38
Chemicals	84	57	0	0–104
Other industry	29	7	0	40
Commercial	9	5	0	9
Residential	7	4	0	7
Transport	0	0	0	21
Total	**185**	**107**	**0**	**115–220**
Pipeline throughput by network (PJ)**				
Transmission network	163	95	0	111–203***
Distribution networks	34	12	0	63

Note: *While data for gas use by sector is available for 2017, its sector disaggregation differs from that used in the Productivity Commission modelling which underpins this analysis. ** Pipeline throughput is smaller than total gas use as around 11% of gas does not pass through the transmission network. Pipeline throughput is not additive; all gas passes through the transmission network; and of this, a smaller share passes through distribution networks. *** Transmission network throughput in the Green Gas scenario depends on whether methanol and fertiliser production are phased out or retained to 2050.

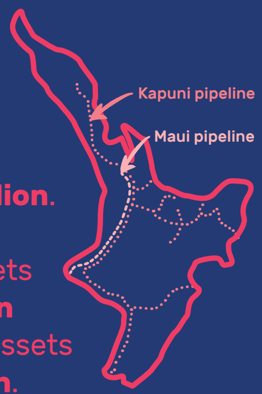
NATURAL GAS FACTS

$12 BILLION
VALUE OF RESERVES

New Zealand has 15 producing fields containing **2,100 PJ** of reserves, concentrated around Taranaki. At current gas prices, these reserves are worth **$12 billion**.

$1.7 BILLION
IN TRANSMISSION AND DISTRIBUTION ASSETS

Natural gas transmission and distribution infrastructure is valued at **$1.7 billion**. This includes transmission assets worth **$0.8 billion** and distribution assets worth **$0.9 billion**.

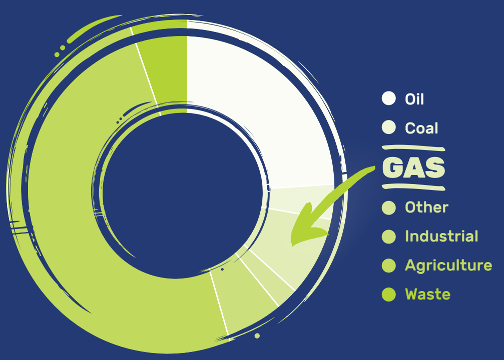


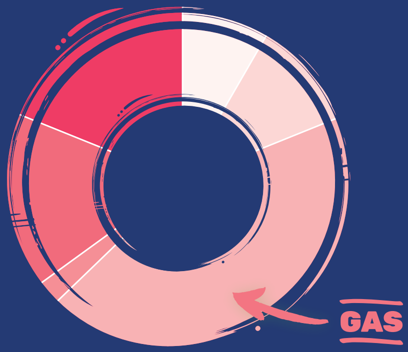
$2.1 BILLION
PER YEAR

Natural gas directly supports **$2.1 billion** of economic activity per year, including the natural gas industry (**$1.3 billion**) and the chemical industry (**$0.8 million**). It also provides fuel to other major industries, primarily the dairy industry.

9% OF GHG EMISSIONS

Around **9%** of New Zealand's total greenhouse gas emissions were from natural gas in 2016.





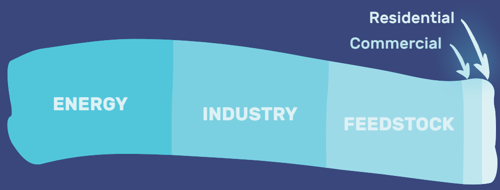
44% OF INDUSTRIAL ENERGY USE

Although natural gas provides **22%** of New Zealand's energy needs, it is an important industrial fuel, meeting **nearly half** of the New Zealand industry sector's energy needs.

Coal · Oil · Geothermal · Other renewables · Electricity

280,900 HOUSEHOLDS AND BUSINESSES

New Zealand's five distribution companies transport natural gas to **280,900** industrial, commercial and residential customers throughout the North Island, and add about **4,000** new customers per year.



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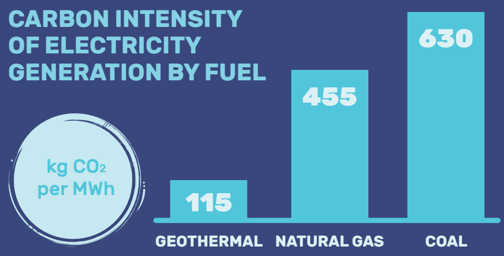
Around **a third** of natural gas is used in electricity generation, **a third** to produce heat for industrial processes, and **a third** as a feedstock for production of methanol and fertiliser. A small amount (**7%**) of natural gas is used to provide space and water heating in commercial and residential buildings.

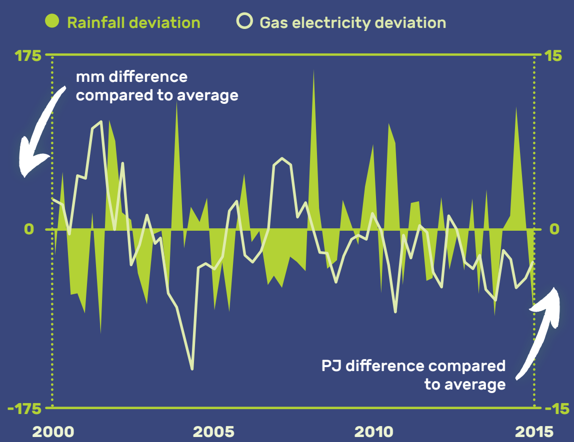
30% LOWER CARBON EMISSIONS THAN COAL GENERATION

Natural gas electricity generation emits 30% less carbon than coal generation, for the same amount of energy.



COMPLEMENTS HYDRO

Natural gas plays an important role in meeting electricity demand when output from hydro plants is low due to low rainfall. When hydro plants output is high, natural gas use is low.



STRUCTURE OF THIS REPORT

This report is structured in five sections:

- **Section 1: Background and technologies** sets out the aims of this study, describes New Zealand's climate change policy context, and provides an overview of the main technology pathways to achieving a net zero emissions target.
- **Section 2: Approach** describes the approach taken in this study, covering the underlying assumptions, the concept of optionality, use of scenario analysis and the approach to estimating the broad costs of the main technology pathways. Section 2 also describes the three scenarios (Diversified Mix, Green Gas and All-Electric) that represent different approaches to meeting the net zero target under key uncertainties.
- **Section 3: The future of gas and its infrastructure** describes the implications of the Diversified Mix, Green Gas and All-Electric scenarios, and the implications of these pathways for the quantity and type of gas used, and the utilisation of gas infrastructure.
- **Section 4: Preliminary cost assessment** describes the potential costs of different approaches to achieving a net zero target.
- **Section 5: Conclusions** summarises the key insights emerging from this study, and details priorities for future research.
- **Annex 1: Hydrogen technology and cost assumptions** sets out the assumptions underpinning the cost and energy system modelling of hydrogen production and end use in the Green Gas scenario.

1

BACKGROUND AND TECHNOLOGIES

1. Background and technologies

1.1 BACKGROUND

New Zealand is currently developing ambitious climate change policy aimed at achieving a significant reduction in greenhouse gas emissions (GHG). Important elements of New Zealand's new approach to climate policy are the introduction of a Zero Carbon Bill, the establishment of an independent Climate Change Commission, and a target to move to 100 percent renewable electricity generation by 2035.

New Zealand is preparing to introduce a Zero Carbon Act, to set strong, legally-binding carbon reduction targets. The Act will set a new 2050 greenhouse gas emissions reduction target in law. It has not yet been determined which greenhouse gases the net zero target will apply to, but options include carbon dioxide only; net zero emissions of long-lived gases (carbon dioxide and nitrous oxide) and stabilised short-lived gases (for example, Methane, Chlorofluorocarbons and Hydrofluorocarbons); or net zero emissions of both long-lived and short-lived gases. The Government recently completed its formal consultation on the approach to the Zero Carbon Bill, including the full range of options for the 2050 emissions reduction target, and intends to pass the Zero Carbon Bill in mid-2019.

The Zero Carbon Act will also establish an independent Climate Change Commission. The role of the Climate Change Commission will be to keep future Governments on track to meeting the long-term emissions reduction commitments, and to provide independent advice on key issues relating to the New Zealand's climate targets. The Government's 100 Day Plan for Climate Change signalled that such issues will include the status of agriculture within the NZ ETS, and on New Zealand's transition to generate 100 percent of its electricity from renewable sources. An Interim Climate Change Committee has been established as a precursor to the Commission, to prepare evidence and analysis prior to the Commission's formation.

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The Government is also planning to set a target to move to 100 percent renewable electricity by 2035

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The Government is planning to set a target to move to 100 percent renewable electricity by 2035. In 2016, 85% of electricity was generated from renewables. The 100 percent target refers to a normal hydrological year (i.e. there remains scope for non-renewable electricity to address electricity shortages during dry years). The Interim Climate Change Committee has been asked to plan the transition to meet this target.

In April 2018 , the Government announced its intention not to issue new offshore oil and gas exploration permits. There is a degree of uncertainty over the overall impact of this suspension; the future role of fossil fuels in New Zealand will depend on the rate at which current reserves are depleted, and the volume of reserves that may be discovered under the 22 current offshore oil and gas exploration permits (some of which are valid until 2030). At the time of writing, the Crown Minerals (Petroleum) Amendment Bill to implement the Government announcement passed its third reading in Parliament.

These new initiatives complement New Zealand's existing climate change policy. The New Zealand Emissions Trading Scheme (NZ ETS), introduced in 2008, is New Zealand's principal climate policy instrument. The NZ ETS currently imposes a limit on total greenhouse gas emissions from key emitting sectors (including the energy, fishing, forestry, industrial, and transport fuels synthetic gases and waste sectors), and requires firms in these sectors to surrender tradable emissions permits for every unit of greenhouse gases emitted, measured in tonnes of CO_2 equivalent. The scheme covers CO_2, CH_4, N2O, SF_6, PFCs and HFCs. Agriculture is the only sector exempted from having to surrender units for their emissions. In addition to the NZ ETS, there are policies in place to encourage afforestation (the Afforestation Grant Scheme), and insulation (Warm Up New Zealand: Healthy Homes Programme), though reducing greenhouse gas emission is not their primary aim.

1.2 AIMS OF PROJECT

New Zealand's climate change policy will have major implications for the use of natural gas. Natural gas (methane) is one of the major fossil fuels used in New Zealand. Therefore, climate change policy developments will have important implications for the use of natural gas, and the transmission and distribution infrastructure that supplies it from gas fields to end-users.

Natural gas use is currently used primarily in electricity generation, industrial heat and as feedstocks in the chemicals sector. Of the 185PJ of total natural gas demand in 2015, around one third (56 PJ) was used in electricity generation; another third (63 PJ) was used to generate heat for industrial processes, and the final third (50 PJ) used as a feedstock in the chemicals sector. Under ten percent (16 PJ) of natural gas was used for space and water heating, and for cooking in the residential and commercial sectors.

Several factors could affect the future role of natural gas. First, as a fossil fuel, its overall use may be constrained to achieve net zero emissions. Second, natural gas has lower carbon content than other fossil fuels such as coal or oil, and there may be scope to switch from these fuels as part of an overall path to lower GHG emissions. Third, it may be possible to continue to use natural gas in key areas, if its emissions can be offset, for example through increased levels of forestry. Fourth, natural gas could be blended with low-carbon gases such as hydrogen or biogas, reducing the carbon content of gas use.

Even if natural gas is phased out, there may be a role for natural gas infrastructure. Natural gas networks offer the opportunity to transport hydrogen or biogas. If natural gas is phased out due to its carbon content, it is possible that hydrogen or biogas could fulfil similar roles under a net zero emissions target.

In this context, First Gas and Powerco have commissioned Vivid Economics to explore the role that natural gas, and gas pipeline infrastructure, can play in a low-emissions economy in New Zealand. This study seeks to contribute to the policy debate about New Zealand's transition to a net zero emissions economy. To this end, this study:

- Provides a clear picture of the current role and contribution that gas pipeline infrastructure (both transmission and distribution) plays within New Zealand's energy system and economy;
- Identifies possible future scenarios for New Zealand's economy and energy sector to lower carbon emissions, ultimately reaching net zero emissions by 2050;
- Explores the role of gas pipeline infrastructure in each of these scenarios;
- Identifies the key uncertainties which will determine the appropriate role for natural gas and its infrastructure; and
- Makes recommendations for near-term decision-making and future work, given these uncertainties.

1.3 MEETING NET ZERO IN NEW ZEALAND: THE EVIDENCE BASE

To date, several studies have considered the pathways and economic impacts of reducing New Zealand's GHG emissions by 2050. A number of these studies are summarised below.

Globe-NZ applied scenario analysis across the New Zealand economy to help illuminate long-term low-emission pathways for New Zealand. Key findings of the Globe-NZ report, *Net Zero New Zealand* (Vivid Economics, 2017) are:

- Any pathway to reducing the country's domestic emissions will involve substantial change to patterns of energy supply and use, including moving towards a 100 percent renewable electricity grid and substantial electrification of the passenger vehicle fleet and low-grade heat.
- It is possible for New Zealand to move onto a pathway consistent with domestic net zero emissions in the second half of the century, but only if it alters its land-use patterns.
- If New Zealand does seek to move its domestic economy onto a net-zero consistent trajectory, there is a choice between the extent to which it is able to make use of new technologies and the extent to which it needs to embark upon substantial afforestation. With some constraints, there will be an opportunity to flexibly adjust the rate of afforestation as the pace of new technological development and deployment becomes clearer.
- If it chooses to substantially afforest and it is fortunate enough to benefit from the extensive availability of new technologies, it could be possible for the country to achieve domestic net zero emissions by 2050.
- Although afforestation will likely be an important element of any strategy to move to a net zero emissions trajectory in the period to 2050, in the second half of the century alternative strategies will be needed.

The New Zealand Productivity Commission identified options for how New Zealand can reduce its domestic greenhouse gas emissions through a transition to a low-emissions economy. In its report on transitioning to a low-emissions economy, the Productivity Commission concluded:

- New Zealand is likely to be able to move towards net zero GHG emissions at emissions prices comparable to those expected to be needed in other developed countries, to achieve the Paris Agreement ambition of keeping global temperature rise to below 2˚C.

- Opportunities to reduce GHG emissions come mainly from the forestry, agriculture and transport sectors, with particular dependence on forestry sequestration in the case of a net-zero GHG emissions target for 2050. New Zealand's decarbonisation strategy should therefore focus on these opportunities.
- While afforestation provides plenty of scope for reducing emissions cost-effectively in the short term and medium term, it is unlikely to continue to do so in the longer term given limited land availability. In the longer term, New Zealand will need to make additional cuts in gross emissions, which will be costly in the absence of technological breakthroughs.

Transpower's *Te Mauri Hiko – Energy Futures* report explored a range of electricity supply, demand and future technology scenarios. Transpower is New Zealand's electricity transmission system operator. In this report, Transpower concluded:

- Electrification is a key route to reducing emissions in New Zealand, particularly stationary industrial energy and New Zealand's light and heavy transport fleets. Transpower project that electric vehicles will reach 85 percent market share by 2050.
- Electrification will cause electricity demand to more than double from around 40 terawatt hours (TWh) per year today to around 90 TWh by 2050. This will require significant and frequent investment in New Zealand's electricity generation portfolio. It will also require sustained investment in the national grid to connect new generators, and in distribution networks to accommodate larger peak loads, distributed generation and new technologies such as electric vehicles and batteries.
- New Zealand can generate a large share of its electricity from renewables given its abundant renewable energy resources. The technology mix could include grid-connected generation (primarily wind and hydro), plus a range of distributed technologies (primarily solar and batteries).
- However, addressing winter and dry year peak demand create a large unresolved challenge, given the exacerbation of peaks caused by large volumes of intermittent energy sources and the large capacity and low utilisation of any storage options needed to meet winter and dry year peak demand. While Transpower describe a number of possible solutions, including building new hydro capacity, over-building renewables or interconnection to Australia, none of these has yet emerged as a feasible, cost-effective solution.

1.4 STRATEGIES TO REDUCE GREENHOUSE GAS EMISSIONS

Taken together, work carried out to date on pathways to reducing New Zealand's GHG emissions broadly indicate a sensible strategy to meet a net zero target. Elements of this strategy include:

- Substantial electrification of end-use sectors, with particular opportunities in the passenger vehicle fleet and low-grade heat.
- An expansion of renewable energy to reduce greenhouse gas emissions from electricity generation, and to meet the new demands from electrification of end-use sectors.
- A large-scale afforestation programme to offset emissions where it is difficult to reduce these directly. These emissions include those from agriculture and certain parts of the energy system.

> **"Any pathway to reducing the country's domestic emissions will involve substantial change to patterns of energy supply and use"**

Overall, work carried out to date suggests that electrification is a cornerstone of any strategy to meet the net zero target. However, hydrogen could prove to be an alternative to electrification in some parts of the energy system. While the studies referenced above do not develop detailed scenarios for hydrogen use, they acknowledge the potential role of hydrogen technologies in meeting the net zero target. Electrification and hydrogen represent two distinct but complementary approaches to delivering deep reductions in greenhouse gas emissions from energy use. Sections 1.4.1 and 1.4.2 describe these approaches.

1.4.1 Electrification

Electrification refers to a shift from technologies that use fossil fuels for energy (such as petrol and diesel vehicles, or coal/gas heating systems) to technologies that use electricity (such as electric vehicles, or heat pumps). Electrification is an important strategy globally to meet national climate targets for two reasons:

1. Electric technologies are generally more efficient than fossil technologies. For example, electric vehicles and heat pumps are around three times more energy efficient than fossil alternatives. Therefore, if it is possible to produce electricity at low cost, electric technologies offer advantages over their fossil equivalents.
2. In many countries, emissions from electricity generation can generally be reduced to very low levels at moderate cost, through deployment of low-carbon generation technologies such as renewables, and supported with battery storage and demand response.

> **An alternative to electrification is the use of hydrogen in electricity, transport, buildings and industry**

A range of electric technologies are at or close to technological maturity. These include electric passenger vehicles and heat pumps for low-temperature heat.

- Electric passenger vehicles are one of the most promising mitigation options in the transport sector. Electric vehicles are expected to approach price parity with internal combustion engine (ICE) vehicles over the next decade as battery costs continue to reduce rapidly. It is theoretically possible to replace most of the passenger fleet with electric vehicles before 2050 without any early scrappage of vehicles, given the average lifetime of cars and vans in New Zealand is around 14 years, and assuming that almost all new vehicles purchased are electric when they reach price parity in the 2020s.
- Electric heat technologies are a cost-effective way to reduce emissions from space and water heating. Electric heat technologies include highly efficient heat pumps or direct electric heating. Heat pumps are supported by programmes such as the EECA's Warm Up New Zealand programme, with installation rates of between 90,000 and 120,000 per annum in recent years. In addition to providing space heat, heat pumps are also suitable for providing low- and some intermediate-grade industrial heat. Direct electric heaters are less efficient than heat pumps, and are better suited to buildings which are already well insulated.

Other electric technologies require further innovation or product development. These include a range of technologies for high temperature industrial heat. High-temperature heat pumps currently have an operational range of 80–150°C; while this is improving, the potential to cover high-grade heat processes is uncertain. The evidence on other technologies (hydrogen, resistive heating, induction heating and plasma torches) is currently poor, and costs are expected to be high.

Electric technologies do not appear suited to heavy goods vehicles (HGV). Electric heavy goods vehicles are not considered feasible due to their long travel distances, and the high cost and weight of batteries large enough to meet their driving range requirements.

1.4.2 Hydrogen

An alternative to electrification is the use of hydrogen in electricity, transport, buildings and industry. Like fossil fuels, hydrogen can be burned directly (for example, in specially designed power stations, boilers or internal combustion engines); or can be converted to electricity in a fuel cell (Energy Transitions Commission, 2018). The main advantage of hydrogen is that it can be stored much more easily than electricity. This makes it suitable for applications in which a large amount of energy is needed relatively infrequently, or in technologies that are not connected to the electricity system. These applications include peaking electricity generation, and space heat (where demand varies by season and time of day); heavy goods vehicles (where electricity storage is very costly due to long travel distances). Potential applications of hydrogen technologies include:

- In electricity generation, surplus electricity generated in times of high renewables output and low demand could be converted to hydrogen for storage, and used to generate electricity at times of high demand and low renewables output.

- In industry, hydrogen can be burned to generate heat for a furnace or boiler, as an alternative to natural gas. Hydrogen could also be used in place of coking coal as a reduction agent in iron production.
- In residential and commercial heating, hydrogen can be transported through converted gas networks and used as an alternative to natural gas in specially designed boilers, or blended with natural gas to reduce emissions with existing appliances.
- In heavy goods vehicles, hydrogen could offer a low-carbon alternative to diesel. Hydrogen can in principle be stored in a fuel tank, and used as fuel in a specially designed internal combustion engine, or converted to electricity in a fuel cell to power an electric motor.

Hydrogen can be produced through steam methane reforming or electrolysis. Steam methane reforming is the use of a chemical catalyst at high temperature to react natural gas with water, to produce hydrogen and carbon dioxide. Carbon capture and storage (CCS) is needed for steam methane reforming to be a low carbon process. In contrast, electrolysis uses an electrical current to separate water into hydrogen and oxygen.

Due to these advantages, hydrogen has received strong interest internationally, and a number of research programmes are in place. These are described in Box 1.1.

There could be good prospects for the use of hydrogen in New Zealand. First, New Zealand's share of low carbon electricity sources is among the highest in the world, and its potential for further development of renewables is very strong due to its excellent wind resource. This presents a good opportunity to produce low-carbon hydrogen through electrolysis. Second, Hydrogen is already produced in New Zealand, and efforts to scale up hydrogen production are already underway. Earlier this year, the Government announced a Provincial Growth Fund investment to help develop hydrogen fuel infrastructure in Taranaki.

Increasing use of hydrogen internationally could offer opportunities for New Zealand to produce hydrogen for export. With sufficient innovation in hydrogen technologies, a global market in hydrogen may emerge. As the costs and potential scale of hydrogen production is likely to differ between countries, a global market could offer opportunities for New Zealand to produce hydrogen for export as well as domestic use, and potentially provide a source of revenue to Government. The development of a hydrogen export sector could also offer solutions to address New Zealand's unique dry year problem, with surplus hydrogen exported during normal years and used domestically to generate electricity during dry years.

BOX 1.1 INTERNATIONAL EXAMPLES

UNITED KINGDOM: LEEDS H21 CITY GATE PROJECT

The Leeds H21 City Gate project is a feasibility study, led by Northern Gas Networks (Leeds' gas distribution company) to explore the potential to transition the city of Leeds from natural gas to hydrogen. The parameters of the study included:

- The conversion area to cover around 660,000 people out of Leeds' total population of 751,000.
- Production of hydrogen from natural gas using steam methane reforming with carbon capture and storage, with the conversion process to be located in the industrial hub of Teesside and the CO_2 emissions from the conversion process transported to and sequestered in depleted oil and gas fields in the North Sea.
- Excess hydrogen production to be stored in nearby salt caves in Hull.
- A hydrogen transmission pipeline, capable of carrying the maximum hourly peak demand of 3,180 MW, to connect the storage facility to Leeds.

The results of the study, published in 2016, demonstrated that:

- Leeds' existing gas network has sufficient capacity for conversion to hydrogen, despite the lower energy density of hydrogen than natural gas.
- The network can be converted incrementally, with staged conversions of isolated sections of the city over a multi-year period to minimise disruption to customers.
- Current natural gas cookers and boilers can be upgraded to allow operation using hydrogen, rather than needing to be replaced before the end of their normal operating lifetime.
- Full conversion of the city of Leeds is feasible by 2025.

Following the feasibility study, Ofgem, the UK electricity and gas regulator, has funded Northern Gas Networks to carry out a new study to provide quantified safety based evidence to confirm the gas distribution networks of Great Britain are suitable to transport 100% hydrogen. The evidence produced will be used to support the case for a full conversion of the gas system.

Elsewhere, trials are underway to blend small volumes of hydrogen with Natural Gas in existing gas networks. Trials are underway in Liverpool and Manchester in the UK, and New South Wales in Australia. The Australian trial (H2GO) is run by utility Jemena, and will convert solar and wind power into hydrogen gas, via electrolysis, to power 250 homes and a hydrogen vehicle refuelling station. At hydrogen blending volumes of up to 15%, existing natural gas appliances can function without modification.

GERMANY: H2 MOBILITY

H2 MOBILITY is a joint government-industry initiative to develop a hydrogen refuelling station network for fuel cell vehicles in Germany. H2 Mobility is funded by the German Federal Ministry of Transport and Digital Infrastructure and from the European Commission, and delivered by six companies: Air Liquide, Daimler, Linde, OMV, Shell and Total.

The first phase of the H2 MOBILITY project is the installation of 100 hydrogen fuelling stations by 2019, with ten stations in each of the six urban regions (Berlin, Hamburg, Dusseldorf, Frankfurt, Stuttgart and Munich) as well as the highways that connect them ('hydrogen corridors'). The second phase is the installation of a further 300 fuelling stations (400 in total) to achieve a complete national hydrogen infrastructure network in Germany by 2023. H2 MOBILITY have committed to sourcing the hydrogen for these stations using 'the highest possible amount' of renewable resources.

At the time of writing, 52 hydrogen fuelling stations have been installed in Germany, with a further 42 stations in development. The hydrogen vehicle fleet in Germany is currently small; there are 500 hydrogen fuel cell cars, and at least 12 fuel cell buses (FCEBs) in operation in German cities, with 51 more to be delivered in 2019.

JAPAN: THE 'HYDROGEN-BASED SOCIETY'

Japan is among the front-runners in hydrogen technology worldwide. Japan has the second largest stock of fuel cell electric vehicles, with 2,400 vehicles (primarily cars) deployed to date; the largest fuelling infrastructure, with 100 fuelling stations, and around 236,000 'Ene-Farm' small scale micro CHP systems.

Japan's fourth Strategic Energy Plan, adopted in April 2014, states that Japan will consider the prospects for a 'hydrogen-based society' which uses hydrogen as an energy source. In 2017, Japan hosted its first Ministerial Council on Renewable Energy, Hydrogen, and Related Issues, at which Prime Minister Shinzo Abe stated: 'Japan will be the first in the world to realize a hydrogen-based society'. Later that year, the same council published its Basic Hydrogen Strategy. The strategy identifies hydrogen's role as a new zero-carbon energy source for Japan, presents a coherent Government-wide policy, and sets out a set of steps for the introduction and diffusion of hydrogen technologies. The Strategy describes a path to realise a hydrogen-based society, based on three broad phases:

- Phase 1 is to substantially expand the use of fixed fuel cells and fuel cell vehicles (FCVs).
- Phase 2 is to introduce hydrogen power generation and a large-scale hydrogen supply system by the late 2020s.
- Phase 3 is to develop a carbon-free hydrogen supply system by producing hydrogen with CCS or renewables, by around 2040.

The Strategy sets out Japan's ambition on hydrogen across a number of areas:

- Sourcing hydrogen from international suppliers. The first step of Japan's strategy is to develop the technological capability of overseas partners to produce and supply low-cost, low-carbon hydrogen.
- Development of hydrogen energy carriers. Developing energy carrier technologies to facilitate the transportation of overseas hydrogen, reducing import costs. Technologies that are planned for development include liquefied hydrogen organic hydride, ammonia, and methanation.
- Developing a domestic end-use market. Developing domestic hydrogen production capacity, with a target to commercialise power-to-gas by around 2032, and subsequently to reduce the cost of power-to-gas to that of imported hydrogen.
- Use in power generation. Commercialisation of hydrogen power generation, with a target to reduce the cost of electricity from hydrogen to 17 yen (NZ 23c) per kWh by 2030, and a view to further reducing the cost to that of LNG power generation post-2030.
- Use in mobility. Deployment of 40,000 fuel cell vehicles by 2020, rising to 800,000 by 2030, and to deploy 160 hydrogen fuelling stations by 2020, with a view to commercialising hydrogen fuelling by the second half of the 2020s. The Strategy also aims to commercialise fuel cell trucks.
- Use in industry. An aspiration to use hydrogen to reduce CO_2 emission from industry, though the strategy does not set any targets.
- Use in buildings. The Strategy aims to lower the price of 'Ene-Farm' domestic fuel cell heaters to 800,000 yen (NZ$11,000) by 2020, with a view to their eventual commercialisation.

In October 2018, the Japanese Ministry of Economy, Trade and Industry (METI) and the New Zealand Ministry of Business, Innovation and Employment (MBIE), signed a Memorandum of Cooperation (MOC) on Hydrogen. The MOC commits both parties to cooperate in the field of hydrogen, including in hydrogen production, development of an international hydrogen supply chain, and hydrogen technology utilisation policies.

2

APPROACH

2. Approach

This section describes the approach taken in this study.

First, it describes the challenge of achieving net zero emissions, and distinguishes between sectors whose emissions are easy-to-treat and those that are hard-to-treat.

Second, it describes the key uncertainties that must be taken into account in setting and meeting New Zealand's climate targets, and the implications of these uncertainties in addressing hard-to-treat sectors.

Third, it describes three scenarios (Diversified Mix, Green Gas and All-Electric) that represent different approaches to meeting the net zero target under key uncertainties. Due to the focus on uses of gas infrastructure in this study, it considers in particular the range of possible futures implied by the Green Gas scenario.

Finally, it describes our approach to estimating broad costs of the main technology pathways.

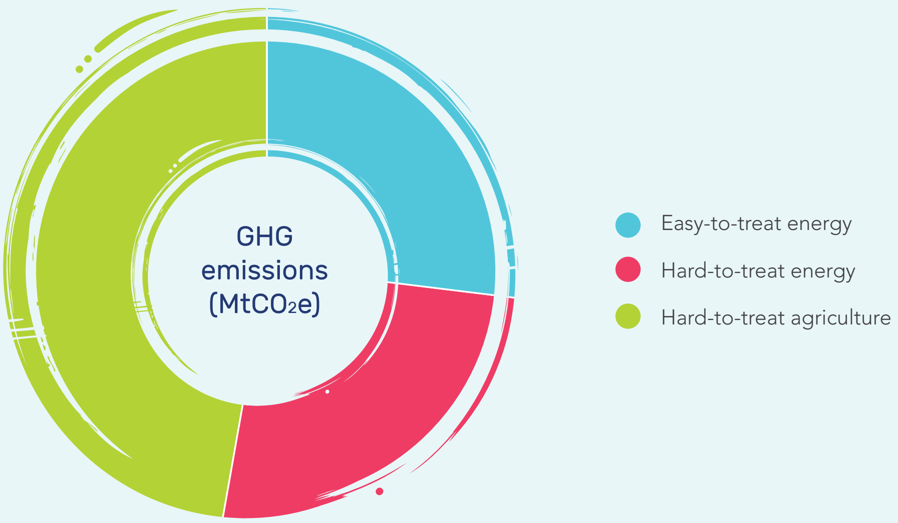
2.1 THE CHALLENGE OF ACHIEVING NET ZERO EMISSIONS

Reducing GHG emissions will be easy in some sectors ('easy-to-treat) and more difficult in others ('hard-to-treat').

Easy-to-treat sectors are those where there is currently a cost-effective solution to address GHG emissions, or where there is a high degree of consensus around the first-best future solution. In New Zealand, easy-to-treat sectors include off-peak electricity generation, space and water heating in the majority of residential and commercial properties, and passenger vehicles.

Hard-to-treat sectors are those where there is currently no cost-effective solution to address GHG emissions, and where the first-best future solution is not yet known. Hard-to-treat sectors include winter peaking and dry years in electricity generation, intermediate-and high-temperature industrial heat, hard-to-treat residential and commercial heat, and heavy duty vehicles, as well as agriculture, waste, and industrial process emissions. Figure 2.1 illustrates the potential balance of easy-to-treat and hard-to-treat emissions in 2050. These sectors, potential solutions, and barriers to addressing them are described below.

Figure 2.1: Balance of easy- and hard-to treat emissions under status quo in 2050



2.1.1 Easy-to-treat sectors

Emissions from off-peak electricity can be reduced with a combination of wind, solar and hydro generation. Variable renewables (wind and solar) are increasingly low-cost sources of electricity generation, and international evidence suggests that they can be deployed in relatively high volumes without their variability creating serious balancing challenges. In New Zealand, balancing challenges are minimised due to the availability and flexibility of hydro generation. Therefore, a generation mix comprising wind, solar and hydro, with additional flexibility supplemented with battery storage and demand response, is sufficient to meet the majority of electricity demand.

Emissions from space and water heating in many residential and commercial properties can be reduced with a combination of energy efficiency and electrified heating. There is significant scope for improvements in the insulation of existing building stock and highly insulated new building stock. Industry also offers opportunities for energy efficiency. Many heat emissions can also be easily reduced by the use efficient heat pumps or direct electric heating, with the former being better suited to buildings which are already well insulated. Heat pumps are used increasingly in New Zealand, with installation rates of between 90,000 and 120,000 per annum in recent years.

Emissions from cars and light commercial vehicles can be reduced with electric vehicles. Electrification of the light duty transport fleet is one of the most promising mitigation options in the transport sector. Electric vehicles are either at or approaching price parity with internal combustion engine vehicles in the next decade. Given that the average lifetime of the fleet is around 14 years, with some of the longest lifetimes ranging up to 20 years, it is possible that a significant proportion of the passenger fleet could be replaced with EVs before 2050 without any early scrappage of vehicles.

2.1.2 Hard-to-treat sectors

Electricity demand during winter peaks and dry years create challenges for electricity generation. Although New Zealand currently experiences a small peak in winter electricity demand, this is likely to increase if space and water heating are electrified. Transpower projections suggest that this peak demand is likely to coincide with reduced output from renewables, leading to a 6 TWh shortfall in renewable electricity generation during winter. This challenge is exacerbated by dry years, where output from hydro is reduced. Transpower projections suggest that a further 6 TWh shortfall may arise in winter in dry years. Because these shortfalls occur over only a small part of the year (and in the case of dry years, do not occur in most years) it is very costly to address these problems by building additional renewables.

There is limited evidence on options to reduce emissions from intermediate-and high-temperature industrial heat. The majority (59%) of intermediate- and high-temperature industrial heat is currently provided by fossil fuels (primarily natural gas, with some coal). A significant proportion (34%) is provided by biomass, and while there is scope to increase the volume of biomass to 2050, the extent of this potential biomass resource will be limited by the volume of large-scale forestry that can be achieved without incurring excessive economic, environmental, and social costs, and the costs of transporting the biomass from the forestry site to the industrial plant. Only 5% of industry heat is provided by electricity, indicating the high cost and technical immaturity of this solution. Currently, high-temperature heat pumps have an operational range of 80–150°C; while this is improving, the potential to cover high-grade heat processes is uncertain. The evidence on other technologies (hydrogen, resistive heating, induction heating and plasma torches) is currently poor, and costs are expected to be high.

Not all residential and commercial premises are well suited to electrified space heat. As described above, it is difficult to reduce emissions from electricity generation to meet winter peak demand. This creates a challenge for electrification of space heat, demand for which is higher in winter. Additional challenges include: the need for reinforcement of electricity distribution networks to accommodate additional electricity demand from electrified space heat; the high cost of electrified space heat in smaller properties, where the low operating costs of heat pumps are not sufficient to offset their high capital costs.

There are no mature options to reduce emissions from heavy duty vehicles. While there is some scope to reduce emissions from heavy duty vehicles through improved energy efficiency, a shift to low-carbon powertrains is needed to fully address emissions. It is widely acknowledged that batteries are unlikely to be able to provide this energy storage, given the size and weight of battery that would be needed to accommodate the longer distances travelled by heavy duty vehicles. However, hydrogen offers better prospects to power heavy duty vehicles, provided key technical challenges in developing sufficiently compact storage tanks can be overcome.

2.2 UNCERTAINTY AND OPTIONALITY

In setting and meeting New Zealand's climate targets key uncertainties must be taken into account. These uncertainties include:

- **Global climate action**. There is considerable uncertainty over the pace and uniformity of global climate action. The challenges of meeting a strong domestic climate target will be significantly smaller if global climate action is strong and uniform, and greater (and less valuable) if global climate action is weak and fragmented.
- **Scope for carbon offsets**. At a global level, the costs of meeting a climate objective are minimised when each country takes advantage of its unique opportunities to reduce emissions at least cost. This raises the possibility that New Zealand could meet a domestic target partly through offsets, i.e. by funding emissions reductions in other countries. Whether this is possible will be determined by any restrictions on offsets imposed by New Zealand's emerging climate change legislation, and by the ambition of other countries' climate targets following future international climate agreements.
- **Ambition of domestic legislation**. While New Zealand is preparing to set a new 2050 greenhouse gas emissions reduction target in law under the forthcoming Zero Carbon Act, it has not yet been determined which whether the net zero target will require net zero emissions of both long-lived and short-lived gases, stabilisation of short-lived gases, or net zero emissions of long-lived gases only. The strength of the legislation will determine the level of emissions reduction effort required across the energy system, agriculture and forestry, to meet the net zero target.
- **Forestry**. As a major carbon sink, forests play a valuable role in offsetting greenhouse gas emissions from the energy sector and agriculture. Given New Zealand's low population density, large-scale afforestation is considered to be a low-cost solution to meet domestic climate targets. However, it is possible that economic, environmental, and social costs will rise as the level of afforestation increases, and further work is needed to assess the level of afforestation that can be achieved sustainably.

"As a major carbon sink, forests play a valuable role in offsetting greenhouse gas emissions from the energy sector and agriculture"

Some of these uncertainties have implications for the level of New Zealand's climate change ambition. These include the pace and uniformity of global climate change action and the scope for New Zealand to meets its domestic targets partly through funding emissions reductions in other countries.

Other uncertainties have implications for the way in which New Zealand's level of ambition is achieved. Assuming strong global and domestic climate action, the most cost-effective strategy to achieve a domestic climate target will depend on the upper bound of sustainable afforestation, and the relative potential for electrification and hydrogen to address GHG emissions in hard-to-treat sectors.

For uncertainties that have implications for the level of New Zealand's climate change ambition, we define a set of starting assumptions that apply across our scenarios. Given the importance of mitigating climate change, and increasing public support for strong climate action in New Zealand, this analysis begins with four premises:

- **Strong global climate action**. Global climate action is strong and uniform, and New Zealand is not acting unilaterally. Risks of carbon leakage are minimised, and New Zealand's domestic mitigation efforts are part of a meaningful global effort to meet the climate objective of the Paris Agreement.
- **Strong domestic climate target**. The net zero target for 2050 is set at a level of ambition that is consistent with strong global climate action and technological innovation, and requires net zero emissions of both long-lived and short-lived gases.
- **Net zero target is achieved domestically.** New Zealand commits to achieving its net zero target without offsets, in order to minimise risks to meeting the target in the event that offsets are not available (for example, if all countries adopt sufficiently stringent domestic targets).

We develop three scenarios to analyse the different ways in which New Zealand's level of ambition is met. The three scenarios, Diversified Mix , Green Gas and All-Electric, are described below:

- In the Diversified Mix scenario, fossil fuels continue to be used in hard-to-treat sectors. This is likely to be the least-cost solution to meet the net zero target if there is sufficient sustainable afforestation potential to offset emissions from both agriculture, and a number of 'hard-to-treat' sectors in the energy system. The Diversified Mix scenario is identical to the net zero-emissions Policy-Driven Decarbonisation (PD-0) scenario developed by the Productivity Commission.
- In the Green Gas scenario, natural gas is fully replaced with green gas (hydrogen or biogas), which is used as a fuel in hard-to-treat sectors. Natural gas pipelines are repurposed to carry the green gas. This is the preferred solution if there is insufficient sustainable afforestation potential to offset emissions from 'hard-to-treat' sectors as well as agriculture, and if innovation in hydrogen technologies outpaces innovation in electrification technologies, with hydrogen emerging as the preferred solution to achieving a net zero target.

- In the All-Electric scenario, natural gas and its pipelines are phased out, and electricity is used as a fuel in hard-to-treat sectors. This is the preferred solution if, as with Green Gas, there is insufficient sustainable afforestation potential to offset emissions from 'hard-to-treat' sectors as well as agriculture, and if innovation in electrification technologies is more rapid, with electrification as the preferred solution.

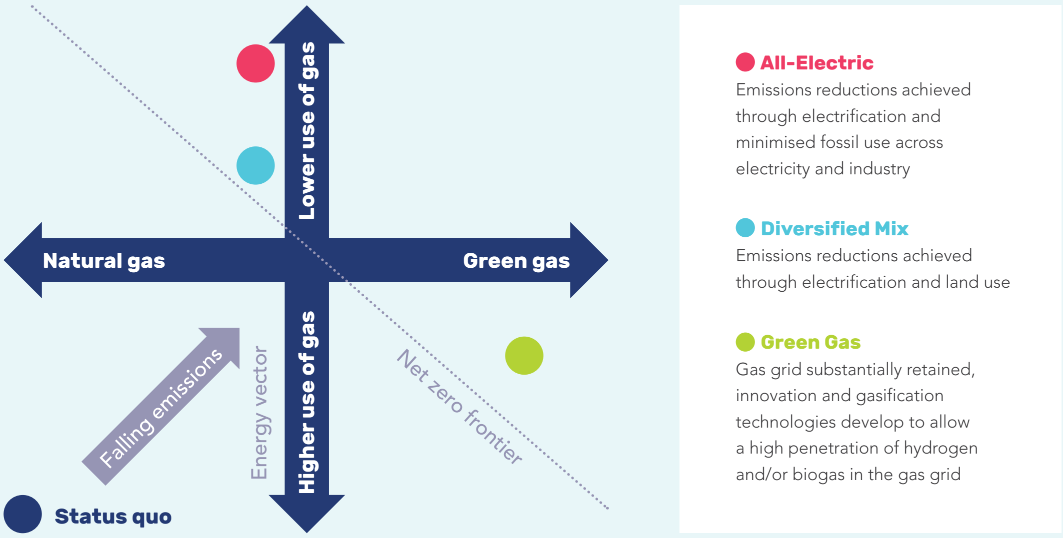
Figure 2.2 characterises the Diversified Mix, Green Gas and All-Electric scenarios in terms of two of the main pathways to reduce emissions from gas use. The vertical axis of this chart represents the use of gas, with the bottom of the axis representing high use of gas, and the top representing a shift from gas to zero-carbon fuels such as electricity. By contrast, the horizontal axis represents the carbon content of gas, with the left side of the axis representing the use of natural gas, and the right side representing a shift from natural gas to green gas, such as hydrogen or biogas.

If New Zealand were to continue with the status quo, it would remain in the bottom left-hand position on this chart, which corresponds with the highest emissions levels. The Diversified Mix scenario achieves net zero emissions partly through a through a shift away from gas towards electrification, and partly through offsetting residual emissions with forestry. The Green Gas scenario achieves net zero emissions largely through a through a shift from natural gas to green gas; and the All-Electric scenario achieves net zero emissions largely through a larger shift away from gas towards electrification, with less reliance on offsetting residual emissions with forestry.

In reality, the preferred solution to meet the net zero target could differ significantly from these scenarios. Variants of these scenarios, or a balanced approach incorporating elements of all three scenarios could make up the preferred solution to meet the net zero target.

- Alternative variants of each scenario. To estimate and compare the costs of these strategies we have had modelled specific solutions, such as a focus on repurposing distribution networks to carry hydrogen in the Green Gas scenario. Alternatives, such as repurposing of the transmission network or greater use of biogas are also possible, and we discuss these possibilities separately.
- A balanced approach. Diversified Mix, Green Gas and All-Electric scenarios represent the implications of committing to and relying on single, specific strategies to address hard-to-treat sectors before developing a sufficient understanding of the likely outcomes. An alternative approach of keeping options open for a range of solutions, and committing to specific solutions only when likely outcomes are better understood, could produce a pathway with more diverse solutions, such as a mix of forestry, hydrogen and electrification represented by the three scenarios.

Figure 2.2: Alternative futures of gas and gas infrastructure in a net zero world



We then assess the feasibility and cost of these scenarios as pathways to meet New Zealand's net zero target. The feasibility and cost of each scenario will differ under different potential outcomes for the upper bound of sustainable afforestation, and the relative potential for electrification and hydrogen to address GHG emissions in hard-to-treat sectors. This assessment of feasibility and cost indicates the risks of incurring unnecessary costs in meeting the net zero target, if New Zealand were to commit to an approach that is poorly aligned with the scope for of sustainable afforestation, and the extent of innovation in electrification and hydrogen technologies.

2.3 NET ZERO EMISSIONS SCENARIOS

In all scenarios, emissions from easy-to-treat sectors are reduced, while residual emissions are offset. 19 $MtCO_2$ of emissions from easy-to-treat sectors are reduced to zero, while 33 $MtCO_2$ emissions from agriculture, and 10 $MtCO_2$ residual emissions in energy (emissions from residual passenger transport, waste, and industrial process emissions) are offset with forestry.

In the Diversified Mix scenario, fossil fuels continue to be used in hard-to-treat sectors. In this scenario, hard-to-treat sectors emit 8 $MtCO_2$ in 2050, which are then offset with additional forestry:

- Gas generation continues to provide winter peaking electricity; gas boilers and furnaces are used to provide some intermediate- and high-temperature industrial heat; gas boilers are used to provide space heat in the hard-to-treat residential and commercial sector; and diesel internal combustion engine heavy goods vehicles are used in the road freight transport sector.

> **"In the Green Gas scenario, natural gas pipelines are repurposed to carry hydrogen, which is used as a fuel in hard-to-treat sectors"**

- Forestry plays the strongest role of the three scenarios. A total of 2.8 Mha of forestry is needed to offset total residual emissions of 47 $MtCO_2e$, comprising 33 $MtCO_2$ from agriculture, 8 Mt from hard-to-treat parts of the energy sector and 10 $MtCO_2$ residual emissions in energy.

In the Green Gas scenario, natural gas pipelines are repurposed to carry hydrogen, which is used as a fuel in hard-to-treat sectors. In this scenario, hydrogen technologies reduce emissions from hard-to-treat sectors by around 8 Mt, such that no additional forestry is needed:

- Hydrogen turbines provide winter peaking electricity; hydrogen boilers and furnaces are used to provide a significant share of intermediate- and high-temperature industrial heat; hydrogen boilers are used to provide space heat in the hard-to-treat residential and commercial sector; and hydrogen fuel cell heavy goods vehicles are used in the road freight transport sector.
- Less forestry is needed in the Green Gas scenario. A total of 2.3 Mha of forestry is needed to offset total residual emissions of 39 $MtCO_2e$, comprising 33 $MtCO_2$ from agriculture, and 10 $MtCO_2$ residual emissions in energy.

In the All-Electric scenario, natural gas and its pipelines are phased out, and electricity is used as a fuel in hard-to-treat sectors. In this scenario, electric technologies reduce emissions from hard-to-treat sectors by around 8 Mt, such that (as with Green Gas) no additional forestry is needed:

- Renewables over-build provides winter peaking electricity; while electric heat technologies (heat pumps or resistive electric heating) are used to provide some intermediate- and high-temperature industrial heat, and as well as space heat in the hard-to-treat residential and commercial sector. As in the Green Gas scenario, hydrogen fuel cell heavy goods vehicles are used in the road freight transport sector.
- Residual emissions, and the level of forestry needed are the same as in the Green Gas scenario, i.e. 2.3 Mha of forestry is needed to reduce residual emissions of 39 $MtCO_2e$.

Table 2.1 provides a breakdown of the three scenarios.

Table 2.1: the Diversified Mix, Green Gas and All-Electric scenarios represent different approaches to meeting a net zero target

	DIVERSIFIED MIX	GREEN GAS	ALL-ELECTRIC
Abatement in 2050 ($MtCO_2e$)			
Easy-to-treat sectors	19	19	19
Hard-to-treat sectors	0	8	8
Forestry*	47	39	39
Approach to hard-to-treat sectors			
Winter peaking electricity	Increased afforestation	Hydrogen turbines	Renewables over-build
Industrial heat		Hydrogen boilers and furnaces	Electrified heat
Residential/commercial		Hydrogen boilers	Electrified heat
Heavy duty transport		Fuel cell HGVS	Fuel cell HGVS

*Abatement from forestry is estimated based on the average carbon stock following 21 years' growth, and assumes a 2:1 ratio of plantation to native forestry.

2.4 CHARACTERISTICS OF THE GREEN GAS SCENARIO

2.4.1 Potential green gas futures

There are many different possible options for the use of green gas. Options include:

- **Type of green gas**. Green gas includes hydrogen, and biogas. Hydrogen can be blended with natural gas in small volumes to reduce the carbon content of natural gas, or it can be used in pure form. When used in pure form, energy technologies that use natural gas (power stations, burners, boilers, furnaces) must be replaced or upgraded to account for the different chemical properties of hydrogen and natural gas. Biogas is a mix of gases created from biomass, and can be produced from solid biomass, or captured from landfill or wastewater treatment plants. The primary component of biogas, biomethane, is interchangeable with natural gas and and once extracted does not require replacement or upgrading of energy technologies.
- **Method of transmission and distribution**. New Zealand's natural gas transmission network is made of steel and their suitability for carrying hydrogen needs further investigation. Should modification be needed, options include adding polyethylene inner lining, or reducing pipeline pressures. However, the distribution networks are predominantly made of polyethylene, and are capable of carrying hydrogen. In order to shift from natural gas to hydrogen, a decision would need to be made about whether to continue to use the transmission pipelines for hydrogen transport (with suitable modification if necessary), or whether to decommission the transmission pipelines and locate hydrogen production and consumption on the distribution networks.
- **Route to hydrogen production**. Hydrogen can be produced through steam methane reforming and electrolysis. Steam methane reforming is the use of a chemical catalyst at high temperature to react natural gas with water, to produce hydrogen and carbon dioxide. Carbon capture and storage (CCS) is needed for steam methane reforming to be a low-carbon process.

The natural gas route to hydrogen production would need to be centralised, and to require use of a transmission pipeline in order to be economic, as hydrogen production would need to occur close to natural gas fields, and carbon capture and storage sites, rather than centres of demand. In contrast, electrolysis uses an electrical current to separate water into hydrogen and oxygen. Low-carbon electricity generation (for example, renewables) are needed for the electrolysis route to hydrogen production to be a low-carbon process. Until recently, the production of hydrogen through electrolysis using electricity generated by renewables was considered prohibitively expensive, and the natural gas route to hydrogen production was considered to be the only potentially viable solution. However, following strong reductions in the costs of both renewables and improved prospects for cost reduction in electrolysers, the lowest-cost route to producing hydrogen is no longer clear.

- **Future of petrochemicals**. The total volume of green gas depends on whether the petrochemicals industry is retained. Natural gas is currently used as a feedstock in the petrochemicals industry, where it provides both carbon and hydrogen content for the production of methanol and fertiliser. In principle, these products could be produced using hydrogen from electrolysis, rather than natural gas. It is therefore possible that these industries could be retained in the event of a switch from natural gas to hydrogen, leading to greater hydrogen demand. It is also possible that these industries may not continue to operate under a switch to hydrogen, for two reasons:
  - » First, methanol and some fertiliser products (for example, urea) also need a source of carbon, and it is not clear what sources of carbon might be available if natural gas use is phased out.
  - » Second, as GHG emissions arise from methanol and urea use, it is not clear that there will continue to be an international market for these products in 2050, if other countries adopt and implement ambitious climate targets by that date.

2.4.2 The core Green Gas scenario

For the preliminary costing assessment, we define a single variant of the Green Gas scenario (the 'core' Green Gas scenario. We define the core Green Gas scenario as follows:

- **Hydrogen as the dominant gas**. The core Green Gas scenario is one in which innovation in hydrogen technologies outpaces innovation in electrification technologies, with hydrogen emerging as the preferred solution to achieving a net zero target. As a result, gas distribution networks are repurposed to carry pure hydrogen.
- **Repurposing the transmission network**. Retaining the transmission network is valuable as industries that are currently located on the transmission network would not need to shift to the distribution network and incur the significantly higher distribution network costs. Therefore, both transmission pipelines are repurposed or replaced in the Green Gas scenario.
- **Renewables route to hydrogen production**. In the core Green Gas scenario, hydrogen is produced through the electrolysis route, as this can occur on the distribution networks it does not require carbon capture and storage.
- **A range of futures for petrochemicals**. Methanol and fertiliser production currently use natural gas as a feedstock. The long-term future of this production pathway is difficult to predict, given uncertainty over the feasibility of identifying CO_2 feedstock from non-fossil sources, and over the existence of an international market for these products in 2050. In the Green Gas scenario, volumes of gas and the resulting level of network utilisation are estimated both with and without continued petrochemicals production.

2.4.3 Variants of the Green Gas scenario

However, there are many different possible options for the use of green gas. Alternatives include:

- **A role for biogas**. Biogas (methane created from biomass) can be produced from solid biomass, or captured from landfill. Potential roles for biogas include blending with natural gas (and possibly small volumes of hydrogen) to produce a gas that is lower-carbon than pure methane; and repurposing of one or more distribution networks to carry pure biogas.

- **Natural gas route to hydrogen production.** Hydrogen can be produced from natural gas by steam methane reformation. If carbon capture and storage (CCS) is used to sequester the resulting CO_2 emissions, the natural gas route to hydrogen production offers emissions savings close to those achieved by the electrolysis route. The feasibility of CCS in New Zealand is currently uncertain; but should CCS become feasible, the natural gas route to hydrogen production could prove significantly cheaper than the renewables route.
- **Decommissioning of transmission network.** New Zealand's natural gas transmission network is made of steel; further work is needed to understand their suitability to carry hydrogen. Should the costs of repurposing or replacing these pipelines outweigh the benefits, there may still be value in converting the distribution networks to hydrogen, decentralising hydrogen production and shifting hydrogen end-use to the distribution networks.
- **Continued iron and steel production.** In the Diversified Mix scenario, in line with the Productivity Commission's PD-0 scenario, iron and steel production phases out in New Zealand given the high expected costs of producing iron and steel with low CO_2 emissions. However, if hydrogen technologies are available there may be an economic rationale to continue to produce iron and steel in New Zealand.
- **The potential to export hydrogen to global markets**. With sufficient innovation in hydrogen technologies, a global market in hydrogen may emerge. A global hydrogen market could offer opportunities for New Zealand to produce hydrogen for export as well as domestic use, and potentially provide a source of revenue to Government. The development of a hydrogen export sector could also offer solutions to address New Zealand's unique dry year problem, with surplus hydrogen exported during normal years and used domestically to generate electricity during dry years.

> **"A global hydrogen market could offer opportunities for New Zealand to produce hydrogen for export as well as domestic use, and potentially provide a source of revenue to Government"**

2.5 APPROACH TO QUANTIFYING SCENARIO COSTS

In order to illustrate the value of optionality in the use of gas and gas infrastructure, we have carried out a preliminary estimate of potential costs of each scenario. Further work would be needed before a detailed costing would be possible, for two reasons.

- First, the evidence base on the costs of meeting a net zero target in New Zealand is relatively limited. To our knowledge, a costing of the full set of solutions – including a hydrogen economy – for meeting a net zero target for New Zealand has yet to be carried out.
- Second, the costs of addressing hard-to-treat sectors are poorly understood, due both to the technical and commercial immaturity of potential solutions, and to the lack of studies that focus on the costs and scope for cost reductions of technologies in these sectors.

Our preliminary costing focuses on hard-to-treat sectors. In the absence of a better understanding of these costs, we have developed simple estimates that capture the broad cost ranges for solutions in the Green Gas and All-Electric scenarios to address winter peaking electricity, industrial heat, residential and commercial buildings and heavy duty transport.

We include a simple estimate of the costs of addressing easy-to-treat sectors. Although only the cost of addressing hard-to-treat sectors varies between scenarios, in order to illustrate overall costs and affordability of meeting a net zero climate target we have included an estimate of the costs of addressing easy-to-treat sectors.

We separately consider the costs of forestry for residual emissions and hard-to-treat sectors. Forests play a valuable role in offsetting greenhouse gas emissions from the energy sector and agriculture. At low levels of forestry, evidence suggests the costs of large-scale forestry could be low. However, it is likely that the economic, environmental, and social costs of large-scale afforestation will rise as the level of afforestation increases. We therefore draw on the lower end of the range of cost estimates for residual emissions, and the higher end for hard-to-treat sectors.

3

THE FUTURE OF GAS AND ITS INFRASTRUCTURE

3. The future of gas and its infrastructure

This section describes three possible technology pathways to achieving a net zero emissions target, and the implications of these pathways for the quantity and type of gas used, and the utilisation of gas infrastructure.

Overall gas use and pipeline utilisation in the Diversified Mix, Green Gas and All-Electric scenarios is set out in Table 3.1 and described in the sections below.

Table 3.1: Overall gas use and pipeline utilisation in the Diversified Mix, Green Gas and All-Electric scenarios

		DIVERSIFIED MIX	ALL-ELECTRIC	GREEN GAS
	2015*	2050		
Gas use by sector (PJ)				
Electricity generation	56	35	0	38
Chemicals	84	57	0	0–104
Other industry	29	7	0	40
Commercial	9	5	0	9
Residential	7	4	0	7
Transport	0	0	0	21
Total	**185**	**107**	**0**	**115–220**
Pipeline throughput by network (PJ)**				
Transmission network	163	95	0	111–203***
Distribution networks	34	12	0	63

Note: *While data for gas use by sector is available for 2017, its sector disaggregation differs from that used in the Productivity Commission modelling which underpins this analysis. ** Pipeline throughput is smaller than total gas use as around 11% of gas does not pass through the transmission network. Pipeline throughput is not additive; all gas passes through the transmission network; and of this, a smaller share passes through distribution networks. *** Transmission network throughput in the Green Gas scenario depends on whether methanol and fertiliser production are phased out or retained to 2050.

3.1 DIVERSIFIED MIX SCENARIO IN 2050

In the Diversified Mix scenario, use of natural gas decreases by around 42% to meet the net zero emissions target, from 185 PJ in 2015 to 107 PJ in 2015. As discussed in Section 2, the Diversified Mix scenario is identical to the net zero-emissions Policy-Driven Decarbonisation (PD-0) scenario developed by the Productivity Commission. The decrease is largest in the chemicals sector where natural gas is reduced as both a fuel and a feedstock, followed by the electricity and other industry sectors. Figure 3.1 describes the change in natural gas use between 2015 and 2050.

In electricity generation, natural gas use is restricted to winter peaking generation. Natural gas use in electricity generation decreases around 40%, from 56 PJ in 2015 to 35 PJ in 2050. The decrease is driven by deployment of renewables, which displace natural gas use in mid-merit generation. The remaining 35 PJ of natural gas is used for winter peaking generation.

In industrial heat, natural gas use is retained in the chemicals sector. Natural gas use in industrial heat decreases 57%, from 63 PJ in 2015 to 27 PJ in 2050. The decrease is driven by displacement of natural gas with biomass and electricity across industrial sectors. The chemicals sector retains the largest role for natural gas in 2050, with natural gas use decreasing around 40%, from 34 PJ in 2050 to 20 PJ in 2050. Other industry sectors (including dairy, meat manufacturing, forestry products, and production of primary metals) retain a small role for natural gas in 2050, with natural gas use decreasing around 70%, from 29 PJ in 2050 to 7 PJ in 2050.

As a feedstock in the chemicals sector, natural gas is largely retained. Natural gas use in chemical feedstocks decreases 27%, from 50 PJ in 2015 to 37 PJ in 2050, as methanol production is assumed to decrease over this period.

In commercial and residential properties, natural gas retains a small role. Natural gas use in commercial and residential properties decreases 44%, from 16 PJ in 2015 to 9 PJ in 2050. The decrease is driven by displacement of natural gas with electricity where this is cost-effective. This will be the case for larger properties with greater heating needs, and where the operating cost savings of heat pumps offset their higher capital costs; and properties in areas where the need for reinforcement of electricity distribution networks is relatively limited. Commercial and residential properties consume similar volumes of natural gas in 2050, of 5 PJ and 4 PJ respectively.

"In the Diversified Mix scenario, use of natural gas decreases by around 42% to meet the net zero emissions target"

The overall decrease in natural gas use reduces utilisation of the transmission and distribution networks. The largest reduction in utilisation occurs on the distribution network, as residential and commercial buildings, and various industries switch to lower-carbon fuel sources and reduce their gas consumption by 50-90%. A smaller reduction utilisation occurs on the transmission network, where the methanol industry output decreases, the use of gas fired electricity generation declines and the chemicals and other industries switch to lower-carbon fuel sources. As a result, total throughput through the transmission network, including both direct connections and demand from distribution network, decreases 40%, from 163 PJ in 2015 to 95 PJ in 2050. Figure 3.2 sets out the change in natural gas use between 2015 and 2050.

3.2 GREEN GAS SCENARIO IN 2050

In the Green Gas scenario, overall gas use could range from 115 PJ to 220 PJ in 2050, as all natural gas is replaced with green gas. The lower end of this range represents the closure by 2050 of the methanol and fertiliser industries in the event that low-carbon routes to feedstock production prove challenging, while the higher end of the range represents continued operation of these industries in the event that feasible low-carbon routes to feedstock production are developed. This section first describes the Green Gas scenario assuming closure of these industries, and then describes the Green Gas scenario assuming continued operation.

At the lower end of this range, overall gas use could decrease 38%, from 185 PJ in 2015 to 115 PJ in 2050, as all natural gas is replaced with green gas. This overall decrease is driven by reductions in overall gas use in some sectors, partially offset by increases in others. The largest decrease is caused by the phase out of the petrochemicals sector, which accounts for an 84 PJ reduction. Offsetting this is a 21 PJ increase in gas use due to a switch from coal to green gas in the other industry sectors, and a further 21 PJ increase due to the shift from diesel to green gas in road transport. Figure 3.3 describes the change in overall gas use between 2015 and 2050.

In 2050, green gas is used mainly in electricity generation, industrial heat and road transport. Of the 115 PJ of total gas demand in 2050, around one third (38 PJ) is used in electricity generation; a third (40 PJ) is used was used to generate heat for industrial processes, and around 20% (21 PJ) is used in road transport. The remaining 16 PJ is used for space and water heat, and for cooking in the residential and commercial sector.

In electricity generation, green gas is used for winter peaking generation. Total gas use in electricity generation decreases around 40%, from 56 PJ in 2015 to 38 PJ in 2050.

In industrial heat, green gas is widely used in the food sector. Natural gas use in industrial heat decreases 63%, from 99 PJ in 2015 to 36 PJ in 2050. This overall decrease is the combined effect of reduced output in some sectors, and a shift from coal and natural gas to green gas in others. An overall 84 PJ decrease is driven by the closure of methanol and fertiliser manufacture; this decrease is partially offset by a 21 PJ increase in other industry sectors, as these industries convert their fuel use from coal to natural gas.

In commercial and residential properties, green gas takes on the role that natural gas plays today. This scenario assumes that commercial and residential properties that use gas today switch to green gas once this becomes available. Total use of green gas in 2050 is the same as use of natural gas today, at 7 PJ in residential buildings, and 9 PJ in commercial buildings.

Green Gas emerges as the dominant fuel in heavy duty transport. As the road freight sector switches from a fleet dominated by diesel internal combustion engine vehicles to one made up of hydrogen fuel cell vehicles over the period 2030-2050, green gas use reaches 21 PJ in 2050.

Assuming continued operation of the chemicals sector, overall gas use could increase around 15%, from 185 PJ in 2015 to 220 PJ in 2050. This overall increase is driven by a 7 PJ increase in gas use due to a switch from coal to green gas in various industry sectors; a further 21 PJ increase due to the shift from diesel to green gas in road transport; and a 20 PJ increase due to the shift from natural gas to green gas in the chemicals sector (a given amount of hydrogen carries more energy as pure hydrogen, than as a component of natural gas).

Utilisation of the transmission network to 2050 will depend on the future of the chemicals sector, while utilisation of the distribution networks would increase significantly. If the methanol and fertiliser industries face closure by 2050 then throughput through the transmission network could decrease by around 40%, from around 163 PJ in 2015 to 111 PJ in 2050. However, if these industries are able to continue to operate then throughput through the transmission network could increase by around 25%, to 202 PJ in 2050. On the distribution networks, total throughput could increase by around 60%, from around 34 PJ in 2015 to 63 PJ in 2050, as existing and new sources of demand in electricity generation, industry, buildings and transport switch from natural gas and other fossil fuels to green gas. Figure 3.4 sets out the change in overall gas use between 2015 and 2050.

3.3 ALL ELECTRIC SCENARIO IN 2050

In the All Electric scenario, use of natural gas is entirely phased out. This phase out is driven by the use of renewables over-build to address winter peaking, the use of electric process heating in industry, and electric space and water heating in hard-to-treat commercial and residential properties. The current natural gas transmission and distribution networks are decommissioned.

Diversified Mix, Green Gas and All Electric are three possible technology pathways to achieving a net zero emissions target; of these, only Diversified Mix continues to use natural gas, while both Diversified Mix and Green Gas continue to use gas pipeline infrastructure, while All Electric represents phase out of both natural gas and gas pipeline infrastructure. Section 4 then describes the possible implications of these different technology pathways for the cost of meeting a net zero target.

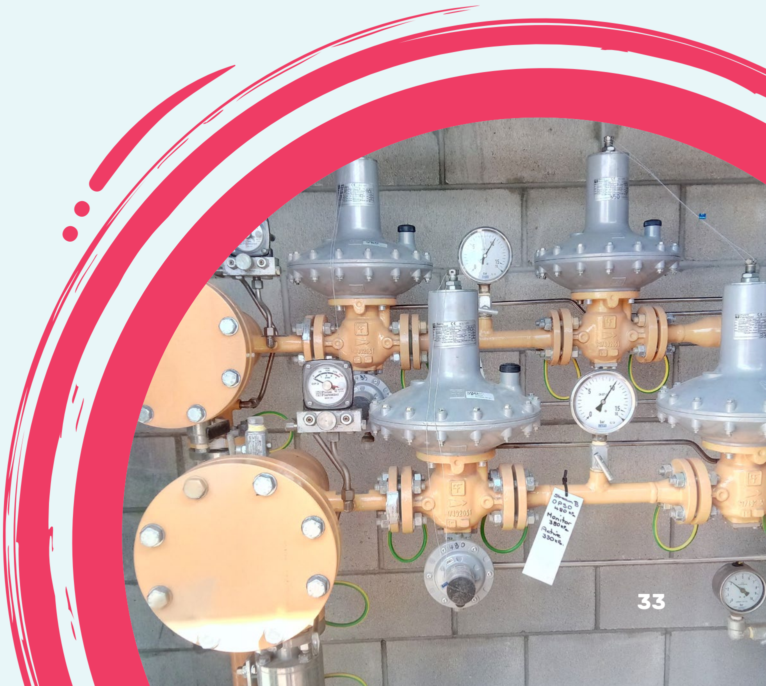
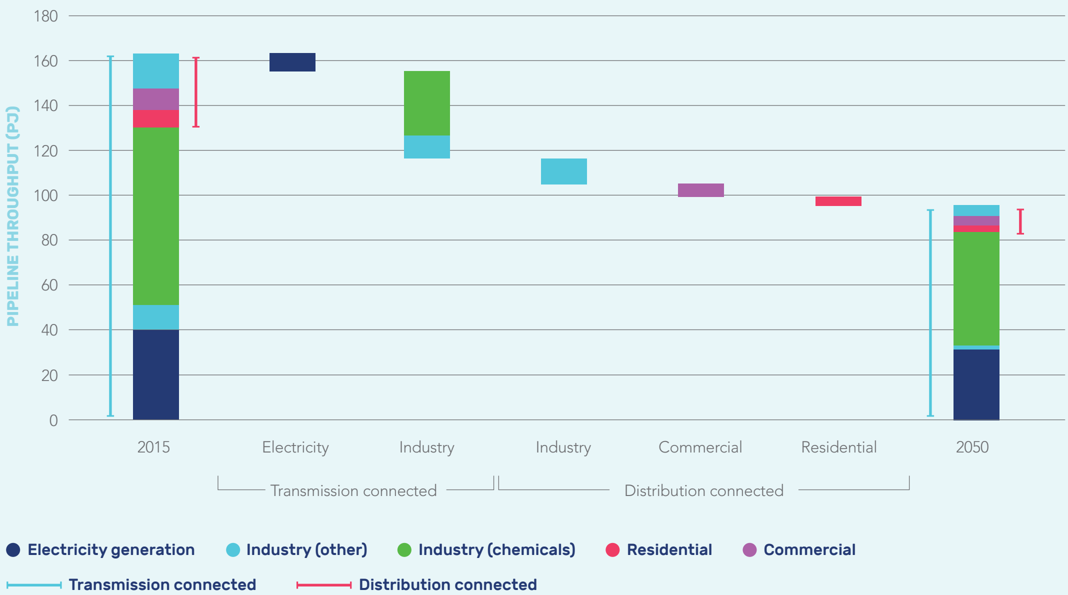


Figure 3.1: Use of natural gas in Diversified Mix decreases by around 40% by 2050

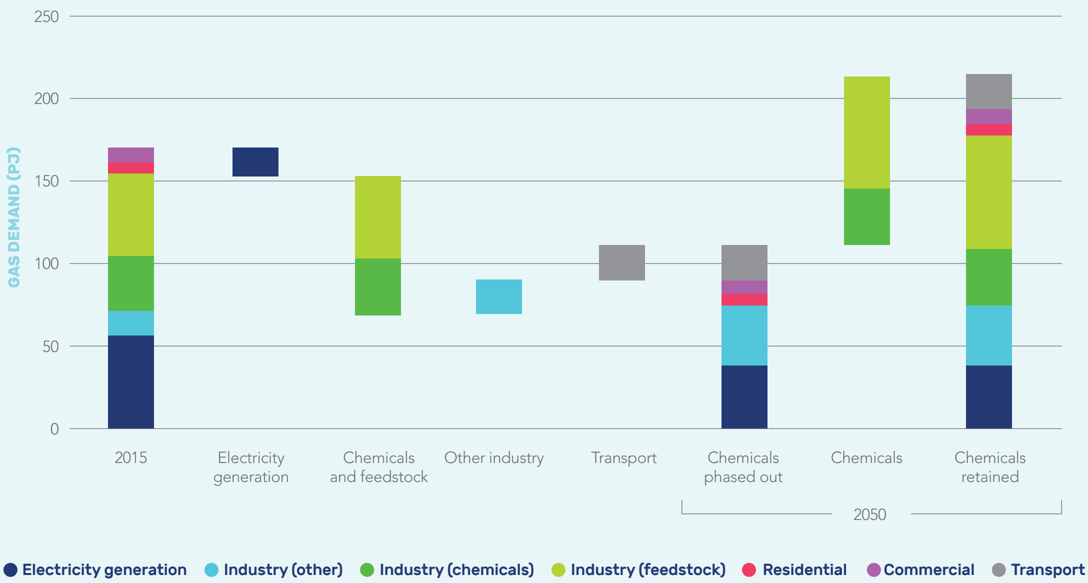
Note: Other industry comprises the dairy, meat, forestry products and metals industries.

Figure 3.2: The decrease in natural gas in Diversified Mix use reduces utilisation of the gas networks to 2050



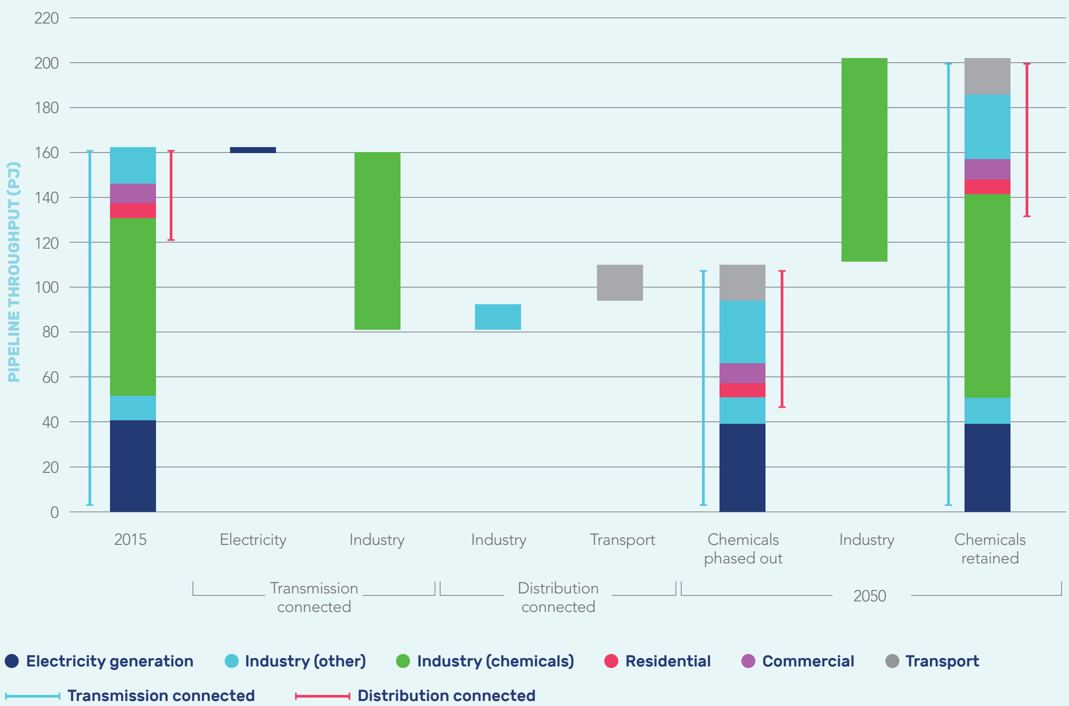
Note: Other industry comprises the dairy, meat, forestry products and metals industries.

Figure 3.3: In the Green Gas scenario, overall gas use could range from 115 PJ to 220 PJ in 2050, as all natural gas is replaced with green gas.

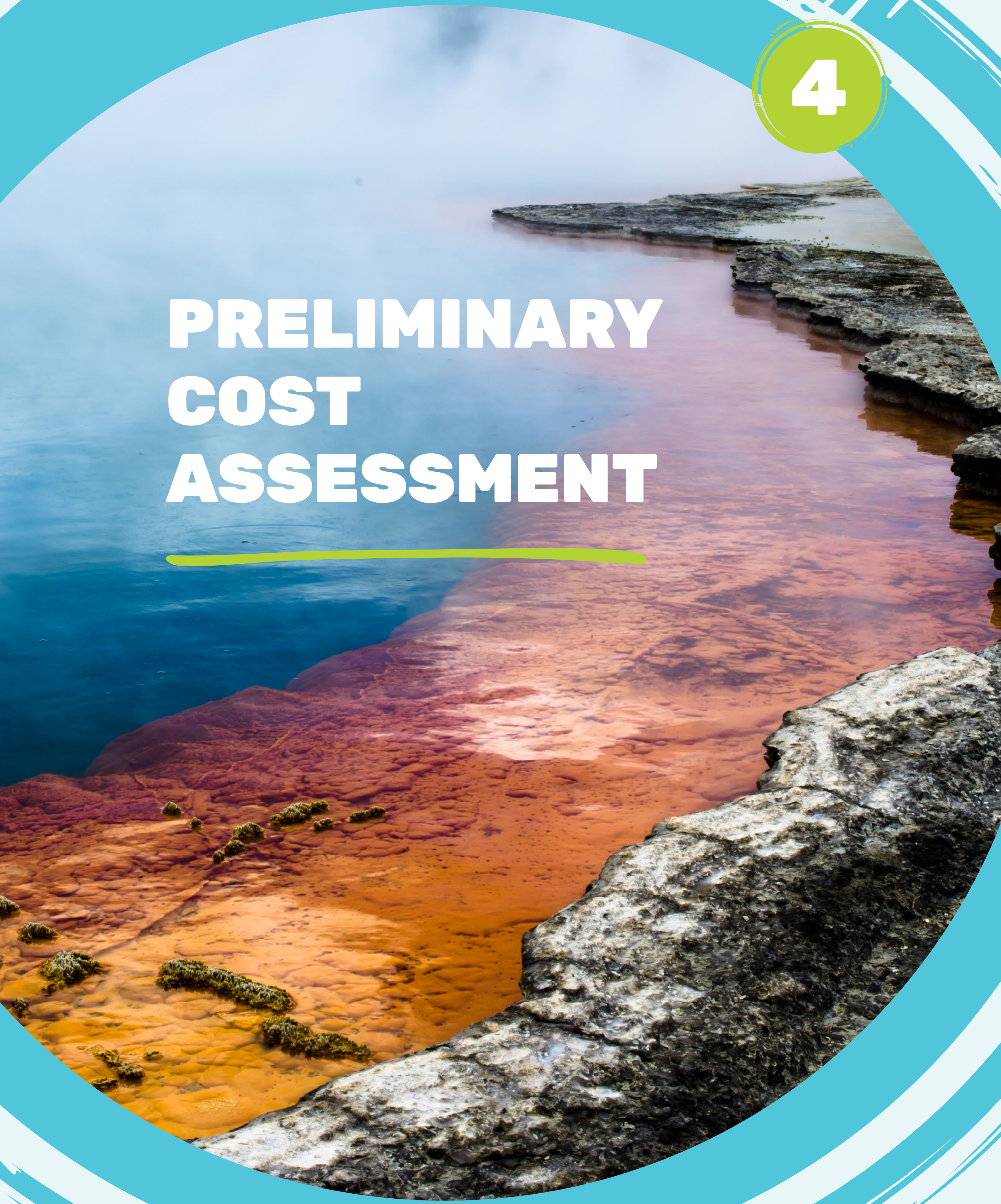


Note: Other industry comprises the dairy, meat, forestry products and metals industries.

Figure 3.4: In the Green Gas scenario, utilisation of the gas networks to 2050 will depend on the future of the chemicals sector



Note: Other industry comprises the dairy, meat, forestry products and metals industries.



4

PRELIMINARY COST ASSESSMENT

4. Preliminary cost assessment

This section presents the results of the preliminary cost assessment carried out in this study.

Section 4.1 describes the detailed preliminary cost estimates developed for the three scenarios, with particular detail on the costs of hydrogen cost estimates underpinning the Green Gas scenario. Section 4.2 describes the impact of meeting the net zero target on affordability in each scenario. As affordability differs significantly between scenarios, a decision now to completely decarbonise using electricity would risk unnecessary costs and key uncertainties need to be resolved before a good decisions on the future of gas and gas infrastructure can be made.

4.1 COST ESTIMATES ACROSS THE SCENARIOS

4.1.1 Easy-to-treat sectors

We draw on two sources of evidence to estimate of the costs of addressing easy-to-treat sectors

- Estimates of abatement costs for specific technologies. Evidence to date on the costs of reducing emissions in New Zealand indicates a range of solutions; the cost of these solutions ranges from zero or negative cost for improving the thermal efficiency of buildings, to relatively high cost for pumped hydro capacity. Table 4.1 describes the range of cost estimates for a number of illustrative technologies.
- Estimates of carbon prices needed to meet New Zealand climate targets. An alternative approach to understanding the costs of addressing easy-to-treat sectors is provided by estimates of the carbon price needed to reach a net zero target. Modelling carried out by the Productivity Commission indicates that meeting a low-emissions pathway (driven by the expansion of forestry, improvements in agricultural production, and electrification in the transport and heat sectors) could require a carbon price of \$75–150/tCO_2e by 2050, and that meeting a net zero emissions pathway could require a carbon price of \$150–250/tCO_2e. The carbon price is determined by the highest-cost solution needed to meet the target, while the average cost is determined by the less costly solutions.

Based on the range of costs in the literature for easy-to-treat sectors, and the carbon price needed to deliver the full range of zero, medium and high cost solutions to meet the net zero target, we have assumed that the average cost of addressing these sectors of \$100/tCO_2e in 2050.

4.1.2 Residual emissions

For moderate levels of afforestation, the cost of offsetting residual emissions with forestry could be up to \$50/tCO_2. Forests play a valuable role in offsetting greenhouse gas emissions from the energy sector and agriculture. At low levels of forestry, evidence suggest the costs of large-scale forestry could be low, with costs ranging from \$10–45/tCO_2e depending on the existing land use (Reisinger et al., 2017). Based on these figures, we have assumed an average cost of offsetting residual emissions (emissions from agriculture, residual passenger transport, waste, and industrial process emissions) of \$50/tCO_2e.

> "As affordability differs significantly between scenarios, a decision now to completely decarbonise using electricity would risk unnecessary costs"

4.1.3 Hard-to-treat sectors – Diversified Mix scenario

For higher levels of afforestation needed to offset hard-to-treat emissions, costs are highly uncertain but could rise to \$100–200/tCO_2. In Diversified Mix, emissions from hard-to-treat sectors are offset with forestry, rather than addressed directly. While substantial evidence indicates that at low levels of forestry, the costs of large-scale forestry could be low, it is likely that the economic, environmental, and social costs of large-scale afforestation will rise as the level of afforestation increases. Modelling carried out by the Productivity Commission indicates that the net zero scenario, where carbon prices reach \$150–250/tCO_2e, is associated with almost double the forestry of the low emissions scenario, where carbon prices only reach \$75–150/tCO_2e by 2050 (Productivity Commission, 2017). Based on these figures, we have assumed a range for the average cost for hard-to-treat sectors of \$100–200/tCO_2e.

4.1.4 Hard-to-treat sectors – Green Gas scenario

In the core Green Gas scenario, the cost of producing hydrogen is primarily determined by the cost of producing electricity. The cost of producing hydrogen is determined by the costs of the electricity input, and the costs of the electrolysers. Figure 4.1 sets out the low and high costs modelled in this study, indicating a range of \$4.10–5.30 per kg, assuming a cost of \$70–90 to produce electricity from wind[1]. In both low and high cost estimates, electricity costs make up the largest share of total cost. The low electricity cost assumption is based on low estimates of the future cost of wind generation (New Zealand Wind Energy Association), while the high electricity cost assumption are based on the low estimates of current costs, and represents limited future cost reductions (MBIE, 2016). The costs of electrolysis make up a smaller share of total cost. The low and high electrolysis cost assumptions are based on the range identified in the research literature, with the low assumption drawn from NEL ASA (2017) and the high assumption based on a cost estimate for 2030, representing minimal innovation in electrolysis technology between 2030 and 2050 (Schmidt et al., 2017).

"Use of hydrogen in electricity generation and industrial heat would incur only transmission charges, while buildings and transport would incur both transmission and distribution charges due to their decentralised locations"

The cost of delivering hydrogen is determined by the location of the end user. Use of hydrogen in electricity generation and industrial heat would incur only transmission charges, while buildings and transport would incur both transmission and distribution charges due to their decentralised locations. Figure 4.1 also sets out the low and high costs of delivered hydrogen to these sectors, including the transmission and distribution costs. The cost of a hydrogen transmission network is expected to be 10–20% higher than that of the current natural gas transmission networks due to the cost of retrofit. The cost of current transmission networks are drawn from the Gas Industry Company (2017), and the uplift is drawn from E4Tech et al. (2015).

Using hydrogen gas turbines for winter peaking in electricity could cost \$450–650/tCO_2. The cost of producing electricity using hydrogen gas turbines is determined by the costs of the hydrogen, and the costs of the hydrogen turbines. Figure 4.2 sets out the low and high costs modelled in this study, indicating a range of \$430–550/MWh. In both low and high cost estimates, hydrogen costs make up the largest share of total cost. Research on costs of hydrogen turbines is limited; both low and high assumptions for gas turbine costs are drawn from an assessment of hydrogen turbine costs in 2050 (E4tech et al., 2015) with the low assumption taken directly from this study and a 25% uplift added to represent the high cost case. These costs are significantly higher than the costs of gas peaking generators of around \$180/MWh, and would need a carbon price of around \$450–650/tCO_2 to be economic without subsidy. Hydrogen fuel cells are an alternative solution, but are likely to be more costly (E4tech et al., 2015).

Using hydrogen to address intermediate-and high-temperature industrial heat could cost \$450–600/tCO_2. The cost of generating intermediate- and high-temperature industrial heat is determined by the costs of the hydrogen, and the costs of the

1. Small-scale hydrogen production could be significantly less costly as surplus generation from existing renewables could provide the electricity. For larger production volumes, new renewables capacity would be needed.

hydrogen boilers and furnaces. Figure 4.3 sets out the low and high costs modelled in this study, indicating a range of $130–160/MWh of delivered heat, compared to around $30/MWh with gas. In both low and high cost estimates, hydrogen costs make up almost all of the total cost. Research on the capital cost of hydrogen boilers is limited, largely because the technology is in principle very similar to conventional gas boilers. The low capital cost assumption is based on the current cost of an industrial gas boiler and is drawn from NERA and AEA (2009), while the high capital cost assumption is based on the projected capital cost of a hydrogen boiler in 2050 and is drawn from E4tech et al. (2015). Overall, total costs of generating heat with hydrogen are significantly higher than with gas, and would need a carbon price of around $450–600/t$CO_2$ to be economic without subsidy.

"Research on the capital cost of hydrogen boilers is limited, largely because the technology is in principle very similar to conventional gas boilers"

Hydrogen appliances in the hard-to-treat buildings sector could cost $400–700/t$CO_2$. The cost of generating heat in buildings is determined by the costs of the hydrogen, and the cost of replacing a hydrogen boiler to replace a conventional gas boiler. Figure 4.4 sets out the low and high costs modelled in this study, indicating a range of $1,800–2,200 per household, compared to around $1,240 per year with gas. In both low and high cost estimates, hydrogen costs make up a large share of the total cost. Research on the capital cost of hydrogen boilers is limited, largely because the technology is in principle very similar to conventional gas boilers. The low capital cost assumption is based on the current cost of a residential gas boiler and is drawn from Element Energy and E4tech (2018), while the high capital cost assumption is based on the projected capital cost of a hydrogen boiler in 2050 and is drawn from Kiwa and E4tech (2016). Overall, total costs of generating heat with hydrogen are significantly higher than with gas, and would need a carbon price of around $400–700/t$CO_2$ to be economic without subsidy.

Converting the heavy duty vehicle fleet to hydrogen could be cost-saving for large HGVs, or cost up to $200/t$CO_2$ for smaller HGVs. The total cost of a hydrogen fuel cell heavy duty vehicle is determined by the costs of the hydrogen, and the cost of the fuel cell vehicle. Figure 4.5 sets out the low and high costs modelled in this study, indicating a range of $0.57–0.65 per km for small trucks, $0.47–0.55 per km for medium trucks and $0.37–0.44 per km for large trucks. Hydrogen fuel cell HGVs are costly but highly fuel efficient. For small trucks, the capital cost of the vehicle makes up the largest share of the costs, but for large trucks the fuel cost makes up the largest share of the costs. The low and high assumptions for costs of hydrogen fuel cell HGVs are drawn from Ricardo AEA (2012), with the low assumption based on the estimated cost in 2050, and the high assumption based on the estimated cost in 2030, representing minimal innovation in fuel cell technology between 2030 and 2050. For small trucks, these costs are significantly higher than the costs of a diesel vehicle due to the higher capital cost, and would need a carbon price of around $50–200/t$CO_2$ to be economic without subsidy. However, for large trucks, the total cost premium relative to a diesel vehicle is lower due to the high mileage, and may need a carbon price of up to only $50/t$CO_2$ to be economic without subsidy.

Should carbon capture and storage (CCS) become feasible in New Zealand, costs of the Green Gas scenario could be significantly lower. The feasibility of CCS in New Zealand is currently uncertain.

Nevertheless, several estimates indicate that the costs of producing hydrogen from natural gas via steam methane reforming (SMR) with carbon capture and storage (CCS) are likely to be cheaper than the costs of producing hydrogen via electrolysis. The International Energy Agency estimates that the hydrogen production via SMR with CCS could cost as little as US$1.7 (NZ$2.6) per kg (IEA, 2017). This would reduce the abatement costs of hydrogen applications to much lower levels than modelled above.

4.1.5 Hard-to-treat sectors – All Electric scenario

The costs of electrification options to address hard-to-treat sectors are less well understood. While research on renewable electricity generation, electrolysis and fuel cell technologies is relatively well-developed, and other end-use technologies that use hydrogen (hydrogen turbines, burners, furnaces and boilers to produce process heat in industry or space heat in buildings) are considered to have similar technical properties to technologies that use gas. However, for electrification, research to date has largely focused on easy-to-treat sectors (electric vehicles, heat pumps) and research on electrification of industrial heat in particular is relatively less developed (though this now receiving renewed focus, with for example the work of the Energy Transitions Commission).

Our preliminary cost assessment for the All Electric scenario is based on four representative solutions to addressing hard-to-treat sectors. These include renewables over-build to address winter peaking in electricity generation; resistive electric heating to address intermediate-and high-temperature industrial heat; heat pumps or resistive electric heating in hard-to-treat residential and commercial heat.

For heavy duty vehicles, electric heavy goods vehicles are not considered feasible due to their long travel distances, and the high cost and weight of batteries large enough to meet their driving range requirements. Therefore, as with the Green Gas scenario, the All-Electric scenario uses hydrogen to reduce greenhouse gas emissions from heavy goods vehicles. If the gas distribution networks are decommissioned due to insufficient overall gas demand, hydrogen could be produced centrally or at depots, and transported to fuelling stations on the strategic road network by truck.

Renewables over-build to address winter peaking in electricity generation could cost \$600–800/tCO_2. In Te Mauri Hiko, Transpower identify a number of potential technical solutions for managing New Zealand's winter and dry-year energy issue, but note that none appears definitely feasible and economically attractive. Potential solutions include battery peakers, generation over-build, biofuels, international grid connection, additional

hydro capacity, storage of energy as compressed air, and more disruptive innovations (the 'bionic leaf', advanced nanotechnology solar). Given the challenges associated with all of these potential solutions, the preliminary cost assessment of the All-Electric scenario is based on renewables over-build as an indicative solution. This solution is costly due to the low utilisation of renewables built exclusively to meet winter peak demand. Peaking generators typically run less than 10% of the time, compared to 90% for baseload generators. Renewables are poorly suited to peaking as the majority of their cost structure is made up of capital costs, and they typically need high utilisation to be cost-effective. A proportion of the electricity generated through renewables over-build could be used in high-and intermediate-temperature heat, increasing utilisation; nevertheless, renewables remain a high-cost option.

"The high energy needs of large, long-distance heavy goods vehicles, and low energy density of batteries, mean that battery solutions are likely to be too large and heavy to accommodate in an HGV without radical breakthroughs in battery technology"

High temperature heat pumps and resistive electric heating in intermediate-and high-temperature industrial heat could cost $200–700/tCO_2$, though more work is needed to determine their feasibility. High-temperature heat pumps currently have an operational range of 80–150°C; this could be sufficient to meet some, but not all, demand for intermediate-temperature (100–300°C) and high-temperature (>300°C) heat. An alternative to high temperature heat pumps is resistive heating; the feasibility of intermediate- and high-temperature resistive heating is poorly understood, and further work is needed to determine its suitability in New Zealand's specific industries. The low end of the range modelled in this study represents significant innovation in heat pump technology, and technical performance of heat pumps improving sufficiently to allow these technology to replace gas and coal boilers and furnaces across the major industrial sectors. The high end of this range represents limited innovation in heat pump technology, and the use of inefficient resistive heating to provide the heat loads previously provided with coal and gas. These costs do not include the cost of any additional upgrades to the electricity transmission and distribution infrastructure needed to accommodate the additional electricity demand; further work is needed to understand the scale of these costs.

Heat pumps and resistive electric heating in hard-to-treat residential and commercial premises could cost $150–700/tCO_2$. In principle, heat pumps can be used in hard-to-treat residential and commercial premises, though they are less cost-effective due to the need for reinforcement of electricity distribution networks to accommodate additional electricity demand from electrified space heat, and the high cost of electrified space heat in smaller properties, where the low operating costs of heat pumps are not sufficient to offset their high capital costs. Resistive heating is another electric alternative. The low end of the range modelled in this study represents significant innovation in heat pump technology, such that they are cost-effective even in areas needing significant reinforcement of electricity distribution networks, or smaller properties with lower heating needs. This high end of this range represents limited innovation in heat pump technology, and the use of inefficient resistive heating, drawing large volumes of electricity at peak times. As with industrial heat, additional costs could arise due to upgrades to the electricity transmission and distribution infrastructure.

Prospects for electric solutions to heavy duty vehicles are highly uncertain. The high energy needs of large, long-distance heavy goods vehicles, and low energy density of batteries, mean that battery solutions are likely to be too large and heavy to accommodate in an HGV without radical breakthroughs in battery technology. Therefore, in the All-Electric scenario, the heavy goods vehicle fleet is converted to hydrogen, as in the Green Gas scenario. Because there is no gas distribution infrastructure in the All Electric scenario, hydrogen production and fuelling occurs at large fleet depots, with hydrogen also transported by road to a limited network of hydrogen fuelling stations on the national strategic highway network.

Table 4.1: A range of low-, medium- and high-cost solutions are available to reduce emissions in easy-to-treat sectors

COST	MEASURE	SOURCES
Low cost (under $50/tCO2e)	Electric passenger vehicles	IEA 2016; Concept Consulting 2016b)
	Improved thermal efficiency in buildings	Grimes et al. 2012; Chapman et al. 2009; Barnard et al. 2011
	Reducing peak electricity demand	Vivid Economics 2017
	Electric heat pumps for residential and commercial water heating	Concept Consulting 2016a
Medium-cost ($50–100/tCO2e)	Electric heating of low-grade industrial heat	Vivid Economics 2017
	Use of biomass in industrial heating processes	Vivid Economics 2017; U.S. Department of Energy Federal Energy Management Program (FEMP) 2016
High cost (over $100/tCO2e)	Pumped hydro	Kear & Chapman 2013

Figure 4.1: Cost range for hydrogen production and delivery

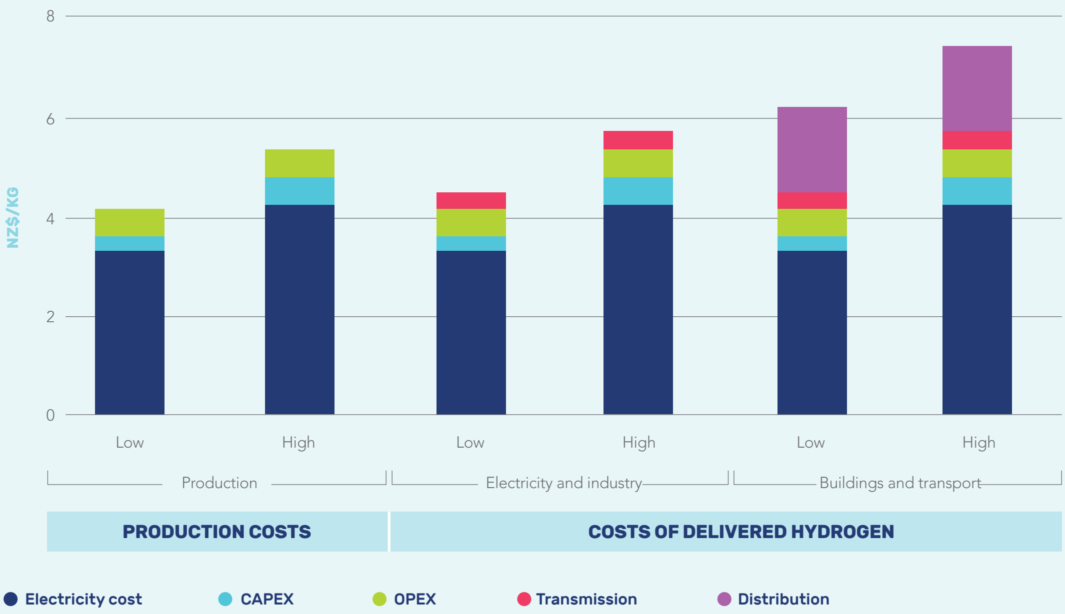


Figure 4.2: Cost range for hydrogen in winter peaking electricity

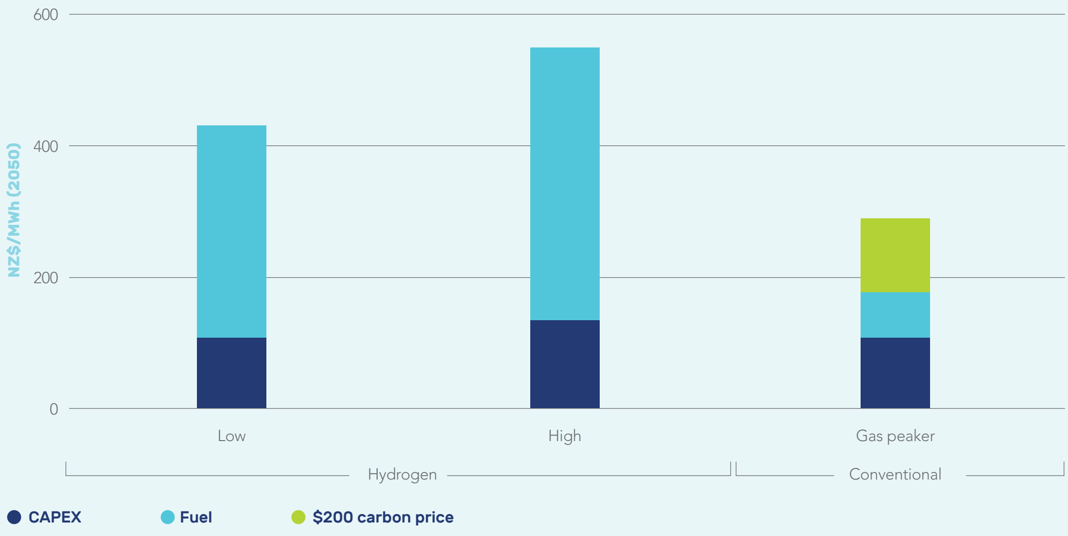


Figure 4.3: Cost range for hydrogen in intermediate-and high-temperature industrial heat

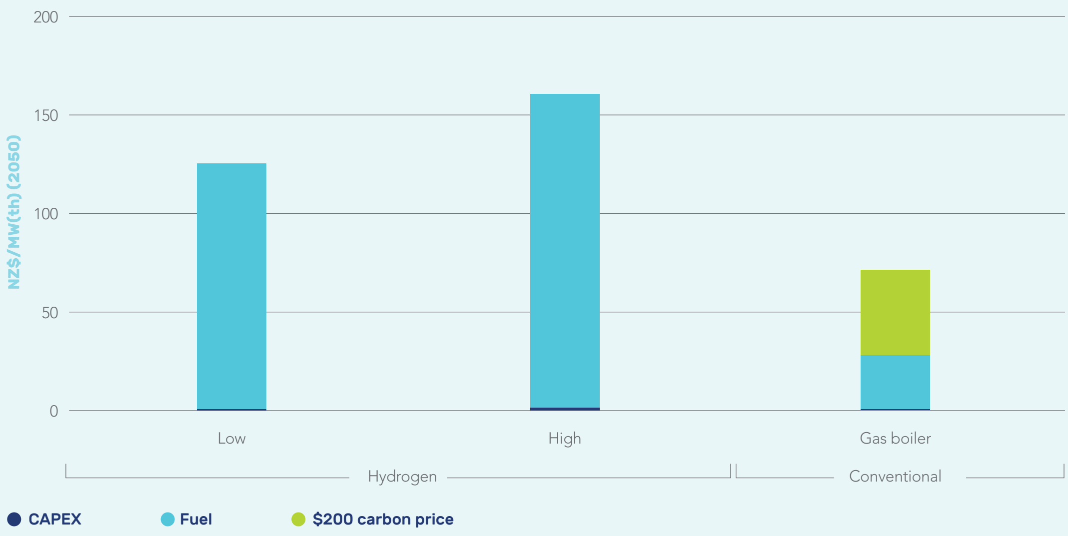


Figure 4.4: Cost range for hydrogen in the hard-to-treat buildings sector

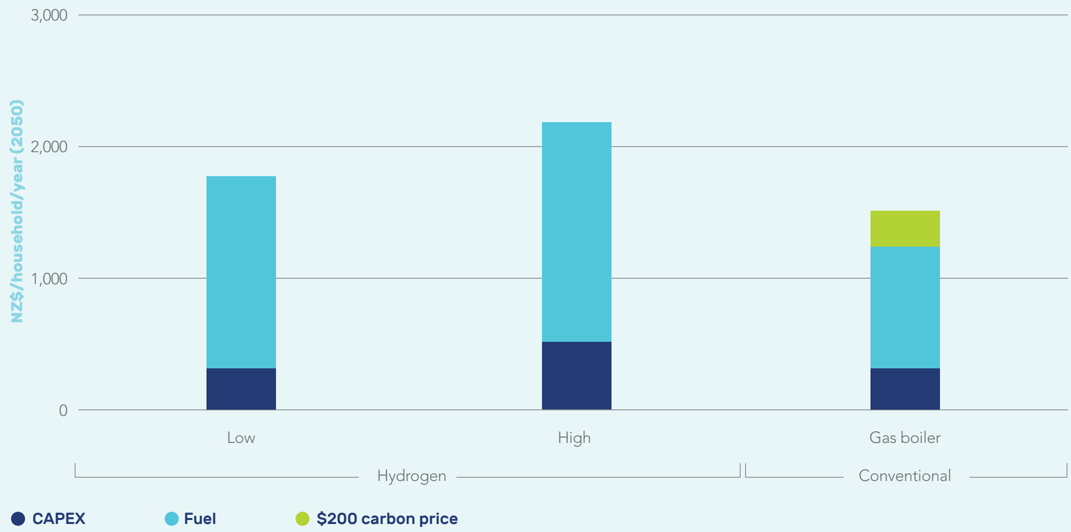
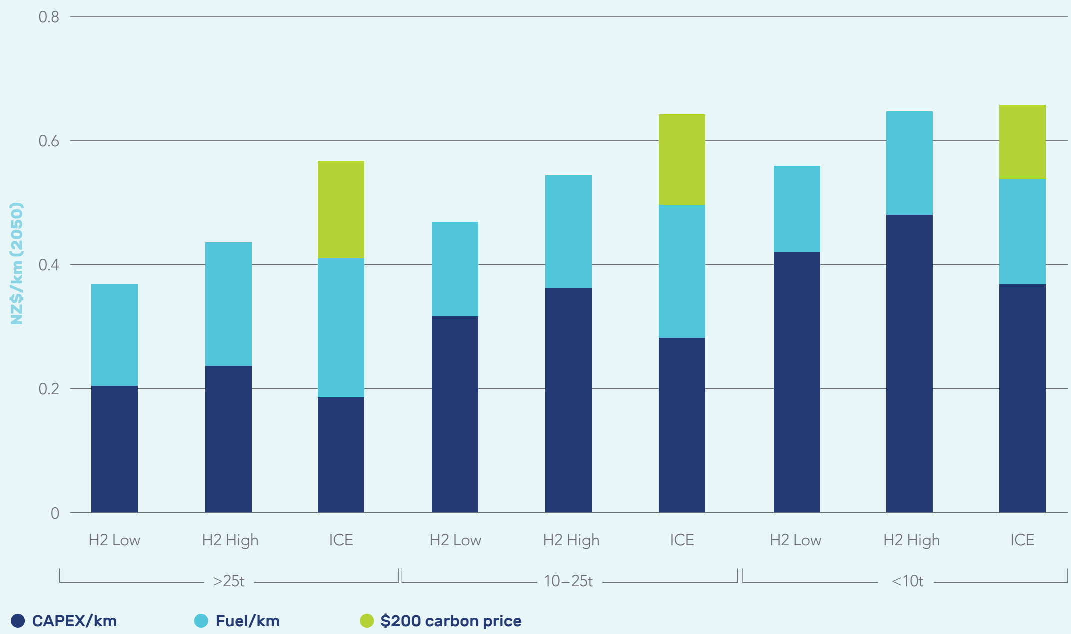


Figure 4.5: Cost range for hydrogen in the heavy duty vehicle fleet



Note: ICE is internal combustion engine.

4.2 AFFORDABILITY IMPACTS OF MEETING A NET ZERO EMISSIONS TARGET

We have carried out a preliminary estimate of the potential costs of each scenario. As described in Section 2, further work is needed to develop a detailed costing of meeting a net zero climate target. Nevertheless, in the absence of detailed cost information, it is important to illustrate how costs are likely to differ between pathways, so that better decisions can be made. Therefore, we have carried out a preliminary estimate of the potential costs of each scenario, with a focus on the hard-to-treat sectors which determine the differences in cost between scenarios.

> **"It is not currently possible to predict whether electrification or hydrogen will prove the more affordable option to meet the net zero target"**

Affordability differs significantly between scenarios. Figure 4.6 shows the affordability of the net zero target in 2050 under the Diversified Mix, Green Gas and All-Electric scenarios. The Diversified Mix scenario is the most affordable. If the potential for sustainable afforestation proves to be sufficient to offset the emissions from hard-to-treat sectors then total annual cost of meeting the net zero target could be around $3.8 – 4.6 billion per year by 2050, equivalent to 0.9 – 1.0% of incomes (expressed differently, the annual cost could be around $1,700 per household, with incomes projected to rise around 35% over this period). If the potential for sustainable afforestation proves insufficient, and hydrogen or electrification is needed to address hard-to-treat sectors then costs would be significantly higher. At the lower end of the range, the total cost of meeting the net zero target in the could rise to $4.8-5.1 billion per year by 2050, equivalent to around 1.1 – 1.2% of incomes, in the Green Gas and All-Electric scenarios. At the upper end of the range, the total cost of meeting the net zero target in the could rise to $6.2 – 7.2 billion per year by 2050, equivalent to around 1.4-1.6% of incomes (or around $2,700 per household).

A decision now to completely decarbonise using electricity would risk unnecessary costs. First, a decision to completely decarbonise using electricity would rule out the continued use of natural gas in hard-to-treat sectors, and the use of forestry to offset residual emissions from natural gas. If the potential for sustainable afforestation proves to be adequate to offset these emissions then ruling out this option could reduce the affordability of meeting the net zero target by up to $3.4 billion per year by 2050, or 0.8% of incomes (or around $1,400 per household). Second, such a decision would rule out the use of hydrogen to address hard-to-treat sectors. If innovation in hydrogen technologies outpaces innovation in electrification technologies, then ruling out this option could reduce the affordability of meeting the net zero target. Furthermore, should carbon capture and storage (CCS) become feasible in New Zealand, the natural gas route to hydrogen production could prove significantly cheaper than the renewables route.

It is not currently possible to predict whether electrification or hydrogen will prove the more affordable option to meet the net zero target. Figure 4.7 sets out the possible cost ranges for electrification and hydrogen to address emissions in hard-to-treat sectors. While in some cases (winter peaking and industrial heat) the cost range for electrification is overall lower than that for hydrogen, in these cases, and in the residential and commercial sectors, these cost ranges overlap, indicating that either electrification or hydrogen could emerge as the most affordable solution. Only in heavy transport is there an unambiguous finding, as the use of electricity as a fuel in heavy transport does not appear feasible.

Figure 4.6: Affordability of the Diversified Mix, Green Gas and All-Electric scenarios

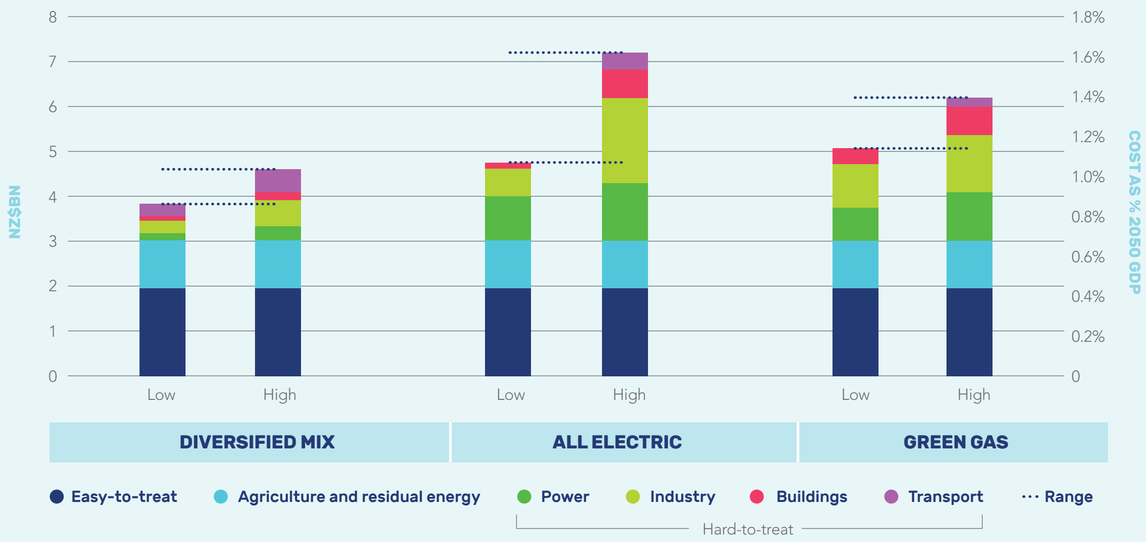
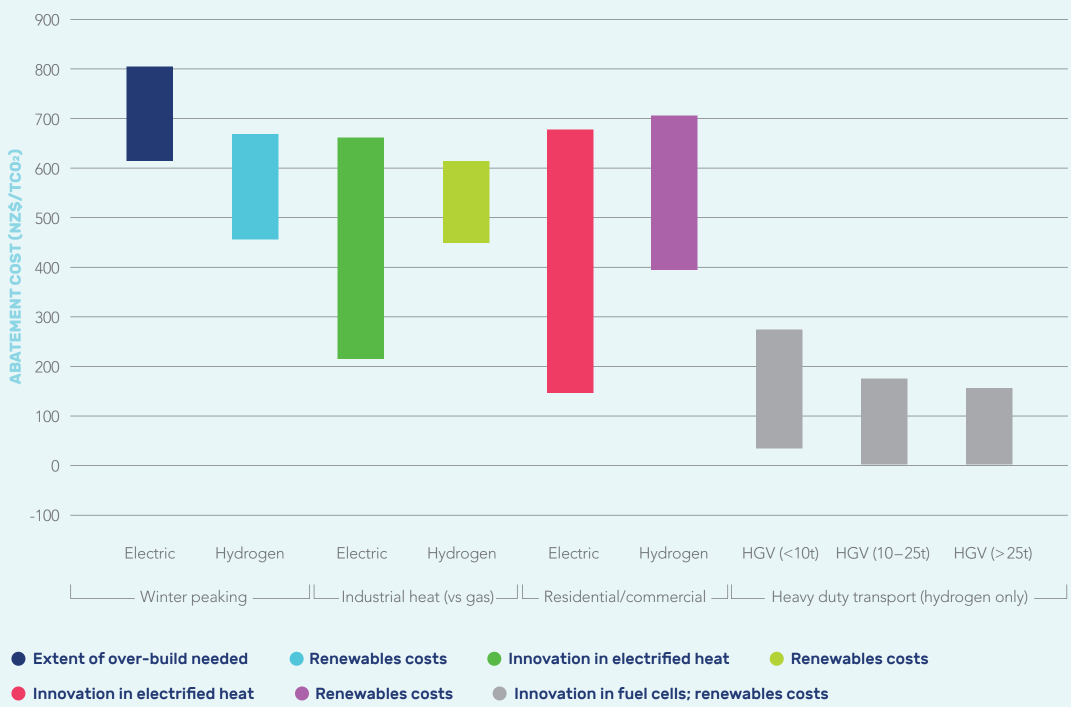


Figure 4.7: Key uncertainties around the suitability of hydrogen and electrification technologies need to be resolved



5

CONCLUSIONS

5. Conclusions

In some sectors, there is there is a high degree of consensus around the first-best future solution to reduce GHG emissions.

Some sectors are easy-to-treat. For example, emissions from off-peak electricity can be reduced with a combination of wind, solar and hydro generation; emissions from space and water heating in residential and commercial properties can be reduced with a combination of energy efficiency and electrified heating; and emissions from cars and vans can be reduced with electric vehicles.

In other hard-to-treat sectors, it is too early to exclude potential solutions. Hard-to-treat sectors include winter peaking in electricity generation, intermediate-and high-temperature industrial heat, hard-to-treat residential and commercial heat, and heavy duty vehicles, as well as agriculture, waste, and industrial process emissions. There is currently a high degree of uncertainty surrounding the least-cost approach to addressing GHG emissions in these sectors.

Important uncertainties affect the prospects for different solutions to address hard-to-treat sectors. Assuming New Zealand sets a strong climate target in line with international climate action, the key uncertainties around the future of natural gas and gas networks are the upper bound of sustainable afforestation, and the relative potential for electrification and hydrogen to address GHG emissions in hard-to-treat sectors.

It is possible that very large volumes of afforestation can be accommodated with low economic, social, and environmental costs. In this case, it is possible that continued use of natural gas in hard-to-treat sectors, and as feedstock for petrochemicals could be the preferred solution to achieving a net-zero target, with the residual emissions from gas use offset with forestry. Gas and its infrastructure should be retained as an option, until more is known.

If the costs of additional forestry are prohibitive, hydrogen technologies could provide an alternative solution. If the potential for sustainable afforestation proves to be insufficient to offset the emissions from hard-to-treat sectors, then the higher costs of addressing these directly through hydrogen and electrification could be justified. In this case, it is possible that innovation in hydrogen technologies outpaces innovation in electrification technologies, with hydrogen emerging as the preferred solution to achieving a net zero target. It is also possible that CCS emerges as a feasible option for New Zealand, potentially unlocking a still lower-cost route to hydrogen production. In this case, natural gas networks could be repurposed and used to address hard-to-treat sectors directly. This reinforces the option-value argument for retaining gas infrastructure.

> **"If the costs of additional forestry are prohibitive, hydrogen technologies could provide an alternative solution"**

If barriers to forestry and green gas are severe, electrification could be the only solution to address hard-to-treat sectors. If this is the case, then use of natural gas could be entirely phased out, and the current natural gas transmission and distribution networks decommissioned.

Affordability differs between scenarios; and a decision now to completely decarbonise using electricity would risk unnecessary costs. The total cost of meeting the net zero target could be $3.8–4.6 billion, equivalent to 0.9–1.0% of incomes if forestry is used to offset residual gas emissions (expressed differently, the annual cost could be around $800 per person, with incomes projected to rise around 50% over this period). However, this cost could rise to $6.2–7.2 billion, equivalent to around 1.4–1.6% of incomes (or around $1,250 per person), if hydrogen or electrification is needed to address hard-to-treat sectors. Furthermore, the cost of the electrification approach could be significantly higher than using hydrogen to achieve net zero emissions, imposing unnecessary additional costs.

A shift to hydrogen could also offer additional advantages over electrification. First, it could offer opportunities for New Zealand to produce hydrogen for export, and potentially provide a source of revenue to Government. Second, the development of a hydrogen export sector could also offer solutions to address New Zealand's unique dry year problem, with surplus hydrogen exported during normal years and used domestically to generate electricity during dry years.

It is therefore a policy and commercial priority to carry out further investigation into forestry availability, and the costs and technical potential of hydrogen and electrification options in New Zealand. Greater certainty over the relative potential for hydrogen and electrification to address GHG emissions in hard-to-treat sectors is needed before good decisions on the role of gas transmission and distribution infrastructure in meeting the net zero target can be made. Further research over the short- to medium-term should include:

- A full study on the impacts of large-scale afforestation in New Zealand. This should consider economic, environmental, and social impacts, and examine the risks of 'tipping points' where small additional increases in afforestation might create large impacts on economies, ecosystems and communities.
- A techno-economic assessment of the potential for hydrogen and electrification options in New Zealand. This should cover the main hydrogen and electrification options to address winter peaking in electricity generation, intermediate-and high-temperature industrial heat, and hard-to-treat residential and commercial heat. It should also consider New Zealand's specific circumstances, particularly with respect to its intermediate and high-temperature heat needs across industrial sectors. Subsequently, or in parallel, hydrogen blending trials such as those carried out in Australia and the UK can strengthen the evidence base for the technical and economic feasibility of wider deployment.
- A feasibility assessment of carbon capture and storage (CCS) in New Zealand. A full feasibility assessment of CCS in New Zealand. This should cover the environmental and economic aspects, including the availability of suitable storage sites, operational safety and long-term integrity of CO_2 storage, the risks arising from New Zealand's high levels of tectonic activity, and the costs of developing a transport and storage infrastructure for CO_2.

"Greater certainty over the relative potential for hydrogen and electrification to address GHG emissions in hard-to-treat sectors is needed before good decisions on the role of gas transmission and distribution infrastructure in meeting the net zero target can be made"

Finally, wider uncertainties around international climate change action could also affect decisions on the future of gas and its infrastructure. In addition to the uncertainties over the upper bound of sustainable afforestation, and the relative potential for electrification and hydrogen, there remains uncertainty over the pace and uniformity of global climate action, the appropriate strength of New Zealand's climate target and the scope for New Zealand to meets its domestic targets partly through funding emissions reductions in other countries. These uncertainties further underscore the benefits of retaining the option to use gas and its infrastructure until the trade-offs of different solutions are better understood.

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ANNEX 1: HYDROGEN TECHNOLOGY AND COST ASSUMPTIONS

Table A1 sets out the uncertainties which determine the magnitude of the cost ranges for electrification and hydrogen technology.

Table A2 describes the technology and cost assumptions underpinning the preliminary cost estimate and energy system modelling of the Green Gas scenario.

Table A1: Future (2050) cost uncertainties for electrification and hydrogen technologies

SECTOR	SCENARIO	SOLUTION	COST RANGE (\$/TCO_2)	UNCERTAINTY
Winter peaking electricity	All-Electric	Renewables over-build	\$600–800	The extent of over-build needed; future innovation in renewables
	Green Gas	Hydrogen turbines	\$450–650	Future innovation in renewables and electrolysers; prospects of hydrogen turbines
Industrial heat	All-Electric	Electrified heat	\$200–650	Future innovation in high-temperature heat pumps and resistive heating; specific heating needs of New Zealand's industries
	Green Gas	Hydrogen boilers and furnaces	\$450–600	Future innovation in renewables and electrolysers; prospects for hydrogen heating technologies
Residential/ commercial	All-Electric	Electrified heat	\$150–700	Future innovation in heat pumps
	Green Gas	Hydrogen boilers	\$400–700	Future innovation in renewables and electrolysers
Heavy duty transport	All-Electric/ Green Gas	Fuel cell HGVS (small)	\$50–200	Future innovation in renewables, electrolysers, fuel cells
		Fuel cell HGVS (medium)	\$-50–50	
		Fuel cell HGVS (large)	\$-50–50	

Table A2: Technology and cost assumptions in the Green Gas scenario

	LOW		HIGH	
COMPONENT	**ASSUMPTION**	**SOURCE**	**ASSUMPTION**	**SOURCE**
Hydrogen production				
Renewables costs	NZ$70/MWh	NZ Wind Energy Association (no date)	NZ$90/MWh	MBIE (2016)
Electrolyser costs	NZ$665/kW	Nel ASA (2017)	NZ$1,294/kW	Schmidt et al. (2017)
Electrolyser efficiency	47kWh(el)/kg(H2)	E4tech, UCL, Kiwa Gastec (2015)	Same as low	
Electrolyser utilisation	50%	Based on average load factor of new wind	Same as low	
Hydrogen transmission and distribution				
Electricity	NZ$0.34/kg	Gas transmission +10%	NZ$0.37/kg	Gas transmission +20%
Industrial heat	NZ$0.34/kg	Gas transmission +10%	NZ$0.37/kg	Gas transmission +20%
Residential and commercial heat	NZ$2.06/kg	Gas transmission +10%, distribution the same as gas	NZ$2.09/kg	Gas transmission +20%, distribution the same as gas
Heavy duty vehicles	NZ$2.06/kg	Gas transmission +10%, distribution the same as gas	NZ$2.09/kg	Gas transmission +20%, distribution the same as gas
Electricity				
OCGT peaker	NZ$1,150/kW	E4tech, UCL, Kiwa Gastec (2015)	NZ$1,438/kW	E4tech, UCL, Kiwa Gastec (2015) +25% for uncertainty
Efficiency	35%	BEIS (2016)	Same as low	
Availability	6%	BEIS (2016)	Same as low	
Industrial heat				
Boiler cost	NZ$93/kW	NERA and AEA (2009)	NZ$192/kW	E4tech, UCL, Kiwa Gastec (2015)
Efficiency	90%	E4tech, UCL, Kiwa Gastec (2015)	Same as low	
Availability	90%	E4tech, UCL, Kiwa Gastec (2015)	Same as low	

	LOW		HIGH	
COMPONENT	ASSUMPTION	SOURCE	ASSUMPTION	SOURCE
Residential and commercial heat				
Boiler cost	NZ$3,900/boiler	Element Energy and E4tech (2018)	NZ$6,435/boiler	Kiwa and E4tech (2016)
Annual demand	25GJ	Gas Industry Company (2017)	Same as low	
Heavy goods vehicles >25t				
Vehicle cost	NZ$164,814	Ricardo AEA (2012)	NZ$190,542	Ricardo AEA (2012)
Annual vehicle kilometres	79,269km	Ministry of Transport (2017)	Same as low	
Efficiency (km/MJ)	0.26	Ricardo AEA (2012)	Same as low	
Heavy goods vehicles 10–25t				
Vehicle cost	NZ$126,498	Ricardo AEA (2012)	NZ$144,854	Ricardo AEA (2012)
Annual vehicle kilometres	39,449km	Ministry of Transport (2017)	Same as low	
Efficiency (km/MJ)	0.29	Ricardo AEA (2012)	Same as low	
Heavy goods vehicles <10t				
Vehicle cost	NZ$78,706	Ricardo AEA (2012)	NZ$89,809	Ricardo AEA (2012)
Annual vehicle kilometres	18,477km	Ministry of Transport (2017)	Same as low	
Efficiency (km/MJ)	0.31	Ricardo AEA (2012)	Same as low	

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