Gas Transition Plan

Gas Industry Co.

Foreword

This document is based on the draft Gas Transition Plan approved by the Gas Industry Co board in February 2023. It outlines our perspective on key issues in the transition at October 2023.

The draft Plan was prepared on the basis of the Terms of Reference approved by Cabinet in 2022. Subsequently, in August 2023, MBIE published an Issues Paper, based in part on analysis and insights from this draft. That Issues Paper is currently out for public consultation.

The driver of this plan is the need to achieve a transition in which emissions from gas sector decline substantially over the next two decades, while also providing sufficient clarity to investment decision-makers, so that security of supply is maintained for gas consumers and electricity generation. Other objectives for the transition were specified in the Terms of Reference, and this plan substantially achieves them.

The draft would need to be revisited if the emissions targets changed significantly or if a very large gas discovery substantially changed expected production volumes. However, we expect this plan is the optimal pathway on the basis of existing knowledge about currently forecast field performance, New Zealand's net zero legislation, and the Climate Change Commission's demonstration pathway, which outlines emissions budgets through to 2035. Therefore, we expect this draft will be useful to decision-makers seeking to understand the potential role of the gas sector in the transition to a net zero economy.

The plan has been developed in close consultation with industry and specialist experts. As the co-regulator of the gas sector, Gas Industry Co has been able to add our own assessment. On behalf of the Board of Gas Industry Co, I commend the outcome to you.

Rt Hon Jim Bolger

Chair

1. Executive Summary

This section summarises Gas Industry Company's insights and recommendations for a gas transition that best meets desired outcomes.

Details of the plan follow in the substantive document, following the contents page.

A Managed Transition

The Gas Transition Plan found that a managed transition is the best pathway to meet emissions budgets consistent with New Zealand's pathway to net zero in 2050, provide energy security and energy equity, reduce emissions efficiently, and deliver energy conservation and efficiency.

In December 2021, Cabinet directed the Ministry of Business, Innovation and Employment (MBIE) to work in conjunction with the gas industry co-regulator, Gas Industry Company Limited, to develop a Gas Transition Plan. The purpose of the Gas Transition Plan is to:

- help inform decision-making and further action by government; and
- help to inform industry on the required investments and work to ensure an equitable transition for natural gas.

This Plan covers the emissions budget periods to 2035, while signalling the longer-term direction out to 2050.

In line with Cabinet's Terms of Reference, it addresses the availability of gas to other markets that use it as an input, such as chemical transformation in industrial manufacturing and thermal electricity generation, emphasis natural gas transition pathways, and facilitates the uptake of renewable gases.

1.1. Objectives

The Gas Transition Plan Terms of Reference outline the desired outcomes for the transition:

1. Sustainability.
2. Energy security.
3. Energy Equity.
4. Emission Reductions.
5. Energy Conservation and Efficiency.

1.2. Emissions Budgets

The Emissions Reduction Plan contains sector targets to help track progress over each budget period, but does not map emissions budgets for sub-sectors. Most gas is included in emissions budgets for the Energy and Industry sector, which emits around 24% of New Zealand's total CO_2 equivalent emissions. The Climate Change Commission's (CCC) advice to government, which underpinned development of the emissions budgets, published a demonstration emissions pathway for natural gas. This demonstration pathway is used for comparison purposes, as a representation of the Emissions Reduction Plan budgets for gas).

1.3. Pathways for the Gas Sector

Any pathway requires investment to unlock opportunities that new technology options may provide, and also to maintain existing standards of energy delivery to consumers.

In 2021, our Gas Market Settings Investigation[1] advised that a transition plan is needed to ensure that emissions from fossil fuels decline while investment continues to avoid a substantial risk of a disorderly exit of the natural gas sector.

We evaluated four potential high-level pathways:

- **Business-as-Usual**. In this scenario, there is a substantial risk of a disorderly exit of New Zealand's natural gas sector. Insufficient investment becomes increasingly likely due to uncertainty around the future for natural gas.
- **Switch to Hydrogen**: Although hydrogen has a role in the energy transition, there is not sufficient confidence about the role of hydrogen to be able to recommend it as a strategy for transitioning natural gas before 2035 as the economics of the option do not currently support a complete hydrogen replacement pathway for the gas sector.
- **Rapid winddown of the sector**: This pathway would reduce emissions from the gas sector faster, but would result in significant social impacts, increasing costs to consumers, elevated electricity prices, worsening energy supply security, potentially worse emissions outcomes through the use of alternative thermal fuels, and widespread impacts on some industries, potentially leading them to exit even though they could be economically viable.
- **A managed transition**. Selective interventions can ensure sustainability and emissions reductions in line with the ERP, while also ensuring security of supply, and meeting objectives for energy conservation and efficiency, and energy equity.

Two pathways are capable of meeting required emissions reductions: a rapid winddown and a managed transition. Only one pathway, the managed transition, meets the objectives (identified at 1.1 above) including emissions reductions. Figure 1, below, shows the modelled emissions forecast of the managed transition compared to the CCC's demonstration path.

1 https://www.gasindustry.co.nz/assets/CoverDocument/Gas-Industry-Co-Gas-Market-Settings-Investigation.pdf

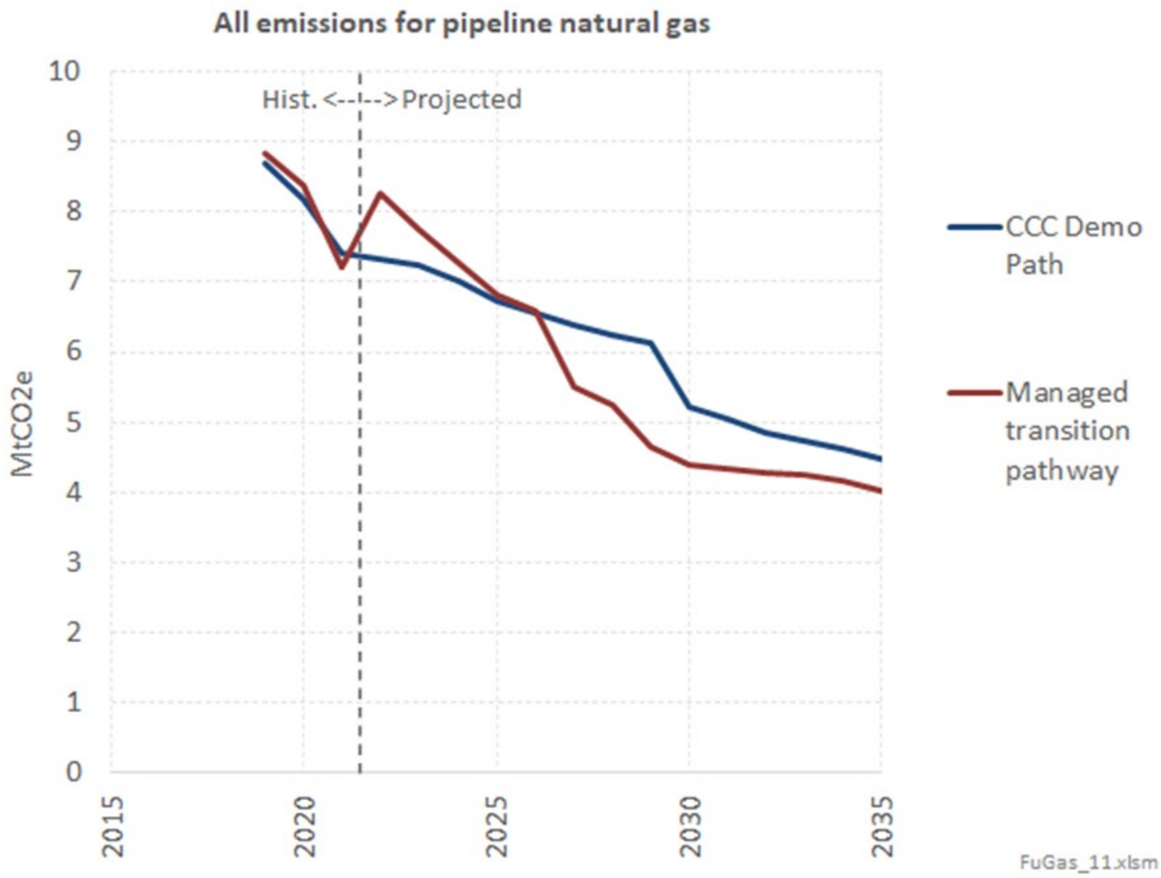

Figure 1. Emissions forecast for the New Zealand gas sector

1.4. Summary: The Pathway to 2035 and Beyond

Achieving the objectives for the Gas Transition Plan will require targeted interventions, changes to policy and regulations, and investment in new technologies, including emissions capture and renewable gas.

Phases of emissions budgets

In the initial emission budget, to 2025, key outcomes of the transition rely on investment that has already occurred. Key initiatives are driven by the ETS and include the exit of some gas-inclusive electricity generation, such as the Taranaki combined cycle plant. Work gets underway to plan investment in further electrification, emissions capture and renewable gas blending.

During second emission budget, to 2030, significant decarbonisation of electricity is expected alongside industrial savings, with biogas blending and emissions capture beginning from the late 2020s. New Zealand's largest energy user, Methanex, achieves 10% emissions reductions through efficiency improvements.

In the third emissions budget, to 2035, emissions capture and other investments continue to drive industrial emissions down by 30% from 2022 levels and reduce emissions associated with gas production.

The major contributor to emissions reductions before 2030 is the shift from gas-inclusive electricity generation to 95-98% renewable. Investment to drive this shift is already underway, driven by the cost of emitting carbon at today's prices.

Post 2025, further emissions reductions to achieve budgets can be achieved consistently with other objectives if emissions sequestration is used. Emissions sequestration could be operating, and helping to reduce emissions, from the late-2020s.

The other major contributor through the budget periods to 2035 and beyond will be emissions reductions from industrial gas use. These will be driven by the carbon price, and achieved through a combination of process and technology efficiencies, switching to other fuels, such as electricity, renewable gas or biomass, and de-industrialisation.

Figure 2 below, shows emissions reductions based on these assumptions.

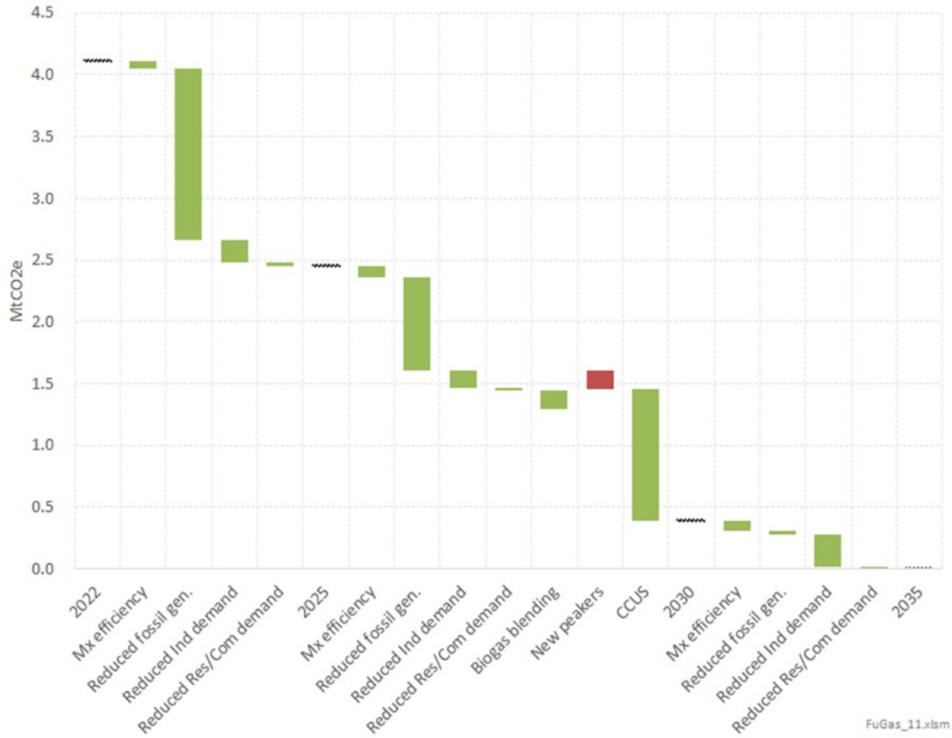

Figure 2. Changes in emissions during each emissions budget

Beyond 2035, further investments would be complemented by innovations in technologies as gas fields begin to deplete. These have not been modelled due to high levels of uncertainty and because the focus of this plan is the budgets to 2035. The Gas Transition Plan is consistent with a viable pathway to meet emission budgets for the natural gas sector out to 2050.

Figure 3. The gas transition

1.5. Transitions for Gas Sector Segments

Electricity

- The electricity sector transitions away from gas use to 95-98% renewable generation by 2030.
- Analysis of New Zealand's electricity sector recognises a need for peaking gas-fired generation to meet periods of peak demand and to firm variable renewable generation until the energy sector can support 100% renewable electricity.
- Where electricity needs gas-inclusive generation only for peak demand periods and dry year conditions, market measures are required to ensure gas deliverability.

Petrochemicals

- Methanex is assumed to achieve 10% reductions in emissions by 2030 and 15% by 2035 through process efficiencies.

Industrial

- The ETS is expected to incentivise industrial gas consumers to reduce emissions from natural gas by 30% by 2035 through a combination of efficiencies, emissions capture, fuel switching, and market exit.

Residential and Small Commercial

- A biomethane market is stimulated through a biogas blend equivalent to 20% of residential and small commercial gas volumes.

Production, Transmission and Distribution

- Emissions sequestration is necessary to achieve the sector's target emissions reductions. Capture and sequestration technology is mature, economic compared to the carbon price, available today and identified sites can begin operation in the 2020s. Regulation of consenting and abandonment needs to be modernised.
- Fugitive emissions from distribution networks reduce through improved assessment methods.
- No change is needed for gas transmission and distribution regulatory arrangements before 2035.

LPG

- LPG can begin to decarbonise through a combination of virtual trading and renewable blending.

1.6. Supporting the Transition with Policy Initiatives

Four key initiatives have been identified to support the gas sector's transition, and have been assessed against the Gas Transition Plan objectives, shown in Figure 4 below.

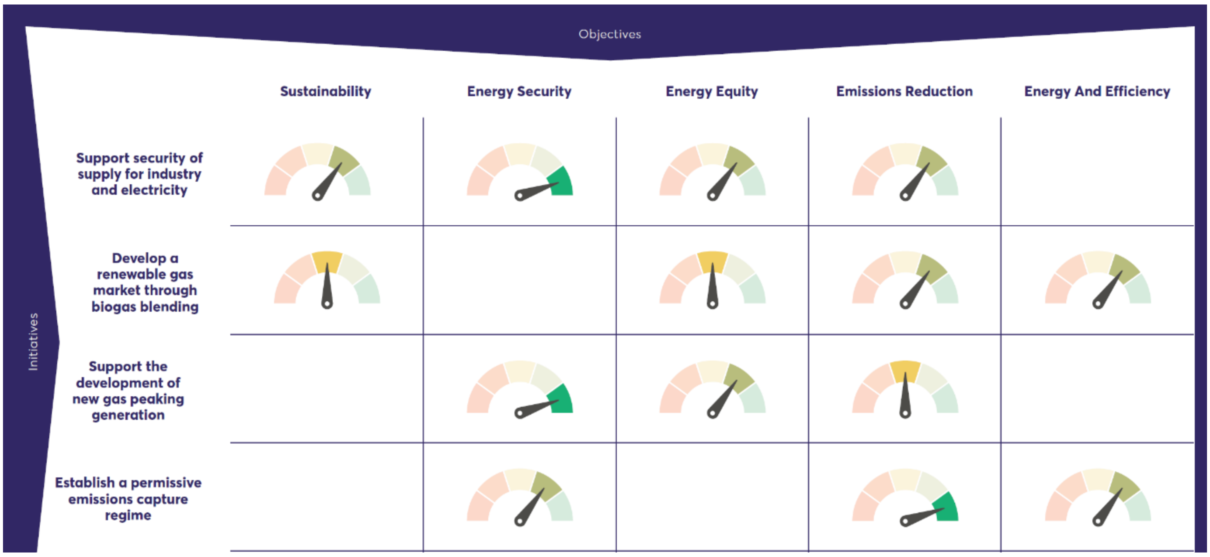

Figure 4. Assessment of initiatives against transition objectives

The four key initiatives are:

Support security of supply for industry and electricity

Gas fields are unlikely to be further developed to supply a peaking electricity plant in a 95-98% renewable scenario as the volumes of gas supplied would not be economic for field operators.

Two options exist to support the deliverability of gas for the electricity sector:

- Petrochemical demand for gas can continue to underwrite field development. An arrangement could be negotiated with Methanex where it continues to operate, invests in efficiencies, and sells options to divert its gas consumption.
- Alternatively, an LNG import facility could be established, providing a reliable and diversified source of gas and acting as a virtual storage system. This option may be more expensive than demand response but lower cost than expanded gas storage, and much lower cost than 'battery' energy storage.

Develop a renewable gas market

- Existing supplies of biogas are sufficient to supply the equivalent of 20% of residential and small commercial gas volumes by 2030. These volume are currently used in lower efficiency plants.
- An initially small amount of biogas blending is expected to stimulate further development of a biogas market.
- The economics of biogas blending are supported by the re-purposing of existing infrastructure (that is, it delays or avoids the cost of abandoning pipelines and appliances).

- Biomethane meets chemical specifications for pipeline natural gas and existing gas access and reconciliation arrangements are suitable for biogas injection into natural gas networks. This means biogas electrons do not need to be piped to biogas purchasers as the transaction can be completed virtually (as occurs today to balance sales and distribution from different fields).
- Regulatory arrangements to support this blended solution should be developed by a Gas Industry Co workstream using its existing regulation development processes.
- In some circumstances, tradeable certificates may allow a 'virtual' alternative to blending, where the cost of operating a single plant on biogas is shared by other plants without that single plant needing to connect its gas into a pipeline (thus decarbonising a proportion of consumption).

Support the development of new gas peaking generation

- Post-2025, a 400MW newly-built gas-inclusive electricity peaking plant will be required to support security in the electricity sector. Gas sector regulators could work with electricity regulators to develop mechanisms to ensure new, low emissions, gas-inclusive generation is brought to market and operates in a way that maximises renewables in the system. For example, regulation could potentially require a new plant to operate only with carbon capture and storage technology installed and make rules to ensure it doesn't run when not required. (These *example* policy interventions are conceptual and have not been fully evaluated).

Establish a permissive emissions capture regime

- Emissions capture can significantly reduce emissions from gas production in the near-term and help to provide greater investment confidence to develop existing fields.
- Additional opportunities for emissions capture have been identified in the upstream, electricity, petrochemicals and industrial segments of the gas market.
- If Direct Air Capture becomes economic, disposal of CO_2 from DAC underground cannot be consented under current planning laws. Current international rules and the NZETS do not allow operators to obtain the benefit of the carbon price for DAC.
- Reform is required to allow parties sequestering emissions to avoid the carbon price, to consenting rules covering reinjection into onshore wells, and to regulate governance of facilities post-operation.

Complementary policies

Further interventions are not required to achieve emissions reductions targets. Regulators should be careful of interventions that may restrict the deployment of low carbon alternatives such as biogas.

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2. Introduction

2.1. Gas Transition Plan Background

In December 2021, Cabinet agreed to develop the Gas Transition Plan to articulate the transition pathway for fossil gas over time, and to meet the emissions budgets laid out in the Emissions Reduction Plan. Cabinet agreed for the Ministry of Business, Innovation and Employment (MBIE) to work in conjunction with Gas Industry Company Limited (the gas industry coregulator) to develop the Gas Transition Plan. The purpose of the Gas Transition Plan is to:

- help inform decision-making and further action by government; and
- help to inform industry on the required investments and work to ensure an equitable transition for natural gas.

This Gas Transition Plan covers the first three emissions budgets out to 2035, while signalling the longer-term direction out to 2050, with an emphasis on natural gas transition pathways, and what is required to facilitate the uptake of renewable gases.

2.1.1. Emissions Reduction Plan

Based on advice from the Climate Change Commission provided in June of 2021 (refer *Ināia tonu nei: a low emissions future for Aotearoa)*, in May 2022 the Government released its first three emissions budgets out to 2035 together with an Emissions Reduction Plan (ERP) detailing the strategies, policies and actions it will use to achieve the budgets as required by the Climate Change Response Act 2002. The Government will publish its next ERP in 2024 and progress will be monitored by the Climate Change Commission.

The ERP, and the strategy for reducing emissions, is based on five principles:

- Playing our part
- Empowering Māori
- Equitable transition
- Working with nature
- A productive, sustainable and inclusive economy

The natural gas sector is covered in the Chapter 11 of the ERP – the Energy and Industry Sector (E&I sector) and sets out a range of actions that the Government will undertake to drive the transition for the E&I sector. The ERP targets for New Zealand and for the E&I sector are discussed in Appendix A. The long-term vision for the E&I sector is:

> *"By 2050, our energy system is highly renewable, sustainable and efficient, and supports a low-emissions and high-wage economy. Energy is accessible and affordable and supports the wellbeing of all New Zealanders. Energy supply is secure, reliable and resilient, including in the face of global shocks."*

2.1.2. Energy Strategy

The New Zealand Energy Strategy (NZES) is intended to be released early 2024. Amongst other things it will set out how the energy sector will decarbonise through greater levels of renewable energy and other low emissions alternatives. The NZES will align policies and projects to ensure there is a coordinated approach to the energy transition.

The development of the NZES is also being supported by several related workstreams:

a) Gas Transition Plan (this document)
b) Electricity Market Measures [TBC – to update in 2023].
c) Framework for offshore renewable energy [due when?]
d) Hydrogen Roadmap.

The GTP focuses on the natural gas sector as a key input into the Energy Strategy, and its development should be seen alongside the other key initiatives in the ERP.

2.1.3. Other ERP Workstreams

The Government has also committed to develop a range of other strategies and programmes of work:

a) The New Zealand Battery Project is a programme of work is to determine a renewable solution to the New Zealand electricity systems 'dry-year' problem. Phase 1 of the NZ Battery Project was considered by Cabinet in February 2023. [update once the Cabinet decision is made].
b) The Building for Climate Change programme is a long-term work programme to reduce emissions from constructing and operating buildings. MBIE conducted a consultation on a 'Transforming Operational Efficiency' framework in 2020, that proposed to set required levels of efficiency for energy use and water use and define minimum indoor environmental quality measures for buildings.
c) The National Direction on Greenhouse Gases – Cabinet has agreed to a National Policy Statement (NPS) and a National Environmental Standard (NES) that will set out nationally consistent policies, rules and requirements to guide regional councils making decisions on industrial process heat GHG emissions (e.g. from coal boilers). A consultation on this was run by the Ministry for the Environment in 2021.
d) Government Investment in Decarbonising Industry Fund (GIDI fund) – a dedicated fund to assist industry decarbonise its stationary energy emissions, with an emphasis on investing in expanded processes heating, commercial space and water heating decarbonisation and upgrading equipment used by SMEs to be more energy efficient (see below).
e) Carbon Neutral Government Programme - aims to make a number of organisations within the public sector carbon neutral from 2025 by phasing out coal-fired boilers, optimising car fleets and requiring NABERSNZ, a system for rating the energy efficiency of office buildings.

Over time it is expected that benefits from these programmes will include:

- Reduced use of fossil fuels to generate electricity in dry years or to support peak load.
- Increase energy efficiency of our buildings, and consequent reduction in missions from the use of fossil fuels. In particular, by requiring NABERSNZ, a system for rating the energy efficiency of office buildings, for government leased office space (over 2,000m2).
- Reduced emissions from the use of low and medium temperature coal boilers, particularly those that emit above a specified tonnage of CO_2-e per year, by requiring users of boilers to apply the best practicable option to their discharging activities, and phasing out use by 2037.
- Reduced emissions from coal-fired boilers from the public sector, with a focus on removing the largest and most active by the end of 2025
- Reduced emissions from the public sector owned transport fleet

2.2. Gas Transition Plan Objectives

The Gas Transition Plan Terms of Reference outline the desired outcomes for the transition for natural gas out to 2035 as:

- **Sustainability:** Aotearoa New Zealand avoids making decisions that further lock in our reliance on fossil fuels.
- **Energy security:** Security of supply is maintained through the transition, as fossil gas continues to be progressively displaced by renewable, lower emissions, alternatives.
- **Energy Equity:** Adverse and unexpected effects on fossil gas consumers are prevented or mitigated and consumers retain access to affordable, reliable and abundant energy. This includes minimising the broader effects on prices paid by consumers, as well as pricing of inputs for businesses as we transition.
- **Emission Reductions:** Aotearoa New Zealand prioritises reducing emissions in the most economically efficient way. The pace of emissions reductions will need to support Aotearoa New Zealand's emissions budgets and 2050 emissions targets.
- **Energy Conservation and Efficiency:** Energy conservation and efficiency play a key role in the overall transition.

Each of these objectives can be applied to the gas sector, but decisions made for the gas sector can have implications for these objectives throughout the energy sector. The wider implications of all fossil fuel use in New Zeland should be considered in the Gas Transition Plan analysis, so that unintended ramifications for New Zealand's energy transition can be mitigated.

Each of these five objectives, and the interpretation of them that has been applied to Gas Transition Plan analysis is discussed in more detail below:

2.2.1. Sustainability

A successful Gas Transition Plan will create a pathway with decreasing gas use in New Zealand. Domestic gas is developed and produced to meet demand, ensuring the needs of users are met. As demand decreases over time, so too will production.

However, this does not mean reducing gas use entirely. Doing so would prioritise sustainability over the remaining 4 objectives that must also be met. Some gas use may remain in the pathway where it is needed to ensure positive security of supply, conservation and efficiency, emissions reductions, and equity outcomes. In some isolated cases it may be that gas use must increase to ensure the remaining 4 objectives are met. A considered decision must be made when this trade off occurs.

Because the decline in gas use will happen over time, it is important that the Gas Transition Plan sets out a fair and efficient pathway while it occurs. The pathway also has an important role in developing other options such as renewable gases so that gas consumers have sustainable alternative options.

2.2.2. Energy Security

While gas demand will decrease through the transition, many users will continue to rely on gas as a source of energy well beyond 2030. The Gas Market Settings Investigation looked at what was needed to ensure secure supply of energy to these consumers, and identified two key factors to support this:

- Because of the way New Zealand's gas fields and industry operate and the capital intensive nature of gas development, ongoing investment is required in order for gas to be available to meet these needs.
- Long-term, baseload, large-volume gas contracts are crucial to support field development and system operation since they provide the certainty of demand needed for producers to commit to funding development and enable the required flexibility in the system.

Petrochemicals (and Methanex in particular) perform a vital role in supporting the rest of the energy sector as they are the only industry sector large enough to be able to play this role. Their ongoing operation is therefore critical to ensure natural gas can play its part in the energy transition.

Natural gas continues to play a vital role in supporting electricity generation. As new renewable electricity projects are developed and come on line, the overall volumes of gas needed to fuel electricity generation will decrease (despite a forecast increase in overall electricity demand). However, natural gas will be needed as a source of back up energy to provide security of fuel supply for electricity, both during sustained dry periods ('dry winters') and for year-round peak demand (likely alongside coal for a period) and this need is likely to become increasingly variable. This will continue until the electricity sector is able to reach 100% renewable electricity.

A successful Gas Transition Plan will support investment where it is needed to ensure stable delivery of energy to consumers in both the gas and electricity sectors.

2.2.3. Energy Equity

Energy equity is focused on the wellbeing of consumers, in particular through energy affordability.

The World Energy Council, which prepares the annual World Energy Trilemma Index[2] defines energy equity as "a country's ability to provide universal access to reliable, affordable, and abundant energy for domestic and commercial use. The dimension captures basic access to electricity and clean cooking fuels and technologies, access to prosperity-enabling levels of energy consumption, and affordability of electricity, gas, and fuel."

While affordability is a fundamental consideration when assessing equity, energy equity has wider meaning than low prices for consumers because if price is insufficient to generate returns on investment, investment will not occur. Markets deal with this by driving prices up until investment does occur or a cheaper alternative is available. However, propensity to pay higher prices is not evenly distributed. There are capital cost considerations as well, as fuel switching can require many years of consumption to earn back the investment, while many consumers do not have access to sufficient capital to upfront costs.

For this reason, energy equity also involves access to energy, the ability for consumers to make their own choices about their preferred energy options, the effect of policy across different communities and the effect that choices have on wellbeing.

[2] https://www.worldenergy.org/transition-toolkit/world-energy-trilemma-index,

In the Gas Transition Plan, equity is assessed as cost and affordability of energy for consumers, with reference to expectations and alternatives, and the equitable distribution of costs across regions, time, and different consumer groups.

Other factors assessed in measuring energy equity include:

- Consistency or reliable provision across regions and consumer types,
- Equity of access to alternative energy options
- Economic impacts on energy consumers, such as job losses and employment opportunities from energy choices,
- Social wellbeing from energy choices, especially distributional costs and benefits,

2.2.4. Emissions Reductions

As outlined in the Gas Transition Plan Terms of Reference, one of the purposes of the Gas Transition Plan is to:

> "establish realistic, but ambitious, transition pathways for the fossil gas sector to decarbonise in line with the 2023-2025, 2026-2030, and 2031-2035 emissions budgets".

As part of their advice to government, the CCC published a demonstration pathway which includes an emissions pathway for the natural gas sector. This pathway was intended to show one potential avenue for decreasing emissions and was not presented as the recommended direction of travel for the natural gas sector.

The Gas Transition Plan Terms of Reference outline a target of hitting the ERP targets for the gas sector (which are show in Appendix A), which have been built up from the CCC demonstration pathway. The ERP does not map emissions budgets for sectors more granular than Energy and Industry, and so the emissions from the natural gas sector in the CCC demonstration pathway have been used as a representation of the ERP emissions budgets for natural gas for the purposes of the Gas Transition Plan. The CCC demonstration pathway is shown in the figure below, with 1.4MtCO_2e of gas sector emissions in net zero 2050.

Figure **5**. Forecast Emissions under the Climate Change Commissions Demonstration Pathway

The CCC pathway demonstrates the expected emissions reductions contribution from the gas sector as part of New Zealand's overall emissions budgets. In 2035, the gas sector is forecast to contribute 10% of the Energy and Industry emissions budgets in the ERP.

CCC Emissions Reductions (Mt CO_2-e)	**First Emissions Budget (EB1) (2022-25)**	**Second Emissions Budget (EB2) (2026-30)**	**Third Emissions Budget (EB3) (2031-2035)**
Natural Gas Emissions	28.3	30.5	23.7
Per year budget	7.1	6.1	4.7
% of E&I EB met by gas sector	9.7%	10.0%	9.8%

A successful Gas Transition Plan will meet or exceed the emissions reductions outlined in the CCC demonstration pathway.

2.2.5. Energy Conservation and Efficiency

In terms of Gas Transition Plan assessments, Energy Conservation and Efficiency could be considered as the efficiency of emissions reduction (cost per emissions reduction achieved), as the emissions generated from an energy input (emissions per energy input), or as the efficiency of products produced (outputs per energy input).

The Gas Transition Plan will consider each of these types of efficiencies in its assessment.

Investment will be required to unlock improvements to efficiency. The key consideration for the Gas Transition Plan will be a stable environment where gas users can see the long term benefit of investing in such improvements. Without this supportive environment, these investments will not be made, and opportunities to use energy more efficiently will not be pursued.

Alongside efficiency, energy conservation can be unlocked with an environment that supports investments. Energy can be conserved if activity is reduced by ceasing energy use altogether, but it is not conserved efficiently. Instead, the Gas Transition Plane can promote conservation by allowing the ETS to drive market participants to reduce wastage in their most efficient method.

The Gas Transition Plan will consider the gains that can be made through these investments in energy efficiency and conservation as one of the opportunities for the transition, and will support these investments by developing a supportive environment.

3. Pathways for the Gas Sector

- The Gas Transition Plan assumes the ETS is the main driver, with a role for complementary policy to ensure all of the ToR objectives are hit.
- Four broad options exist for the fossil gas sector to meet the GTP objectives.
    - Business as usual.
    - Hydrogen replacing natural gas.
    - Winddown of natural gas.
    - A Managed transition that meets the budgets over time through a combination of initiatives.
- These scenarios were evaluated, in summary:
    - Business as usual fails to meet any of the objectives. The Gas Market Settings Investigation determined that a pathway forward was required rather than the trajectory that the gas sector is currently on.
    - Hydrogen has a role in the energy transition. However, assessments of the role of hydrogen in potentially replacing some or all natural gas does not give sufficient confidence to recommend it as a strategy for transitioning natural gas before 2035.
    - A winddown pathway achieves sustainability and emissions reductions objectives in the gas sector, but does not support security of supply, conservation and efficiency, equity outcomes.
    - A managed transition outperforms a winddown pathway on all objectives.
- Therefore, Part 2 describes how to do the managed transition in a way that meets all of the objectives.

3.1. The need for investment under any pathway

The transition of our energy systems to a low carbon future relies on significant, continuing investment. New renewable generation requires investment to increase the proportion of renewable electricity in New Zealand. New technologies that can decarbonise gas use can only come to market with the support of significant investment. Even known gas reserves require continual investment to maintain field deliverability.

As highlighted in the Gas Market Settings Investigation, there is a higher risk hurdle for capital investment in gas production and development in New Zealand than has previously been the case. While investment is happening now, future capital investment is at risk for a variety of reasons and a higher risk premium is being attached to any investment to compensate. The report considered that this leads to a real risk that insufficient investment will be committed to ensure that gas reserves and contingent resources will come to market. Security of supply for both electricity generation and major users could therefore be compromised during the transition to 2030 and beyond. The Gas Market Settings

Investigation found that, in relation to the gas development and production investment needed during the transition, three key factors combine to elevate risk:

- Demand for gas drives investment into field development and production but demand is affected by: concern about businesses or industries becoming uneconomic or closing despite being economic, a lack of clarity about the expected timing balance between reduced gas use and overall decarbonisation for major gas users, and lack of confidence that gas supply will be available to meet demand.
- There are fewer opportunities to manage risk as the size of the industry decreases during the transition. This is because investment risk is managed over a portfolio or fields. As the field decreases, opportunities for diversification reduce and fewer parties are willing and available to share risk.
- Investors in both production and in industries that consume gas understand and expect that the policy and regulatory approach that is inevitable in a transition will change the economics of their investments, but they are unsure about the extent to which intervention will affect the return on investment.

Most of these factors are unavoidable through the transition, but management of them can reduce the costs of transition and 'frictional' costs associated with uncertainty. For example, compromised security of supply can have economic and social costs far in excess of the economic incentive for any single investor to provide security. It will sometimes be rational for an investor to manage risk by exiting a market (or decline to enter one, or defer development), even if security of supply for others is compromised by that decision. The prospect that investment may not occur itself becomes an elevated risk to others – industrial customers may consider investment in their business sub-economic based on risk-adjusted returns if they perceive that investment may not make place to deliver energy they need.

A gas transition plan can provide confidence required to support investment, so that market exits do not occur while the security of supply those investments provide is still required.

3.2. The ETS is the main driver for emissions reductions in the gas sector

As a consistent and predictable driver of change, a key component of a supportive investment environment is provided by the emissions trading scheme. The Gas Transition Plan recognises the carbon price applied through the emission trading scheme as the most significant driver of behaviour change. A description of the New Zealand Emissions Trading Scheme (NZ ETS) is on the Ministry for the Environment website.[3] The ETS helps to reduce emissions by:

- requiring businesses to measure and report on their greenhouse gas emissions
- requiring businesses to surrender one 'emissions unit' (known as an NZU) to the Government for every tonne they emit
- limiting the number of NZUs available to emitters (i.e. that are supplied into the scheme)

The Government sets and reduces the number of units supplied into the scheme over time. This limits the quantity of emissions in line with New Zealand's emission reduction targets. Businesses who participate in the NZ ETS can buy and sell units from each other. The price for units reflects supply and demand in the scheme. Emissions reductions are informed by the marginal cost of abatement, with lower cost emissions reductions opportunities being

[3] https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/ets/about-nz-ets/

targeted first. For example, in many situations the replacement of coal fired boilers has a lower cost of abatement compared to the replacement of fossil gas boilers because of the higher emissions intensity from coal use.

3.2.1. Why it's efficient

The ETS price signal allows businesses to make economically efficient choices about how to reduce emissions. For example, the electricity sector is expected to transition almost completely to renewables during the 2020s because electricity generated from renewables is more economically efficient, even allowing for the cost of retaining some gas-inclusive peaking generation and storage (if that is required past 2030). One reason that renewable electricity is cheaper is that gas-inclusive generation incurs a carbon cost. The components of cost and a discussion of the levelised cost of energy are out of scope for the Gas Transition Plan, but the impact of the carbon price is an important driver behind the relative economics of new renewable electricity generation, even allowing for thermal firming.

Industrial consumers will innovate and fuel switch more as production input costs associated with gas increase and as markets mature. For example, the carbon price incentivises businesses to look for process efficiencies even in hard-to-abate industries. It is likely that innovation will lead to cheaper biogas as the availability of a market gives potential producers the confidence to invest in new plant.

Price drives producers and consumers to make decisions about whether to invest or consume with consideration of the economic costs and benefits. Individual consumers can assess the cost of alternatives and expected market conditions and whether alternatives are likely to be cheaper or more suitable for their particular conditions. In contrast, regulators do not have as much information and generally cannot tailor sector regulation to individual circumstances. Therefore, regulatory instruments, such as bans and restrictions that act to replace market decisions, need to be employed with care as they can lead to inefficiencies in allocation of scarce resources and even cause more emissions to result from displaced activity.

3.2.2. Applying the ETS in the Gas Transition

In the Gas Transition Plan, the emissions reductions budgets are met using existing expectations for the carbon price. The transition to renewable electricity, for example, is being planned on the basis of existing price expectations.

If emissions reductions occur more slowly than expected, then that may mean a higher carbon price is needed to drive behaviour change. On other hand, if emissions fall faster, it will be important to understand the causes- technology uptake may occur faster than expected, indicating the carbon price is functioning properly. However, if emissions fall faster than expected because of more de-industrialisation than expected, then that implies the carbon price is affecting industry more than intended.

3.2.3. Other policy instruments also have a role

While emissions pricing plays a central role in reducing both gross and net emissions, emissions pricing alone will not support transition in an equitable way across all consumer segments.

In the absence of complementary policies, emissions pricing may fail to achieve many otherwise low-cost emissions reduction opportunities, due to the existence of other barriers and market limitations hindering some sectors and communities to respond to an emissions price.

Complementary policies need to be carefully targeted. Emissions reductions from industrial and commercial gas consumers are based on expectations about the likely adoption of fuel switching (to electricity, renewable gas or bio-mass), carbon capture and exit from the economy. Complementary policies can facilitate those outcomes, particularly where initiatives are efficient, such as removing barriers to investment. Examples of complementary policies that have been introduced internationally are discussed in Section 6.2.

The Gas Transition Plan will identify specific gaps and barriers to a transition to ensure any policies that are recommended will facilitate outcomes.

3.2.4. Monitoring and Reporting

Planning for transition is forward-looking. It sets out expectations for outcomes to be achieved at milestones across the transition period for significant objectives, including emissions reductions and security of supply.

Policy-makers need assurance today that milestones will be achieved. Assurance can be delivered through monitoring and reporting.

To ensure that key assumptions still hold true, a monitoring regime should be put in place.

Certain obligations are already in place. The Climate Change Commission has a statutory responsibility for reporting progress on emissions reductions and the success of policy instruments in achieving them.

Gas Industry Co has existing reporting obligations to parliament covering the performance of the gas sector, and collects detailed information about gas supply and demand. These can be amended to include reporting on gas sector performance against transition objectives. Gas Industry Co also has formal industry engagement processes and the institutional understanding of the gas sector to investigate issues with meeting milestones and targets and report publicly.

Formal monitoring requirements that can be introduced at very low cost should include:

- Assessment of progress in meeting the gas sector emissions budgets,
- Assessment of other milestones and metrics adopted in the Gas Transition Plan:
- Assessment of impacts of recommendations on other objectives in the Gas Transition Plan Terms of Reference: Sustainability, energy security, energy equity, and energy conservation and efficiency.
- Recommendations for further investigation and regulatory action, including updates to the gas transition plan where material changes in performance and assumptions occur.

Requirements to report progress should be provided in regulation, reports should be annual and reports should be tabled in parliament.

3.3. Potential Gas Sector Pathways

In December 2020, the Minister of Energy and Resources wrote to Gas Industry Co asking if the current market, commercial and regulatory settings that provide for gas availability and flexibility were fit for purpose in supporting the transition to net-zero. This letter was the foundation of the Gas Market Settings Investigation[4] (GMSI) which was published in September 2021. Gas Industry Co investigated the settings in the natural gas market with a view to advising how these:

- affect overall availability and flexibility of gas supply
- support security of supply in the electricity market
- provide major gas users with sufficient certainty/transparency about gas supply for their operations, and
- whether they are fit for purpose for the transition.

The GMSI highlighted that in the absence of a transition plan for natural gas there was a substantial risk of a disorderly exit of New Zealand's natural gas sector. Of key concern is that insufficient investment would be committed to ensure that gas reserves and contingent resources will come to market to maintain fair and efficient deliverability to all consumers.

The transition of our energy systems to a low carbon future requires significant investment. Even known reserves require continual investment to maintain field deliverability. If investment does not happen at the levels needed to fill medium and longer-term gas demand, this is likely to mean that businesses, particularly those that are not sufficiently contracted, may not be able to secure all of the gas they would like to at prices that support their ongoing business continuity. Limits to upstream investment would risk supply to all gas consumers, and likely compromise security of supply for both electricity and gas consumers.

In the absence of intervention, this risk of insufficient investment becomes increasingly likely due to uncertainty around the future for natural gas; with concerns raised that businesses or industries could become uneconomic, a lack of clarity about the consequences of decarbonisation policy changes, and weakening consumer confidence that gas supply will be available to meet demand. As gas production is developed off the back of contracts with the demand side, upstream parties must have confidence in what demand will be in the future before they will be prepared to commit to investment happening today.

The Gas Market Settings Investigation advised that a transition plan is needed to ensure both that emissions from fossil fuels decline and to ensure investment needed to avoid a substantial risk of a disorderly exit of the natural gas sector.

Three broad options remain for the fossil gas sector to meet the Gas Transition Plan objectives:

- Complete hydrogen replacement
- Winddown
- Managed transition

Each of these pathways have been evaluated below to give clear direction to the Gas Transition Plan. With this direction determined, the detail of the pathway is laid out in the remainder of the report.

[4] https://www.gasindustry.co.nz/assets/CoverDocument/Gas-Industry-Co-Gas-Market-Settings-Investigation.pdf

3.4. Hydrogen as a Replacement

Key Points:

- Hydrogen has a role in the energy transition. However, assessments of the role of hydrogen in potentially replacing some or all natural gas does not give sufficient confidence to recommend it as a strategy for transitioning natural gas before 2035.
- Blue hydrogen production is only competitive with advanced CCS technologies, but CCS would also help decarbonise natural gas. Thus, New Zealand would probably continue to consume natural gas for key uses cases.
- Continued use of the gas pipeline network is consistent with hydrogen having a greater role in industry and infrastructure post-2035.

3.4.1. Background

Hydrogen is the simplest, lightest and most abundant element in the universe, making up more than 90% of all matter. Hydrogen is a promising technology with a wide range of applications. In its normal gaseous state, it is odourless, tasteless, colourless and non-toxic. It reacts readily with oxygen, releasing considerable amounts of energy as heat and producing only water as exhaust. Hydrogen is generally an energy carrier that can transfer and store energy. It is not a primary energy source such as natural gas, coal, biomass or wind.

The New Zealand government sees green hydrogen as important to leverage New Zealand's renewable energy and a pathway for decarbonisation of the energy sector. For this reason, transitioning the natural gas sector to hydrogen has been assessed as one potential scenario for the future of the sector.

Different types of gas are qualified by adjectives such as 'natural gas', 'fossil gas', 'biogas', 'town gas', 'green hydrogen' and 'blue hydrogen'.

- 'Green' hydrogen is produced by splitting water molecules into the constituent elements of hydrogen and oxygen, using renewable electricity to power an electrolyser.

- Hydrogen produced from natural gas or coal gasification and the associated release of carbon dioxide into the atmosphere, is called 'brown' hydrogen. 'Grey' hydrogen is a product of an industrial process.

- If the CO_2 emitted in this process is captured and sequestered (CCS), the resulting hydrogen is called 'blue' hydrogen.

- 'Blended' hydrogen gas in this section refers to natural gas blended with hydrogen and distributed through pipelines (unless context means other uses). Hydrogen can be blended with natural gas up to a maximum of about 20 per cent by volume.

3.4.2. Analysis

"While hydrogen produced from fossil fuels and industrial processes (brown, blue and grey) may play a role in the transition of New Zealand's regions and existing industries, the Government

considers there is greater opportunity for New Zealand in exploring the use of our renewable energy to produce green hydrogen as an alternative fuel for domestic use and for export." [5]

In its 2021 Gas Market Settings Investigation[6], Gas Industry Co noted that green hydrogen has been gaining traction as an alternative to natural gas, since it can deliver the same qualities of natural gas without emitting CO_2.

A hydrogen economy is beginning to emerge in New Zealand, as discussed in Section 5.5.1. Because of the interest in hydrogen, a 'hydrogen scenario' has been evaluated for the Gas Transition Plan to assess whether green or blue hydrogen could potentially replace some or all of the existing natural gas sector.

Castalia was commissioned to develop and evaluate scenarios specifically for transitioning natural gas, either fully replacing natural gas in new hydrogen-ready pipeline infrastructure or blending into existing networks, or as a fuel to help industry reduce CO_2 emissions. Blue hydrogen was also modelled because parallel analysis identified emissions sequestration potential.

The potential role of green hydrogen in other parts of the economy is briefly referenced below. As the focus was the impact on the natural gas transition, the role of hydrogen elsewhere in the economy was not evaluated except to the extent that other sectors may influence the role of hydrogen in replacing or reducing emissions from natural gas or natural gas infrastructure may influence hydrogen uptake in future. Castalia also evaluated whether competing technology options could be more cost effective at achieving the same policy objectives for hydrogen. Conclusions from previous studies have arrived at a similar conclusion about the role of green hydrogen have also been considered, and are referenced in more detail in Appendix A.

Low confidence that green or blue hydrogen will replace natural gas during emissions budgets to 2035

Modelling and analysis suggests that:

- New Zealand could demand a large amount of green hydrogen, but the demand is likely to be located in a way that does not require production in Taranaki nor transmission across large distances.
- Blue hydrogen production is competitive with advanced emissions capture (CCS) technologies, but CCS would also help decarbonise natural gas. New Zealand would probably continue to consume natural gas for key uses cases such as electricity generation and industrial uses, rather than use natural gas to produce hydrogen for the same use cases.
- Blended hydrogen could be financially viable for commercial and residential consumers on the distribution network. This might make hydrogen blending a viable option for partial decarbonisation. It could also make hydrogen blending (including at higher concentrations) a viable future option in case there is a technological breakthrough that lowers the cost of hydrogen or enables higher blending rates. However, blended hydrogen has a high marginal abatement cost, meaning blended hydrogen is unlikely to be cost-effective at reducing emissions compared to other options. This option is discussed further in Section 5.5.2.

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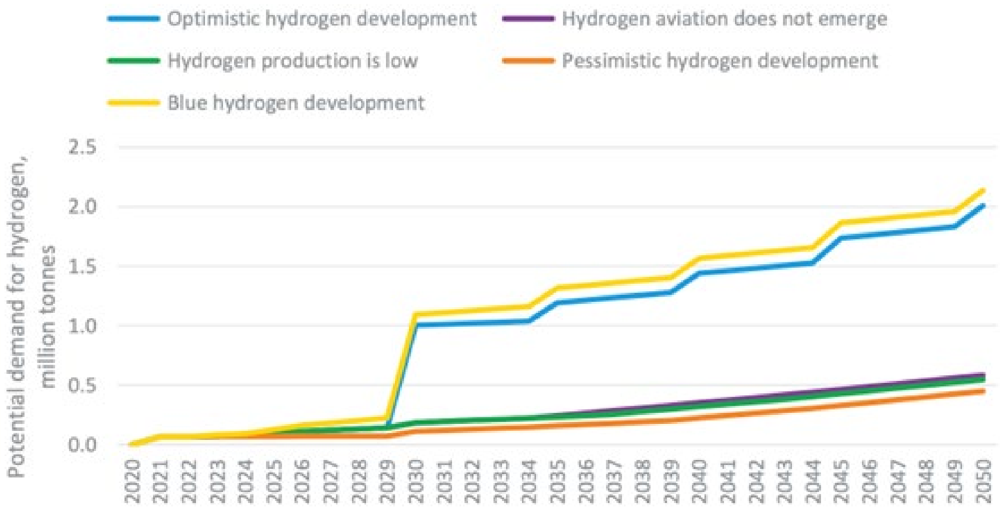
[5] A Vision for Hydrogen in New Zealand, Green Paper, Ministry of Business, Innovation & Employment, September 2019, page 11. At https://www.mbie.govt.nz/dmsdocument/6798-a-vision-for-hydrogen-in-new-zealand-green-paper

[6] https://www.gasindustry.co.nz/assets/CoverDocument/Gas-Industry-Co-Gas-Market-Settings-Investigation.pdf

The outcome is that there is not enough confidence in hydrogen's role pre-2035 to recommend it as a transition strategy for natural gas.



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

Introducing a large-scale hydrogen economy to New Zealand would require far reaching and capital-intensive investment and development, and major change throughout the energy sector. Hydrogen production facilities would need access to sufficient electricity supply to drive the electrolysis for hydrogen production. End-use technologies would need to be adapted or swapped. Suitable standards need to be developed. Transmission and distribution networks need to be updated to account for the change in fuel consumption and deal with practical issues like embrittlement and potential cracking of steel pipes (around a third of the Firstgas transmission network) when exposed to high pressure hydrogen.

Green hydrogen's role will grow post-2035

Castalia found that green hydrogen is likely to be important to New Zealand's energy transition, especially in heavy-duty vehicles and aviation.

Potential demand could also come from maritime transport and energy export. Other green hydrogen uses are possible, but they are less likely, or are relatively niche.

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

Continued use of gas distribution and transmission infrastructure maximises optionality for the uptake of green hydrogen post-2035 if new technologies require pipelines. Even if existing pipelines need to be upgraded, preserving the corridors, labour force skills and industry arrangements is likely to facilitate the introduction of new (low emission) pipeline gas.

Although hydrogen cannot be recommended as a complete gas transition solution, it may have a role to play as part of the gas transition. This opportunity is discussed further in Section 5.5.

3.5. Winddown

Another option is to winddown the use of gas in New Zealand, prioritising sustainability in the gas sector over the remaining GTP objectives. In this scenario, a lack of investor confidence increases the risks associated with a disorderly transition, resulting in a forced residential winddown and largely negative outcomes throughout the whole energy sector. A number of initiatives could support this pathway, and are being employed internationally. These are referenced in more detail below in Section 6.2.4.

An assessment of this winddown pathway is shown in Figure 6 below against the five outcome measures described above (Sustainability; Energy Security; Energy Equity; Emissions Reduction; and Energy Conservation and Efficiency). Green icons indicate a materially improved outcome relative to current state in 2023, while red icons indicate a poorer outcome.

As Figure 6 shows, while it could reduce emissions and generally improve sustainability compared to current state, overall a winddown would likely substantially undermine energy security and energy equity, and remove options to unlock energy conservation and efficiency.

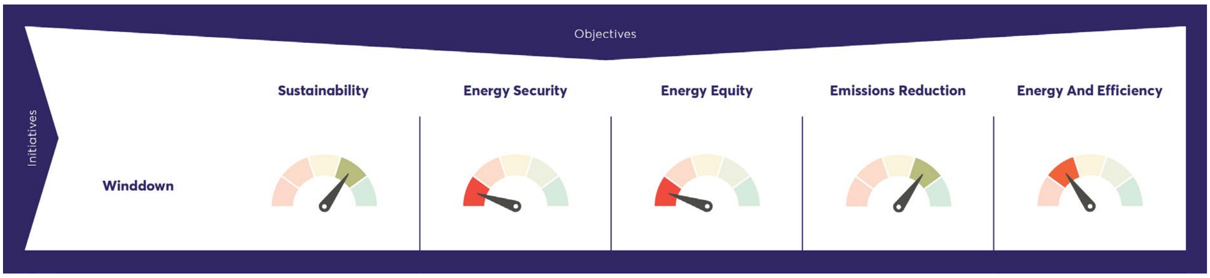


Figure 6. Assessment of winddown pathway against five outcome measures

Sustainability

Under a winddown pathway, consumers and producers of natural gas will be driven away from reticulated gas use to other alternatives. For some, these alternatives will be non-fossil fuel options, such as heat pumps for residential consumers.

For those without technically or economically viable alternatives, their exit from New Zealand will drive a reduction in fossil fuel use through de-industrialisation.

While this exit from gas consumption will have an overall positive impact on sustainability in the gas sector (and therefore is assessed positively for the Gas Transition Plan), consumers will continue to rely on other fossil fuels for longer to supplement their energy needs. Large industrials and electricity generators that do not have readily available alternatives will continue to rely on other fossil fuels, such as coal and LNG imports. Without the development of a renewable gas market, there are reduced options for consumers who are looking to fuel switch, and will mean that some consumers may continue to use coal, or switch to LPG.

Energy security

Security of supply is not maintained for the gas sector or the electricity sector under a winddown pathway.

A key driver of poor security outcomes from the winddown pathway is due to stalled investment into gas production. Poor investor confidence results in a decline in natural gas production. Insufficient investment to support delivery of gas will risk consumers energy needs not being met.

Methanex has the scale to continue its operations until it no longer operates, but Ballance may struggle to secure contracts in a declining gas market.

Industrial players will be forced to switch to non-gas alternatives, as the renewable gas market has not been sufficiently developed to be a near term option. If electricity and woody biomass are not technically or economically feasible options, the industry will be forced to exit.

The reduced demand for the electricity sector will be insufficient to support development of gas reserves to support security of supply. As gas generation switches from baseload to peaking operation, the infrequent and short operation of peaking generation will challenge gas supply due to the erratic nature of its demand, with ramifications passing through to electricity security of supply.

Energy Equity

Through a winddown pathway, there is an increased chance that industries will choose to cease operations in New Zealand rather than face the cost of conversion to non-gas fuels. The associated job losses with this de-industrialisation will cause negative equity issues throughout New Zealand.

Energy is modelled to quickly become unaffordable for many consumers under a winddown pathway, especially as transmission costs begin to rapidly increase for all consumers.

A lack of upstream investment confidence will in turn reduce the number of domestic fields producing gas, leading to price impacts from reduced scale of operations and reduced competition.

Without baseload demand from the remainder of the gas sector to support the steady state operation of gas production, the additional costs of producing gas to meet the variable demands of peaking electricity will drive elevated electricity prices for all electricity consumers. If the domestic market is unable to meet electricity demands, more expensive LNG imports may be required.

Reduced job security, increased prices for consumers, and instability throughout the energy sector will cause disruptions to societal norms and negative equity outcomes.

Emission Reductions

The reduced emissions from residential and commercial exit from gas provide a small amount of emissions reduction, but emissions reductions from the remainder of gas users (who currently produce 89% of total gas sector emissions) will stagnate. Industrial consumers that cannot readily switch to non-gas alternatives will continue to burn coal or switch to LPG to support their energy needs. Removing gas from the electricity mix prematurely may mean that coal-fired generation remains to ensure there is sufficient electricity generation, or potentially importing LNG.

Energy Conservation and Efficiency

A winddown pathway does not allow for energy conservation or efficiency to play a part in the gas sector's decarbonisation as the rapid decline of the sector is aligned with exit rather than investments into efficient use of energy. Under this winddown pathway, residential and commercial consumers will switch to more efficient electric technology such as heat pumps, but larger gas users will not have any incentive to improve their own efficiencies as there will be an insufficient payback period to earn a return on these efficiency investments.

A winddown pathway performs poorly overall against the five outcomes. It scores positively on Sustainability and Emissions Reductions for the gas sector, but only when viewed in isolation from the entire energy sector. Energy Security, Energy Conservation and Efficiency, Energy Equity all score poorly.

3.6. A Managed Transition

While a winddown pathway for natural gas may meet the emissions budgets for the gas sector, the wider ramifications throughout the entire energy sector would be disruptive to the overall decarbonisation transition and to all gas consumers. Instead, a managed transition must balance the security, social and equity impacts beyond emissions reduction.

A planned pathway requires action across both the supply side and demand side. Turning off some forms of gas consumption will be insufficient to meet the emissions budgets; remaining users must reduce their emissions in other ways in order to meet targets. This could be by modifying existing equipment and processes to improve efficiency, to switching to low-emitting fuels or finding new ways to capture and sequester CO_2 emissions. Investment into the natural gas sector will be necessary to reach the decarbonisation objectives regardless of the pathway chosen. The Gas Transition Plan details what actions are needed, including ongoing investment to maintain security of supply and avoid inequitable social impacts while meeting the emissions budgets.

This Gas Transition Plan is therefore designed to:

- Find pathways to meet the emissions budgets, as described in the Emissions Reduction Plan, while also
- Providing the sector with sufficient confidence so that investment continues to be made where appropriate, thereby
- Providing consumers with security of supply at an affordable price as the transition is implemented.

The report that follows outlines how this managed transition could occur, and what measures could be taken to ensure a fair and efficient transition.

Part 2

4. A Managed Transition

- Part 2 outlines a managed transition
- Updates to biogas and emissions capture potential in New Zealand is presented in Section 5
- The international landscape provides insight into other countries managed transition pathways
- Current operation and trajectories of each gas market segment is analysed in Section 7
- A baseline for the overall transition is formed when these market segments are assessed as a whole
- This baseline informs where there are gaps to meeting the GTP objectives
- Policy options are assessed to address these gaps in Section 8

4.1. Approach

Part 2 of the Gas Transition Plan report outlines what a managed transition could look like.

First, research into new technology options is presented in Section 5, including updates on opportunities for biogas in New Zealand, and detail on emissions capture, including carbon capture and storage (CCUS), as well as direct air capture (DAC), and the potential role of hydrogen as part of the solution. A summary of mechanisms being used internationally is included in Section 6, giving insight into the direction other countries are taking in their own managed transitions.

The Gas Transition Plan takes a consumption-led approach to identifying the alternative pathways. The emissions from each of these consumer segments are not directly proportional to their gas consumption. In some cases, gas is used as a feedstock, and therefore does not produce emissions, while in other cases the efficiency of gas use can differ depending on the method of gas consumption, for example high temperature industrial processes will have a higher efficiency than gas that is used for space heating. Each segment of the gas market was examined in Section 7 to understand current pathways, giving insight into how different user groups are currently operating as well as any future plans.

When these segments are then assessed as a whole, the current trajectory of the gas sector comes into focus. At this stage, specific barriers or gaps which mean that the GTP objectives aren't being met come to light, showing areas where targeted policy intervention can ensure solutions that address particular needs and guide towards a gas future that meets all of the GTP objectives. Consideration needs to be given to a range of policy instruments to complement the NZ ETS, taking into account the best methods for emissions reductions, the different consumer groups, and the associated ways that gas is used when designing the policy response. These policy options are outlined and assessed against the GTP objectives in Section 8.

5. Technology Options

Key Points:

- Sufficient biogas is available at feasible prices to quickly increase the volume of biogas being sold in existing natural gas networks to 20% of residential and commercial consumption by 2030.
- Larger volumes of bio-methane are expensive. There could be sufficient feedstock to make very large quantities of biogas technically feasible, but not at prices that are economic for gas-inclusive electricity or large industry with mature technology.
- Once a biogas market is established, industrial innovation is likely to bring low maturity technology to market and represents upside decarbonising potential.
- Emissions capture is technically and economically viable and can significantly reduce emissions. Emissions capture is necessary to achieve the sector's target emissions reductions but regulatory reform is required.
- Direct Air Capture (DAC) will be an important tool in the future. It is not currently economic but is likely to become so in the 2030s. 'Disposal' of CO_2 from DAC underground cannot be consented under current planning laws. Current international rules and the NZ ETS do not allow operators to obtain the benefit of the carbon price for DAC.
- Although hydrogen has a role in the energy transition, there is not sufficient confidence about the role of hydrogen to be able to recommend it as a strategy for transitioning natural gas before 2035.
- Imported LNG could improve security of gas and electricity supply by adding unconstrained dynamic gas feed-in capacity, but it is more expensive than long-term indigenous gas prices.
- The storage of indigenous gas requires there to be sufficient indigenous gas market liquidity available to cycle into and out of storage to meet demand. Adding storage capacity for indigenous fuel does not on its own increase the size of the fuel pool.
- Imported LNG could integrate with existing and/or new underground storage facilities to provide further optionality for in-country storage to receive imported gas.

The key technology options available to support decarbonisation of the gas sector are biogas, carbon capture and storage, direct air capture, hydrogen, LNG, and storage. Each of these options have their own benefits and barriers which determine the key opportunities for decarbonisation that they present for New Zealand's transition. This chapter explores the details of these key technology options.

5.1. Biogas

- Some biogas can be accessed and injected into the natural gas network at relatively low cost.
- Sufficient biogas is available at feasible prices to quickly increase the volume of biogas being sold in existing natural gas networks to 20% of residential and commercial consumption by 2030.
- Existing gas access and reconciliation arrangements are suitable for biogas to be injected into natural gas networks. This provides an opportunity to begin decarbonising quickly without expensive or disruptive replacement of equipment.
- Larger volumes of bio-methane are expensive. There could be sufficient feedstock to make very large quantities of biogas technically feasible, but not at prices that are economic for gas-inclusive electricity or large industry with mature technology.
- Once a biogas market is established, industrial innovation is likely to bring low maturity technology to market and represents upside decarbonising potential.
- Downside risks include:
- the rules for CO2 released from biomethane could change in the future, exposing biomethane to a price on carbon, which would make it uncompetitive,
- in the absence of a regulatory mechanism, businesses selling biomethane could be undercut by competitors selling natural gas at a lower price than biogas,
- as the potential biogas supply is less than demand, and it can't easily respond to market signals. Beyond a certain supply level, demand from other sectors may push feedstock prices higher than expected,
- potential existing biogas suppliers may be reluctant to sell their gas even if doing so would be efficient for them,
- the cultural impact of using biogas from waste in food treatment needs to be weighed.

5.1.1. The biogas sector is maturing

Before work began on the Gas Transition Plan, a Gas Industry Co workstream had begun to look at barriers to biogas as a replacement for some uses of natural gas.

In 2020, Gas Industry Co engaged PWC to provide advice[7] on international examples of renewable gas certification and considerations for the implementation of a New Zealand scheme.

At the time, 3.66 PJ of biogas were being produced for energy use (2018), mainly for electricity and heat at the location of extraction. No biogas is being refined and injected into the natural gas pipeline.

In late 2022, Certified Energy began to provide a commercial renewable gas certificate that verifies the emissions content of gas (and may be extended to other environmental qualities).

Early engagement by Gas Industry Co found widespread industry support for a competitive assurance and certification scheme. Industry generally believes that assurance will help biogas to gain a share of the natural gas market. Industry prefers to see a regulatory

[7] PWC (2020), Green Gas Certification Scheme Research, PWC, 9 September 2020, available at https://www.gasindustry.co.nz/assets/WorkProgrammeDocuments/PWC-Report-v2.pdf

framework and monitoring of providers. Gas Industry Co's current Statement of Intent provides for a workstream to implement this framework.

In 2021, Beca, Firstgas and Fonterra published a report[8] on biogas and biomethane. It said biogas has the potential to replace nearly 20% of New Zealand's total gas usage by 2050 and avoid 4% of total energy-related emissions (that report was intended to demonstrate the potential benefits of biogas, and explicitly not intended for use as a policy document).

Further work was commissioned for the Gas Transition Plan, focusing on the emissions reduction targets for the five-year periods to 2035. WoodBeca looked[9] at the scope of supply and the feasibility and economics of possible supply opportunities across the emissions reduction budget timeframes.

5.1.2. Enough biogas exists to rapidly introduce blending up to 20% of residential consumption and achieve worthwhile emissions reductions

WoodBeca investigated a range of established and developing technologies. The technologies were divided into several tiers, based on technical maturity and the ability to feasibly implement the technologies in the short to medium term future.

Its main findings included:

- Anaerobic digestion and biogas upgrading are the only two technologies likely to make a significant impact on the gas network by 2035.
    - Anaerobic digestion and biogas upgrading have high technical maturity and are commonly used today in commercial systems here and overseas.
- The lifecycle emissions of biogas generated from organic wastes and residues is on average 17 $kgCO_2e/GJ$, which is equivalent to a 70% emissions reduction when compared to an equivalent natural gas (57 $kgCO_2e/GJ$).
- In addition to those emissions reductions, large net reductions in emissions intensity result when biogas is derived from a material going to landfill (or other processes that generate large quantities of biogenic methane).

Biogas from landfills, wastewater treatment plants and food waste digesters can be accessed, upgraded, and injected into the natural gas network at relatively low cost. However, the majority of the biogas potential identified is economically challenging to access.

- 24PJ/year is available from organic waste/agricultural residues). Syngas from woody biomass can produce 63 PJ/year, and the total biodiesel potential (oils and fats) is 4.5 PJ/year. Of this, around 3PJ is available for $20/GJ or less.
- The total accessible and economic size of biogas potential prior to 2035 is about 7PJ – equivalent to the entire residential and small commercial market today.

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[8] Beca et all (2021) Biogas and Biomethane in NZ - Unlocking New Zealand's Renewable Natural Gas Potential, Beca, Firstgas Group & Fonterra, 2021, available at https://www.beca.com/getmedia/4294a6b9-3ed3-48ce-8997-a16729aff608/Biogas-and-Biomethane-in-NZ-Unlocking-New-Zealand-s-Renewable-Natural-Gas-Potential.pdf

[9] WoodBeca (2022:Biogas) Gas Transition Plan - Biogas Research Report, Wood Beca Limited, 9 December 2022

- The total land required to replace New Zealand's natural gas demand (at approx. 150PJ) is 1.7m ha, or 21% of New Zealand's productive grassland.
- Current estimated biogas and landfill production around New Zealand (including the South Island) totals 4.9PJ/year.
- Blending residential gas consumption with biogas to 20% would require 1.5PJ of biogas, which is likely to be available for around $15/PJ.

5.1.3. Virtual Trading

Sale of biogas to an end consumer does not have to involve physical supply from a plant in one place to a consumer in another. Examples of virtual supply are an everyday occurrence in natural gas supply: For example, a retailer buys gas from a field in offshore South Taranaki for sale to customers in Auckland, while all of the physical gas from the field in practice goes south to Wellington, and the Auckland customer actually receives gas from an onshore field. While the customer receives gas, the retailer and field operator settle the exchange through the industry's balancing and reconciliation processes.

Different fields produce gas with different properties. The industry resolves variations through existing mechanisms. NZUs must be surrendered for each tonne of CO_2, with the liability occurring at the point of production.

The same mechanisms can be deployed to offer production from a biogas plant to retailers, who sell biogas virtually, not as actual molecules. What matters is that a trade occurs, which provides the financial incentive to supply biogas.

Virtual trade makes it possible to introduce biogas into networks seamlessly and as soon as biogas is available. Some adjustments to the LPG industry would make decarbonisation of the LPG sector possible as well, allowing for decarbonisation of gas use in the South Island, which is currently entirely dependent on an LPG industry.

The limit on biogas is the volume available anywhere, and the cost of supplying it. It does not require transport or a particular production location to participate in a market, provided it can be supplied to some end user.

5.1.4. Risks around obstacles for introducing biogas are manageable

Early engagement with industry for the Gas Transition Plan identified scepticism about whether several barriers to biogas could be removed to allow the market to mature.

Although these issues can likely be resolved, there are some risks to a strategy of growing the biogas share of residential gas markets in the 2020s.

Some of the main issues to be resolved are set out in the table below:

Issue	Discussion
Specification of biogas qualities for injection into natural gas networks, and authentication of net emissions intensity.	Gas produced from geological reservoirs naturally comes in a variety of specifications. Operators process this gas to meet required specifications, and the industry routinely balances variation in content. Biomethane is chemically the same product. It is categorised low emissions because of the way emissions from renewable sources are treated, not because of the chemical composition of the gas (this quality makes it a substitute for fossil gas). Injection of gas from biological sources is not an

Issue	Discussion
	intrinsically different proposition to the existing market. Existing reconciliation and specification systems are assessed as suitable for a biogas blending market. A commercial market in emissions certification exists today and is available to provide assurance for biogas entering natural gas networks.
Capability of relatively small biogas production to participate in gas network access arrangements designed for much larger plant.	There is a significant operational step in capability required to supply into a network, as opposed to a plant recycling production for its own use. Businesses capable of operating in a high hazard industry have the technical capability to comply with specification and certification processes and would be expected to adapt.
Questions of whether biogas sustains the fossil gas market for longer.	The focus of the Gas Transition Plan is on emissions from the sector, not on the source of the energy. The Gas Transition Plan reduces emissions across the sector sufficiently to meet a net zero 2050 pathway. Emissions from residential consumption are such a small proportion of gas consumption that net zero emissions budgets could likely be met without reducing residential consumption. However, the fairest arrangement is for all consumers to contribute to emissions reductions. Using biogas in networks allows for expected emissions reductions. The second issue is whether a rising carbon component in the price of natural gas will lead to consumers switching to electricity, causing economic loss from the value of stranded equipment. There appears to be price inelasticity in natural gas because of consumer appetites for the qualities of flame. Demand for decarbonised energy is likely to increase the appeal of biogas blending for some consumers.
Application of a carbon price to emissions from waste and biological sources.	The treatment of biological CO_2 emissions is a matter of policy. Price forecasts are included in the expert study of the biogas sector[10] using current expectations of regulatory settings. Those settings could change in future if policymakers decide to treat biological emissions differently. Investment decisions-makers will take regulatory uncertainty into account when they decide whether to invest in biogas production and supply. Uncertainty can be reduced through policy settings. Some residual potential for change will remain, and to the extent that it affects investment decisions, it may slow the replacement of natural gas with biogas.
Willingness of waste and wastewater plants to sell their biogas and willingness of consumers to pay a higher price for biogas than they currently pay for fossil gas alternatives.	Some examples of existing biogas production are set out in the WoodBeca report[11]. Some plants have been established to generate electricity by utilising their own gas. Engagement with those facilities has established that electricity produced this way is likely to be less efficient than selling the gas and buying electricity, and the latter option would also de-risk energy needs for a plant. This means that selling the gas could potentially increase returns (or reduce costs) for municipal ratepayers without reducing environmental performance (and potentially significantly helping to further reduce

[10] WoodBeca 2022:Biogas.
[11] WoodBeca 2022:Biogas, p 21-22.

Issue	Discussion
	emissions). If retailers agreed an obligation to sell biogas in networks, then their demand for supply would be likely to provide offers to existing and new plants. Those would be able to participate in a market in which biogas certificates were sold (see discussion above) in a market, the same user would continue to utilise biogas, but would not be able to make the claim that their gas is fully decarbonized because they sell the right to make that claim to others, who would 'virtually' decarbonise. Not all plants may wish to sell their biogas, even for higher value, and their production would not be counted towards decarbonisation of natural gas. One treatment of this risk is that the expected volume of biogas in natural gas networks is less than half the biogas available. Growth in supply is a potential upside from creating a new market.
Cultural concerns	Mixing waste with food preparation is offensive to some cultures. Biomethane is derived from waste, but its composition is significantly altered, and it is chemically the same as natural gas methane. Some view the resulting product as analogous to vegetables grown in compost, while others have reservations. Engagement with Maori on this point is necessary.

5.2. Emissions capture

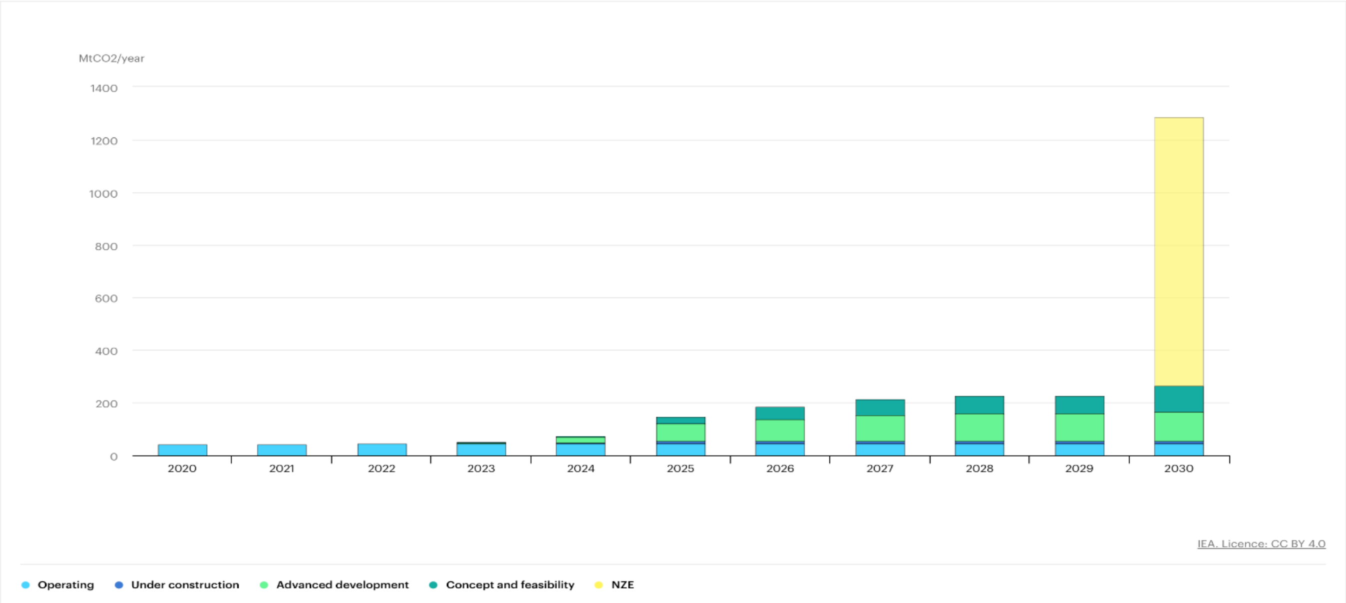
- Emissions capture is technically and economically viable and is ready to begin in the mid-2020s.
- Emissions capture technology is mature, safe and stores carbon better than alternatives such as forestry.
- Significant emissions reductions can be achieved.
- The gas sector's target emissions reductions cannot be achieved consistently with the objectives for the transition without emissions capture.
- Reform is required to entitlement to carbon credits, regulations permitting emissions capture, and governance of facilities post-operation.

5.2.1. What is emissions capture?

The term 'emissions capture' refers to the range of technology that comprises CCUS, direct air capture, CO_2 capture, and other sequestration technologies (although a further, more detailed discussion of direct air capture is below, at 3.4). The International Energy Agency (IEA) uses the term CCUS (Carbon Capture, Utilisation and Storage) to refer to a suite of technologies that they consider to have a valid role in decarbonising the energy sector.

"Emissions capture involves the capture of CO2 from large point sources, such as power generation or industrial facilities that use either fossil fuels or biomass as fuel. The CO2 can also be captured directly from the atmosphere. If not being used on-site, the captured CO2 is compressed and transported by pipeline, ship, rail or truck to be used in a range of applications, or injected into deep geological formations (including depleted oil and gas reservoirs or saline aquifers) for permanent storage."[12]

The IEA graphic in Figure 7, below, shows current and planned large scale emissions capture projects globally compared to the number needed in its pathway to net zero scenario (in yellow).



[12] IEA (2022), Carbon Capture, Utilisation and Storage, IEA, Available at https://www.iea.org/reports/carbon-capture-utilisation-and-storage-2, License: CC BY 4.0

Figure 7. Capacity of large-scale CO2 capture projects, current and planned vs. Net Zero Scenario, 2020-2030. The blue bars show the number of projects operating (light blue) and under construction (dark blue). Green bars are projects in development. The yellow bar represents the number of projects needed globally by 2030 in the IEA's Net Zero scenario. Source: IEA (2022).

5.2.2. Two studies looked into emissions capture for NZ

To assess the potential and feasibility for emissions capture in New Zealand, two studies were commissioned

- A review of the technical and economic potential of using existing natural gas reservoirs to sequester carbon, which also assesses the likely emissions reductions that could result.
- A review of the regulatory issues that need to be resolved to enable emissions capture to take place using natural gas reservoirs.[13]

These reports have been included in the annex to the Gas Transition Plan.

5.2.3. Experts recommending emissions capture to reduce emissions

The International Energy Agency's special report on Carbon Capture Utilisation and Storage in 2020, states[14], "Alongside electrification, hydrogen and sustainable bioenergy, [Carbon capture, utilisation and storage (CCUS)] will need to play a major role. It is the only group of technologies that contributes both to reducing emissions in key sectors directly and to removing CO_2 to balance emissions that cannot be avoided."

The IEA identifies several ways that CCUS can contribute to the transition:

- **Emissions from existing energy infrastructure.** CCUS can be retrofitted to existing power and industrial plants that could otherwise emit CO_2.
- **A solution for emissions from cement, iron and steel and chemicals manufacturing.** CCUS is virtually the only technology solution for deep emissions reductions from cement production. It is also the most cost-effective approach in many regions for iron and steel and chemicals manufacturing.
- **A cost-effective pathway for low-carbon hydrogen production. CCUS** can support a rapid scaling up of low-carbon hydrogen production, where hydrogen has a role.
- **Removing carbon from the atmosphere.** For emissions that cannot be avoided or reduced directly, CCUS underpins an important technological approach for removing carbon.

In June 2021, Ara Ake published its report, *Carbon Dioxide Removal and Usage in Aotearoa New Zealand*, to promote fresh discussion about the role of emissions capture as a tool for reducing the detrimental effects of greenhouse gas emissions.[15] Ara Ake's report noted

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[13] Barton (2023), *Carbon Capture and Storage: Taking Action under the Present Law*, Barry Barton Centre for Environmental, Resources and Energy Law, Te Piringa Faculty of Law, University of Waikato.
[14] IEA (2020), Special Report on Carbon Capture Utilisation and Storage: CCUS in clean energy transitions, IEA Energy Technology Perspectives 2020, P 13.
[15] Ara Ake (2022), Carbon Dioxide Removal and Usage in Aotearoa New Zealand: A summary of carbon capture, utilisation and storage, and its possible application in supporting New Zealand's climate goals, Ara Ake, available at https://www.araake.co.nz/projects/ccus/

benefits of carbon capture from biomass, direct air capture or CO_2 mineralisation, and observed:

- Re-injection technologies have been long employed in New Zealand at Kapuni (enhanced oil recovery) and Ahuroa (gas storage) and are being used around the world.
- The Intergovernmental Panel on Climate Change (IPCC) says the use of CCUS technologies is 'unavoidable' if anthropogenic global warming is to be limited to 1.5°C.

5.2.4. Earlier reviews of emissions capture were mixed

In 2009 an industry and government consortium, the NZCCS Partnership, commissioned a Transfield Worley Consortium to look into technical, economic, legal, environmental, and social aspects of CCS. As Ara Ake found a decade later, significant capital investment and regulatory barriers exist, and it said there was a lack of detailed information about suitable reservoir sites and uncertainty about future carbon prices. Overall, it found[16],

"some scenarios in which CCS has potential to reduce carbon dioxide emissions safely, cost-effectively, …and in a manner that has minimal impact on the environment. Alongside other carbon-reduction technologies, therefore, CCS could be viable in New Zealand and could deliver value to the country as we move towards a low carbon future."

In contrast, a 2008 study[17] focused on a pre-2020 period concluded that CCS technology was inappropriate for New Zealand conditions. "Carbon capture and storage (CCS) technology will not assist New Zealand to meet interim GHG reduction targets of 20-40% by 2020," it reported.

5.2.5. At least two major emissions capture projects are viable

A variety of potential emissions capture projects are under consideration in New Zealand. Some of those include technologies such as biogenic capture and mineralisation. For example, a project in Canterbury is looking at "methods that could sequester vast amounts of carbon dioxide" using olivine[18].

These projects have potential and scientific credibility, but they are out of scope for a gas transition plan as they are primarily carbon removal activities that do not appear to involve the gas sector value chain and they are not yet sufficiently advanced commercially to be able to be recommended as a decarbonisation strategy prior to our 2035 area of focus. If they are successful earlier, they may offer further options for faster carbon removal.

Geothermal electricity generators are today capturing significant quantities of carbon dioxide and hydrogen sulphide, which is then dissolved and reinjected into a geothermal

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[16] NZCCS Partnership (2011), CCS in New Zealand: Can carbon capture and storage deliver value to New Zealand as we head towards a low carbon future?: Summary Report, September 2011, Available at https://www.mbie.govt.nz/dmsdocument/2873-ccs-nz-carbon-capture-summary-report-pdf

[17] Page, Mason, and Williamson, (2008) Carbon Capture and Storage: An appropriate technology for New Zealand? S.C. Page, I.G. Mason, and A.G. Williamson. Available at https://www.thesustainabilitysociety.org.nz/conference/2008/papers/Page-Mason-Williamson.pdf Accessed 10 January 2023.

[18] See https://www.stuff.co.nz/environment/climate-news/126685010/new-zealand-company-that-could-revolutionise-carbon-capture-gets-1m-funding

reservoir[19]. Geothermal projects are a significant decarbonisation strategy, but out of scope for a gas transition plan. Geothermal carbon reinjection is materially different to CCUS using reservoirs that were first developed to extract natural gas:

- Geothermal wells are much shallower than gas wells (depths around 800m, compared to 3-5000 metres),
- Geothermal reservoirs are engineered to release energy (as steam) and recycle the fluids, whereas natural gas reservoirs sequester the contents permanently (other than content produced through the well).

Nevertheless, geothermal CO2 reinjection is likely to benefit from clarification of the law relating to underground CO2 disposal.

As the potential range of emissions capture projects in New Zealand is too wide to assess in its entirety WoodBeca investigated whether *any* projects have worthwhile scale, are likely to proceed, and likely to deliver significant emissions reductions under more permissive regulatory settings. It looked into whether any potential projects in New Zealand are likely to be economically feasible, whether there were any technical obstacles to them, and what emissions reductions would be achievable if the projects went ahead.

WoodBeca's report is attached as an appendix[20].

WoodBeca has confirmed emissions capture projects are technically viable at OMV's offshore Taranaki Maui East field and at Todd's onshore South Taranaki Kapuni field.

Both known and suspected gas in place at these locations carry high (e.g. >30%) CO_2 volumes.

These projects could commence CCS operations in 2027.

These projects provide an example of the viability of CCUS in New Zealand, and other potential projects exist that may further reduce emissions.

Beyond Maui East and Kapuni, other CCS candidates include the Pohokura field due to its proximity to Methanex, and the Rimu-Kauri-Manutahi fields due to proximity to Fonterra's Whareroa plant. No detailed review was conducted for the WoodBeca report, but these projects present potential further candidates that may be explored with a permissive regulatory regime.

A discussion of the detailed impact of those projects is below, at section 4.7.

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[19] See, for example, Mercury Energy's Ngātamariki plant, https://www.mercury.co.nz/why-mercury/renewable-energy/geothermal-generation

5.2.6. Regulatory changes are required to enable emissions capture to occur

In 2013, the Centre for Environmental, Resources and Energy Law at the University of Waikato compiled a major report[21] about the legal and regulatory framework for carbon capture and storage. It has been updated by Professor Barry Barton for the Gas Transition Plan and is annexed to this report.

A comprehensive CCS Act is an option but the time taken to draft and pass a substantial new statute may cause delays that ultimately prevent projects from going ahead. Lighter weight changes to regulation to address the main regulatory issues is easier to adopt quickly, but "entails options in the legal and regulatory framework that may be less than perfect, and that organisations will have to take into account in examining the risks and uncertainties that are associated with projects. When CCS becomes established in New Zealand, it will become more important to have a suitable legal regime, that addresses complications such as multiple operators working at different sites with different kinds of CO_2 sources and different sinks."[22]

5.2.7. Certain emissions capture projects can be consented today

A discharge permit would need to be obtained from the regional council for projects covered by the RMA, and from the EPA for activities in the EEZ. The policy environment is neutral, but onshore and in the coastal marine area it does allow the environmental benefits of CCS to be tabled. A gas producer carrying out re-injection of CO_2 "behind the meter" does not have to account for the gas in the NZETS. Re-injection that is an incidental part of petroleum mining may need approval by NZPAM but does not need permission to inject under private land. Other CCS injection may require the consent of landowners.

5.2.8. Some projects cannot be consented. Abandonment rules need attention

Third party CO_2 injection in the coastal marine area is a prohibited activity and cannot be granted a discharge permit.

Long-term liability for the security of sequestered CO_2 is not well managed by existing legislation.

The general design of sub-surface regulation is tailored to operations to extract resources and then abandon the site after operations cease. The framework has not generally been designed with the aim of injecting resources into the ground to be left there permanently. Operators will need to understand liability and obligations at project end-dates before sanctioning new projects. The main issues to resolve include:

- Arrangements for abandonment and post-operation monitoring.
- Liability for repairing wells and reservoirs post-operation.
- Liability for any emissions costs avoided if those emissions leak.

In general, sequestration underground will provide more permanent and secure removal of CO_2 than biological sequestration in forestry. Reservoirs that have stored oil and gas several

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[21] Barton et al (2013), *Capture and Storage: Designing the Legal and Regulatory Framework for New Zealand*, B Barton, KJ Jordan and G Severinsen, Carbon, Centre for Environmental, Resources and Energy Law, University of Waikato, 2013, for the Ministry of Business, Innovation and Employment and the New Zealand Carbon Capture and Storage Partnership, available at https://researchcommons.waikato.ac.nz/handle/10289/8530

[22] Barton (2023), page 6

kilometres beneath the surface for tens of millions of years are likely to be secure because that is why the oil and gas has been trapped. Other types of reservoir will mineralise CO_2, turning it into a stable, solid rock.

Technology for monitoring the subsurface is in widespread use around the world, including New Zealand, and is well understood.

However, regulation needs to provide assurance, and plan for circumstances where things go wrong.

Some of the main issues that need to be resolved are set out in the table below.

Issue	Cause	Management option
Compensation	Contribution to the public for the use of a common resource for disposal	A form of royalty is payable to the Crown for extraction of resources. A similar arrangement for disposal is likely to be expected, although the economics of disposal are less amenable than the economics of extraction and use of a resource. Some proportion of the value of disposal may be paid as a royalty to the Crown on behalf of the public, and potentially to the land owner and mana whenua in recognition of their interest.
Operational risk	Potential for seepage or release of CO_2 from the reservoir	As for oil and gas extraction, sites and operations will be approved only if they are assessed to be secure and stable. If CO_2 were released, the safety of the site would be subject to well site safety regulation. A release would contribute to overall global emissions, but otherwise CO_2 is a component of air, harmless and contained in everyday products including food, drink.
Monitoring during operations	Emissions capture is envisaged to continue for one to two decades. If direct air capture is employed, then operations could continue for decades longer	Well monitoring during operation, through technologies such as wellbore logging, 3D seismic, soil gas testing, and atmospheric monitoring. Liability during operation for the cost of monitoring would lie with the operator, with existing monitoring and assurance arrangements as for existing subsurface operations. A liability bond market (a kind of insurance) is vibrant in the US and Canada, and provides for the costs of remediation in the event of operator default.
End of operations	Well abandonment and approval of post-operation arrangements	Approval by a government agency such as NZ P&M. Regulatory arrangements designed for permanent underground disposal.
Post-operation monitoring	Ensuring the reservoir is stable and CO2 is not being released back to the atmosphere	Sub-surface monitoring is well understood. It is likely to be conducted using equipment in the well site and potentially acoustic sampling (depending on the type of reservoir). Liability for the costs of monitoring would rest with the operator until such time as the regulator was satisfied. In some jurisdictions this can last for 50 years, although the expectation is that a regulator can certify compliance in 5-

Issue	Cause	Management option
		10 years. Some form of bond or insurance is needed to cover events where the operator can't.
Repair and well interventions	As for monitoring, liability for the cost of repairs needs to be assigned	Liability for post-operation repairs should rest with the operator until the regulator certifies that the reservoir is likely to be permanently stable. As for monitoring, some form of insurance or bond is required to provide for circumstances where the operator is no longer available.
Ongoing ETS liability	Emissions will only be sequestered when someone can avoid a carbon charge. If the carbon is later released, then the carbon cost is avoided unfairly	Liability for avoided carbon costs can be treated the same way as liability for monitoring and repairing sites.
Transfer of risk	At some point the Operator's liability ends	Companies eventually cease operations and need to be able to move on from projects. Operators should not generally be able to avoid costs of their operations, but at the point where further costs are unlikely to be incurred, risk is generally likely to be transferred to the Crown. The liability is similar to the end of mining operations. The Crown may collect a royalty during operations in recognition of its ultimate residual liability.

5.2.9. International experience of emissions capture.

A discussion of the international rules is included in Appendix A.

In most regions where CO_2 underground storage occurs, a permit or licence is required for the activity. There can be significant delays to issuance of permits, which has been a major obstacle for carbon capture projects in the USA, while in Australia each state has its own CCUS regime creating legal uncertainty and transaction costs.

Some governments, such as the United States, Australia and Canada, have provided for emissions capture by adapting their existing oil and gas or reservoir use frameworks as a basis for some storage authorisations. Western Australia introduced project-specific regulations to enable first-mover projects; the Gorgon CO_2 injection project was Australia's first end-to-end demonstration of CCUS. Gorgon was unsuccessful due to technical issues, and other states have amended their regulation in response.

While most of the saline aquifers that are being discussed for large-scale CCS have not yet been explored in any detail, the reservoirs from which oil and gas has previously been produced are much better understood. This makes already active oil and gas draw sites promising locations with which to get started on emissions capture in the near term. Oil companies have equipment, experience, and capital to manage emissions capture.

Under the right policy regime, the profit-making motive could be harnessed in service of burying carbon. Nevertheless, CCUS has not advanced faster due to commercial considerations and a lack of consistent policy support. Where projects have progressed, governments have been a key player either through regulation (emission trading schemes in particular), capital investments or operational incentives.

Countries and states are increasingly using regulation as a tool to incentivise development. Norway, Canada and Australia have incorporated CCS projects into carbon tax or emissions trading schemes. The Australian Government's "CCS method" allows eligible projects to receive Australian Carbon Credit Units (ACCUs), which can be sold to the government under contract or to private entities through the secondary market. This is the first financial incentive scheme for CCS-specific CO_2 abatement in the Asia Pacific region.

In Europe, the CCS Directive provides a comprehensive regulatory framework for CCUS in the European Union, encouraging member states to review and update their regulations to support CCUS – such as removing barriers to transportation of CO_2. For example, in 2019 Norway and the Netherlands secured an amendment to the London Protocol (an international agreement on preventing marine pollution) to permit cross-border CO_2 transportation. (See the discussion in Professor Barton's report about further work required to amend the London Protocol.)

To facilitate the growth of CCUS technologies, Alberta, Canada is enabling carbon sequestration rights through a competitive process that enables the development of carbon storage hubs. If demonstrated that the sites can provide safe and permanent storage, the selected companies can work with government on an agreement providing the right to inject CO_2 while enabling open access to emitters on a commercially viable basis.

Gaining public support in regions where CO_2 storage is viable is critical to success, not least to obtain consent. For example, in Japan, sustained public engagement proved a key factor in the success of the Tomakomai project.

The capital-intensive nature of CCUS projects has proven a major inhibitor to investment, which has limited the rate of adoption and scale of deployment. Grant funding was instrumental in early deployment of carbon capture technologies, with Boundary Dam receiving CAD250 million from the Canadian government and Petra Nova benefiting from almost USD200 million from the United States Department of Energy. Costs are coming down however, and as the price of carbon increases this will further improve commercial viability. The Quest CCS project, funded by Shell and the governments of Canada and Alberta, has captured and stored over 6 Mt of CO_2 ahead of its original schedule, and cost 10% less than the budget case estimate.

Governments continue to commit billions of dollars to CCUS development and deployment. For example, in 2021, the Australian government announced plans to make CCUS eligible for existing funding programmes for clean technologies, including via the Clean Energy Finance Corporation's AUD10 billion (USD 7.1 million) investment fund. In 2022, four of the seven projects selected for grant preparation under the first call of the European Union's Innovation Fund were CCS projects. In 2020 the Dutch Government expanded the Sustainable Energy Transition Subsidy Scheme (SDE+) into the "SDE++" to include support for renewable energy projects and CO_2 reduction efforts, such as CCS. Denmark intends to devote at least USD 2.2 billion to CCUS development, including transport and storage infrastructure. In 2021 Denmark also provided grant support to Project Greensand and Project Bifrost, both of which target offshore CO_2 storage development and the Norwegian government announced it would provide NOK 16.8 billion (USD 1.8 billion) in funding for the Longship CCS project.

Tax credits provide an alternative policy tool in the absence of a carbon price, however, the size and duration of US 45Q credits is currently insufficient to incentivise retrofits of many eligible power and industrial facilities. Operational subsidies, such as contract for difference mechanisms can cover the cost differential between the higher generation costs and the market price. In the Netherlands, the SDE ++ scheme will stimulate the roll-out of renewable energy and CO_2 -reducing technologies by compensating the unprofitable top of these technologies.

Governments in Canada, Japan, the United Kingdom and the United States, as well as the European Commission, are providing significant RD&D support for CO_2 use. While a limited number of large-scale capture facilities plan to send all the captured CO_2 for use, a number of smaller-scale CCU facilities planning to source the CO_2 from nearby industrial emitters are also under development.

Case Study: Moomba CCS plant

Moomba is located approximately 800 km north-east of Adelaide, South Australia. The Santos-operated Moomba processing facility processes oil and natural gas from surrounding fields, made up of more than 1000 producing wells. The oil and gas is piped to Moomba where it is refined and distributed via pipelines to markets in South Australia, New South Wales, Queensland, and other domestic and international markets.

In 2021, the Moomba joint venture announced[23] a final investment decision to proceed with a project, to capture CO_2 emissions from the Moomba Gas Plant. It is expected to start operations in 2024. The captured CO_2 will be dehydrated, compressed, and then transmitted via pipelines to suitable locations, where it will be injected into geological formations deep underground. The CO_2 may be stored in hydrocarbon bearing formations or deep saline geological formations. The project is expected to reduce Santos net emissions by 26-30% by 2030. A royalty is payable to the traditional owners of the land for the entire period of injection.

The South Australia government has a regulatory project web page[24] for the Moomba CCS project including the carbon storage environmental impact report[25] and statement of environmental objectives[26]. These reports indicate how potential issues in storage can be managed by regulators.

Liability post closure is dealt with under a statute that provides for a licensee to apply at the end of a project life seeking relinquishment approval and for long term liability to be either limited or excluded. Based on an independently verified assessment of residual risk associated with this remaining liability, the minister may grant approval with or without conditions. In the case of CCS, the minister's decision is based on monitoring of the CCS reservoir performance against the approved Monitoring and Verification Plan.

Case study of obligations in a US emissions capture project

Upon conclusion of sequestration project, the operator is required to complete post injection site care (PISC) that has been agreed during the permitting phase. The Environmental Protection Authority requires up to 50 years of monitoring. The operator may request an alternative timeframe, which is at discretion of the director's office (the California Air Resources Board, CARB, currently requires a 100 year monitoring period). Most current projects expect to receive approval for a 10-20 year post injection site care period. Monitoring may include wellbore logging, 3D seismic, soil gas testing, atmospheric

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[23] https://www.santos.com/news/santos-announces-fid-on-moomba-carbon-capture-and-storage-project/

[24] https://www.energymining.sa.gov.au/industry/energy-resources/regulation/projects-of-public-interest/cooper-basin-carbon-storage

[25] https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/sarig1/image/DDD/PGER003212021.pdf

[26] https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/sarig1/image/DDD/PGER003222021.pdf

monitoring, plugging. As for other mining projects, the technology and methods are subject to operator design and regulator approval. Once commitments are complete, the project receives a closure certificate, financial responsibilities are released, and liability transferred to government.

5.2.10. Emissions capture in te ao Maori

One way of seeing emissions capture in te ao Maori is the return of resources from the sky father, Ranginui, to the earth mother, Papatuanuku.

Formal consultation on the principle is scheduled to commence at an early stage, long before any project is consulted on. Views collected to date have not been 'on behalf' of any interest, however informal discussion has suggested topics for exploration.

Some commentary has expressed support for the principle of environmental guardianship through the process of carbon removal. Elsewhere, concern has been raised about the principle of moving resources from one rohe to another, the response to which depends on the nature of the resource. CO2, for example, naturally distributes itself evenly around rohe, so removal anywhere has beneficial effects. Perspective will also be valuable on a compensation regime similar to the South Australia model, where the traditional owners receive a share of the royalty.

5.2.11. List of changes required to facilitate emission capture

The full list of changes is summarised in the annexed report.

Policy changes

- A national policy statement for emissions capture and sequestration under the RMA (an NPS-CCS). A new NPS could take a year to produce once the proposal is accepted.
- Amendment of regional regional policy statements, regional plans and district plans under the RMA, to recognise and provide for the benefits of emisions sequestration in emissions reduction. A regional policy statement or regional plan can take two or three years.
- Provide for emissions sequestration in emissions reductions budgets (the next ERP is due by 31 December 2024).

Regulations and Similar Instruments

- RMA: a new regulation is made under section 360(1)(e) for an emissions sequestration project or work to be declared a network utility operation.
- RMA and EEZ regulations. The Resource Management (Marine Pollution) Regulations 1998 and Exclusive Economic Zone and Continental Shelf (Environmental Effects-Discharge and Dumping) Regulations 2015 to be amended for clarity and to reflect the 2006 change to the London Dumping Protocol allowing emissions sequestrration. Third-party CO2 injection in the coastal marine area depends on the RMA Regulations being amended.
- CCRA: Order in Council to add emissions sequestration (with an expanded definition) to the list of removal activities in Schedule 4 Part 2 Subpart 2.

- CCRA: new regulations to accompany the listing of emissions sequestration as a removal activity, to provide for calculation of removals and to provide for the long-term management of geological sequestration.

Amendments of Acts

- EEZ Act: repeal s 59(5) on CO2. This provision in the EEZ Act is anomalous now that its equivalent in the RMA has been removed.
- Natural and Built Environment Bill and Spatial Planning Bill: ensure that emissions capture regulation in these replacement statutes does not prejudice emissions capture regulation.

Changes that are lower priority, but would be useful to facilitate emissions capture

Policy Changes

- Amendment of the New Zealand Coastal Policy Statement under the RMA to provide for CCS in the coastal marine area and coastal environment. The Department of Conservation reviews the Coastal Policy Statement from time to time, but there is no time limit in the RMA by which a revision must take place. There has been no practice of making amendments to the NZCPS, so the opportunity for amendment would be a general revision.
- An EEZ Policy Statement under the EEZ Act. No such statement has been made yet. It would probably not be made solely for emissions capture, so it would be a large wide-ranging policy exercise.

Regulations and Similar Instruments

- RMA National Environmental Standard to accompany an NPS-CCS. Closer investigation of an NPS would show whether rules in an NES are required.

Amendments of Acts

- RMA and EEZ Act: insert a power to make regulations for the post-closure phase including requiring a consent, and the consent to last longer than 35 years, in order to improve the post-closure regulatory regime.
- Crown Minerals Act: enable powers over petroleum mining to be exercised in a way that facilitates emissions capture.

5.2.12. CO_2 Utilisation

While concentrations of CO_2 in the atmosphere have climate impacts, CO_2 as a product has many uses in the economy, ranging from carbonised beverages, such as beer and soft drinks, to chemicals and aviation fuels, to horticultural businesses that add residual CO_2 from gas heating into soil to enable faster growth of produce.

The domestic market for CO_2 is limited in size but enhances productions at relatively large businesses.

Since the closure of the Marsden Point oil refinery, only a third of CO_2 used by businesses in production is sourced from New Zealand (all of it from the Kapuni natural gas plant). The rest is imported as bottled gas. As has been seen in the summer of 2022-23, current CO_2 supplies are vulnerable to supply outages.

The demand for CO_2 as a product already exists in New Zealand. CO_2 capture is an opportunity to find further value.

5.3. Direct Air Capture[27]

- Direct Air Capture will be an important tool in future to achieve climate goals.
- The IEA says DAC at large scale in the near term, "will require targeted government support, including through grants, tax credits and public procurement of CO_2 removal."
- The current cost of capturing CO_2 with DAC is far above alternative emissions reductions technologies. With considerable investment taking place in innovation, future prices are likely to fall, and DAC will likely become economic sometime in the 2030s (that is, the future cost of DAC is likely to fall below the expected future carbon price.) The IEA says prices could fall below USD$100/tCO_2e by 2030.
- DAC is currently not feasible in New Zealand because international rules (as well as New Zealand's ETS) do not provide a mechanism for a DAC plant operator to obtain the benefit of the carbon price, and because 'disposal' of CO_2 underground cannot be consented under current planning laws.
- Other sectors such as geothermal electricity generation may benefit from clarifying the law around emissions capture and utilisation.

5.3.1. How Direct Air Capture works

Direct Air Carbon capture, or DAC, is the process of capturing CO_2 directly from the air and permanently storing it to remove the CO_2 from the atmosphere. Two technologies approaches are used to capture CO_2 from the air:

- Solid DAC (S-DAC) is based on solid adsorbents operating at ambient to low pressure (i.e. under a vacuum) and medium temperature (80-120°C).

- Liquid DAC (L-DAC) relies on an aqueous basic solution (such as potassium hydroxide), which releases the captured CO_2 through a series of units operating at high temperature (between 300°C and 900°C).

Other DAC technologies are on the drawing board. Considerable investment is being made globally in direct air capture innovation. S-DAC and L-DAC innovation efforts are mostly focused on sorbents and solvents, and optimised processes and layouts. Emerging DAC technologies include electro-swing adsorption (ESA) and membrane-based DAC (m-DAC). ESA is based on an electrochemical cell where a solid electrode adsorbs CO2 when negatively charged and releases it when a positive charge is applied (swinging therefore the electric charge, rather than the operating temperature or pressure as happens in other physical separation techniques). M-DAC has been proposed as another feasible option for capturing CO2 from the air; however, it is still in its infancy and major challenges are yet to

[27] Unless noted, this section is mostly sourced from the IEA. See in particular, IEA (2022), Direct Air Capture 2022, IEA, https://www.iea.org/reports/direct-air-capture-2022

be overcome (including the need for the expensive compression of a very large amount of ambient air to separate CO_2 efficiently).

5.3.2. DAC is relatively costly, but costs are expected to fall to US$100/t$CO_2$

DAC is more energy intensive and therefore expensive than capturing it from a point source. This is because the CO_2 in the atmosphere is much more dilute than, for example, in the flue gas of a power station or a cement plant. Consequently, DAC requires more energy and costs more relative to other CO_2 capture technologies. The heat needed is influenced by the operating temperature of the technologies.

A voluntary market exists for DAC-based CO_2 removal. The IEA reports that companies purchasing DAC removal to offset their CO_2 emissions include Microsoft, Stripe, Shopify, Swiss Re and Airbus. In some of these agreements, the company purchasing the offsets is effectively supporting the capital investment to build the DAC plant that is eventually going to capture CO_2 from the atmosphere.

Some DAC companies are willing to pay a recurring subscription to have CO_2 removed from the atmosphere and stored underground on their behalf. The price of the subscription currently is reported to be USD 600/tCO_2 to USD 1 000/tCO_2.

The IEA says[28] future capture cost estimates for DAC are uncertain, reflecting the early stage of technology, but are estimated at between USD125 and USD 335 per tonne of CO_2 for a large-scale plant built today.

Factors affecting the cost of DAC include capture technology, input energy cost, and plant configuration.

In locations with high renewable energy potential and using best available technologies for electricity and heat generation, DAC costs could fall below USD 100/tCO_2 by 2030[29].

5.3.3. Direct Air Capture has advantages for hard to abate sectors

DAC can be part of the solution for hard to abate sectors, such as from long-distance transport and heavy industry, and for legacy emissions. Carbon removal using DAC has several advantages compared to afforestation: it has a relatively small land and water footprint. "A single Carbon Engineering DAC plant sequesters about 100 times more atmospheric carbon dioxide than a forest occupying the same land area, and that the land under a DAC plant does not need to be arable."[30]

5.3.4. DAC requires law and ETS changes. Can use existing gas reservoirs.

The latest IPCC Guidelines for National Greenhouse Gas Inventories do not include an accounting methodology for DAC. Therefore carbon removed using DAC cannot be counted towards meeting international mitigation targets under the United Nations Framework Convention on Climate Change. Efforts have begun to develop consistent methodologies and certification.

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[28] IEA (2022:DAC, p.9
[29] IEA (2022:DAC), p.9
[30] Ara Ake (2022), p. 8

Sequestration of CO_2 from DAC cannot be consented under current law. Professor Barton's report notes[31], carbon capture "might be attractive in the market for voluntary carbon credits, but most parties will have a strong preference for reducing their obligations in the compulsory NZETS market, in order to help make the business case for investing in CCS separation and injection facilities.".

If Direct Air Capture is considered to be beneficial, then his recommendation relating to CCUS should be expansive enough to extend to DAC:

- It is recommended that Schedule 4 of the CCRA be amended by an Order in Council removing the existing definition of CCS as an activity, adding a new and more extensive definition, and bringing it into effect so that CCS becomes an activity in respect of which a person can become a voluntary participant in the NZETS and obtain NZUs for CO_2 sequestered; and that regulations be made to provide for CCS including long-term sequestration and the terms on which the participant will be obliged to surrender NZUs in the event of a leak from sequestration.

If this were not, an alternative mechanism to access the economic benefits would be necessary to incentivise any investment in emissions capture.

5.3.5. Opportunities for DAC are significant

In the IEA's scenario for net zero 2050, 85 Mt of CO_2 will be captured using DAC in 2030, and 980Mt in 2050[32], but this "will require targeted government support, including through grants, tax credits and public procurement of CO_2 removal."

A DAC plant can be situated in any location that has available energy from renewables and either a reservoir for storage or an opportunity to use CO_2. Some investigation of the potential for DAC in New Zealand is underway for example Capture6[33] has publicly discussed[34] a plot capable of removing 50kt of carbon per year, scalable up to 1Mt. To date, DAC plants have been successfully operated in a range of climatic conditions similar to those in Taranaki, where all of New Zealand's reservoir's are located.

The flexibility of DAC may provide an advantage for New Zealand if future electricity generation from wind creates a large surplus energy 'spill'. This occurs when more generation is available than demand. As wind generation is intrinsically intermittent, spill conditions would be expected to be frequent in a renewables dominated electricity future. It would be expected that spilled energy would be available at the marginal cost of generation and would be supplied to the use with the highest propensity to pay. For DAC to use spilled wind energy in Taranaki, therefore, it would be need to be able to outcompete alternative uses for spilled energy, including battery storage (such as pumped hydro), or used to make hydrogen.

Although it is unlikely to be viable in the 2020s, it's worth preparing for Direct Air Capture early. This is because:

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[31] Barton (2023), p.47

[32] IEA (2022: DAC), *Direct Air Capture 2022*, IEA, https://www.iea.org/reports/direct-air-capture-2022, Available at https://iea.blob.core.windows.net/assets/78633715-15c0-44e1-81df-41123c556d57/DirectAirCapture_Akeytechnologyfornetzero.pdf

{$NOTE_LABEL}

https://capture6.org

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https://carbonherald.com/capture6-sets-out-to-remove-5m-tons-co2-from-the-air-in-new-zealand/

- experience from the exploration of oil and gas demonstrates it can take up to a decade, and generally at least half a decade, to discover and evaluate a potential underground reservoir. Even then, the properties of a new reservoir are not known until the expense of drilling a well has been incurred.
- Further, while underground reservoirs suitable for long term carbon storage are known today, investment on the scale required to facilitate underground carbon sequestration is likely to require years of planning, and a de-risked regulatory environment.

The WoodBeca discussion of CCUS illustrates that reservoirs are viable for permanent carbon sequestration and more are likely to become available. Although there is uncertainty about when direct air capture will be economic, reservoirs that are known today are likely to be required for DAC, and the availability of them provides option value.

5.4. Other Sequestration Technologies

Other sequestration technologies may be promising, but are out of scope. This includes technologies such as biogenic capture and mineralisation, with one project in Canterbury is reportedly[35] looking at “methods that could sequester vast amounts of carbon dioxide” using olivine.

Although these projects have exciting potential and genuine scientific credibility, they are out of scope for a gas transition plan, as they are primarily carbon removal activities that do not appear to involve the gas sector value chain and they are not yet sufficiently advanced commercially to be able to be recommended as a decarbonisation strategy prior to the 2035 area of focus.

Geothermal electricity generators, such as Mercury Energy’s Ngātamariki plant, are today capturing significant quantities of carbon dioxide and hydrogen sulphide, which is then dissolved and reinjected into the geothermal reservoir. Geothermal projects are a significant decarbonisation strategy, but out of scope for a gas transition plan. Geothermal carbon reinjection is materially different to CCUS using reservoirs that were first developed to extract natural gas:

- Geothermal wells are much shallower than gas wells (depths around 800m, compared to 3-5000 metres),
- Geothermal wells are engineered to release energy (as steam) and recycle the fluids into it, whereas natural gas reservoirs sequester the contents permanently (other than content produced through the well).

Nevertheless, geothermal CO_2 reinjection is likely to benefit from clarification of the law relating to underground CO_2 disposal.

5.5. Hydrogen as part of the solution

- Although complete hydrogen replacement pathway has not been pursued, hydrogen may still have a role to play as part of the Gas Transition Plan solution.
- Blended hydrogen may be viable but has a higher marginal abatement cost than other emissions reduction options

5.5.1. A hydrogen industry is beginning to emerge

The Hydrogen Council has produced a map of current hydrogen projects[36]. Further projects are linked on MBIE’s hydrogen page[37]. Examples of projects in New Zealand include:

- In March 2021, Firstgas announced its plans to gradually supplement natural gas transported through the transmission pipeline with hydrogen in increasing proportions,

[35] See https://www.stuff.co.nz/environment/climate-news/126685010/new-zealand-company-that-could-revolutionise-carbon-capture-gets-1m-funding

[36] https://www.nzhydrogen.org/nz-hydrogen-projects

[37] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/hydrogen-in-new-zealand/

starting with a 5% blend and reaching 100% hydrogen in the pipes by 2050. The target would rely on continued investment in gas networks during the trial phases (which are starting immediately), with the first 1% of hydrogen blend expected in the transmission pipes in around 2030 increasing to a 20% blend by around 2035.

- Meridian and Contact published a study they jointly commissioned from McKinsey on the potential role for hydrogen in New Zealand.
- Meridian is working with Woodside, Mitsui and Ngai Tahu on a Southern Green Hydrogen Project.[38] The project is targeting production of 500,000 tonnes per year of ammonia utilising electrolysis from renewable power. It has commenced front-end engineering design. Technical work on the facility is continuing in parallel with the design of the commercial structure for the project.
- Ballance Agri-Nutrients is working with Hiringa Energy to develop the Kapuni green hydrogen project.[39] It involves the construction of four new wind turbines. The project creates a reliable and flexible supply of green hydrogen, providing electricity to Ballance's Kapuni site and to the grid. It will be able to power up to 24,000 homes during peak production. The plant will be capable of producing green hydrogen by electrolysis using electricity flexibly during off peak. Green hydrogen generated will replace diesel in heavy transport and at the Ballance plant. The Ballance plant provides a steady use for the hydrogen as the transport market develops while also decarbonising the production of urea. The companies estimate that, if the full hydrogen production were used for heavy transport, annual diesel consumption would be reduced by 4.4 million litres, equating to 11,700 tonnes of CO_2.
- Hiringa is building a green hydrogen production and re-fuelling network across New Zealand focused on heavy transport.[40] The first four stations are expected to be operational in 2023 in Hamilton, Palmerston North, Auckland and Tauranga, providing coverage for the heavy freight routes in the North Island. A further 20 stations across the North and South Islands are planned by 2026 and 100 by 2030. The project can support development of a reliable source of hydrogen for other applications, including aviation, marine and shipping, construction and off-road equipment, and stationary heat and power.
- Halcyon Power, a joint venture between New Zealand's Tuaropaki Trust and one of Japan's leading construction companies, Obayashi Corporation. Halcyon has developed a 1.25 MW green hydrogen plant. The plant uses renewable geothermal energy produced at Tuaropaki Trust's geothermal power station at Mokai near Taupo and can produce 180 tonnes of hydrogen per year. It estimates that around 180 tonnes of hydrogen could fuel 1000-1200 passenger vehicles or 30 delivery trucks or buses per year.

5.5.2. Blended hydrogen

Blended hydrogen may be viable but has a higher marginal abatement cost than other emissions reduction options.

Hydrogen has lower volumetric density and higher gravimetric density than natural gas. For a given amount of energy, blended hydrogen has higher volume and lower mass. If blended with natural gas to 20 per cent hydrogen by volume, then the hydrogen component would comprise only 6.5 per cent of the energy content. In this mixture, the blended product has 86.5 percent of the energy content of natural gas. In emissions terms, the 20 per cent by volume mixture achieves a 6.5 per cent reduction in emissions compared to natural gas.

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[38] https://www.meridianenergy.co.nz/news-and-events/meridian-selects-southerngreenhydrogen-partner

[39] https://www.greenhydrogennz.com/

[40] https://www.hiringa.co.nz/post/hiringa-refuelling-nz-commencing-construction-of-nationwide-green-hydrogen-refuelling-network

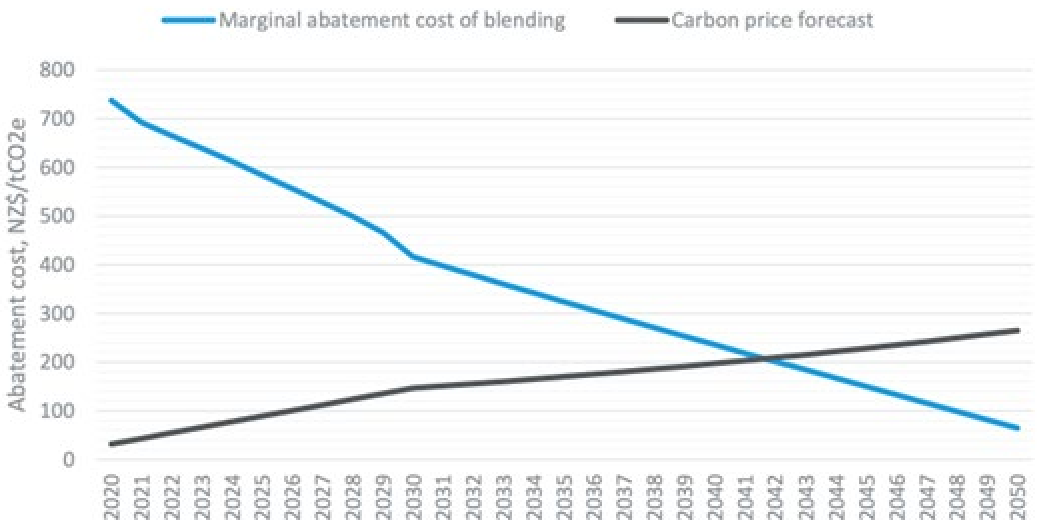
Castalia found that blended hydrogen could be economic for commercial and residential consumers, which could make hydrogen blending a viable option for partial decarbonisation.

Blending at lower concentration could help to later make blending at higher concentrations viable if there is a technological breakthrough that lowers the cost of green hydrogen or enables higher blending rates.

However, blended hydrogen has a high marginal abatement cost. This means that blended hydrogen is unlikely to be cost- effective at reducing emissions compared to other options. Incurring the cost of carbon is likely to be cheaper than using blended hydrogen to offset emissions until the 2040s.

As a result of these insights, there is not sufficient confidence about the role of green or blue hydrogen, or hydrogen blending with natural gas, to be able to recommend it as a strategy for decarbonising natural gas before 2035.

Development of green hydrogen technology is the focus of considerable research, particularly overseas. If pathways to technologies are discovered that make green or blue hydrogen more economic sooner, then that would represent an upside risk for decarbonising the gas sector.



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

Figure 8. Cost effectiveness of blending in reducing emissions

5.5.3. Potential for green hydrogen in ammonia or methanol production from captured carbon

WoodBeca's analysis of the potential for CCS in Taranaki notes that future e-chemical production of urea and methanol and integrate with large scale offshore wind projects. For example, when not supplied to the electrical grid energy from wind farms could be used to make hydrogen by electrolysis, and for e-chemical production of urea and methanol, which also need access to CO2. The mothballed Kapuni – Methanex LTS line is a potential CO2 transport vector for (e)chemical off takers.

Ballance Agri-Nutrients' ammonia-urea manufacturing plant is also located close to the Kapuni gas field. Approximately 220kt of CO2 from natural gas is consumed annually in urea production at Ballance Kapuni. The site emits approximately 180 ktpa CO2, of which around 44% is emitted from the reforming process.

If some urea production can benefit use hydrogen energy, as well as CCS for CO2 emitted in production, then green hydrogen can help to support the de-carbonisation of the hard to abate sectors.

5.6. Liquefied Natural Gas (LNG)

- Major advances in floating LNG storage and regasification infrastructure (FSRUs) over the past decade have also dramatically reduced the scale and cost of acquiring import capability.
- The addition of a FSRU into the NZ market could improve security of gas and electricity supply by adding unconstrained dynamic gas feed-in capacity of as little as 2 TJ per day through to as much as 500 TJ per day.
- The main disadvantage of LNG is that it is more expensive than long-term indigenous gas prices.
- Four potential receiving sites have been identified at Marsden Point, Port Taranaki, South Taranaki Bight and as a tie-in to the Maui-A platform.

A study was commissioned to understand the current status of LNG technology and application worldwide, and to identify potential options for LNG imports into New Zealand. Further information is included in the report *LNG import and options to increase indigenous gas market capacity and flexibility in New Zealand*.

5.6.1. What is LNG?

At its point of origin, LNG is simply natural gas that has undergone a refrigeration process that condenses it to a liquid state. LNG is 1/600th the volume of its gaseous state and, as a liquid, is not combustible, making it ideal for bulk transportation. At its point of destination, LNG is heated to restore it to its gaseous state then injected into the local gas transmission and/or distribution networks or combusted in-situ. LNG can therefore be regarded simply as a virtual gas pipeline that serves to connect a point or points of gas production to a point or points of gas consumption. Due to its energy density, LNG can also be stored to help balance variability in dynamic gas demand, known as peak shaving.

The energy density and transportability of LNG has made it a commodity of increasing demand globally, often to substitute for coal. A useful local market analogue is to compare a single coal shipment delivered to New Zealand to a standard international LNG cargo, similar to that which delivers coal for operating the Huntly Rankine units. A coal shipment contains around 650 TJ of Rankine fuel whereas a standard LNG shipment can contain more than 4 PJ of equivalent fuel – a six-fold difference.

As it is simply natural gas, LNG also presents 40% lower CO_2 emissions than coal at the burner tip. This means that a single LNG cargo carries with it 150,000 tonnes less CO_2e emissions than its energy-equivalent of coal for a saving at current carbon prices of $6m per LNG cargo. Plant operating efficiencies associated with using gas in place of coal to generate power are additional and range from a low of 15% (versus OCGT) to 50% (versus CCGT).

Offsetting these benefits, is that imported LNG is considerably more expensive than imported coal on a per-unit-of-energy basis, even after accounting for the much higher carbon impost of coal.

5.6.2. LNG trade

LNG has been produced since the 1940s and traded internationally since 1959. There are now more than 60 countries that trade LNG. Major LNG producer/exporters include Australia, Qatar and the US. Major LNG consumer/importers include Japan, South Korea, China and Europe.

The focus over most of this time has been on large-format export/import trade involving world-scale liquefaction (export) plants and regasification (import) terminals underpinned by long-term sale contracts. Smaller and more flexible liquefaction and regasification solutions are now mainstream and there is a vibrant LNG spot market with a wide range of tradeable derivatives. Production infrastructure that is now common includes floating liquefaction (FLNG), floating storage units (FSU), floating regasification units (FRU) and floating storage and regasification (FSRU) options.

Compared to indigenous gas, imported LNG is an expensive option on both a capex and opex basis. Compounding this has been the recent disruptions to international trade patterns brought about by COVID-19 and the Ukraine conflict which has led to a step-change increase in LNG demand and price benchmarks. While the current period of high demand and prices is likely to be transitionary, it does serve to highlight the exposure of LNG prices to international factors. This is however no different to other fuel formats that NZ already imports to meet its energy demand including petrol, diesel, LPG and coal.

5.6.3. LNG and New Zealand

NZ does not currently have infrastructure to enable the handling of LNG. If LNG infrastructure was to be developed, it could provide substantial additional gas market capacity and flexibility to complement existing indigenous supply and, in doing so, improve security of NZ's gas and electricity supply.

Imported LNG would likely provide optionality and flexibility to New Zealand. Additional gas could be imported as and when needed and the seaborne import facility itself could be permanently demobilised at relatively short notice and at a relatively low cost if and when access to imports is no longer required. Rates of feed-in are also flexible with FSRUs able to deliver energy at up to 500 TJ per day but can be throttled-back to feed-in as low as the "boil off rate" which, on a full-sized cargo, could be as little as 5 TJ per day. To put this in perspective, the maximum feed-in rate would be more than sufficient, transmission permitting, to fuel all 2 GW of current thermal generating capacity at once. The minimum boil-off rate would be broadly comparable in scale to the current demand of NZ Steel's Glenbrook site.

In respect of likely NZ market impacts, also worth noting is that:

- LNG-backed gas would stand in the market as marginal gas at or near the bottom of the merit order and by doing so serve to provide users with a floating ceiling price proxy.
- The LNG-backed commodity price would include an embedded value for flexibility whereas existing commodity-only price benchmarks for indigenous gas do not.

- LNG would provide supply certainty and flexibility during periods of constrained indigenous gas availability, including cover for major scheduled and unscheduled asset outages.

5.6.4. Potential New Zealand LNG Options

LNG could be imported into NZ from a LNG exporter nation, such as Australia. Imported product would require receiving infrastructure to be constructed and the LNG itself would be subject to international pricing. Potential New Zealand sites and their potential development concepts are (in alphabetical order):

1. Marsden Point: A FSRU or FSU+FRU moored permanently to the existing jetty would receive LNG transferred from a shuttle carrier via conventional ship-to-ship transfer with the carrier and FSU or FSRU alongside each other. The sheltered conditions of the waterway would reduce the risk of discharge delays and the location, being north of Auckland, could serve to reduce the impact of major system outages elsewhere, such as what occurred with the 2011 rupture of the Maui pipeline. LNG operations appear also likely be able to be carried out under existing resource consents which could significantly reduce construction lead time. A major drawback with this option however is very low (20 TJ/day) existing transmission capacity in the Northern pipeline system although this could be increased to 30 TJ/day with additional compression. The gas feed-in rate would likely therefore be a continuous (baseload) profile instead of being able to flex with peak demand and prices which would significantly weaken the investment case for receiving LNG into Marsden Point. A debottlenecking option could be to add trucking loadout directly from the FSRU to enable the relay of LNG by road to a vaporiser and compressor installed at an injection point south of the pipeline constraint. While this would likely take longer to deliver, a fleet of 44-62 standard container-sized cryogenic trailer units could, through multiple truck movements, ship up to 145 TJ/day of gas flex directly into the transmission system atop the 20-30 TJ/day of pipeline export from Marsden Point. Any remaining flex required by the gas market could be provided by Ahuroa. The road channel would be fully scalable and could also open other LNG deployment options such as peak shaving and transport fuel. Alternatively, given there is power generators that require the greatest load profile flexibility, gas-fired generation could be sited next to the LNG import concept at Marsden Point, for example there is sufficient connection capacity at Bream Bay, where small 10 MW peakers already operate. The concept would also support security of electricity supply by providing Auckland with fast start peaking generation from the north.

2. Maui-A: LNG would be transferred at sea, via ship-to-ship transfer, from a shuttle carrier to a FSRU connected to a single-point mooring system. The FSRU would connect, via the mooring system, to the Maui-A wellhead platform and the existing 35km undersea pipeline through which regasified LNG could be exported into the existing high-pressure gas network. This option has the advantage of using existing infrastructure that is underutilised. The main drawback of this option is the local sea state which would require a bespoke mooring system and potential difficulties with undertaking ship-to-ship cargo transfers. However, given the distance of the site from shore and existing oil and gas activities in the immediate area, consenting processes would be less complicated.

3. Port Taranaki: LNG could be handled through Port Taranaki which is nearby to existing high-capacity gas infrastructure. The Port's existing jetties are currently unsuitable for accommodating both a FSRU and shuttle carrier alongside each other for cargo unloading without disrupting other port operations and without those other port operations constituting a hazard to the FSRU more generally. A potential solution could see LNG transfer undertaken at sea, either within or outside the breakwater, depending on technical and economic viabilities and profiles. Regardless, significant investment would be required to undertake necessary modifications to the port, with the preferred outcome being the construction of additional jetty infrastructure and an increase to the port's draft to be able to accommodate the FSRU and discharging carrier vessel. The securing of resource consents to support such a development is a key execution risk. In addition, the port has potential to become the shore base for offshore wind development within a decade and it may in future prove difficult to accommodate both FSRU and wind turbine assembly operations.

4. South Taranaki Bight: LNG could be received through a fixed-point mooring system installed at a site in the South Taranaki Bight connected via a new subsea pipeline to shore that connects with the existing Southern section of the existing high pressure gas transmission network. The attraction of the site is that it is sheltered from most swell directions apart from those from the W-NW. This would likely support a fixed spread mooring system which is considerably less expensive than the single-point system that would likely be required at Maui-A to be able handle the sea state at that site. A drawback is that the onshore high pressure network can only accommodate up to 200 TJ per day of feed-in depending on where it connects.

Costing estimates conclude a likely development cost range of between $250-338m for Marsden Point, $140-210m for Port Taranaki, $328-511m for South Taranaki Bight and $426-$624m for Maui A.

Additional to the cost of LNG would be the variable cost of using the facility which could be as high as $3.00-$4.67 per GJ for Marsden Point and as low as $1.63-$3.40 per GJ for South Taranaki Bight and Port Taranaki. Maui-A lies in between with a range of $1.72-$3.68 per GJ. Excluding the fixed option cost, the variable cost of LNG delivered to the market would therefore potentially cost between $44.34 per GJ and $63.88 per GJ based on post-Ukraine LNG prices and between $11.23-16.47 on historic pre-Ukraine prices.

5.7. Storage

- Underground storage expansion and construction options provide the greatest scope for providing additional system flexibility at the lowest relative cost.
- However, any domestic storage option is reliant on domestic fuel availability to charge and draw-down storage as it is needed.
- If sufficient indigenous gas does become available, the conversion of Tariki presents as the most attractive option for additional system flexibility given its ability to introduce significant further storage capacity into the market.
- Imported LNG would also bring the benefit of fuel certainty in the case where there is insufficient indigenous gas market liquidity available to cycle into and out of storage to meet demand.

Options to address supply and demand balancing have been assessed in the report *LNG import and options to increase indigenous gas market capacity and flexibility in New Zealand*.

5.7.1. Storage Options in New Zealand

Currently the only ability to defer the consumption of significant volumes of indigenous gas is provided by the Ahuroa underground gas storage facility, however a shortage of gas to cycle through the facility has reduced its utility. This will change by 2023 if indigenous gas supply meets operator forecasts of increased production. Options to better balance supply with demand across time include expanding cycling capacity at Ahuroa, constructing a new underground storage facility, building LNG peak shaving facilities, paying gas producers to provide standby production and agreeing terms with major users to provide demand-side response. Underground storage expansion and construction options provide the greatest scope for providing additional system flexibility at the lowest relative cost.

There are at least two known underground storage options:

a. **Expansion**: Increase the cycling capacity of the Ahuroa underground storage facility from 65 TJ/day to 150 TJ/day. Available gas storage capacity would remain unchanged between 10-12PJ. Due to the recent decline in performance of the Ahuroa underground storage facility this has not been assessed as an expansion option. Indeed, the decline could have the effect of increasing the need for further storage capacity.

b. **Conversion**: Development of new underground storage capacity, probably via the conversion of the depleted Tariki field, to meet the buy-side interest expressed by Genesis Energy for up to 55 TJ/day of cycling and 20 PJ of storage. The ultimate cost of adding underground storage capacity at Tariki would depend on development costs and in particular individual requirements for new compression and production wells. Analysis indicates a capacity reservation fee for the Tariki option of $104-215 per GJ.MDQ depending on payback horizon.

A shared challenge with any gas storage investment case is the term against which a buyer of storage capacity would commit. For underground storage options, it is expected that an investor would require a commitment term of at least 15 years.

5.7.2. Fuel availability for storage

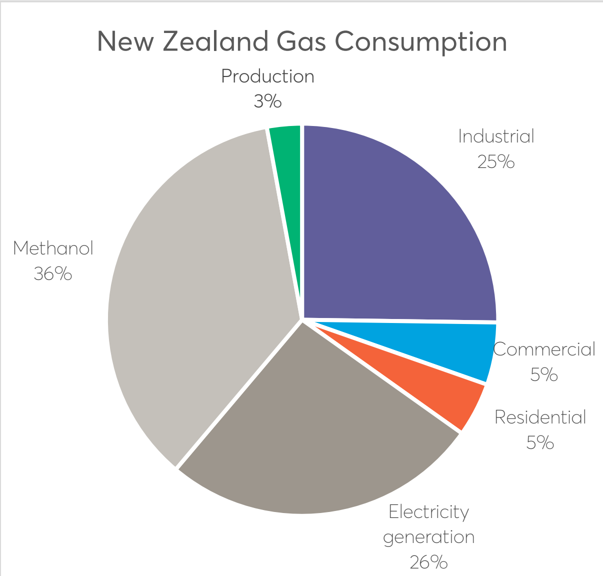
Any domestic storage option is a reliance on domestic fuel availability to charge and draw-down storage as it is needed. Adding storage capacity for indigenous fuel does not on its own increase the size of the fuel pool. It simply increases tankage volume which, without gas to cycle through it, could serve little purpose. If sufficient indigenous gas does become available to enable unconstrained cycling, as recent reserve disclosures from field operators suggest is likely to occur, then underground storage options present as the most cost-effective solution. Within this, the conversion of Tariki presents as the most attractive option given its ability to introduce significant further storage capacity into the market.

Imported LNG would also bring the benefit of fuel certainty in the case where there is insufficient indigenous gas market liquidity available to cycle into and out of storage to meet demand. Imported LNG could integrate with existing and/or new underground storage facilities to provide further optionality for in-country storage to receive imported gas. Access to local underground storage would however represent an additional supply chain cost to it would likely be less expensive for users to manage flexibility through the FSRU given that the fixed costs of the facility would already be paid for via the fixed option cost.

6. New Zealand in the International Landscape

6.1. Natural Gas Sector today

Figure 8 below provides an overview of the market segments and their respective emissions and market profiles.



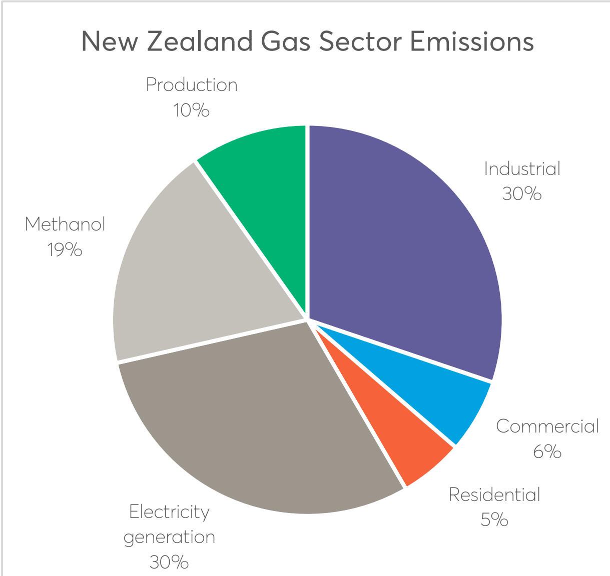


Figure 8. New Zealand gas consumption and emissions, 2021

A high level description of each gas market segment is included below:

a. **Petrochemical**, particularly methanol manufacture. Methanex is New Zealand's largest energy user, by far. Nearly all of its production is exported. Emissions are incurred in the manufacture of methanol and urea, while much of the gas consumed is feedstock that doesn't count towards New Zealand's emissions output. Demand from Methanex, in particular, tends to underwrite the development of gas fields. Gas fields are unlikely to be developed solely for other purposes, such as gas-inclusive electricity; contracted demand from methanol provides investment confidence that results in field development that produces supply for other consumers.

b. **Electricity.** Natural gas is used to generate both base load and peaking electricity. Peaking electricity is required when generation from renewables is constrained and can't meet electricity demand. When extra gas is required for gas-inclusive peaking generation, it is generally met by demand response from the gas sector. That is, other gas consumers reduce demand and the gas is diverted. Some gas is available from storage but generally gas fields are not engineered to vary output in response to demand. Fields tend to produce steadily at maximum output and the gas is pre-sold under long-term contracts. Even when short term prices rise, gas fields do not change output.

c. **Industrial.** Industrial consumers are generally those businesses with industrial processes involving manufacture, typically for other businesses. Some industrial sectors that use little gas in their production may be able to benefit from gas emissions abatement technologies, especially CCS. For example, industries such as cement and limestone create carbon emissions from chemical processes. No easy abatement technology exists for this category of manufacturing emissions, but it may be possible for those industries to sequester their carbon emissions in gas reservoirs.

Waste water treatment is another example of potential spillover benefits from gas transition: Some waste plants capture methane emissions that they use to generate their own electricity. If a biogas market develops using existing pipelines, it may be significantly more efficient for those waste treatment plants to sell their biogas and buy electricity. Opportunities for transition to electricity are constrained by relative cost and international competitiveness - averaging all sector costs divided by all energy at the point of supply, a unit of energy from electricity is nearly six times more expensive than an equal unit of energy from gas for an 'average' industrial gas consumer (although appliance efficiencies offset some of the differential)[41]. Some businesses cannot absorb carbon prices without making their products uncompetitive against competitors that do not pay for emissions.

d. **Commercial.** Commercial users span a wide range of economic activity, from cooking in cafes and heating in hotels, to greenhouse processes that re-use carbon dioxide, to crematoriums and other facilities that require very high heat, to LPG supply to remote areas where electricity cannot easily be supplied at required energy loads. Opportunities to fuel switch for commercial consumers are specific to individual circumstances. Some applications such as low-to-medium space heating of warehouses can be economically replaced by electric heat pumps. Others such as precision temperature applications require a flame because these processes are not suitable for micro outages that can occur from electrical energy supply.

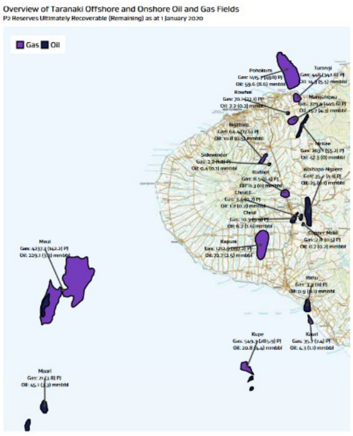
e. **Residential.** Natural gas is supplied through pipelines only in the North Island. LPG distribution occurs in places that are not served by pipeline infrastructure, including the South Island. Only 4% of natural gas is consumed by households, but they are over 90% of all connections. Residential consumers often use gas for its perceived qualities and continue to do so even when they can access the same energy content from a different technology at a lower price.

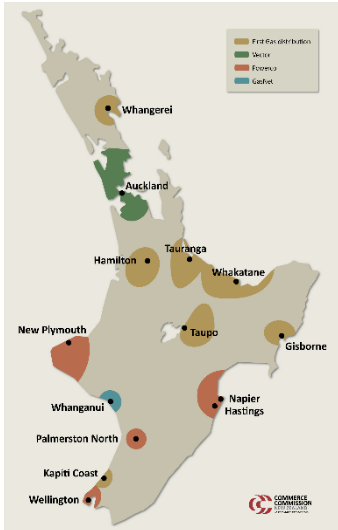
f. The other crucial sectors are transmission and distribution infrastructure and upstream gas fields. Transmission pipelines move bulk supplies around the country. Distribution lines carry gas to the end consumer.

[41] Modelling for Gas Industry Co by Sapere, Cost benefit analysis of information disclosure in the gas industry, p.8 https://www.gasindustry.co.nz/assets/WorkProgrammeDocuments/SOP-Gas-Production-Storage-Outage-Information.pdf and also shown in MBIE, Real Quarterly Average Fuel Price, March 2022. https://www.mbie.govt.nz/dmsdocument/23550-energy-in-new-zealand-2022-pdf Energy values at point of supply do not reflect appliance efficiency.

The diagram below shows the fields, transmission and distribution of natural gas across the North Island.

Fields[1] Transmission[2] Distribution





The current arrangements in the New Zealand gas sector are shaped by the nature of natural gas development and operation. Some technical aspects of gas field development, maintaining production, and specific characteristics of different well/reservoir types impact the deliverability of New Zealand's gas supply, and limit the way the sector can operate.

While there is no one fixed path in the development of a gas field, the full lifecycle of discovery of a new gas field through to initial production can take in the order of 5+ years (for onshore) to 10 years or much longer (for offshore) from beginning to end, although there is a wide variation in development times depending on specific technical and non-technical circumstances. In New Zealand developments can take as little as a year and as long as 40 years. Offshore developments normally take longer due to the need for more complex (and expensive) drilling rigs that have a long lead time to secure, as well as additional engineering and logistical challenges.

A field will be developed if it is technically and commercially viable, taking a range of risks into account (see below). Construction activities following a final investment decision will involve several key activities, including the construction of surface facilities and the drilling of the development wells. Plans are approved by government and regulatory authorities, and implementation is carefully monitored. Stakeholders are engaged with to consider environmental, social, economic and operational issues.

Once a field is developed, it will typically produce gas for the next 20-50 years. Every field has its own characteristics which require bespoke production concepts, but ongoing development of the field is carried out through the drilling of further wells, the installation of new pipelines, facilities and compression in the most cost-effective way in order to meet future gas market requirements, and with regard for the environment and local communities that may be impacted. Once in production, a field will produce at a maximum rate (known as 'plateau production') for a number of years, and then enter the 'decline phase'. This decline phase can last for decades, depending upon the size of the gas field.

New Zealand's producing gas fields are in the decline phase and require step out drilling of new wells or other investment to maintain production and slow the decline. Based on future gas demand market forecasts, field operators replace declining production by investing in further field development to bring reserves into production and/or undertake further appraisal of the field's potential (including of 'contingent' resources) to ensure that demand can be met.

It is often stated that there are "ten years of gas in the ground" as an approximation of gas remaining for consumption. This timeframe is calculated as how long current rates of consumption could be met from known gas reserves, which producers have a relatively high degree of confidence in being able to recover (known as '2P' reserves). But this approximation does not account for:

- the dynamics of gas development and production, such as the impact of deliverability decline on the production of 2P reserves
- investment that is required to bring the gas to market (with the ongoing investment required to bring reserves into production having been estimated by Enerlytica to be in the order of $200 million a year averaged across all Taranaki fields) or the likelihood of that investment being made
- the long production 'tail' to most wells.

The 2P reserves can only be recovered, delivered and eventually consumed if ongoing investment is made as planned, and therefore should not be thought of as equivalent to natural gas in storage ready to be consumed. Development that can unlock 2P reserves can include installing compression, drilling new wells into different but known reservoirs, or drilling infill wells into existing reservoirs and between existing wells, to increase both production rate and reserve recovery.

For example, reserves at Maui B are classed as 2P because an in principle commitment has been made to develop them and the field's owners are reasonably confident they will be able to deliver them, but wells need to be drilled (at considerable expense) in order to recover those reserves.

In relation to the third point, field operators are limited in their ability to control the rate at which reserves are extracted, with that rate becoming slower as a field declines. The "ten year" figure is a result of dividing the total reserves by current consumption, and we heard from producers that it is often more likely to take 20 years for that volume of gas to be extracted.

It may therefore be more helpful to think of the 10 years as a bow wave of the potential level of production of known reserves that producers are relatively confident of being able to recover in the coming years. This bow wave is maintained by the exploration and appraisal activities of upstream gas parties, which bring resources that were previously considered only 'contingent' into the assessment of 2P reserves as those 2P reserves are matured, delivered and consumed. Known 2P reserves are also constantly being revised as new drilling locations are investigated, and the performance of existing fields becomes better understood.

As New Zealand's gas fields are in the decline phase, ongoing investment decisions need to be made today to ensure deliverability of gas in the mid to late 2020s, and even into the 2030s. In addition, ongoing investment is required to maintain the gas pipeline infrastructure in order to keep the pipes safe and operational, even if gas use reduces to a level where the transmission system can be run at lower pressure.

6.2. International Landscape

A list of international emissions reduction initiatives is included in Appendix A.

The New Zealand gas sector is unique in its scale, isolation, and operation compared with gas sectors worldwide. These unique attributes mean that while some policy initiatives execute overseas may be applicable to New Zealand, others are less applicable where the countries gas sectors differ. For some countries, for example, residential gas use may contribute a significant proportion of other countries gas sector emissions, and therefore a significant area of focus for these countries emissions reductions policies. In New Zealand, where the residential sector is only a small proportion of gas demand, this segment of the market requires less policy intervention to drive emissions reductions.

Internationally there is wide-ranging recognition that transition away from non-renewable carbon based fuels is necessary. At the same time governments understand it is important that mechanisms deployed to drive this transition do not have unintended adverse consequences, such as driving up the use of coal in electricity generation. Many countries are grappling with finding the right balance to support an orderly transition away from fossil fuels – including natural gas – without significant unintended economic costs.

While some locations (typically at a local level) have imposed interventionist measures such as banning new gas connections or the installation of any new gas-fired appliances (the Netherlands, northern California), most are taking a more measured approach including significant investment in new technologies such as carbon capture and storage and transition to renewable fuels.

Monitoring, reporting and verification regulations are important for the enforcement of measures. For example, the US EPA's Greenhouse Gas Reporting Program requires all facilities that emit at least 25,000 tonnes CO_2 equivalent per year to report their emissions. In November 2020, UNEP, CCAC, European Commission, the Environmental Defense Fund and 62 oil and gas companies launched Oil & Gas Methane Partnership 2.0, a methane reporting framework, aiming to provide a gold standard for companies reporting on methane emissions.

6.2.1. Reduced leakage

Some of the emissions associated with natural gas come from leakage of methane along the gas supply chain. Policy measures employed to reduce these "fugitive" methane emissions range from prescriptive to outcome-based, economic incentives or information-based.

Prescriptive or mandatory performance-based measures have been used in some US states (for example, Maryland and Colorado). In Europe, ten companies suggested, in their policy recommendations for Europe's Green Deal, that a methane intensity-based performance standard be applied to the upstream segment of the supply chains. The Global Methane Alliance also advocates for methane intensity targets, recommending that countries pursue a 0.2% intensity goal.

The main advantage of performance standards compared with prescriptive standards is that the regulated entity has the freedom to seek the most cost-effective solution. However, in order for this type of regulation to be effective, both the company and regulator must have reliable data and mechanisms to track progress. Saskatchewan in Canada has set requirements at company level for yearly methane reductions for all upstream companies that emit at least 50,000 tonnes of CO_2 equivalent per year.

Economic incentives include taxes, subsidies or market-based instruments such as tradeable emissions permits or credits. Several countries use emissions taxes and trading schemes to incentivise reduction of fugitive emissions. Russia enables offsets of its pollution impact fee when an operator can document that the money was used to invest in the capture and use of associated gas. Alberta, Canada is providing loans and grants to companies for methane abatement projects at existing and orphaned wells.

6.2.2. Carbon Capture, Utilisation and Storage

In light of the potential importance of CCUS as a key strategy to meet emission reduction targets, many countries and states have embarked on ambitious work programmes to enable and encourage investment in CCUS initiatives.

Appendix A contains a full list of CCUS projects, initiatives and programmes underway internationally.

6.2.3. Renewable gas

Biogas and biomethane are well-established technologies, particularly in Europe. Internationally, biogas and biomethane production provides over 2,011 PJ of energy annually which is used for electricity and heat generation and as a vehicle fuel. Full utilisation of the available sustainable feedstocks for biogas and biomethane could cover up to 20% of today's worldwide gas demand.

Germany is the clear leader in global biogas/biomethane production, representing more than 50% of production in the EU. There are more than 9500 biogas plants in Germany which generate over 300 PJ of raw biogas, equal to around 10% of the energy Germany gets from natural gas. Denmark is also considered a leader in biogas and biomethane. Biogas has been a significant part of Denmark's energy mix since the 1970s and in 2022 the biomethane production is expected to make up 30 % of Denmark's total gas consumption.

Hydrogen

Markets for green hydrogen are still in the early stages of development. Several governments have committed funding the development of hydrogen production facilities and transport infrastructure and are anticipating the need to update regulations and develop standards to consider green hydrogen. Green hydrogen is important for hard to abate sectors, supported by a variety of policies.

The IEA reports that 26 governments have committed to adopt hydrogen "as a clean energy vector in their energy system".[42] However, it warns there has been 'very limited progress' in policies to stimulate demand creation.

While hydrogen is expectedly to contribute comparatively modest emission reductions before 2030 in the IEA's Net Zero Scenario, it is expected to have an important international role in hard-to-abate sectors.

> "The contribution of hydrogen technologies is significantly lower than the contributions of other key mitigation measures, such as the deployment of renewables, direct electrification and behavioural change. However, hydrogen and hydrogen-based fuels can play an important role in sectors where emissions are hard to abate and where those other mitigation measures may not be available or would be difficult to implement.

[42] The data in this section is drawn from IEA (2022), Hydrogen, IEA, Paris https://www.iea.org/reports/hydrogen

Hydrogen's total contribution is also larger in the longer term as hydrogen-based technologies mature."[43]

Internationally, new applications are being piloted in steelmaking (hydrogen-based direct reduced iron [DRI] and hydrogen blending in DRI or blast furnaces), while in other industrial sub-sectors the use of green hydrogen for high-temperature heat production will help reduce reliance on fossil fuels.

The majority of policies focus on supporting demand in transport, mainly through purchase subsidies, with about 20 countries offering subsidies for fuel cell vehicles.

A small number of policies target industrial applications. Low-carbon fuel standards or renewable transport obligations, are currently in place in Canada, the United Kingdom and California, and the Dutch government announced that the use of renewable hydrogen in refineries will count towards the renewable fuel transport obligation from 2025.

No government has to date announced quotas and mandates to support demand creation in industry, aviation and shipping.

International markets for green hydrogen are still in the early stages of development. A complete dataset covering all projects commissioned worldwide since 2000 to produce hydrogen for energy or climate-change-mitigation purposes is freely available at https://www.iea.org/data-and-statistics/data-product/hydrogen-projects-database.

Hydrogen demand is concentrated in refining and chemical sectors, with very limited penetration in new applications. Most of this demand is met by 'brown' or 'grey' hydrogen produced from unabated fossil fuels with accompanied CO_2 emissions.[44]

Demand in new applications, such as transport, and high-temperature heat in industry, grew by 60% in 2021 to reach around 40kt of H_2, which represents only 0.04% of global hydrogen demand. Most of this is concentrated in road transport.

However, in the past two applications of hydrogen have entered operation in chemicals production (Iberdrola-Fertiberia Project in Spain), iron and steel (Hybrit project in Sweden) and power generation (JERA project in Japan).

Electrolyser manufacturing capacity doubled from 2021 to 2022, reaching nearly 8 GW per year. The IEA says realisation of all projects in the pipeline could lead to an installed electrolyser capacity of 134-240 GW by 2030.

Some countries have policies to transition infrastructure from natural gas to hydrogen.

The Netherlands Ministry of Economic Affairs and Climate Policy commissioned Gasunie to develop the national infrastructure for the transport of hydrogen. The project, with an estimated investment of €1.5 billion, is scheduled for completion in 2027. The new national hydrogen network will consist of 85% reused natural gas pipelines, compared to costs four times higher if entirely new pipelines were laid.

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[43] IEA (2022), Hydrogen, IEA, Paris https://www.iea.org/reports/hydrogen

[44] IEA (2022), Hydrogen, IEA, Paris https://www.iea.org/reports/hydrogen

One of the most developed support mechanisms for hydrogen trade so far is the H_2Global double-auction programme in Germany, which includes only low-emission electrolytic hydrogen and its derivatives. The initiative emulates a Contracts For Differences scheme. Using a market intermediary, it will hold an auction to purchase products from non-European Union suppliers through fixed-price, ten-year contracts. It will then conduct a separate auction to sell the hydrogen to buyers using roughly one-year contracts. Since the cost of producing electrolytic hydrogen will likely exceed buyer willingness to pay in the near term, the intermediary will sell at a loss. This price difference will be covered using public funds. The German government has approved a EUR 900 million (~USD 1 billion) grant for this purpose. The Netherlands government has also expressed interest in contributing funding.

Several governments have committed funding to the development of hydrogen production facilities and transport infrastructure and are anticipating the need to update regulations and develop standards to consider green hydrogen.

Several governments use certification schemes to drive uptake of green hydrogen or to verify the carbon content of hydrogen from any source. Examples include:

- CertifHy is developing a European Union voluntary scheme for the certification of hydrogen. The German certification body, TÜV Rhineland, provided the world's first clean hydrogen certificate to a project for the production of renewables-based ammonia in Oman.
- The Netherlands has become the first European country to issue green Guarantees of Origin for hydrogen following a pilot test conducted by the hydrogen exchange initiative HyXchange in cooperation with Vertogas.
- The United Kingdom has a Low Carbon Hydrogen Standard published in April 2022 after a public consultation. It sets a maximum threshold of 20g CO_2e/MJLHV H_2 (2.4 kg CO_2e/kg H_2) for emissions from the production of hydrogen, if the output is to be considered low-carbon hydrogen. Hydrogen producers seeking support from government programmes need to meet this standard.
- The United States has announced a Clean Hydrogen Standard (with a threshold of 2kg CO_2e /kg H_2 at the point of production).

Connection/injection rights and liabilities

The concept of "right to inject" guarantees access to the gas grid for the output of a biomethane plant, providing a revenue guarantee to the plant operator, increasing the financial viability of the project. A number of European countries including Denmark, Germany, France, Italy, Finland and Latvia have introduced a 'Right to inject' policy where gas grid operators are obliged to connect biomethane plants upon request with standardized terms of connection including a transparent cost sharing framework. This is a much more efficient use of biogas than simply using for local heat and power (for example at a waste treatment plant) which results in significant wastage.

Certificates and standards

Internationally, there are several renewable gas certification schemes in place or under development. The most established schemes are in Europe, with the EU Renewable Energy Directive providing both the renewable energy targets and sustainability characteristics for gases. Many member states currently operate pilot or fully implemented national biomethane registries including Ireland, Italy, Portugal, France, Switzerland, Germany, Austria, Czech Republic, Slovakia, Poland, Denmark, Estonia, Latvia, and Lithuania. The

European Renewable Gas Registry (ERGaR) has also been established as a scheme for cross-border trading of Guarantees of Origin.

In Australia, GreenPower is a national renewable energy accreditation program, enabling business and household customers to match their electricity use with renewable energy, which is added to the grid on their behalf. GreenPower has facilitated $900 million of investment into the renewable energy sector, and 16 Mt CO_2-e emissions reduction. GreenPower is now investigating opportunities to support emerging renewable gases, such as biomethane and renewable hydrogen. It is expected that the pilot will start operating in mid-2022 and run for at least two years. Learnings from the pilot could inform a potential permanent renewable gas certification scheme.

Other forms of support for biogas

As with CCUS, government can play an important role in development of biogas facilities by carrying out or funding feasibility studies. Many EU members have conducted their own domestic biogas feedstock potential assessments including Belgium, France, Denmark, Germany, Latvia, Ireland, Italy, and Spain.

In Sweden the majority of Sweden's biomethane is used as a vehicle fuel (63%), thanks to incentives promoting CNG vehicles powered by biomethane. Biogas and biomethane make up around 22% of total energy gas supply in Sweden, however most of this renewable gas is imported from Denmark. The Swedish government recently announced a long-term investment plan using subsidies to boost biogas/biomethane production. Meanwhile the Netherlands is commissioning Gasunie to develop the national infrastructure for the transport of hydrogen, using 85% reused natural gas pipelines.

6.2.4. Phase-Out of Gases

Some mechanisms, including initiatives that facilitate switching, mandates, and strategic decommissioning, that may have a role to play within a winddown pathway have been assessed. These have the effect of phasing out all types of pipeline gas, including biogas, as the pipeline infrastructure is decommissioned.

Facilitated switching

As gas consumption decreases both gas utilities and consumers are at risk of becoming owners of stranded asserts. Often those who will be most vulnerable to rising gas rates are commercial and residential consumers with low incomes, as they cannot afford the upfront investment to replace gas appliances with electrical appliances.

Some nations and states have taken actions to reduce barriers to switching from gas to electricity.

Although focused on switching from oil rather than gas, the Finnish Sustainable Growth Programme is an example where the government is supporting the conversion of heating systems in buildings to abandon oil-fired heating systems. The state aid of EUR 70 million will be directed to small houses, municipalities, associations and parishes, as well as to suppliers and installers.[45]

[45] https://www.iea.org/policies/13595-sustainable-growth-agenda-fossil-fuel-phase-out

Mandates

One approach to halt new investments in gas infrastructure and appliances has been to ban new gas connections or the installation of new gas appliances. The Netherlands banned the installation of gas heaters in new homes from 2017. In Northern California, more than 60 cities and counties, starting with Berkeley in 2019, have established local mandates committing to limiting or banning fossil gas infrastructure in new construction.

In the Netherlands, since the Climate Act was introduced, fewer than 10,000 houses have been renovated to become carbon-free, and 92% of households still used gas for heating in 2021. A failure to achieve local consensus and support is leading some of the gas-free pilot neighbourhoods to fall behind its schedule of 50,000 dwellings by several thousand households.[DG1]

Strategic decommissioning

The primary challenge with phasing out gas is that as the number of users decreases, the fixed costs of maintaining shared pipeline infrastructure are shared among a smaller number of users, leading to higher gas bills. A targeted approach to replacing or repurposing gas pipeline infrastructure may minimise transition costs.

As discussed above, government mandates preventing installation of new gas infrastructure can be unpopular. Both the Netherlands and California have allowed local governments to make decisions regarding their gas networks. The Netherlands Climate Act put districts in charge of choosing their heating systems.

7. New Zealand Gas Market Segments

Previous works that have analysed New Zealand's energy sector transition have approached the gas sector as a whole, relying on high level assumptions around the nature of gas sector operation. But the gas market is made up of segments with very different pathways into the future. The analysis in the Gas Transition Plan has focused on finding the most suitable pathway forward for each of the different segments of the gas sector rather than a whole of system solution. This has provided the opportunity to uncover unique solutions for each user segment. These segments are petrochemicals, electricity generation, industrial users, residential and commercial users, LPG users, distribution and transmission infrastructure, and production. When each of these pathways are combined, the overall pathway formed is one that meets the emissions budgets but also crucially meets the particular needs of each segment of the gas market.

7.1. Petrochemicals Segment

- Methanex is New Zealand's largest gas consumer.
- It performs an important role underpinning development of New Zealand's natural gas resources.
- Demand response from Methanex supports electricity security of supply.
- Methanex will achieve 10% reductions in emissions by 2030 and 15% by 2035 in line with its global corporate policy.
- Additional emissions capture opportunities exist for Ballance AgriNutrients.

Petrochemicals are manufactured by two companies in New Zealand – Methanex and Ballance AgriNutrients.

As New Zealand's largest gas user, Methanex can consume up to 90PJ of gas per year with all trains operational, although in 2021 this was only 55PJ reflecting reduced levels of operation. Methanex utilise this gas as both a fuel for their industrial processes and as feedstock to produce methanol. Its New Zealand facilities are the company's largest operations in the world with three production facilities located in Taranaki; two at Motonui and one at Waitara Valley which is currently idled.

Ballance AgriNutrients operates two fertiliser manufacturing facilities located in Hawera, Taranaki. The combined gas consumption across these plants was around 6TJ for 2021. Ballance has also signalled its intentions to produce and use hydrogen in its facilities.

Methanex performs an important role underpinning development of natural gas resources in New Zealand. It has supported the development of most significant gas fields in New Zealand since the early 2000s, which has provided security of supply to electricity and energy sectors whose demand profile is insufficient on their own to support field development. The process of bringing natural gas to market is expensive and takes many years. Upstream parties will carry out exploration to discover potential reserves, and go through the process of developing these resources to then produce the natural gas for market. Upstream parties will only do this if they are sure of a customer to purchase the gas at the other end, and so this process is underpinned by gas supply arrangements (GSAs) between upstream parties and consumers. The GSAs must be of sufficient scale and duration to warrant upstream parties investing their funds into the process to bring gas to market, to ensure they will get a return on their investment. Methanex has the scale of operation to support the stages of exploration, development and production of natural gas, to the benefit of the wider energy sector.

Methanex also performs a key role for electricity security of supply. In recent years, Methanex have adjusted some of their planned shutdowns to coincide with the winter electricity peak season, enabling additional gas to be transferred to gas-fired electricity generators who have insufficient supplies for New Zealand's elevated electricity demand.

Methanex demand response: The particularly dry conditions at the start of winter 2021 meant that there was elevated thermal generation demand. By temporarily idling one of its Motonui trains to reduce its own gas demand, Methanex was able to free up between 3.4PJ and 4.4PJ of gas over three months for Genesis, enabling a commercial arrangement between the parties to provide sufficient gas supply to support ~500GWh of electricity generation.

As New Zealand shifts further from coal-fired generation, which currently provides a large volume of this dry year response, the gas-firming that Methanex has provided in the past will become even more critical.

For these reasons, Methanex has a vital role to play in both gas and electricity security of supply throughout the energy sectors transition. Were Methanex to cease operations in New Zealand prematurely, imported LNG and/or coal may be required to support security of supply for industrial gas users and thermal electricity generators.

Methanex have recently announced their plans to improve efficiency of their Motonui trains, with 3.7% reduction in emissions announced, and more emissions reduction potential from subsequent stages. Methanex has set a global target of 10% emissions reduction by 2030, with further emissions reduction expected to continue after this date.

In September 2022, Methanex announced a multi-million-dollar investment to reduce carbon emissions at its Motunui facility in New Zealand. This will involve improving the technology in the facility's distillation columns over the next 12 months. Once completed, this project has the potential to reduce the site's carbon emissions by over 50,000 tonnes per annum.

The value that Methanex provides to electricity and natural gas security of supply, considered with the capture of CO_2 from natural gas that is used as a feedstock in its processes, means that Methanex provides more value to New Zealand's energy system decarbonisation by continuing operation than by shutting down prematurely.

The emissions capture opportunity discussed in Section 3.3.5 has additional capacity available above the emissions that would be captured at the production site. This additional capacity could be utilised by a number of different industrial players, and Ballance is a potential candidate. For this reason, the confirmed additional emissions capture capacity available has been included as petrochemical emissions reduction, but could as easily be considered as part of the industrial sectors future emissions reduction potential.

7.2. Gas Inclusive Electricity Segment

- Natural gas fuelled electricity generation provides baseload and peak electricity to the national grid.
- Rapid uptake of renewable electricity generation is essential for decarbonising the gas sector.
- The government has an aspirational target for 100% renewable electricity.
- The emissions reductions targets can be reached with 95-98% renewable electricity.
- In the period of transition to 100% renewable electricity generation, gas peaking is the lower emissions option consistent with necessary levels of security of supply. The gas sector must have confidence to invest until the renewable electricity transition is complete.
- New peaking generation will be needed to replace existing facilities to ensure electricity security of supply until the energy sector can support 100% renewable electricity.
- New peaking generation will only be built if policy measures provide confidence that a return on investment can be achieved.

Natural gas is used for electricity generation in 35 locations across the North Island. These include 11 dedicated generation facilities and an additional 24 cogeneration facilities where businesses have the ability to inject surplus energy from their gas consumption back into the grid as electricity[6].

Generation of electricity from natural gas consumes around 29% of New Zealand's available natural gas (MBIE)[7], which in turn contributes around 10% of New Zealand's electricity generation through baseload, peaking and cogeneration activities (MBIE)[8].

Existing electricity sector studies predict that demand for natural gas from gas-fired electricity generators will decrease over time. This is largely as a result of the decommissioning of baseload thermal generators, which will be displaced by new baseload renewable generation as it is commissioned. This decommissioning of baseload thermal generators contributes a significant proportion of decarbonisation of the natural gas sector. This Gas Transition Plan assumes by 2030, the CCGTs and Rankines have been retired, displaced by a combination of renewable generation plus approx. 400 MW of new peakers, consistent with assumptions used by Boston Consulting Group in their recent The Future is Electric report.

As more variable renewable generation is commissioned, increased peaking generation is required that can be dispatched on demand to ensure electricity security of supply is maintained. Until alternative sources of firming generation become technically and economically viable, gas-fired peakers will continue to be the primary solution to filling this niche. They provide short and medium-term security of supply for the electricity sector by operating when demand is elevated or when supply from other electricity generators is limited.

The government has an aspirational target for 100% renewable electricity. In the period of transition to 100% renewable electricity generation, gas peaking is the lower emissions option consistent with necessary levels of security of supply. As highlighted in *The Future is Electric*, as well as Transpower's recent *Security of Supply Annual Assessment 2022*, without this firming operation in the electricity sector, the risks of shortage events and elevated electricity prices are significantly higher, both of which will only slow wider electrification and decarbonisation efforts throughout the energy sector.

These electricity sector studies not only recognise the importance for continued operation of gas-fired peakers, but also the need for additional gas-fired peakers to be built. In particular, they have identified a need for these new gas-fired peakers provide electricity security of supply for short-term peaks. While new gas-fired peakers will have associated emissions with their operation, commissioning these new peakers will allow other higher emitting thermal generators to be decommissioned. This results in an overall reduction from the electricity sector due to the improvements to efficiency with new technology. Additionally, with a permissive emissions capture regime, there is potential for these new gas peakers to utilise this technology and negate the associated emissions. This has not been considered for the existing gas-fired peakers as current assessments note that the cost of retrofitting onto the existing plant provides an economic barrier. Commissioning new gas-fired peakers will have little impact on gas prices to consumers, but is predicted to contribute a ~5% reduction in wholesale electricity prices.

Under the current landscape, there is a real risk that these peakers will not be built. Consent holders do not see sufficient certainty that they will earn a return on their investment due to two factors. First, because the gas-fired peakers operate for a short duration during peak demand periods, there is a risk that these limited periods of income do not cover the baseline operation and maintenance costs. Second, it's not clear for how long these gas-fired peakers will be required to support electricity security of supply. At some point in the future, battery technology and other alternatives will become a technically and economically viable alternative. At that point, the gas peakers will no longer be competitive, and will close. This identified risk of early shut down before earning sufficient return on investment is currently stalling investment in this space.

If this pathway is adopted, ongoing investment into domestic natural gas supply will be required to support peaking gas-fired electricity generation. If investment into domestic supply of natural gas is insufficient, it may be that the next best alternative is to import LNG, as discussed in section 5.6. Alternatively, rather than relying on international imports of LNG, Methanex's continued operation in New Zealand could support domestic production to provide natural gas to fuel these gas-fired peakers.

An increase in emissions from gas-fired electricity generators is expected in the near term, which results in the first emissions budget for the gas sector being exceeded. External analyses of the electricity sector have determined that this level of gas-fired generation will be required to ensure electricity security of supply over the next 2-3 years. Once new baseload renewable generation has been commissioned, the subsequent decommissioning of baseload gas-fired generation reduces the associated emissions, and gas sector emissions reduction can get back on track. The ability to meet the first emissions budget to 2025 is largely driven by measures that are already in place, with few options available to make the significant changes necessary to meet this short-term goal. This provides a good example of the importance of planning ahead and implementing change before it is needed.

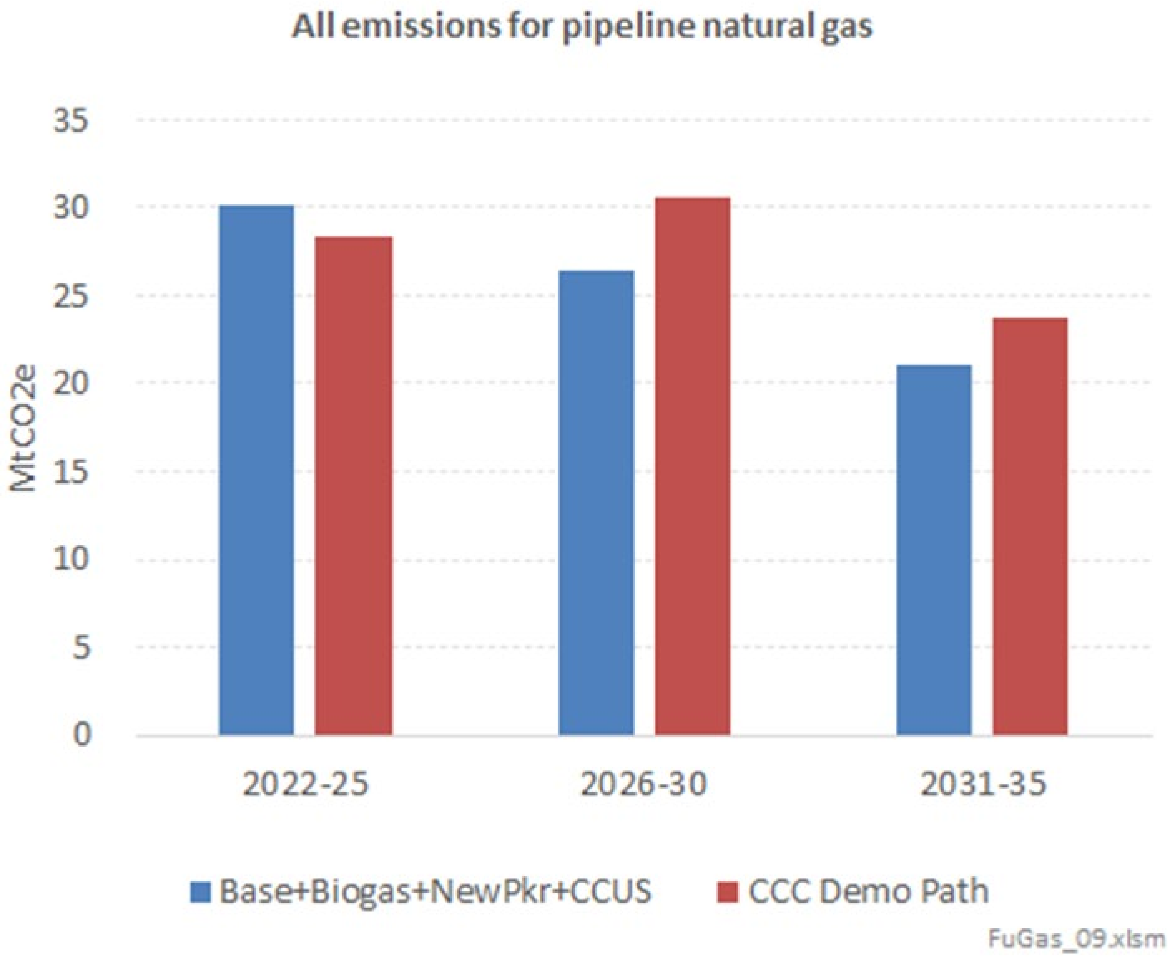

Figure 9. Total forecast emissions vs. gas sector emissions budgets

The impact of this short-term increase in emissions from the electricity sector can be seen in the figure above, with the current emissions budget being exceeded. However, gains in emissions reductions made through to 2035 quickly make up the difference, and overall emissions reductions from the time period out to 2035 far exceed the total emissions budget from 2022-2035.

7.3. Industrial Segment

- Industrial gas use includes a wide range of consumers, from milk processing to healthcare and social assistance.
- These consumers have a wide range of options available to their decarbonisation pathways, including biogas, hydrogen, emissions capture, direct air capture, electrification, woody biomass and other non-gas alternatives, efficiency improvements, and exit.
- A co-ordinated gas sector transition allows industrial consumers to select the best pathway for their specific industry as driven by the ETS.
- A 30% reduction in industrial emissions is sufficient for New Zealand's natural gas sector to meet its emissions budgets. Additional emissions reduction is possible though emissions capture.
- Without the right settings, these consumers are at risk of de-industrialisation, which would result in wide reaching societal ramifications, impacting local jobs and supply chains for important products.

This group includes consumers of natural gas who are large enough to either have facilities which are directly connected to the transmission system pipeline, or have a meter specifically designed to capture large gas volumes. The operations of the largest of these industrial consumers is well understood due to their scale:

- **Oji Fibre Solutions (NZ) Ltd** is a producer of pulp, paper, and fibre-based packaging. Natural gas is used to fuel each of its sites which are Kinleith Mill, Tasman Mill and Penrose Mill. Kinleith is in Waikato and is the largest of the three mills. It produces over 600,000 tonnes per annum of packaging papers and bleached softwood kraft market pulp, using around 2.5TJ of natural gas per year as feedstock into this production. The next largest is Oji's **Tasman** mill, which is in Kawerau, Bay of Plenty. It has a capacity to produce around 300,000 tonnes of unbleached kraft market pulp used by manufacturers of high-quality paper and building products, using around 0.5TJ of natural gas per year as feed stock into this production. **Penrose** mill is the smallest of these mills which is in Auckland and produces recycled medium liner.

- **Fonterra** is New Zealand's largest milk processor with 30[5] plant sites across the country. Nine of these sites use natural gas as a feedstock to run their plants, all of which are in the North Island. These sites are in Whangarei, Lichfield, Morrinsville, Maungaturoto, Pahiatua, Te Awamutu, Tirau, and Edgecumbe and used a combined total of around 4.5PJ of gas during 2021.

- **New Zealand Steel** is the only steel producer in New Zealand using locally sourced iron sand to manufacture around 650,000 tonnes of steel each year at its Glenbrook site located south of Auckland. Glenbrook site also relies on natural gas as a feedstock into its manufacturing processes and used around 1.5TJ during 2021.

The remaining industrial gas consumers can be broken into the following categories:

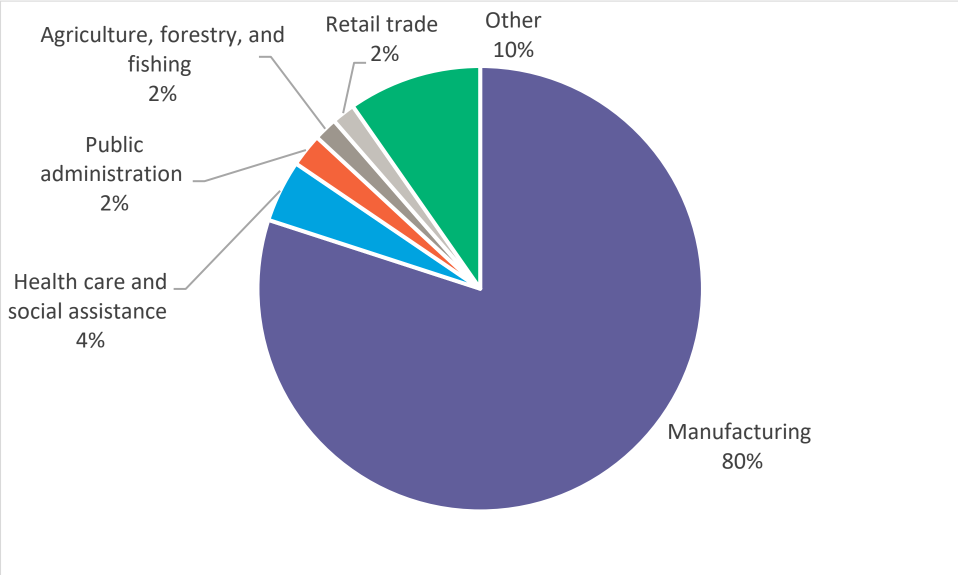

Figure 10. Gas consumption from small/medium industrial gas users

- *Manufacturing* is the largest industrial gas consumer group in New Zealand, the majority (nearly 50% of manufacturing demand) for dairy milk processing, even after Fonterra is excluded. Other large manufacturing groups also include:
  - Meat and meat product manufacturing (e.g., abattoirs)
  - Pulp, paper, and paper product manufacturing (e.g., paper mills)
  - Cereal, sugar, confectionary and other food product manufacturing
  - Building and construction materials manufacturing (e.g., cement, timber milling, metal)
- *Health care and social assistance* is the next largest industrial gas consumer, largely made up of hospitals, medical centres, and residential care services with gas use primarily being for space heating.
- *Public administration and safety* is largely gas used by central government and includes the buildings and infrastructure used by government. These include prisons and corrections facilities, defence facilities, sports and recreation centres owned by local councils.
- *Agriculture, forestry, and fishing* is mostly split between poultry farming, and nursery and floriculture production. The small portion of gas use outside this is used for support services for agriculture and fishing (i.e., plant and machinery workshops, and service centres).
- *Retail trade* is largely made up of food retailing for specialised foods, supermarkets, and grocery stores. Food and beverage services also fits into this category which is largely cafes, restaurants and takeaway food services who rely heavily on gas for their cooking facilities.

As outlined in the Technology Options chapter, industrial gas users may utilise hydrogen, biogas, emissions capture, or direct air capture to reduce their emissions. They can also choose to reduce emissions by improving efficiency, switching to electricity or woody biomass, or ceasing operations and exiting New Zealand.

7.3.1. INDUSTRIAL OPTION: Efficiency

Efficiency improvements can be unlocked by adapting technologies and established processes throughout the natural gas sector.

For many parties throughout the sector, replacing old technology with newer and more efficient technology can unlock significant emissions reductions. This change is often driven by the primary benefit of reduced energy bills, especially as the carbon price increases. These efficiency improvements reduce the energy consumption requirements of a process to get the same energy output, which in turn reduces the emissions from the process. Efficiency improvements can also be made by adapting established processes and operations.

> While they wait for technological alternatives to become commercial, New Zealand Steel Mill are working to improve the internal efficiencies of their steel manufacturing processes, reducing the amount of CO_2 emitted for each ton of steel produced. These efforts have been hampered when electricity and short-term gas prices have been elevated in the past. In these situations, New Zealand Steel Mill operated some parts of their plant at inefficiently low levels to avoid incurring high energy costs, which increases the CO_2 per ton of steel produced. With a stable energy system, industries are able to focus on efficient operations to ensure the emissions from their processes are reduced.

7.3.2. INDUSTRIAL OPTION: Switching to electricity and woody biomass

Electricity and woody biomass are currently the leading non-gas options that provide an alternative energy source to natural gas in New Zealand. There has already been uptake of these fuels throughout New Zealand, primarily led by the shift away from coal used for process heat, and also as new technology becomes more cost competitive.

> Supported by the GIDI fund, Napier Pine Limited are purchasing a new 4MW biomass boiler that will operate at their Hastings site. The biomass boiler will supply steam to their wood drying kiln and eliminate gas consumption. The bark, shavings and sawdust used to fuel the biomass boiler are produced onsite negating the need for product to be shipped to site. This project has an estimated lifetime carbon abatement of 104,125 tonnes.

While these non-gas alternatives provide a valuable energy source for some, there are limitations on the number of applications of these alternative fuels for many natural gas users. Two examples of these limitations are described below.

High temperature process requirements

While electric technologically can be a viable alternative for low and medium temperature process heat, the technology for high temperature processes is not yet economically viable for many gas users.

Biomass systems can produce the high temperatures, and are often the preferred solution for such industries, but for many large gas users the volume of woody biomass required to meet their demands cannot be met from the country's limited biomass resource.

The New Zealand Steel Mill located at Glenbrook consumes electricity, coal and natural gas, with gas providing high temperature heat to the steel making process.
"The natural gas is used to preheat ladles for holding iron and steel and to reheat the steel slabs before they are rolled. A number of the downstream finishing processes also use gas fired furnaces for heating and drying."
There are currently no viable alternatives to gas in their processes due to the high temperatures required. Alternatives are being developed internationally, for example induction heating could be used to heat cool slab, but none of these options are commercially viable yet. As well, these alternatives are largely powered by electricity (or hydrogen), which are only viable if electricity prices are very low.

Retrofitting to accommodate different fuels

Existing sites that use natural gas are built in such a way that the natural gas infrastructure is incorporated into the facility. Swapping to an alternative fuel can require a major expenditure for some of these sites due to the nature of their building construction around their existing energy systems. For example, a hotel that uses natural gas for space and water heating would require a large scale retrofit. Similarly, some industrial sites that have been built to use natural gas, and have this technology integrated into their processes, would require a large scale rebuild of their facilities to allow a conversion to an alternative. The cost of conversion is not purely the cost of the new technology, but also the setting in which the conversion is taking place and the disruption to normal operations that the conversion can cause.

Fonterra have raised concerns about converting their existing natural gas systems alongside the coal conversions that they are prioritising in their decarbonisation efforts. They see limits to the speed with which they can carry out the conversions due to limits to the number of biomass boilers that can be manufactured to their specifications each year and the need to ensure there is sufficient processing capacity operational during the peak milking season. During peak milk production season, there is 24/7 operation of their sites around New Zealand to ensure all the milk is processed. There is little spare capacity in their plants, so any plants that are out of operation due to conversions will reduce this capacity, risking insufficient processing capacity.

While conversion to low-emitting alternatives can seem like the simplest path to decarbonisation, gas users can experience different barriers to this pathway unique to their current use of energy. For these users that struggle to swap to non-gas alternative fuels, it may be that gaseous alternatives, such as hydrogen or biogas, are a better fit.

There are also risks associated with investment in plant designed to avoid carbon charges by using biological sources of energy. The treatment of biological CO_2 emissions is a matter of policy. Regulatory settings could change in future if policymakers decide to treat biological emissions as equivalent to other emissions. Investment decisions-makers will take regulatory uncertainty into account when they decide whether to invest in biogas production and supply.

7.3.3. INDUSTRIAL OPTION: Exit and De-Industrialisation

Industry is expected to reduce natural gas use by 30% by 2035, in part because some industry will exit New Zealand

This mode of decarbonisation is a shift away from energy consumption entirely, rather than to another form of energy through fuel switching, and can be represented as de-industrialisation.

Natural gas provides between 30-35% (55-70PJ) of New Zealand's industrial energy consumption. Industries use natural gas for a range of reasons, including cost competitiveness with alternative fuels, the chemical composition that is critical to their processes, or the specific qualities of the resource that can enable high temperature process heat.

Decarbonisation of these industries is driven by the carbon price. As the carbon price increases, so too does the cost that these industries pay for their energy to run their processes. This increase in cost is intended to drive decarbonisation of these industries, shifting their processes away from those that produce emissions.

But rather than being driven to decarbonise by changing operations, an industry may instead be driven to cease operations and shut down, at least in New Zealand. The cost of alternatives fuel sources may be too high to warrant transitioning even before even considering the cost of investing in the necessary technology conversions. In some cases, it may not be technically possible for an industry to convert to another fuel source, for example in processes where very high temperatures are required that cannot be met by alternative technologies. If this is the case, it could be that the trade-off between costs and benefits of transitioning does not warrant continued operation in New Zealand.

If transition is unfeasible or unaffordable, shut down can occur by ceasing operations entirely, or by shifting operations to another country, effectively exporting emissions. Some industries may continue to operate as they do currently and pass the additional cost on to consumers to maintain operational viability. But in cases where domestic costs increase and imported products are cheaper, they will no longer be competitive and will not be able to continue to operate.

> The Norske Skog Tasman Mill operated in Kawerau for 66 years, manufacturing paper products for publishers and print media organisations in New Zealand and overseas. Norske Skog announced that the mill would close in 2021, with 160 staff made redundant. "The mill is the victim of a declining newspaper market, high electricity prices, and being undercut by mills in China that are subsidised by their Government."[52]

While it may be economically more efficient for New Zealand to import some products rather than producing them domestically, there is a risk that industries that manufacture critical products are no longer produced in New Zealand. New Zealand must be aware of this risk, and not fall into decisions around which industries are needed in New Zealand.

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[46] https://www.nzherald.co.nz/business/the-last-days-of-the-norske-skog-tasman-mill/XD2EQJGH5DWI74DOPVEJ3WSUWI/

While there are various opportunities to decarbonise industrial processes in New Zealand, some of these industries may see that importing their products from international sources is a preferred alternative to investing in decarbonising domestic operations. While this could be a cheaper pathway to domestic decarbonisation, global emissions may increase as a result of this offshoring of industrial processing, as international sources may operate with greater emissions from their processes (for example the process that uses natural gas in New Zealand may utilise coal overseas, which has a much higher emissions factor). Shipping emissions must also be considered.

Not only does this domestic de-industrialisation risk increasing global emissions, but it also has wide reaching societal ramifications, impacting local jobs and supply chains for important products.

7.3.4. Industrial Pathway

With greater certainty about the pathway forward for New Zealand's natural gas sector, industrial players will be able to select the best of the pathways for their specific industry. Crucially, a coordinated gas sector transition means that this industrial transition will be driven by the carbon price, rather than the unintended drivers that uncertainty of New Zealand's energy future can produce. Carbon price currently makes up a third of an industrial consumers bill. If the carbon price doubles by 2035, carbon becomes the dominating proportion of an industrial consumers overall bill.

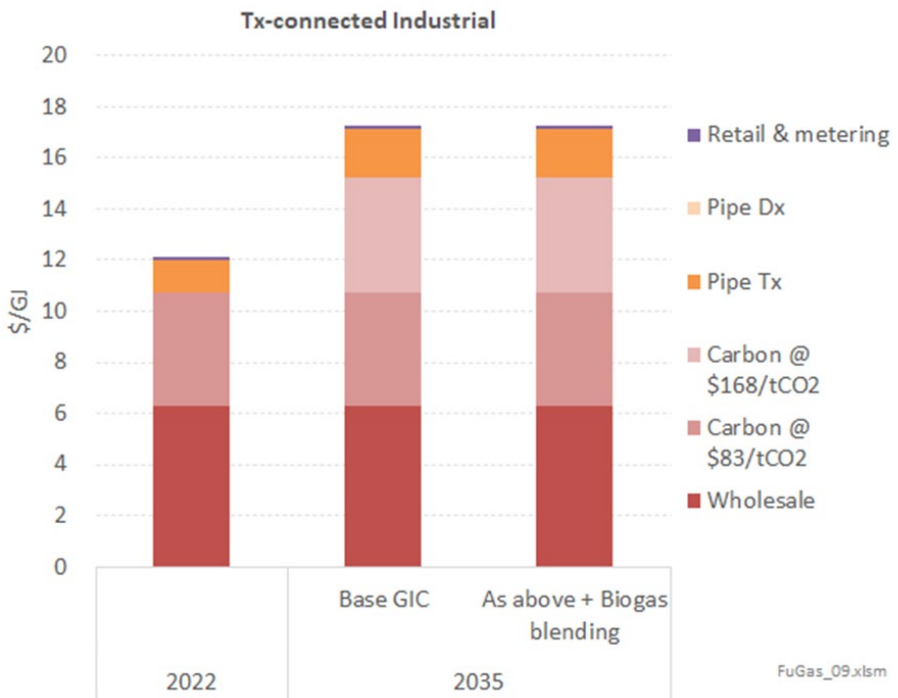


Figure 11. Gas bill for transmission connected industrial gas consumers

Considering the range of technology options available to industrial gas users, a 30% reduction in industrial emissions by 2035 is sufficient for New Zealand's natural gas sector to meet its emissions budgets. This figure was derived from a combination of the Climate Change Commission's demonstration pathway, analogy from other contexts and analysis, and feedback during targeted engagement. It is expected to be achieved mainly as a result of the increasing carbon price combined with introduction of emissions sequestration and the emergence of a more vibrant biogas market.

Further initiatives to facilitate emissions reductions from industrial use of gas are not required, as the carbon price (ETS) alone will drive business decision makers to make efficient decisions about which strategy to employ. Where policy initiatives such as subsidies and planning regulations are used to help businesses to transition, the focus would be distributional and equity outcomes, or resource management priorities. Those interventions are not required to achieve emissions reduction targets. In some circumstances, further initiatives may frustrate transition objectives, including security of supply, equity, and emissions reductions themselves.

7.4. Residential and Commercial Segment

- Although this group only consumes around 5% of the total natural gas available, they are the largest gas group of users by customer numbers, with 95% of all gas connections.
- Gas is used by these customers to fuel space heating, water heating and cooking.
- While these processes can technically be electrified, but this will not be the preferred option for all consumers due to the upfront cost of conversion Including appliance replacement and building reconfiguration), the perceived qualities of flame, requirements for high heat in areas where electricity cannot be economically delivered at required loads, and physical constraints such as floor space for heated water storage.
- No emissions reduction is required from this user group to meet the emissions budgets, while carbon costs (Emissions Trading System) means consumers internalise decisions to consume.
- Blending a proportion of biogas into the natural gas networks can decarbonise residential and commercial energy use while at the same time supporting the development of renewable gas resources in New Zealand. Arrangements are needed to develop a biogas market.

Despite using the smallest volumes of natural gas of all users, residential and commercial natural gas users make up the largest number of consumers in New Zealand. Of the 306,000 total natural gas connections in New Zealand, 290,000 of these are for residential consumers. Although this user group only consumes around 5% of the total natural gas available, they are the largest gas user by customer numbers with 95% of all gas connections.

This group is made up of small businesses and households connected to local gas distribution networks, which in turn are connected to the transmission pipelines that transport gas from the fields in Taranaki. Residential consumers are individual households and dwellings. These businesses range in size and type and generally include cafés, laundromats, fast food outlets, panel beating businesses, hotels and motels, theatres, schools, restaurants, and other accommodation. Gas is used by these customers to fuel space heating, water heating and cooking.

While these processes can technically be electrified, but this will not be the preferred option for all consumers due to the upfront cost of conversion and physical constraints. Any pathway forward for the natural gas sector must consider the equity and affordability implications for these types of consumers.

No emissions reduction is required from this user group to meet the emissions budgets but, due to the number of consumers within the residential and commercial segment, they have an important role to play in aiding the decarbonisation of the natural gas sector. Renewable gas blending presents a viable pathway forward for these users.

By blending a proportion of biogas or hydrogen into the natural gas networks, residential and commercial consumers can decarbonise their energy use while at the same time supporting the development of renewable gas resources in New Zealand. Enough biogas exists to rapidly introduce blending up to 20% of residential consumption and achieve worthwhile emissions reductions. Hydrogen may be considered in this renewable gas blending target, but biogas has been prioritised due to its ready availability and ease of blending.

Where biomethane is chemically identical to existing pipeline gas, which is injected with a range of specifications and reconciled in the market platform, the energy content per volume of hydrogen is quite different to that of biogas or natural gas due to its density. As a result, less natural gas is displaced when hydrogen is blended by volume than from biogas blending, and the associated emissions reduction is also lower. If the blending target were to extend to hydrogen, different specification and reconciliation arrangements may be necessary to account for the different levels of emissions reduction for an injected volume of hydrogen when compared to biogas.

While using a small proportion of natural gas sector volumes, the energy used by these consumers is not insignificant when compared to other energy sources. Under a pathway that shows large volumes of gas users switching to electricity, some electricity networks may struggle to support the investment require to upgrade their electricity networks to support increased load. This impact will differ depending on location, and the different opportunities and challenges in different electricity and gas networks. We see an elevated risk particularly for community owned networks that do not have the depth of capital to support significant increases to investment demands.

7.4.1. Cost implications for residential and commercial consumers

An average residential consumers bill of $1175 in 2022 is forecast to increase by 23% to $1440 in 2035. This is largely due to increases in carbon price, with relatively smaller increases to transmission and distribution charges as demand reduces.

In the case where 20% biogas blending is included, this residential bill increases again by 10% to $1600 per year. While biogas blending means that some carbon charges are avoided, the additional cost of the biogas that is blended into the system (which is currently more expensive than natural gas) results in a net increase to the total bill.

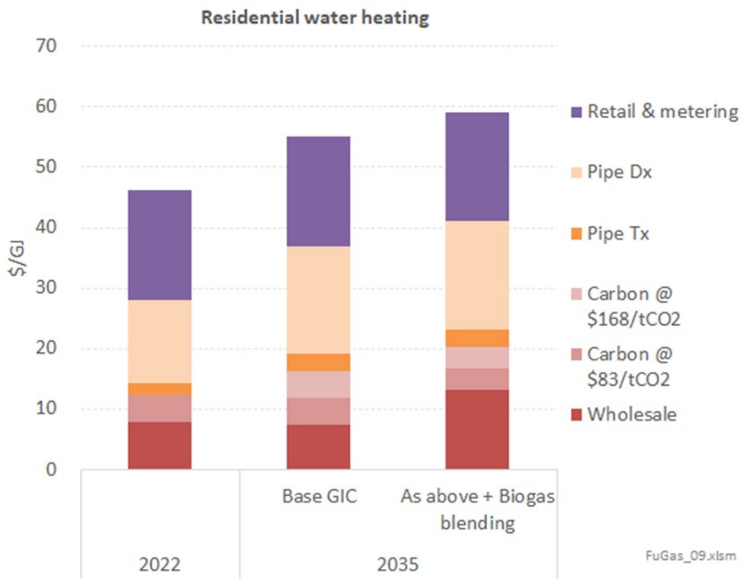


Figure **12**. Average charges for residential water heating

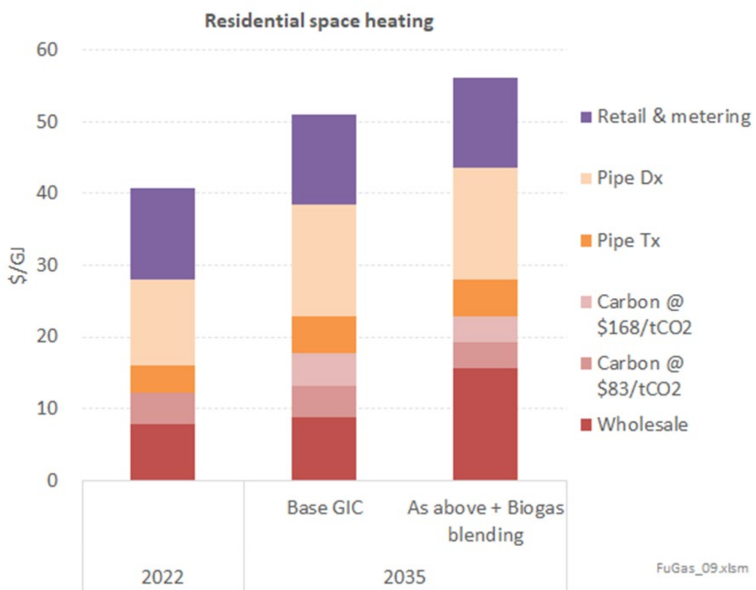


Figure 13. Average charges for residential space heating

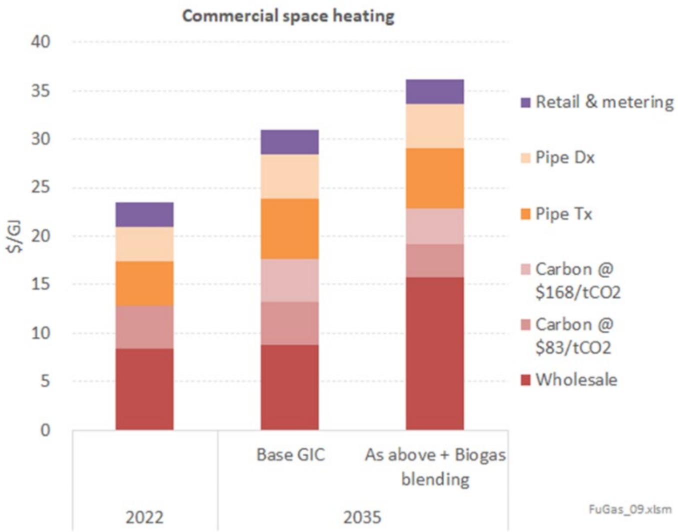


Figure 14. Average charges for commercial space heating

The graphs above indicate which components of a typical gas users bill will increase out to 2035. Transmission and distribution only increase slightly (transmission charges increase by 2% from 2022 to 2035), reflecting changes in demand. Wholesale gas price increases as more expensive biogas is blended into the system, with a 20% biogas blend increasing an average residential consumer's bill by 10%. The largest increase in a consumer's bill is as a result of carbon price increasing. A doubling of carbon price from today's \$83/tCO_2 to \$168/tCO_2 in 2035 results in a 10-15% increase in total charges to residential and commercial gas consumers. Spread over more than a decade, this increase compares to increases in prices of up to 30% for some residential LPG consumers in the past year. The equity implications are likely to be acceptable.

Gas prices will increase through the gas transition, and for some consumers this price increase will be sufficient incentive to switch to electricity space and water heating and cooking. For those who remain, the decision to continue using gas reflects the value that these consumers assess from the qualities of the fuel, such as instant water heating, low floor space impact from the technology, and a flame for space heating and cooking.

A policy that supports biogas blending for these consumers allows them to make this assessment for themselves, rather than being forced to switch against their preference as would occur under a winddown pathway. Forced switching would require potentially high capital costs for some consumers, involving potential purchase of new appliances for cooking and heating, and in many cases building re-modelling.

In addition, significant capital costs would be imposed on electricity consumers in some regions for upgrade for the additional energy loads. For example, in Wellington, where more energy is supplied by gas than by electricity, electricity loads could more than double, requiring replacement of much of the region's distribution lines. These costs will be spread unevenly in different regions, determined by features such as intensity of industrial load, but will amount to thousands of dollars for each ISP in some regions. Regional inequity would result.

Very serious equity issues arise in a rapid wind down because of upfront capital costs. Many households do not have savings sufficient to fund replacement of appliances. A post-covid survey of bank accounts by ASB Bank revealed 40% of households have less than $1000 of savings[47].

Phase in regulatory tools, such as banning new connections, do not avoid equity issues, as the scenario still leads to rapid wind down, with heavy upfront capital costs for capital conversion and electricity lines upgrades, distributed unevenly across the community.

Public assistance with a transition would be an option. The costs have not been modelled. Fairness issues would arise in extending public assistance to some energy consumers or some regions, and these need to be weighed in an assessment of equity.

Biogas blending avoids potential equity issues involved in driving conversion of up to 290,000 residential gas consumers and the additional households that use LPG.

7.5. Liquified petroleum gas (LPG) Segment

- Renewable LPG products are not expected to be available at significant volumes before 2035.
- Decarbonisation of LPG consumption can be achieved through a combination of virtual trading with a renewable blending target.
- A 30% reduction in industrial LPG can be expected alongside those reductions seen in industrial use of reticulated gas.

A portable source of gas, LPG is imported and produced domestically for the New Zealand market. The following illustration highlights the share of LPG used by the various consumer groups who collectively consumed around 9,643TJ during 2021. This was more than total natural gas consumption by residential households.[10] While reticulated natural gas can only be found in the North Island, LPG provides a gas product to consumers in the South Island.

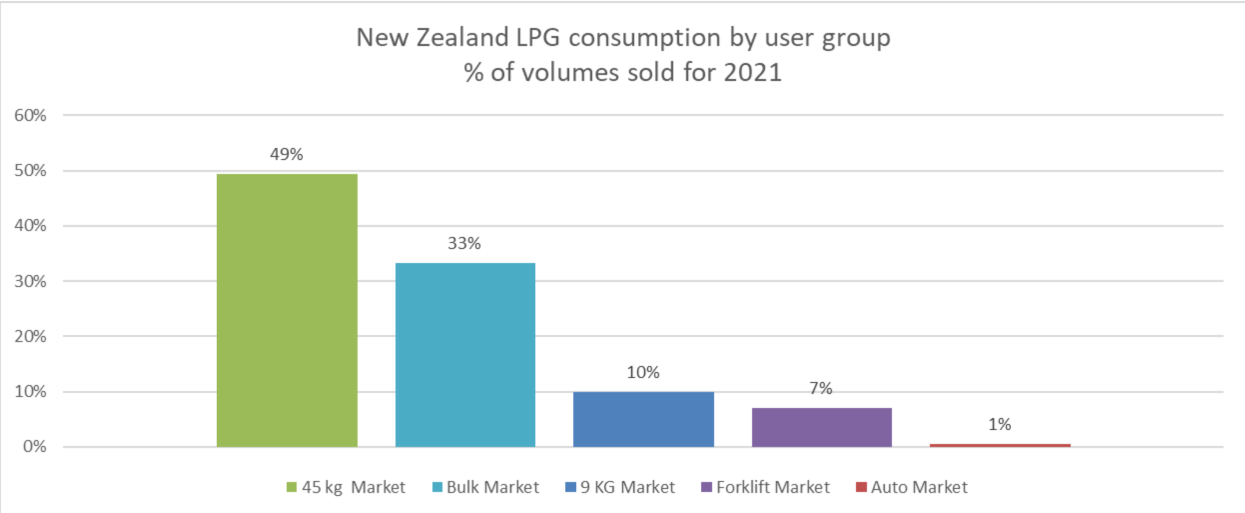


Figure 15. New Zealand LPG consumption by user group

The first three consumer groups (45kg, Bulk, and 9kg) are largely residential households who use LPG for a mix of space heating, water heating and cooking. Combined, these groups

[47] https://www.stuff.co.nz/business/126800836/four-in-10-people-have-less-than-1000-saved-in-case-of-need-asb-says

account for the majority of LPG usage with some variation in how each use and are supplied the fuel.

Of those customers who use 45kg bottles, 90% of these are for private dwellings, with the remainder being commercial. These customers use LPG as their primary source of fuel for space heating, water heating and cooking, with these bottles being delivered on an as needed basis.

The next group - Bulk - who are also largely households, are supplied through reticulated networks[11]. These are generally subdivisions where the gas is supplied and distributed via a single bulk gas container.

The 9kg bottles are largely use for barbeques and outdoor heating appliances for residential customers.

There are also LPG driven Forklifts which are largely used by businesses who regularly need to transport crates between transport vehicles and their storage warehouses. Auto represents the smallest LPG consumer, reflecting the very small portion of New Zealand's vehicle fleet which runs off LPG.

Similarly to the residential and commercial users within the natural gas sector, the small scale of LPG consumption lends itself to a renewable gas blending solution to reduce LPG emissions. While there may be future opportunities for renewable LPG products, the assessment from WoodBeca concluded that the availability of these products could not be relied upon before 2035. Until these products come to market, a 20% blending target can be met through virtual trading, as discussed in Section 3.2.3. In a similar manner, industrial LPG use is exposed to the same carbon price drivers and technology options as industrial natural gas users, and so a similar 30% reduction in industrial LPG emissions can be expected. Decarbonisation of the LPG sector possible through virtual trading of renewable gases, allowing for decarbonisation of gas use in the South Island.

7.6. Natural Gas Infrastructure Segment

- Pipeline infrastructure for distribution networks has been considered separately to transmission networks as their revenue streams and users bases differ, and therefore their future pathways are independent.
- Distribution networks have a largely unchanged role for timeframe out to 2035.
- Significant emissions reductions have been achieved by improved assessment methods for fugitive emissions from distribution networks.
- While volumes of gas through the transmission system will reduce, these volumes will remain at levels above those required for transmission system operation.
- The future for gas pipeline infrastructure is dependent on the nature of the pathways pursued by natural gas consumers. At forecast gas consumption for different market segments, any transmission price increases will be small relative to the total bill to consumers.

Natural gas is delivered to consumers through transmission and distribution infrastructure, with 2,200km of high-pressure gas transmission pipelines and over 18,000km of regional gas distribution networks.

The future for gas pipeline infrastructure is dependent on the nature of the pathways pursued by natural gas consumers. Pipeline infrastructure for distribution networks has been considered separately to transmission networks as their revenue streams and users bases differ, and therefore their future pathways are independent. Future roles and issues for these networks can be uncovered by considering the whole of system direction of the pathways described above for each user group.

7.6.1. Distribution

Distribution networks predominantly supply natural gas to residential, commercial, and some industrial users. As the residential and commercial use of natural gas is not predicted to decline significantly by 2035 or beyond to 2050, these distribution networks have a largely unchanged role for this timeframe.

Assessment of fugitive emissions includes a category for distribution networks, which represents emissions from leaks from pipelines and other operations, such as gas releases when maintenance is being carried out on parts of the network. Historically these fugitive emissions have been based on a tier 1 estimate, assuming that 1.75% of gas throughput is leaked from the distribution system. Gas distribution networks have been working to understand their emissions in more detail, and have recently worked with MBIE to update the method for this fugitive emissions assessment. This improved emissions assessment results in a significant reduction in fugitive emissions.

7.6.2. Transmission

Transmission infrastructure transports natural gas to directly connected industrial users and electricity generators, and connects the distribution networks to Taranaki where domestic gas is produced.

The gas transmission is subject to economic regulation under Part 4 of the *Commerce Act 1986*. This defines the revenue that the gas transmission business (GTB) can receive to cover its capital and operating costs. The revenue comes almost entirely from pipeline charges, paid by shippers and interconnected parties, on both a fixed and volume basis. These costs are then passed through to consumers.

To date, the revenue cap model defined by the price-quality path under Part 4 regulation has been suitable for recovering costs of running and investing in the gas transmission network. This is because demand for gas has generally been stable with no significant long-term changes in gas supply or consumption.

Previous discussions around New Zealand's natural gas sectors future have focused on the future of the gas transmission system. This has primarily been driven by the interconnected role of the transmission system delivering gas to the majority of consumers, with a perception that any issues with the transmission system can permeate through to nearly all gas consumers. The two potential issues that are surfaced most often are:

- a perception that the transmission system cannot physically operate if there are reduced volumes of gas being transported through the pipelines, and
- concerns about the cascading implications of a rapid exit from natural gas consumption. As the number of natural gas users decreases, this means a smaller number of consumers to share the overall costs of infrastructure, so the infrastructure cost for the remaining consumers could increases.

The work carried out for the Gas Transition Plan has investigated the issues outlined above, and concludes that there are simple solutions to avoid these risks from eventuating.

Technical operation under reduced flows

The report titled "Gas Transmission System Operations in the Gas Transition Future", which is annexed to this report, was commissioned to assess the technical operation of the transmission system under reduced flows. This report investigated whether there was a physical limit to the minimum flows required to make the transmission system technically feasible to operate, and concluded that the transmission system can be reconfigured to continue to supply remaining users at very low levels, with a viable solution for even as low as 6.4PJ of demand. Transmission volumes under the Gas Transition Plan pathway well exceeds this 6.4PJ figure, with predicted flows through the transmissions system at 111PJ, and flows excluding petrochemicals and electricity generation at 28PJ. While the 6.4PJ example described above isn't expected to eventuate in the Gas Transition Plan forecast, it provides an example of feasible operation at very low levels of demand.

One such configuration could be to utilise the capacity in the pipelines to store natural gas for consumption over the week ahead. Under this model, the pressure and volume in the pipelines would be increased to a high level once per week and allowed to slowly decline as the gas is consumed. This mode of operation would only require a small number of compressors that would operate less frequently that current operations, which also reduces the OPEX of the transmission system.

Infrastructure costs for reduced consumer numbers

Previous studies of the New Zealand natural gas future have focused on whole of system solutions to avoid the cascading risk of increasing transmission cost identified above. While there is a risk that this scenario could occur, it would only come to pass under certain conditions as a result of a disorderly exit from natural gas. Thus the first priority of the Gas Transition Plan was to understand future gas use by segmenting the gas market and determining the optimal solutions for each user group. As described above, there are decarbonisation options available to each of these user groups, and these pathways can inform the future infrastructure needs of all gas consumers.

As demand for natural gas decreases, particularly as electricity generation and industrial users reduce their demand for natural gas, transmission costs will increase by $23 on an annual bill for residential consumers. As demonstrated in Figure 16, for the average residential consumer with a $1,175 bill, the transmission component is $71 (incl GST). This transmission component is forecast to increase from $71 to $94.

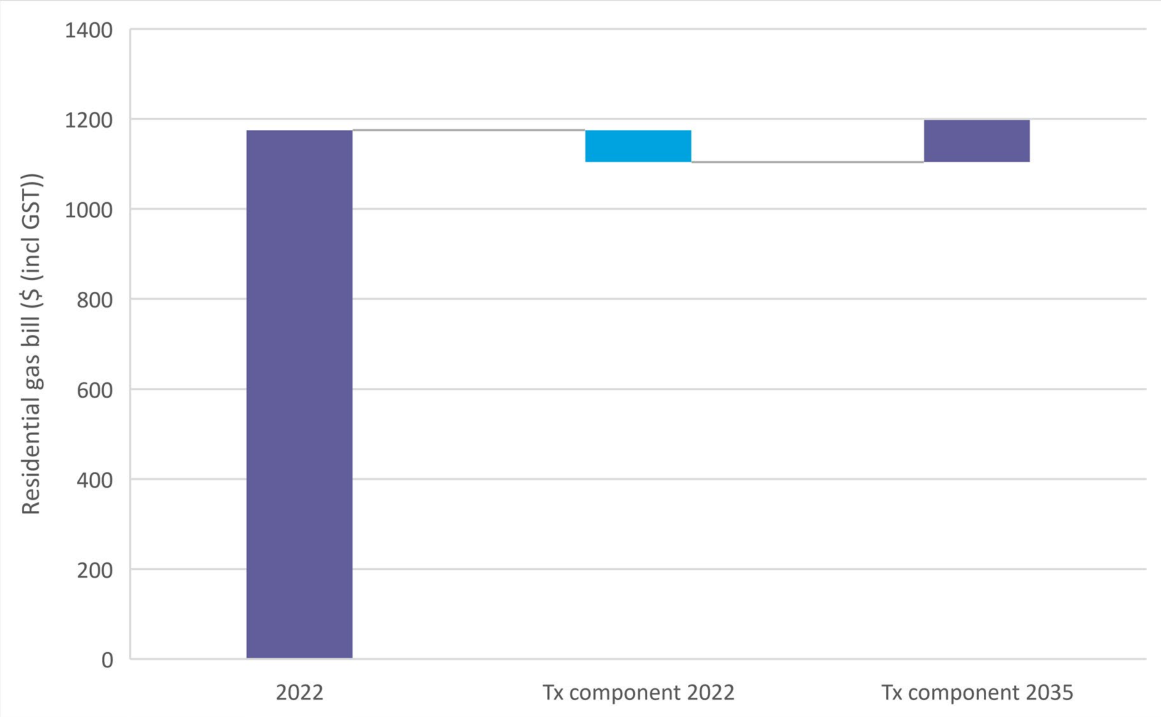


Figure 16. Changes to transmission charges for residential consumers

This analysis assumes the revenue from transmission will be unchanged, but as shown above, the operation of the transmission can be adjusted to better suit the volumes of natural gas and numbers of consumers utilising the transmission system. The future of the transmission system will be different to today - demand will be lower, the daily and seasonal shape of load will change, and this will lead to modified and improved operation of the transmission system to ensure a secure, reliable and affordable delivery of gas.

Even if the total transmission revenue were to be sustained into the future, the transmission charges make up such a small proportion of the charges to a consumer that it will not have a significant impact on their bill. As demand decreases as predicted and the transmission costs are shared among the remaining consumers, this only increase the overall annual bill by $23.

7.7. Production Segment

- The upstream gas sector operates gas fields and processing stations to prepare natural gas for delivery to consumers.
- Continued production of domestic natural gas is important for ensuring security of supply to both gas and electricity consumers.
- Emissions occur from upstream operations through venting, flaring, and as fugitive emissions related to production operations.
- Reductions in venting and flaring are expected in response to the ETS.
- Significant emissions reduction opportunities have been discovered at two domestic gas fields through the use of CCUS.

Available only in the North Island, natural gas is supplied from 15 fields located onshore and offshore to over 305,000 industrial, commercial, and residential consumers.

The upstream segment of the New Zealand gas sector operates gas fields and processing stations to prepare natural gas for delivery to consumers. The emissions associated with this segment are from upstream operations, through venting and flaring, and as fugitive emissions related to production operations. Oil and gas fields vent and flare natural gas as part of their normal operations to ensure safety standards are adhered to. Many oil fields that also produce natural gas as a by-product flare the gas as a method of disposal. To date, these oil sector emissions have been included under gas sector emissions. With an increasing carbon cost, these upstream parties are already being incentivised to reduce the frequency of these practices. Oil fields that flare the largest proportion of natural gas are reaching end of life, with Tui already decommissioned, and more expected to follow in the coming years.

Emissions capture also provides an opportunity for these gas fields at the production site, whereby the emissions associated with gas extraction and production can be re-injected. New Zealand's demand forecast is described in the following sections of this report, and future gas production will be developed to meet this demand. CCUS implemented in upstream production is a tool to reduce the associated emissions with this forecast gas production.

With the opportunities provided by reductions to venting and flaring and the utilisation of CCUS, production emissions will reduce significantly by 2035.

While some of these changes can be made by modifying behaviours and practices, investment will be required to make improvements to equipment, and to establish emissions capture at production sites. Upstream parties will only invest in improvements if there is sufficient certainty of a return on their investments. Maintained deliverability from the upstream gas sector is vital to New Zealand's wider decarbonisation journey.

Fonterra are prioritising their transition away from coal to reduce their highest emitting processes as a priority. If Fonterra has confidence in secure gas supply during the transition to net zero carbon by 2050, it will be able to continue to prioritise phasing out its highest-emissions, lowest-efficiency plant first, resulting in significantly lower emissions from its energy use during the transition.

7.8. Identifying Barriers to Transition

Each of the segment pathways described above throughout Section 7 is considered together as the baseline trajectory for the gas sector:

- Methanex remains in operation in New Zealand until the electricity sector reaches 100% renewable electricity, recognising the important role Methanex has in supporting electricity and gas security of supply. Maintained operation in a stable environment allows Methanex to invest in efficiency improvements to their plants. If Methanex ceases operations, their emissions will reduce further. In this case, an LNG import facility may provide the necessary delivery to support electricity generation and industrial gas users through the transition.
- Residential and commercial consumers remain at steady levels of gas consumption, but some of their emissions are reduced by moving some supply to biogas. Historic trends have shown increases in residential connections, and recent decreases to commercial. Going forward, new gas connections continue where it is the best option for some use cases, while some existing gas consumers will choose to electrify. It is assumed that there is overall nil growth among these consumers.
- Industrial consumers reduce their emissions by 30% by pursuing their favoured decarbonisation opportunity.
- Calculations of fugitive emissions are reduced to reflect improved emissions assessment from distribution networks, and reductions in venting and flaring activities. CCUS provides significant potential contributions to production emissions reductions.
- Baseload electricity generation is decommissioned as new renewable baseload generators come into service. Gas-fired peaking remains operational for electricity security of supply.

As highlighted in the Gas Market Settings Investigation, investor confidence is crucial to any managed transition. All options to ensure a fair and efficient transition will require investment, and these investments will only occur under a stable and predictable environment. For this reason, any policies put forward in the Gas Transition Plan will be recommended in response to identified risks or barriers to transition.

With improved investor confidence, the gas sector is able to decarbonise in an orderly manner, maximising opportunities for decarbonisation while driving for sustainable, equitable, secure and efficient outcomes.

Key barriers that have been identified to the Gas Transition Plan objections being met under the above pathway are:

- Security of supply for electricity and gas
    - Electricity and gas security of supply is currently supported by the scale of operation and demand response provided at Methanex. Continued security of supply for the energy sector requires either demand response from Methanex, or analternative mechanism, such as LNG imports or until 100% renewable electricity is achieved in the electricity sector.
- Supporting the development of a new biogas market
    - Some biogas is already produced in New Zealand, but the market is not mature and doesn’t currently support injection into pipelines. Further opportunities for supply and a subsequent biogas market should be supported

    to increase sustainability and diversity of energy resources. At the same time, blending allows each gas consumer to support decarbonisation activities in New Zealand. While residential and commercial consumption contribute only 5% of gas sector emissions, they can still play a role in supporting the gas sector transition.
- Barrier to new gas-fired peaking being built
    - There is a risk that new gas-fired peaking generation will not be built in the absence of mechansims that provide confidence that a return on investment can be recovered.
- Regulatory barriers to emissions capture
    - Emissions capture has been shown to have significant potential to reduce emissions through the immediate future of the gas sector's transition through carbon capture and storage, and direct air capture provides an opportunity for New Zealand's emissions reduction journey beyond. However, these technologies will not be deployed under current regulatory settings.

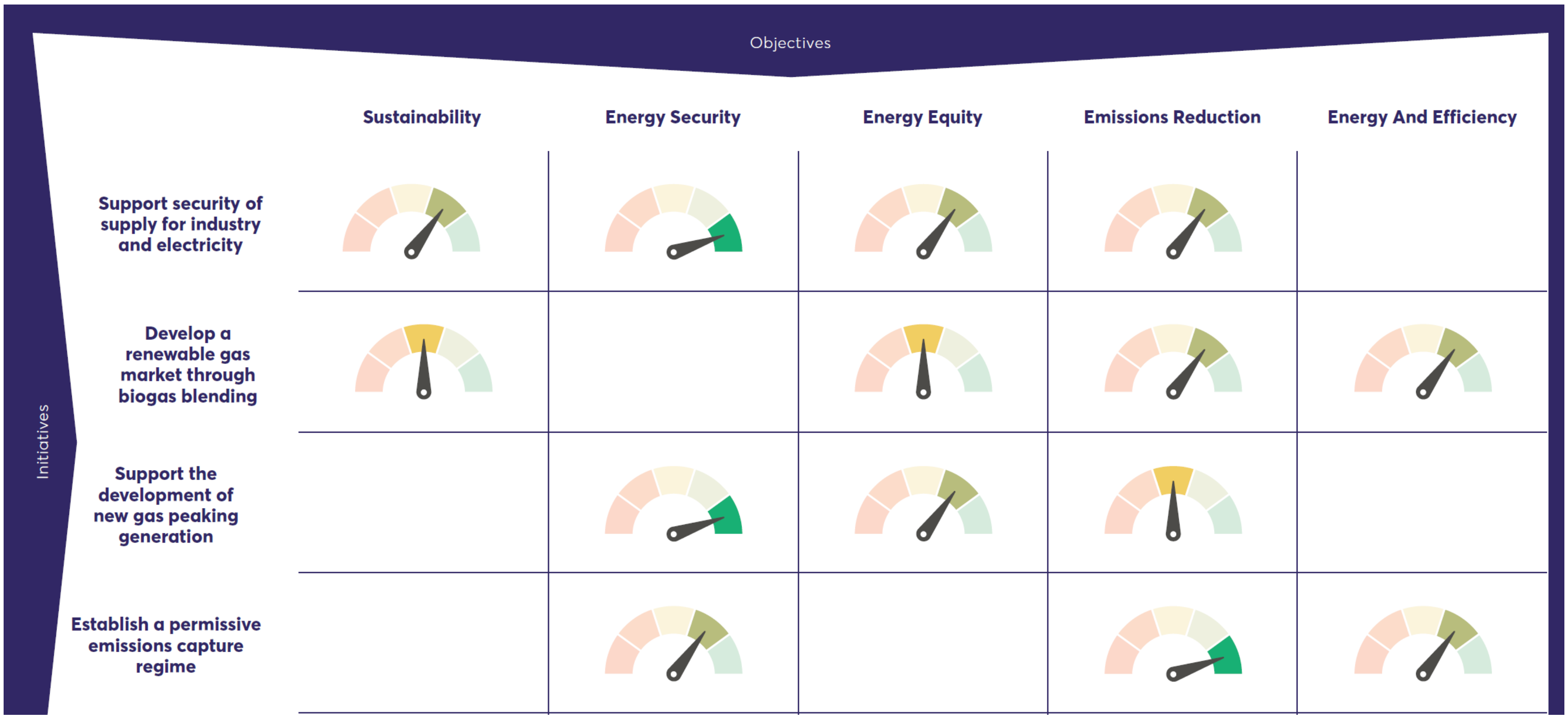
These four barriers have been highlighted as the core areas of focus for the Gas Transition Plan policy options assessment.

8. Assessing Policy Options against Transition Objectives

8.1. Overall Policy Assessment

A selection of policy options has been proposed below to support the gas sector transition.

Each of the policy options have been assessed against the five metrics set out in the Gas Transition Plan Terms of Reference: sustainability, energy security, energy equity, emissions reduction, and energy conservation and efficiency.



8.2. Policy Options

8.2.1. Supporting Energy Security of Supply

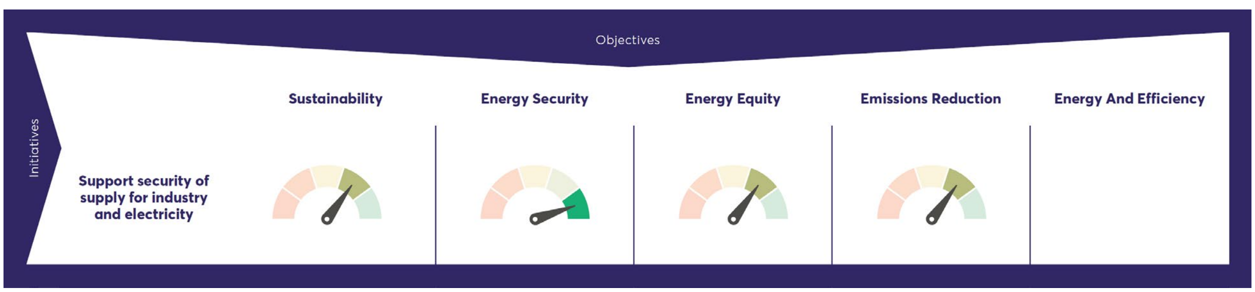
As recognised in the Gas Market Settings Investigation, Methanex have a critical role in supporting security of supply of the energy sector. It recommended a workstream on

> "the appropriate commercial arrangements to underpin any planned demand response, how these are enabled and who ultimately pays".

This report concluded that in the medium to longer term as the transition progresses, the measures need to support security of supply may include large-scale planned demand response, domestic storage or developing a new LNG import facility in New Zealand.

Policy Option

An arrangement to deliver large scale security of supply will be required. Options to address this include demand response from Methanex, incentivising domestic storage, or developing a new LNG import facility for New Zealand.

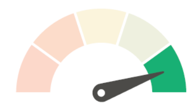


Sustainability

Major industrial gas users, including Methanex, will only be able to operate in New Zealand until the gas fields deplete, which will occur at some point after the 2035 timeframe. Although these users will continue to use gas in the near term, their use of fossil fuels is not locked in due to the limited gas resource that can be produced in New Zealand.

Measures focused on security of supply can support electricity sector decarbonisation by allowing reliable operation of peaking electricity generators with secure gas supply.

A direct trade-off occurs between sustainability and security of supply by retaining gas use by residential and commercial consumers and gas producers – some fossil fuel use is maintained, and in response these segments of the gas sector are provided with security of energy supply.

Energy security Methanex can provide security of supply to both the gas and electricity sector by underpinning gas development and through demand response. Continued operation at Methanex can support electricity security of supply until the energy sector can support 100% renewable electricity. LNG imports can provide supply certainty and flexibility during periods of constrained indigenous gas availability, including cover for major scheduled and unscheduled asset outages. **Domestic storage can provide additional system flexibility, however, any domestic storage option is reliant on domestic fuel availability to charge and draw-down storage as it is needed.** As mentioned above, security of supply for residential and commercial consumers is supported by continued use of gas.	
Energy Equity Greater security and confidence in the gas sector also flows through to cost to consumers. In particular, this impacts transmission costs to consumers as the death spiral is avoided. Industrial gas users are able to avoid premature exit from New Zealand, retaining jobs and reducing equity ramifications.	
Emission Reductions A mechanism to support security of supply, such as Methanex demand response or LNG imports, means that the electricity sector is able to continue investment into renewable generation while being supported by gas firming generation, reducing emissions from the electricity and gas sectors as baseload thermal generators are decommissioned. A stable electricity sector means that electrification is an achievable decarbonisation tool for fossil fuel users.	
Energy Conservation and Efficiency In an environment with improved confidence in the security of the gas sector, efficiency improvements become a viable transition tool as gas consumers have the confidence in future gas delivery to invest in these improvements.	

8.2.2. Develop a Renewable Gas Market

Renewable gasses, such as biogas and hydrogen, can play a valuable role in New Zealand's decarbonisation. As they are currently in the early phases of development in New Zealand, a renewable gas market is still in its infancy.

Biogas supply is not likely to be sufficient by 2035 to economically supply industrial consumption. Decarbonising all of residential gas would require all the biogas likely to be produced by 2035, which would be double the volume currently produced (including volumes that are being used in existing industrial and commercial processes and are not physically available to residential consumers). Research by WoodBeca assesses that the volume of biogas potentially available in the 2020s is equivalent to 20% of the volume of gas currently consumers by residential and small commercial consumers (such as restaurants and cafes using gas for cooking and small footprint locations that use gas to heat water). The Gas Transition Plan therefore sets out a pathway focused on decarbonising a significant proportion of residential and small commercial gas consumption before 2030.

Enough biogas exists to rapidly introduce blending up to 20% of residential consumption and achieve worthwhile emissions reductions. Hydrogen may be considered in this renewable gas blending target, but biogas has been prioritised due to its ready availability and ease of blending. Due to the density of hydrogen, the energy content per volume of hydrogen is quite different to that of biogas or natural gas. As a result, less natural gas is displaced when hydrogen is blended by volume than with biogas blending, and the associated emissions reduction is also lower. If the blending target were to extend to hydrogen, different regulatory arrangements may be necessary to account for the different levels of emissions reduction for an injected volume of hydrogen when compared to biogas.

Biogas is currently more expensive than natural gas even with the current carbon price included. This means biogas is unlikely to be supplied in the absence of a mechanism to bring it to market. If one market participant sought to supply a blend of biogas, then there may be an appetite among some consumers for a renewable product, but that supplier would also risk being undercut by cheaper suppliers. A market totalling 20% of residential and small commercial consumption is large enough to incentivise innovation and market development, as well as achieving emissions reduction targets for this sector.

Gas Industry Co has an existing model for engaging with industry to develop regulatory options in detail.

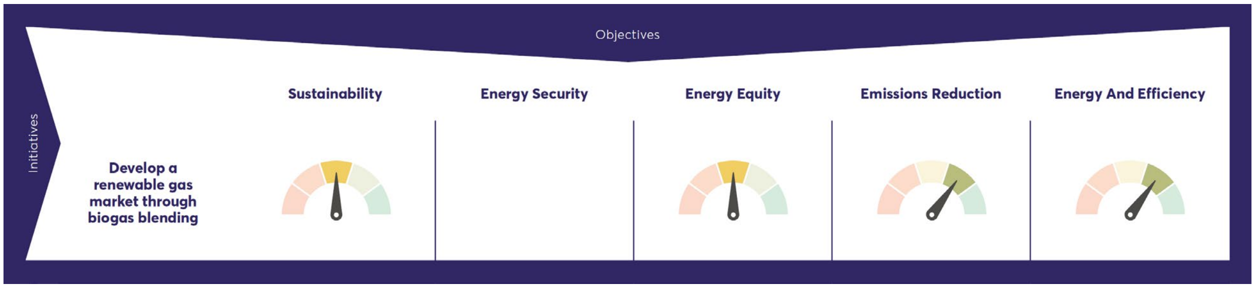
An industry-wide accord is preferable, in which retailers agree that a proportion of the gas they sell, measured over a year, would be backed by renewable gas certificates. This could be accomplished while avoiding competition concerns if a regulator were to publish a code that retailers would publicly sign up to.

Gas Industry Co regularly reviews distribution company contracts with retailers, and retailer contracts with customers. A review of the suitability of those contracts for supply of biogas as part of the total gas supply is one option to facilitate biogas blending into distribution networks.

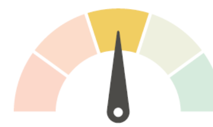
Gas Industry Co could also investigate connection/injection rights and liabilities, certificates and standards, and other forms of support discussed in Section 6.2.3. Some industry participants have an appetite for a mandate requiring a proportion of gas sold to be biogas. However, views are mixed. A question would exist about to whom the mandate would apply—gas is supplied by the network owner, but sold by retailers. Interference in the market may distribute resources inefficiently and it would offload to a regulator the responsibility for ensuring sufficient biogas is available and allocated to the sector.

Policy Option

- 20% of residential and small commercial gas volumes to be from biogas by 2030.
- Gas Industry Co workstream to develop a regulatory option to bring renewable gas into networks and to introduce a governance framework for renewable gas certification and principles for a certification scheme.



Sustainability

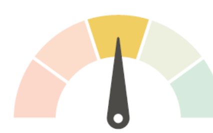


Biogas blending has been identified as a valuable way to support the development of a renewable gas market in New Zealand. The use of fossil fuels cannot be reduced until other alternative fuels are available, and the markets for these alternatives must be established so that these products can become available to consumers. This applies directly to residential and commercial consumers whose gas consumption will be displaced by a proportion of biogas, but also applies to large industrial consumers (such as Balance in their plans to produce hydrogen for their operations) who will be supported in their own renewable gas investments by the development of a renewable gas market.

Energy security

There is a potential wider benefit in creating a biogas market. Continued use of gas-inclusive energy delays the need for investment in electricity distribution networks to replace gas energy use. This is important because very large sums of capital are already required to meet expected increases in electricity demand (for example, because of the expected increase in load caused by electrification of transport). BCG estimates those costs are expected to be $22 billion[48] . These electricity networks are able to avoid rapid increases in demand, and the corresponding necessary modifications to their systems, by avoiding a rapid transfer of consumers from gas to electricity.

Energy Equity



Blending residential gas consumption with biogas to 20% would require 1.5PJ of biogas, which is likely to be available for around $15/PJ. This is a slight increase to current wholesale gas prices, but this biogas proportion of the bill will not be exposed to any increases to carbon price. Overall, the inclusion of this biogas for residential and commercial users will increase their energy costs by approximately 7-16%, depending on their scale of energy use.

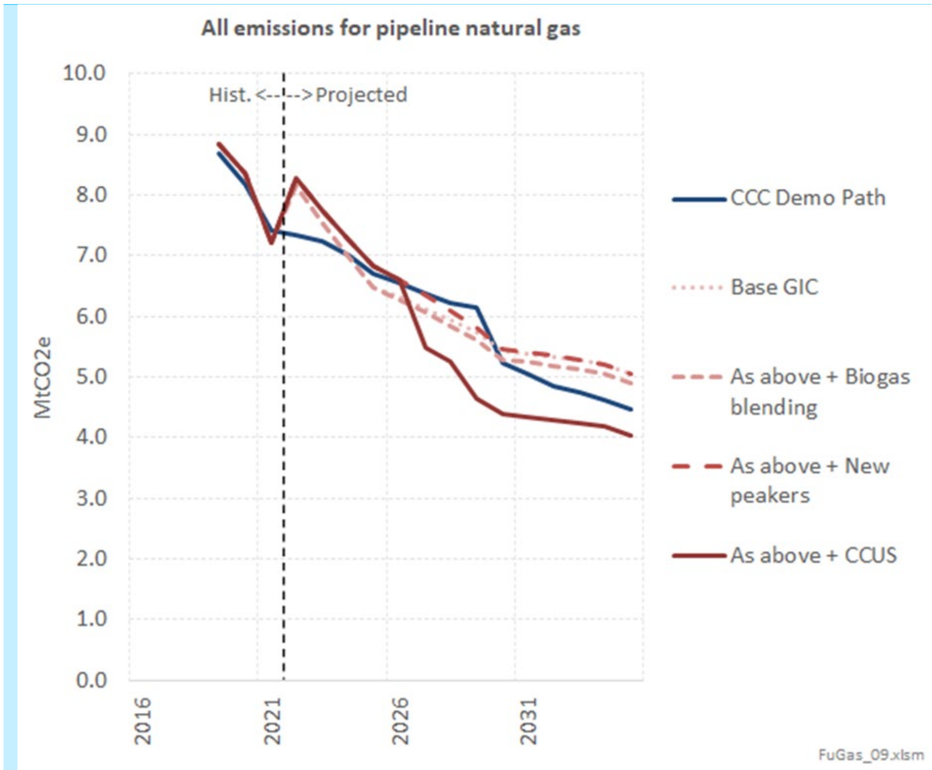
[48] https://www.bcg.com/publications/2022/climate-change-in-new-zealand

A wider biogas market would help to reduce the risk of creating a monopsony. Without consideration into the development of this market, it could develop with few very large buyers competing against a large number of dispersed smaller purchasers. This may lock up available biogas supplies for buyers with significant market power, such as government and large, hard-to-abate sectors, who have an appetite to reduce their carbon intensity even if the impact is to reduce options for other sectors. This could inhibit creation of a wider biogas market, although the outcome may be acceptable if it led to the same reduction in emissions.

Emission Reductions

Due to the small scale of residential and commercial gas consumption, 20% biogas blending for these users does not provide significant emissions reductions for New Zealand as a whole. These more significant emissions reductions must come from the larger emitting sections of the natural gas sector. However, there is a role for all gas consumers to play in reducing emissions in New Zealand, and there is a notable reduction in emissions for residential and commercial consumers when current emissions from these consumers are considered.

A developed renewable gas market provides additional opportunity for industrial gas users to decarbonise and therefore reduce the risk of de-industrialisation.



Energy Conservation and Efficiency

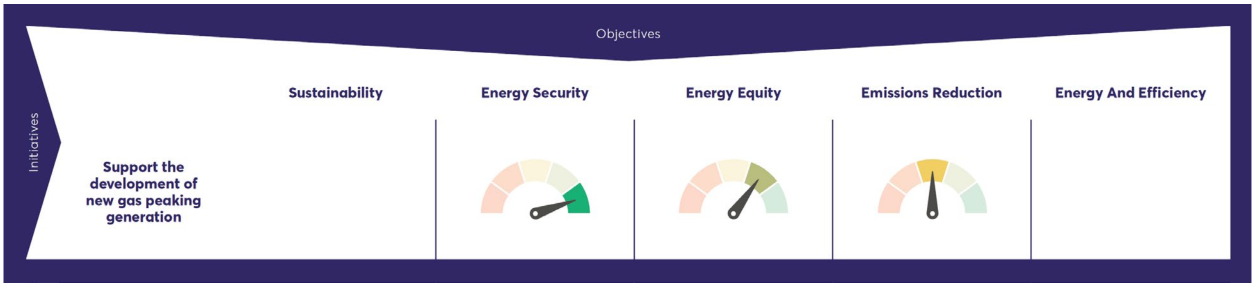
The introduction of renewable gas blending improves the emissions efficiency of residential and commercial gas users – for each PJ of gas consumed, the emissions will reduce by 20%, proportional to the percentage of biogas blending that has been achieved.

8.2.3. Support the Development of New Gas-Fired Peaking Electricity Generation

Electricity sector analyses have highlighted the need for new peaking generation to be commissioned to ensure electricity security of supply for New Zealand as a whole. As noted in Section 4.2, there is currently a risk that new gas-fired peaking will not be developed due to the risk of the plant ceasing operations before a sufficient return of investment has been earned. Without new gas peakers, this risks shortage situations similar to those on 9 August 2022 and elevated electricity prices, which will in turn hinder wider decarbonisation efforts.

Policy Option

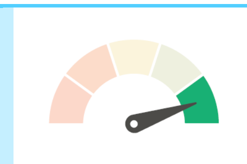
Gas sector regulators should work with electricity regulators to develop optimal mechanisms to ensure new, low emissions gas-inclusive generation is brought to market and operates until the energy sector can support 100% renewable electricity.



Sustainability

While new gas peakers would reduce sustainability by introducing an additional source of gas demand, it is essential to support wider electrification throughout New Zealand. Electrification is a core opportunity for energy sector decarbonisation, but reduced security of supply and subsequently elevated electricity prices will act as a barrier to consumers switching to electricity. These consumers may include some current gas users, particularly industrial users, but will also importantly includes the transport sector as large proportions of transportation is electrified. The gas sector has a vital role in supporting the electricity sector throughout the transition so that these levels of electrification and significant emissions reductions can occur throughout the entire energy sector.

Energy security



Electricity sector analyses have highlighted the need for new peaking generation to be commissioned to ensure electricity security of supply for New Zealand as a whole. In The Future is Electric, Boston Consulting Group identified that
"To achieve peak demand by 2030, we need 1.1 GW of new supply-side peaking resources (OCGT or batteries) by 2030."
Gas-fired peakers can ensure electricity security of supply is maintained until the energy sector is able to support 100% renewable electricity.

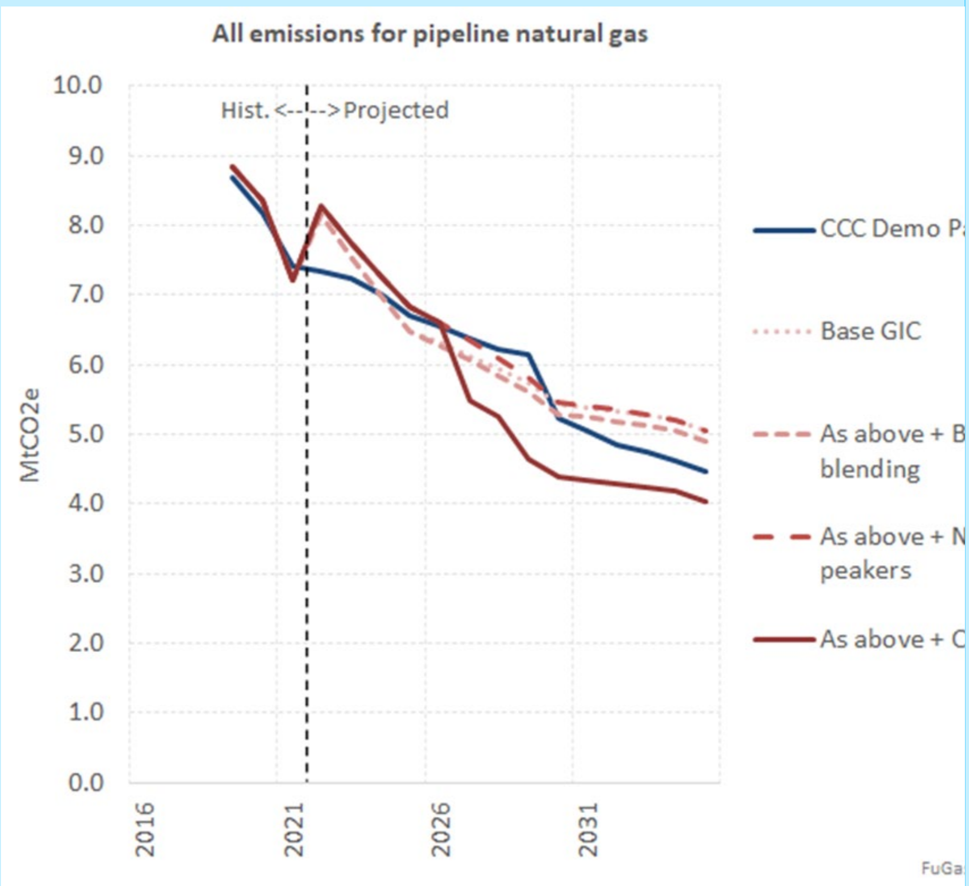
Energy Equity

Commissioning new gas-fired peakers will have little impact on gas prices to consumers, but will contribute a ~5% reduction in wholesale electricity prices. Electricity prices significantly increase during any security of supply event, and long term electricity prices will also elevate in response to security of supply risk.

Emission Reductions

While new gas-fired peakers will have associated emissions with their operation, commissioning these new peakers will allow other higher emitting thermal generators to be decommissioned. This results in an overall reduction from the electricity sector due to the improvements to efficiency with new technology.

The support that this additional peaking generation will provide to the energy sector will support electrification throughout the energy sector. With secure and affordable electricity, industrial gas users will be able to use electrification as one of their decarbonisation tools. A well-functioning electricity sector is critical for emissions reductions throughout the energy sector.



Energy Conservation and Efficiency

The transition for the electricity sector will involve the decommissioning of less efficient baseload generation and as new gas peaking generation is built, the associated plant efficiencies will be improved due to newer technologies and the design of the plant being optimised for peaking operation.

8.2.4. Establish A Permissive Emissions Capture Regime

1.3-1.5MtCO_2e of potential emissions reduction from emissions capture has been identified, but these emissions reductions can only be pursued with a permissive regime. Direct air capture also provides a real opportunity to reduce emissions beyond the scope and timeframe of the Gas Transition Plan, but will also require similar changes to current regulations to allow this activity when it becomes economically viable. While certain CCS projects can be consented under existing regulation[49], some projects cannot be consented and other issues need clarification.

Policy Option

The changes required for a permissive emissions capture regime are outlined at a high level below, and are discussed in detail in [*Barton 2023*]. The recommendations are potentially suitable for a changing RMA. While a fresh review of the effects of new RMA legislative framework will be required when amendments are passed, the 2023 report notes, "there will be a certain amount of continuity in basic features such as resource consents and designations."

Changes for a Permissive Emissions Capture Regime

Changes that the report identifies as a priority, if policy-makers wish to advance emissions capture as a decarbonisation strategy, are outlined below.

Policy changes

- A national policy statement for CCS under the RMA (an NPS-CCS). A new NPS could take a year to produce once the proposal is accepted.
- Amendment of regional regional policy statements, regional plans and district plans under the RMA, to recognise and provide for the benefits of CCS in emissions reduction. A regional policy statement or regional plan can take two or three years.
- Provide for CCS in emissions reductions budgets. The next ERP is due by 31 December 2024.

Regulations and Similar Instruments

- RMA: a new regulation is made under section 360(1)(e) for a CCS project or work to be declared a network utility operation.
- RMA and EEZ regulations. The Resource Management (Marine Pollution) Regulations 1998 and Exclusive Economic Zone and Continental Shelf (Environmental Effects-Discharge and Dumping) Regulations 2015 to be amended for clarity and to reflect the 2006 change to the London Dumping Protocol allowing CCS. Third-party CO2 injection in the coastal marine area depends on the RMA Regulations being amended.
- CCRA: Order in Council to add CCS (with an expanded definition) to the list of removal activities in Schedule 4 Part 2 Subpart 2.

[49] This section is entirely drawn from Barton (2023)

- CCRA: new regulations to accompany the listing of CCS as a removal activity, to provide for calculation of removals and to provide for the long-term management of geological sequestration.

Amendments of Acts

- EEZ Act: repeal s 59(5) on CO2. This provision in the EEZ Act is anomalous now that its equivalent in the RMA has been removed.
- Natural and Built Environment Bill and Spatial Planning Bill: ensure that CCS regulation in these replacement statutes does not prejudice CCS regulation. Opportunities to facilitate CCS.

Changes that are lower priority, but would be useful to facilitate CCS

Policy Changes

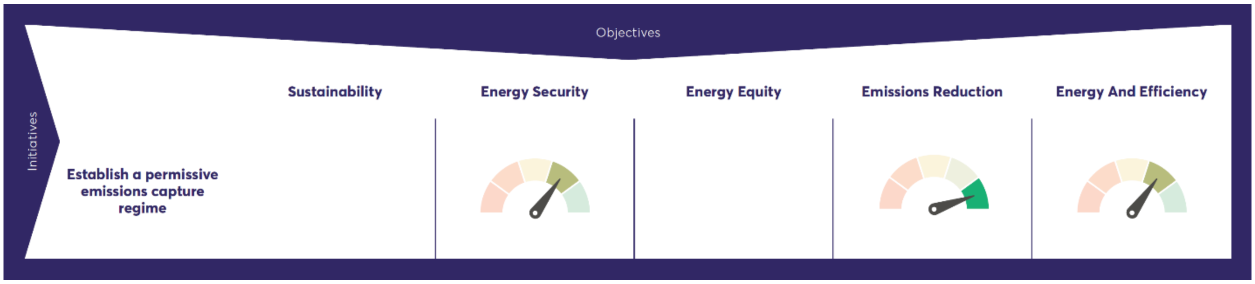
- Amendment of the New Zealand Coastal Policy Statement under the RMA to provide for CCS in the coastal marine area and coastal environment. The Department of Conservation reviews the Coastal Policy Statement from time to time, but there is no time limit in the RMA by which a revision must take place. There has been no practice of making amendments to the NZCPS, so the opportunity for amendment would be a general revision.
- An EEZ Policy Statement under the EEZ Act. No such statement has been made yet. It would probably not be made solely for CCS, so it would be a large wide-ranging policy exercise.

Regulations and Similar Instruments

- RMA National Environmental Standard to accompany an NPS-CCS. Closer investigation of an NPS would show whether rules in an NES are required.

Amendments of Acts

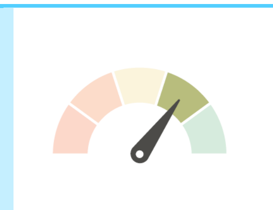
- RMA and EEZ Act: insert a power to make regulations for the post-closure phase including requiring a consent, and the consent to last longer than 35 years, in order to improve the post-closure regulatory regime.
- Crown Minerals Act: enable powers over petroleum mining to be exercised in a way that facilitates CCS.



Sustainability

Under the Gas Transition Plan, CCUS does not contribute to an expansion of New Zealand's gas sector but is a tool that can reduce the emissions from gas that will be produced in any scenario. The opportunities that have been identified as part of the Gas Transition Plan reduce emissions from the production segment of the gas sector. New Zealand's gas demand is forecast to decrease over time, and associated production will follow this decline. CCUS can reduce the emissions associated with the gas production that is required over this period without locking in additional gas consumption.

Energy security



Statutory reserves reporting, correlated by WoodBeca with the Operators allow the following perspective on primary energy security to form:

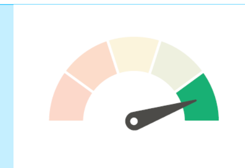
Without additional discoveries, remaining 2P reserves will retreat across most producing fields in Taranaki. Upgrades to CO2 rich 2C resources at Kapuni, and successful appraisal of the potentially CO2 rich Maui East discovery may result in nationally important upside, pushing respective end of field life comfortably into the late 2030's. A current lack of CCS legislation does represent significant risk and uncertainty to the Operators, which struggle to sanction future and costly development of these known and suspected CO2 rich gas volumes.

CCUS can support the development of reserves that are required to maintain delivery to consumers, reducing the risk of future shortfalls in gas production and delivery.

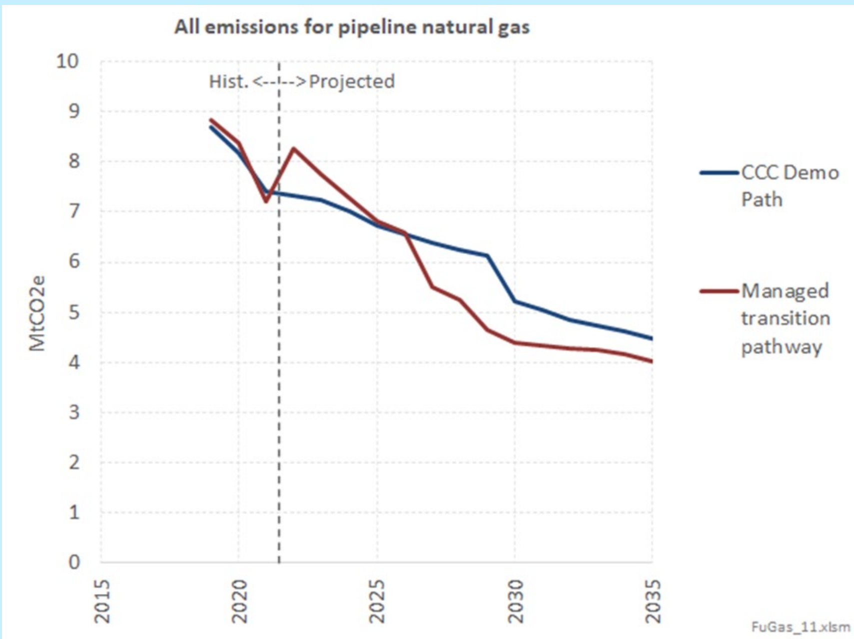
Energy Equity

CCUS is viable under current carbon price forecasts. It can prevent producers from paying the carbon price for their production emissions, and reduces exposure to further increases to carbon price.

Emission Reductions



CCUS can contribute significant emissions reductions under current carbon price projections. The two opportunities identified by WoodBeca amount to 1.3-1.5MtCO2e of emissions that can be prevented from entering the atmosphere, and many more projects beyond these two exist to contribute further emissions reductions before and after 2035. While it can be too difficult to add CCUS infrastructure to existing electricity generators, CCUS could be incorporated into the design of the new gas-fired peakers that are needed to maintain electricity security of supply.



In a future where DAC becomes economically viable, the emissions reduction is highly promising, and internationally it is viewed as a key tool for reaching necessary levels of global emissions reductions.

Energy Conservation and Efficiency

Further efficiency improvements exist at Methanex through injection of CO_2 that is produced from CCUS.

8.3. Additional Options

As well as the policy changes that were modelled, there remain some additional recommendations that cannot be modelled, but are still important to address barriers that have been found to gas sector decarbonisation and will support the recommendations outlined above.

8.3.1. Refine Some Details in the Emissions Trading Scheme

The Emissions Trading Scheme is the core mechanism to drive decarbonisation throughout New Zealand and is already having an impact on investment and operation decisions to reduce emissions through the gas sector. The ETS enables these users to determine their most appropriate solution to reduce their emissions, a vital part of ensuring security of supply and affordability are maintained throughout the transition. It is important that the ETS is allowed to operate to drive decarbonisation of gas producers and users, but there are some areas of the regime which require refinement to unlock all opportunities for decarbonisation.

8.3.2. Maintain a Supportive Environment for Hydrogen

As identified by Castalia, the economics of hydrogen mean that it will not be accessible at scale to decarbonise the gas sector before 2035. While the Gas Transition Plan has not identified hydrogen as part of the pathway to decarbonise the gas sector, it may be used in some niche applications within the gas sector, and has more potential for beneficial use in other sectors such as transport. The economics of hydrogen may improve to have broader opportunities of use beyond 2035 as hydrogen technology continues to improve At this point it may have a more significant role in decarbonising the natural gas sector. Until that time, the Government should maintain a supportive environment for hydrogen to unlock its potential, but not rely on hydrogen as a core decarbonisation tool for natural gas before 2035.

The IEA makes a series of recommendations for policy makers to accelerate the uptake of hydrogen. These measures may have applicability for faster uptake of hydrogen in New Zealand. As green hydrogen is not expected to play a role in the natural gas sector before 2035, they have not been evaluated. However, as noted above, PWC has evaluated regulatory arrangements for New Zealand.[50]

The IEA's menu of options includes:

- Create incentives for using low-emission hydrogen to displace unabated fossil fuels.
- Mobilise investment in production assets, infrastructure and factories. Providing tailor-made support to selected, shovel-ready flagship projects can kick-start the scaling up of low-emission hydrogen and the development of infrastructure and manufacturing capacity from which later projects can benefit.
- Provide strong innovation support to ensure critical technologies reach commercialisation soon.
- Establish appropriate certification and standardisation schemes and adapt regulatory regimes. (A certification scheme already exists in New Zealand.)

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[50] https://www.mbie.govt.nz/dmsdocument/25671-new-zealand-hydrogen-regulatory-pathway

- Develop and complete demonstration projects to gain operational experience. The adoption of low-emission hydrogen as a clean energy vector presents technology challenges. First movers will face risks due to a lack of knowledge and market uncertainty; however, completing demonstration projects to gain operational experience and develop in-house know-how can position them ahead of their competitors at the moment when deployment of the technology scales up.
- Form cross-sectoral alliances to bring together skills and strengths from stakeholders across the whole value chain. An example is the IEA's Hydrogen Technology Collaboration Programme[51], which aims to accelerate the deployment and use of hydrogen technologies by carrying out and co-ordinating collaborative analysis, applied research and communications.

In their report *New Zealand Hydrogen Scenarios and the Future of Gas*, Castalia made four recommendations relating to the hydrogen sector.

a. Investment activity aimed at fully transitioning the sector to hydrogen should be de-prioritised for the time-being.
b. The case for blending hydrogen into natural gas networks depends on:

   i. Maintaining demand for scale hydrogen production ahead of demand emerging in the transport sector over the medium and longer-term.

   ii. Creating an option for the gas sector to avoid irreversible decisions on the future of gas (like decommissioning pipelines), particularly as new information emerges on costs and viability of green hydrogen

   iii. Blending hydrogen with natural gas has a high marginal abatement cost. It is unlikely to be more cost- effective at reducing emissions than other options.

c. Green certificate schemes for blended hydrogen are a low priority, unless the cost of hydrogen decreases significantly in the short to medium-term. (Certificates may be more economic for other renewable gases.)

d. Investigate the technical and economic viability of blending other renewable gases in the distribution network, independently of the transmission network.

8.3.3. No Immediate Changes for Gas Pipeline Regulation are Required

The Gas Transition Plan prioritised understanding future gas demand before addressing potential concerns with gas pipeline regulation. This better highlighted whether any risks due to gas pipelines and gas pipeline regulation were likely to eventuate. The Gas Transition Plan analysis concluded that future demand was sufficient that these risks would not eventuate, in particular during the transition out to 2035. In the case where these risks did eventuate, research was commissioned to understand issues relating specifically to the gas transmission network and the impact that changing gas demand will have on its economic regulation.

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[51] https://www.ieahydrogen.org

The high-level assessment presented in "Regulatory options for New Zealand's gas transmission system", included as an annex to the Gas Transition Plan, suggests that in a future where gas volumes through the transmission network declines, there is no clear evidence that an alternative regulatory option, different to the current revenue cap model, would be better suited to align the gas transmission network with the outcomes set in the Gas Transition Plan.

The potential economic regulation options, such as price cap and revenue cap models and deregulation, that could be applied to the New Zealand gas transmission network were to ensure it aligns with the desired outcomes set in the Gas Transition Plan Terms of Reference. The performance of different regulatory options were considered in relation to the purpose of monopoly regulation and Part 4 of the Commerce Act 1986, the effort to implement regulatory change and potential impacts on the gas transmission business.

Each regulatory option could play a role in the gas transition depending on which outcomes are most important for the gas transition. For example, if protecting consumers from gas price shocks has a relatively higher importance than the other criteria, then the price cap model is likely to be better because the price is set from the outset and has limited ability to increase in response to falling gas throughput. However, declining gas throughput results in declining units of gas that the gas transmission business can charge for. This creates the risk that the business will under recover their revenue and may not be able to recover their costs. A revenue cap model decreases this risk for the business as prices may better encourage continued investment, particularly in safety and reliability, but will have a more limited ability to protect consumers from price shocks. Trade-offs will be required in whichever option is used.

The report also identified that deregulation may play a role in the gas transition but likely only in a staged approach. A similar approach could be used as used in the copper to fibre transition where parts of the network are deregulated over time as the critical mass of consumers transition to alternative energy sources. Safeguards and careful deregulation design would be required to protect consumers from adverse effects.

The gas transmission network can play its role in enabling the gas transition and decarbonising New Zealand's energy use. The high-level assessment suggests that there is no clear evidence that an alternative regulatory option would be better suited to align the gas transmission network with the outcomes set in the Gas Transition Plan. Instead, how the incentives and mechanisms within the regulatory option are set and how directive the regulator chooses to be will likely make the most impact.

Supported by the research included in "Regulatory options for New Zealand's gas transmission system", the current regulatory model is deemed to be adequate through to 2035. The nature of the gas transition beyond this time is largely unknown. The opportunities to continue decarbonising New Zealand's gas sector range from increased CCUS, renewable gases such as biogas and hydrogen, potentially DAC, and each of these opportunities will have a different impact on the nature of transmission utilisation. We recommend that the transition pathway be reviewed in 2030 to better understand the beyond 2035 pathway for the gas sector, and once the future demand and use of natural gas is understood, assessment be made on the nature of gas pipeline regulation out to 2050. By setting this date for review now, gas users can better understand the regulatory space in the near term and have time to prepare for any future changes. Similarly, the Commerce Commission can have confidence in their regulatory approach out to 2030 and likely beyond.

9. Perform Continued Monitoring of Gas Sector Emissions Reductions

9.1. Milestones to 2035

At each step of the way to 2035, emissions reduction will be taking place in different parts of the gas sector. The package of policies discussed above have been crafted to enable the necessary emissions reduction from the gas sector, while meeting broader security and affordability objectives. The stages of emissions reduction achieved as a result of these policy recommendations are portrayed in the figure below, with each emissions budget representing a milestone stage.

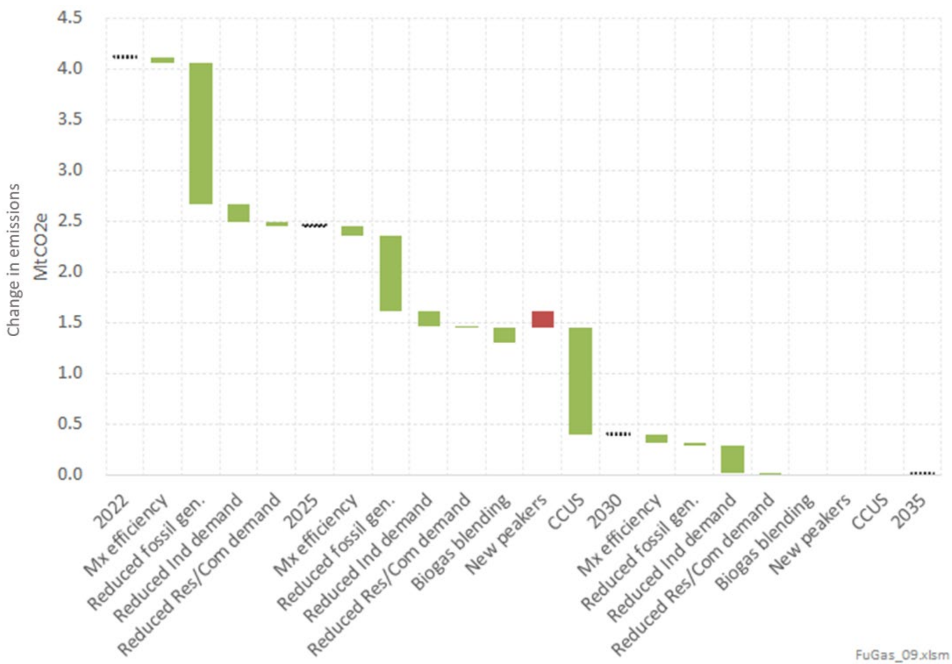

Figure 17. Changes in emissions during each emissions budget

The effectiveness of these policies once put in place must be monitored to ensure the necessary emissions reductions are being achieved, and no amendments are required to the policies.

9.2. Risks

Additionally, the modelling and pathways derived as part of the Gas Transition Plan have been founded on core assumptions which, if they did not eventuate as assumed, may require a reassessment of the Gas Transition Plan. Some of these disruptors could include:

New technology comes to market faster.

The assumptions about the current and future availability of DAC and hydrogen could be proved wrong by more rapid acceleration of improvements in these areas. Should such technologies become more economic sooner, it may justify reassessing the Gas Transition Plan to ensure those opportunities can be seized.

Renewable electricity generation uptake is delayed.

Much of the emissions reductions achieved in the Gas Transition Plan within the second emissions budget is as a result of the decommissioning of baseload gas-fired electricity generation. This decommissioning is reliant on new renewable electricity sources, such as wind, being developed and commissioned so that the baseload gas-fired generators are no longer required to support the electricity sector. If the electricity sector cannot be decarbonised, it will be difficult to decarbonise the gas sector without relying on coal to support electricity generation. The Gas Transition Plan may require a reassessment if headwinds to new renewable electricity generation prevent the required level of development in this space, or potentially the emissions budgets for the gas sector may require re-evaluation.

Field performance is materially different than predicted.

Future gas supply relies on the success of exploration and development of resources, and while the expertise of the upstream gas sector can inform which reservoirs provide the best prospects, the nature of gas production means that there is always a risk that production will not be at the desired level once the wells have been developed. Even existing wells that are already operating are exposed to this risk, such as was seen when the Pohokura gas field reduced production in 2018. This drop in production was within the realms of forecast possible field output, which highlights the inherent uncertainty of future gas production.

This risk is currently mitigated by diversifying fields, but in the event that current fields do not perform as expected, or outputs from new reserves are unsuccessful, the lower than expected production may demand a reassessment of future gas supply and demand in New Zealand.

The ETS is insufficient to drive behaviour change.

A core assumption in the Gas Transition Plan is that carbon price will drive behaviour to decarbonise. This is fundamental to decarbonisation throughout New Zealand, and is a particularly important tool for driving CCUS uptake and the decarbonisation of industrial gas consumers in the gas sector. As the future carbon price is yet to be determined, the response that can be expected from gas users is unknown. If the carbon price is too low, or if it is not able to drive decarbonisation outcomes, other mechanisms may be required to achieve necessary change.

9.3. Pathway beyond to 2050

The policy options outlined above have been designed to achieve the desired outcomes of the Gas Transition Plan and meet the emissions budgets out to 2035. Beyond this point, the future becomes uncertain, and to model or assume this pathway further into the future would imply a level of certainty that does not exist. In 2035, some opportunities for decarbonsation may be more or less available than they have currently be assessed. Beyond 2035:

- Biogas supply may increase at lower prices. Biogas blending up to 20% is viable based on current expected biogas supplies, but with the support of a renewable gas market, we expect that more lower cost biogas will become available.
- More emissions capture projects can be implemented. While the Gas Transition Plan has focused on the two projects identified by WoodBeca, there are many more opportunities

beyond these that may contribute even further emissions reductions throughout the gas sector. With a permissive emissions capture regime, these additional projects will have the opportunity to be investigated and developed.

- While hydrogen has not been considered as a key decarbonisation tool for the gas sector pre-2035, it may become more technically and economically viable beyond this time.
- Direct air capture technology is in its infancy, but even developments show a rapid increase in viability of the technology. The economics of this technology is expected to rapidly improve, with DAC becoming a more viable emissions reduction option for New Zealand post-2035.

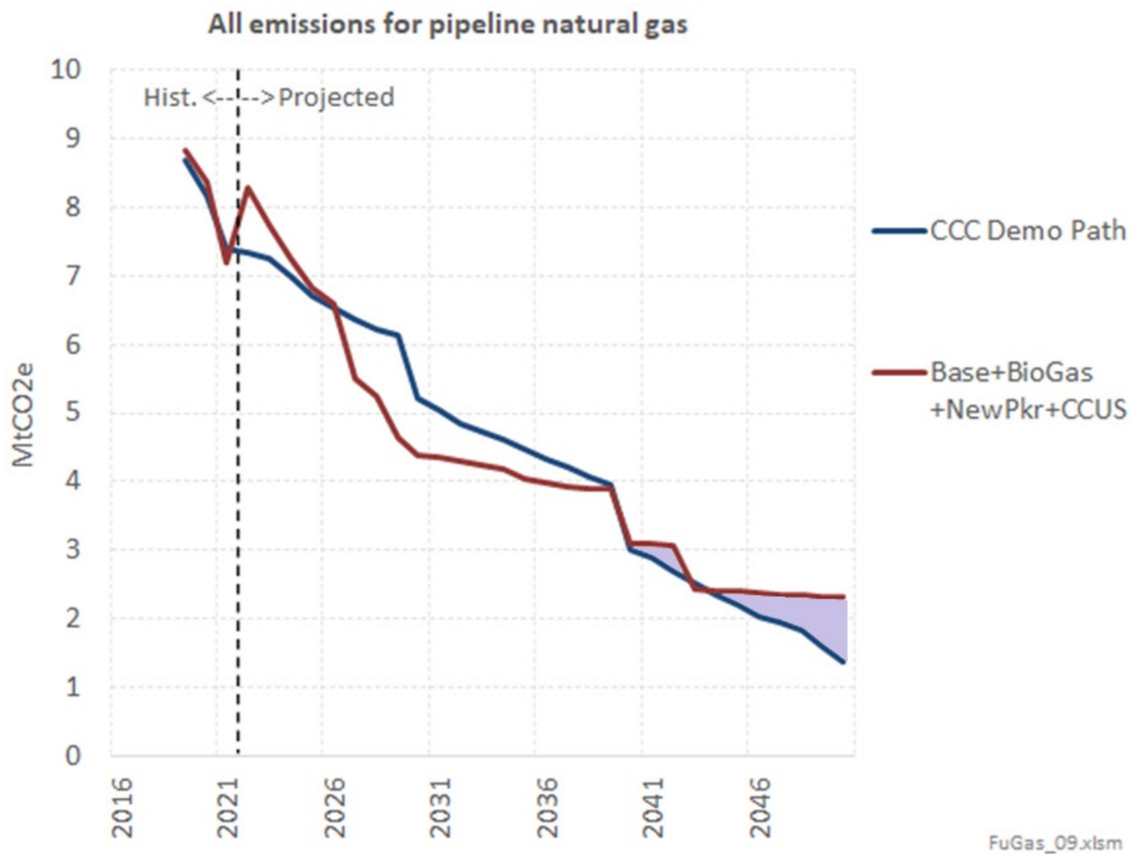

Figure 18. Meeting the 2050 emissions reduction target

The wide range of options for future development in technology and economics of decarbonisation options give confidence that the emissions budgets out to 2050 can continue to be met, and this pathway to continued emissions reduction should continue as these opportunities come to light.

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