2035/2050 Vision for Gas

Final Report

Embargoed until 5.00am Wednesday 22 March

MARCH 2023

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Definitions

$	New Zealand Dollar
BAU	Business As Usual
CCC	Climate Change Commission
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation, and Storage
CMA	Crown Minerals Act
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DME	Dimethyl Ether
DSR	Demand Side Response
EECA	Energy Efficiency and Conservation Authority
ETS	Emissions Trading Scheme
GHG	Greenhouse Gas
GIC	Gas Industry Company
GJ	Gigajoule
GTP	Gas Transition Plan
$ktCO_2e$	Kilotons of Carbon Dioxide Equivalent
LPG	Liquefied Petroleum Gas
LRMC	Long-Run Marginal Cost
MBIE	New Zealand Ministry of Business, Innovation and Employment
MGUG	Major Gas Users Group
NZECS	New Zealand Energy Certificate System
NZUs	New Zealand Emission Units
PJ	Petajoule
PV	Photovoltaic
RMA	Resource Management Act
T&D	Transmission and Distribution
tCO_2e	Tonnes of Carbon Dioxide Equivalent

Executive summary

Climate change is a major policy challenge. To address this challenge, the New Zealand Government has set a target to reach national net zero emissions by 2050. The Government intends to publish a National Energy Strategy in 2024, which will set out how New Zealand will decarbonise its energy sector. The National Energy Strategy will be partially informed by the Government's forthcoming Gas Transition Plan (GTP). The GTP is being co-developed by the New Zealand Ministry of Business, Innovation and Employment (MBIE) and the Gas Industry Company (GIC) and is expected to be published by the end of 2023. The GTP aims to provide a pathway to "phase-out fossil [natural] gas" in New Zealand by setting out transition pathways and actions to 2035[1] (pillar 1), signalling the longer-term direction for the sector out to 2050, and developing a cohesive view on renewable gases (pillar 2).

This Report has been prepared by Castalia for Energy Resources Aotearoa, Gas New Zealand, and Major Gas Users Group (MGUG). The purpose of the Report is to:

- Estimate future gas demand and emissions under current expectations of energy costs and policy (that is, under business as usual (BAU) conditions)
- Identify plausible pathways for the decarbonisation and transition of New Zealand's gas sector, informed by evidence provided by sector stakeholders and previous modelling and forecasting work
- Demonstrate the trade-offs between pathways using the energy trilemma (sustainability, affordability, and reliability), and indicate the distribution of costs across individual sectors
- Identify opportunities for the gas sector to support the decarbonisation of New Zealand's energy sector, including recommendations to decision-makers.

Gas demand will decline moderately in New Zealand if current policies continue

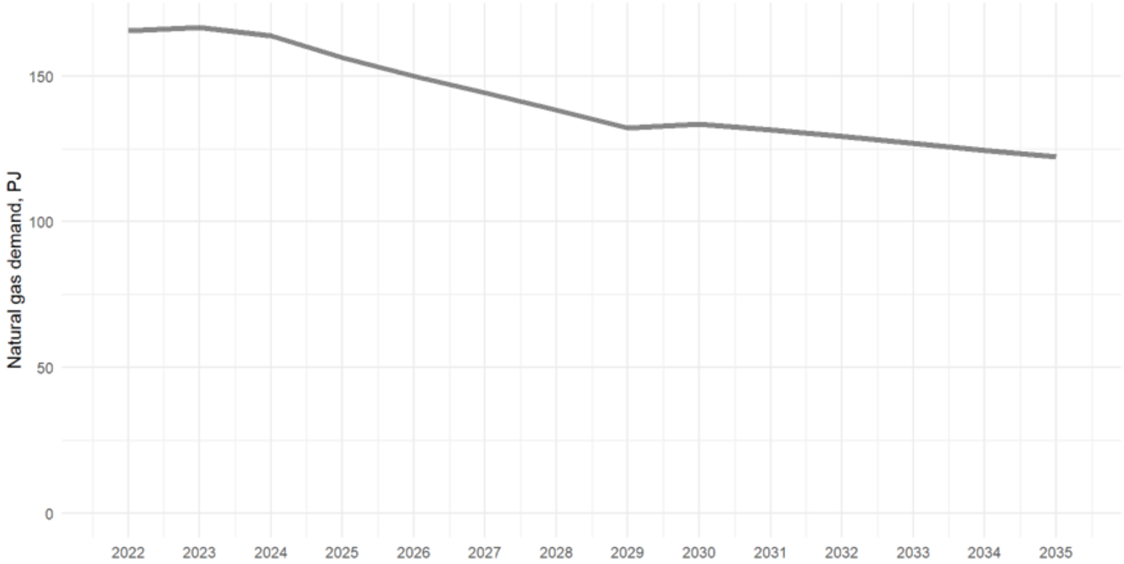
To understand the trade-offs involved in different policy choices for the gas sector, it was necessary to estimate gas demand and emissions if the sector continued under BAU conditions. We developed the Reference Pathway for this purpose.

We carried out extensive consultations with gas sector representatives to understand how gas demand would develop to 2035. We held workshops with natural gas producers, Liquefied Petroleum Gas (LPG) suppliers, natural gas network operators, major natural gas users, other industrial natural gas users, and representatives of commercial and residential natural gas and LPG users. We also consulted MBIE, GIC and Energy Efficiency and Conservation Authority (ECA) representatives on the core assumptions and modelling approach.

The Reference Pathway modelling shows the results of the gas sector's transition in response to current and expected policy settings and available technologies, consumers' responses to the energy prices, and the carbon price. Natural gas demand will decline by 2035, and therefore emissions will also decline. Figure 0.1 shows natural gas demand under the Reference Pathway.

[1] The GTP will cover New Zealand's first three emissions budgets (2022–2025, 2026–2030, and 2031–2035).

Figure 0.1: Natural gas demand under the Reference Pathway (BAU)



Source: Castalia modelling

Gas Transition Plan involves key policy choices for the gas sector

The Government will make key policy choices when it develops the GTP. To understand the trade-offs, Castalia modelled six pathways that illustrate key policy choices (along with the Reference Pathway). Figure 0.2 provides a summary of the pathways modelled.

The pathways show the key choices that could be made. They do not describe the world as it really is (or as it will actually turn out). Instead, the modelling explores the impact that key decisions relating to the gas sector could have on New Zealand's energy mix, emissions profile, and energy affordability. It provides insights into the key factors that may influence future outcomes. The pathways are also not mutually exclusive. New Zealand’s future gas sector could incorporate elements of many of the pathways.

Figure 0.2: Pathways modelled

Reference Pathway	BAU pathway for New Zealand gas demand and emissions, based on sector participants' views of likely government policy. It includes a carbon price that rises to $140 by 2030, and $160 by 2035
CCC Demonstration Pathway	Models gas demand using the CCC's 'demonstration path', developed as part of the CCC's 2021 advice in *Ināia tonu nei.* Gas demand is adjusted to account for actual (higher) gas demand in 2021. CCC's other assumptions affecting demand, including those that have been superseded by real events, are unchanged
100% Renewable Electricity by 2030 Pathway	Models how gas demand and emissions could evolve if New Zealand transitions to 100 percent renewable electricity by 2030. Gas-fired generation is phased out and investments are needed to improve reliability of electricity supply
Direct Interventions Pathway	Models how direct mandates could affect gas demand and emissions. It includes stopping gas use in low-medium heat industrial processes and banning new gas connections in commercial and residential buildings. Methanol production also switches to electricity for heat processes, and urea production switches to green hydrogen and biogenic carbon for feedstock and electricity for heat processes
High Carbon Price Pathway	Models the impacts of a high carbon price on gas demand and emissions. The carbon price rises to $300 per tCO_2e by 2035
Renewable Gas Pathway	Models how blending renewable gases in the natural gas network and in LPG could affect gas demand and emissions. The relevant least-cost gas (hydrogen, biogas, bioLPG, and DME) is blended
CCUS Pathway	Models the impact of capturing emissions of large emitters and storing or utilising the captured CO_2. CCUS technologies are available from 2026

Pathways were evaluated using the energy trilemma, adjusted for reliability

The energy trilemma is used to evaluate the pathways. It is a well-understood framework for assessing energy systems against three important dimensions—environmental sustainability, energy equity, and energy security (outlined in section 4.1). It is used by the World Energy Council and is referenced as a guiding framework by MBIE in the GTP Terms of Reference.[2] The trilemma framework is adapted in this Report to focus on affordability, reliability, and sustainability. The interpretation of these three elements for the purposes of this Report are provided below:

[2] MBIE, Gas Transition Plan Terms of Reference, available at: https://www.mbie.govt.nz/dmsdocument/20265-terms-of-reference-gas-transition-plan. Definitions by the World Energy Council can be found here: https://www.worldenergy.org/transition-toolkit/world-energy-trilemma-index

- **Sustainability** refers to the amount of greenhouse gas (GHG) emissions associated with gas use in New Zealand from 2022 to 2035 under each pathway.[3] GHG emissions are expressed as carbon dioxide equivalent (CO_2e)
- **Affordability** refers to the total cost of energy under each pathway, including the total cost of the energy sources modelled, any cost of increasing energy reliability to match the current level, the costs of blending any renewable gases, and the estimated costs of carbon capture, utilisation, and storage (CCUS). Where energy use may reduce due to high energy costs, we describe the magnitude of the economic impact
- **Reliability** refers to the ability of energy users to access energy at the same level of reliability and for the same purposes as they currently do. For the electricity system, this means the ability of the system to meet expected electricity demand at the same reliability level.

The modelled pathways are normalised for reliability. We ensure that each pathway delivers energy (whether gas, electricity, or other energy sources) at the same level of reliability that people and businesses currently enjoy. A pathway with less energy reliability will not be a viable least-cost option for New Zealand. This is because New Zealanders are unlikely to accept policy decisions that deliver less energy reliability than what is currently enjoyed. Normalising for reliability focuses analysis on the trade-off between sustainability and affordability, without compromising New Zealand's energy reliability.[4]

Gas demand declines under all pathways

The Reference Pathway shows a steady decline in natural gas demand from 165.6PJ consumed gas in 2022 to a predicted 122.3PJ in 2035. Increasing carbon prices, technological developments, and falling renewable electricity costs make natural gas relatively more expensive than alternative energy sources. Commercial and residential users, and low-medium temperature heat industrial users, switch from natural gas when alternative energy sources reach price parity (subject to some behavioural adjustments for households and businesses).

The six other pathways illustrate the impact of different policy choices on demand. The CCUS Pathway results in the same gas demand as the Reference Pathway across the modelled period. Demand does not decrease, even with costs associated with CCUS technologies. Natural gas demand is lower in the other five pathways, compared to the Reference Pathway. The Climate Change Commission's (CCC) Demonstration Pathway, the 100 Percent Renewable Electricity by 2030 Pathway, and the Direct Interventions Pathway result in the largest reduction in natural gas demand, due to natural gas being forced out. However, significantly higher costs are expected under some pathways (discussed in 5.3), so demand reduction results should be interpreted carefully.

Figure 0.3 shows natural gas demand across the modelled pathways from 2022 to 2035.

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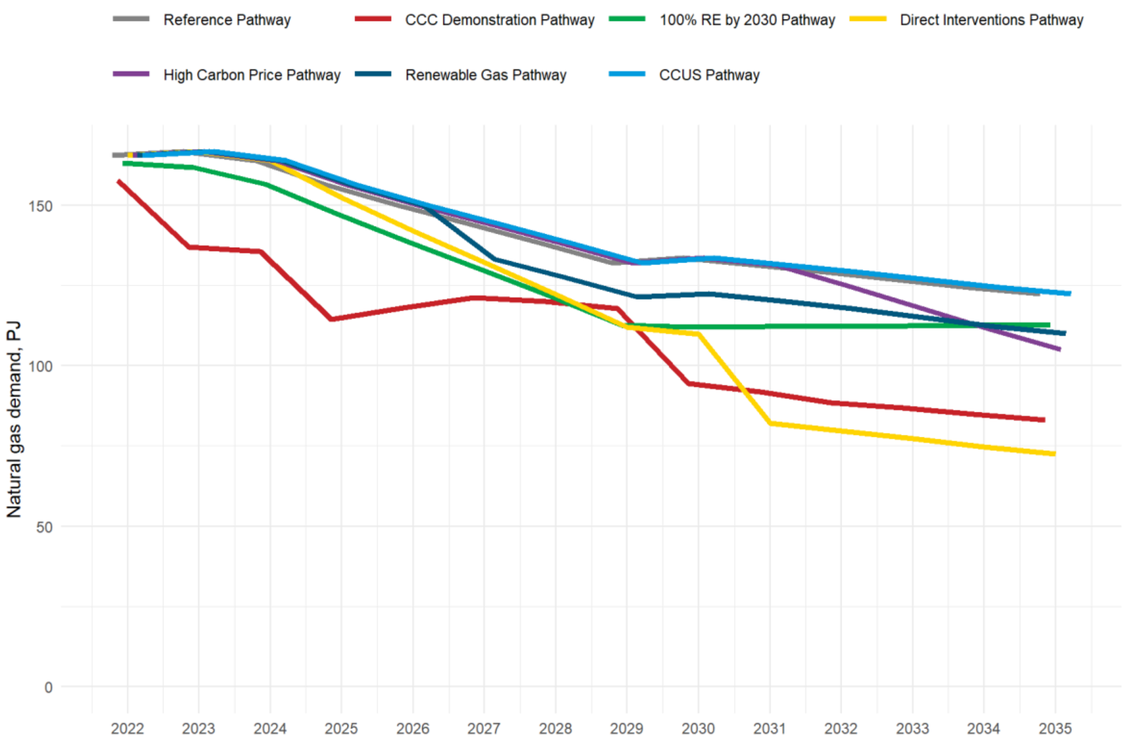
3 Emissions associated with non-energy use are not included because carbon is embedded in the products (for example, the emissions associated with the production of chemicals).

4 Castalia's approach to determining the sustainability and affordability of each pathway, and normalising the reliability of each pathways is detailed in section 4.2.

Figure 0.3: Comparison of natural gas demand across pathways from 2022 to 2035

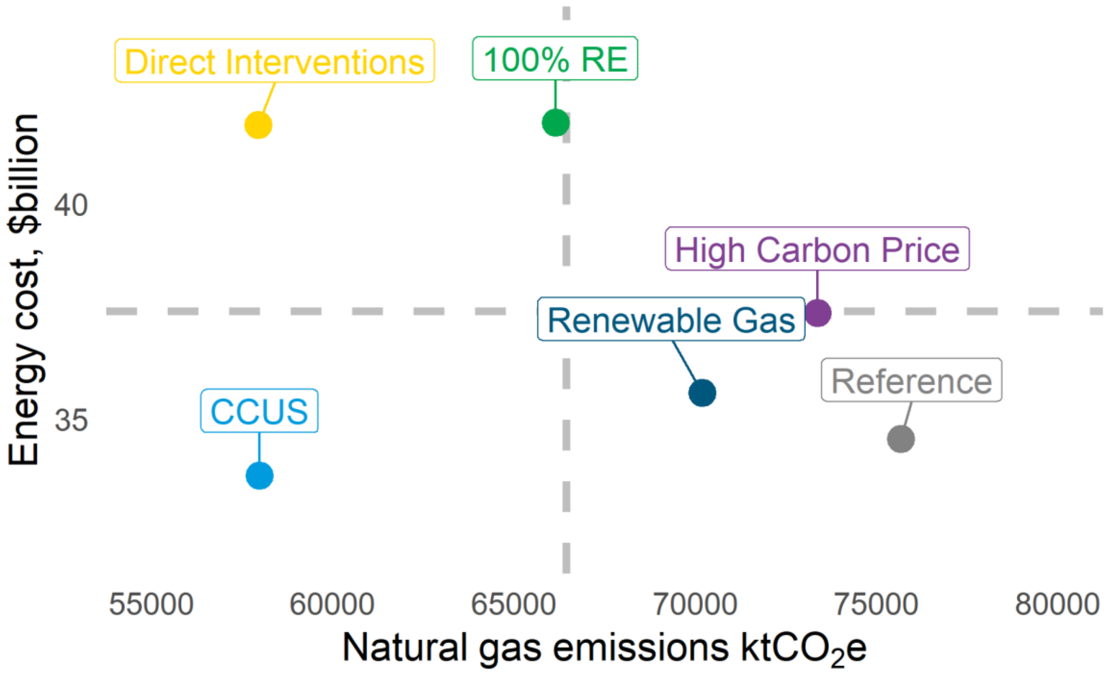


Note: The data for each pathway was offset slightly to show overlapping data at the same time.
Source: Castalia modelling

Evaluation against trilemma suggests CCUS would deliver greatest emissions reductions for least-cost

We evaluated the pathways against the sustainability (emissions) and affordability (energy cost) dimensions of the energy trilemma. Reliability was equalised over all the pathways. The evaluation suggests that CCUS would deliver the greatest emissions reduction for the least cost. In the other pathways, greater emissions reductions increase energy costs (for the same level of reliability). Figure 0.4 shows the total emissions from natural gas use against total energy costs for each pathway over the modelled period. Detailed discussion of each dimension of the trilemma follows.

Figure 0.4: Evaluation results: total emissions compared to costs of pathways



Note: The CCC did not disclose the full energy costs of its demonstration path of energy sector transition, so costs are not plotted. The cost of the CCC Pathway are discussed in detail in section 5.3.
Source: Castalia modelling

Sustainability: Emissions decline with all policy choices, but CCUS and direct interventions reduce emissions most

Emissions from natural gas users reduce in the Reference Pathway from 6.7MtCO_2e to 4.3MtCO_2e (in both cases excluding scope 1 emissions from production and fugitive gases from networks). Emissions decline in all pathways, in line with declining natural gas demand.[5]

The Direct Interventions Pathway, closely followed by the CCUS Pathway, would achieve the largest emissions reduction potential (but the Direct Interventions Pathway is expected to be high cost, discussed below). Emissions under the Direct Interventions Pathway reduce significantly compared to the Reference Pathway, due to large industrial and petrochemical users being forced to use alternative energy sources. However, more electricity is demanded under the pathway because it is used for heat processing, which increases gas use in electricity generation. In addition, this pathway is expected to result in significantly higher energy costs compared to the Reference Pathway which would probably cause production to stop and impose negative economic impacts (discussed in the 'costs' section below). Under the CCUS

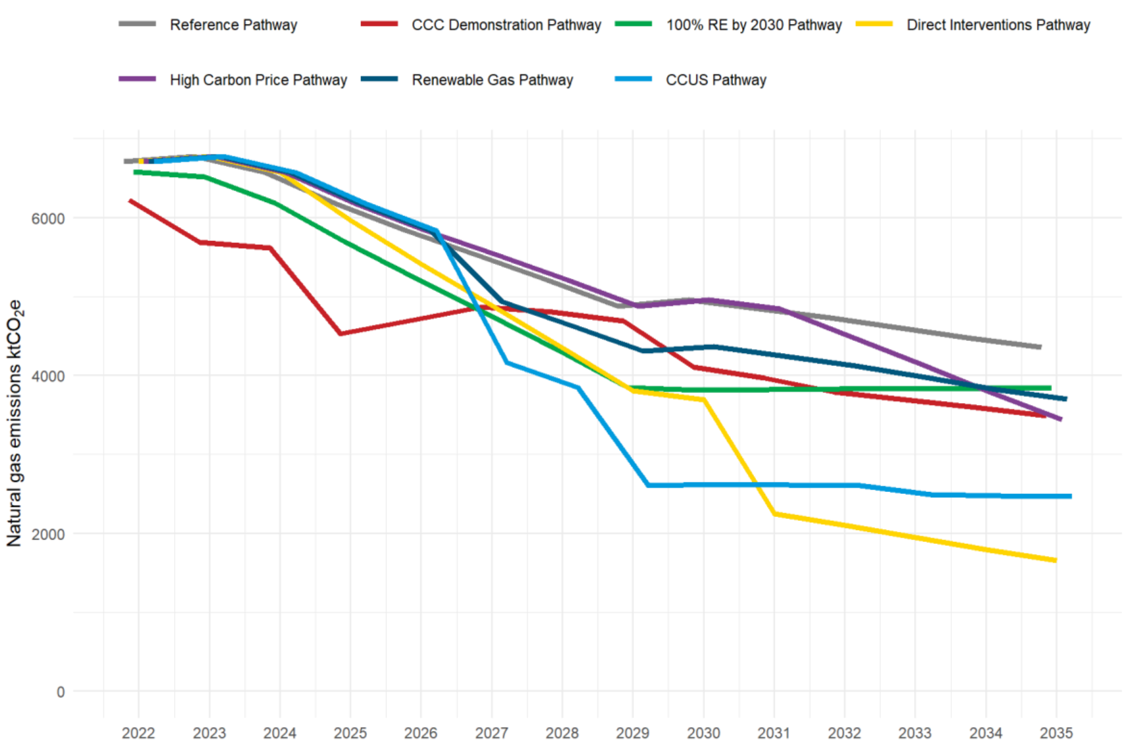
5 Emissions refer to emissions associated with the use of natural gas, and does not consider emissions from other areas of the economy or emissions removals from land-use change and forestry. Emissions associated with non-energy use are not included because carbon is embedded in the products (for example, the emissions associated with the production of chemicals).
Emissions under the CCUS Pathway are not consistent with gas demand due to the availability of CCUS technologies.

Pathway, natural gas demand does not decrease compared to the Reference Pathway, but technological advances (that is, CCUS, which is available after 2026) enable emissions from large natural gas users and electricity generation to be captured (at 85 percent efficiency). However, the emissions reduction benefits obviously depend on the timing and availability of CCUS.

The other four pathways also result in reduced emissions from natural gas users, compared to the Reference Pathway. Emission reductions occur sooner in the CCC Demonstration Pathway relative to other pathways. Due to the time value of carbon, an earlier reduction in emissions could make the CCC Demonstration Pathway more effective at mitigating the impacts of emissions. The 100 Percent Renewable Electricity by 2030 Pathway reduces significant emissions associated with electricity generation. However, this pathway may result in higher national net emissions as it makes electrification in other sectors more expensive. Emissions reductions are relatively modest under the High Carbon Price and Renewable Gas Pathways.

Figure 0.5 shows emissions from gas consumption across the modelled pathways from 2022 to 2035.

Figure 0.5: Comparison of emissions from natural gas use across pathways from 2022 to 2035



Source: Castalia modelling
Note: Emissions are directly correlated with downstream natural gas demand (except for CCUS Pathway), and do not include emissions from upstream or midstream sectors. The data for each pathway was offset slightly to show overlapping data at the same time.

Affordability: Energy and economic costs will be highest if direct interventions are used

Energy costs for gas users[6] in the Reference Pathway will increase from $2.2 billion in 2022 to $2.7 billion in 2035. Total energy costs gradually increase over the modelled period as the carbon price rises, impacting both natural gas prices and electricity prices.

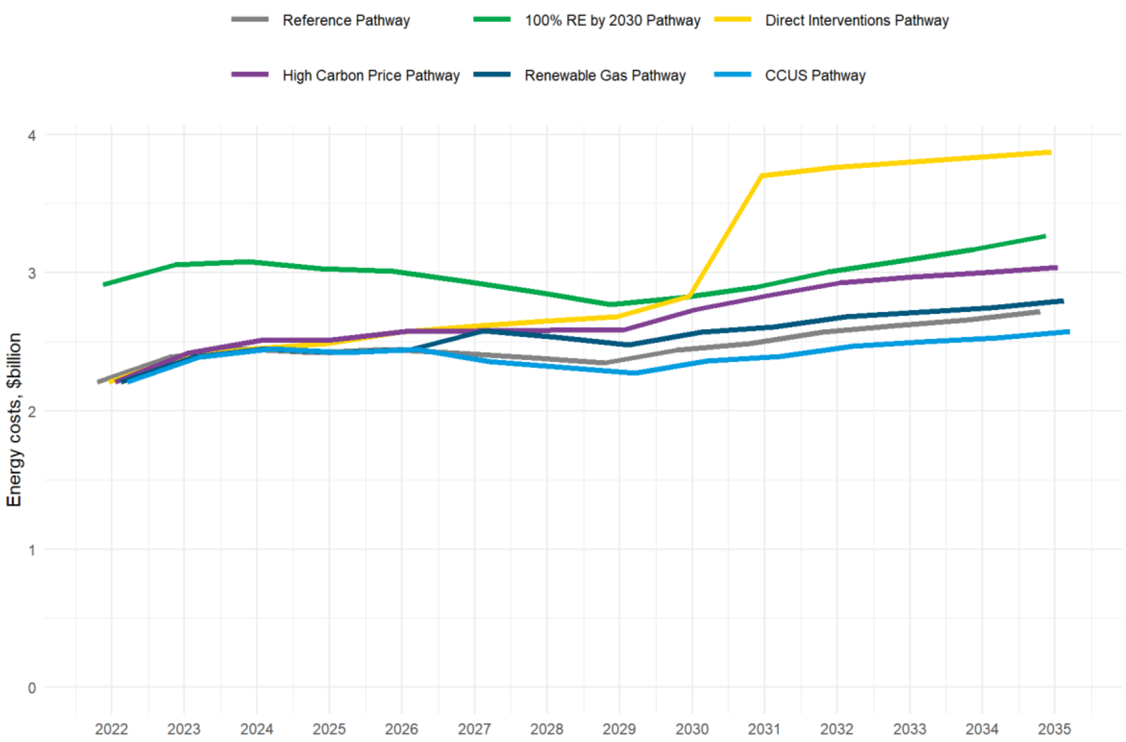
The cost of energy varies greatly across the other six pathways when specific policy choices are modelled. Energy costs are higher compared to the Reference Pathway, where significant investment is required to supplement reliability (the 100 Percent Renewable Electricity Pathway), when users are forced to switch to higher cost energy sources (Direct Interventions Pathway), and when the carbon price is significantly higher (High Carbon Price Pathway).

The CCUS Pathway has slightly lower energy costs than the Reference Pathway. For most large natural gas users that can implement CCUS, the cost of deploying CCUS is lower than paying the cost of carbon to use natural gas. If available (and supported by regulation), CCUS

[6] Energy costs are based on the total cost of the energy sources modelled (principally natural gas, biomass, and electricity), any cost of increasing energy reliability to match the current level (100 Percent Renewable Energy by 2030 Pathway), the costs of blending any renewable gases (Renewable Gas Pathway), and the estimated costs of CCUS (CCUS Pathway).

technologies can significantly reduce emissions associated with natural gas use, while being comparatively low-cost. Figure 0.6 shows energy costs across the modelled pathways from 2022 to 2035.

Figure 0.6: Comparison of energy costs across pathways from 2022 to 2035



Note: Includes adjustment for reliability and CCUS costs. The data for each pathway was offset slightly to show overlapping data at the same time. The CCC Demonstration Pathway costs could not be modelled due to a lack of published data from CCC.
Source: Castalia modelling

The 100% Renewable Electricity by 2030 Pathway, closely followed by the Direct Interventions Pathway, have the highest energy costs. The high costs under 100% Renewable Electricity by 2030 Pathway is primarily due to the cost of additional investments required to ensure energy reliability (that is, renewable energy generation 'overbuild'). The Direct Interventions Pathway is costly because the pathway assumes that after 2030, Methanex facilities switch to electricity for heat processes[7], while Ballance Kapuni completely stops using natural gas and utilises green hydrogen and biogenic carbon for feedstock and electricity for heat processes. In reality, production of methanol and urea may cease due to high energy and feedstock costs. Methanol and urea demand is driven by global market prices. Stopping methanol and urea production would have a negative impact on New Zealand's economy, including foregone gross domestic product (GDP), loss of higher-paying jobs, a loss of export income, and a need to substitute domestically produced commodities with imports after 2030. It may also result in emissions

[7] Under this pathway, Methanex continues to use natural gas as a feedstock. The carbon embedded in methanol from natural gas feedstock is mostly exported (and emitted outside New Zealand, if emitted at all) so does not contribute significantly to net emissions in New Zealand.

leakage if products are produced elsewhere in a country with higher-emitting processes.[8] Closure of production facilities is also a potential consequence of the High Carbon Price Pathway.[9]

The CCC did not disclose the full energy costs of its demonstration path of energy sector transition so this could not be modelled. However, the CCC Demonstration Pathway is likely to impose higher costs on New Zealand than most of the pathways modelled in this assignment (costs associated with the CCC Demonstration Pathway are discussed in detail in section 5.3).

Key recommendations for GTP to 2035

The optimal GTP pathway will probably include a combination of choices and options considered in this Report, as well as some technological innovations and changes that are currently unknown. Based on our modelling analysis and acknowledging limitations, the optimal pathway to transition New Zealand's gas sector appears to be a combination of CCUS for large-scale emitters, and using the carbon price to incentivise net emissions reductions. The future is radically uncertain, so flexibility to adapt to changes in technology and new information in the future (which a dynamic carbon price would promote) is important.

Investment in CCUS technologies and adoption should be prioritised, so ensure regulatory regime is supportive

CCUS technologies and adoption can support significant gross emissions reductions and help contribute to the national net-zero target.[10] CCUS should be rapidly investigated as an option to capture point source emissions from industrial, chemical, electricity generation, and process heat users of natural gas, as well as scope one emissions from upstream oil and natural gas producers. Policymakers should focus on how investment in CCUS can be accelerated and ensure regulatory certainty enables investment. The sooner CCUS is available, the greater the emissions reduction benefits are realised. Regulatory settings need to be developed, and technical feasibility analysis for New Zealand's geography and technology cost forecasts also need to be confirmed before CCUS is considered an effective long-term and stable decarbonisation option.

Reduce but retain natural gas as part of New Zealand's electricity system and ensure policy settings support investment confidence

Natural gas could continue to play a smaller but more important role in electricity generation. Natural gas can provide flexible, reliable, and cost-competitive energy source for New Zealand's electricity generation needs (particularly for dispatch), which could support the country's high renewable electricity generation mix. Utilising natural gas for select electricity generation could enable New Zealand to shift to lower economy-wide electricity costs with a higher share of renewable electricity generation than is currently the case, but without

8 Wider economic impacts of the Direct Intervention Pathway are discussed in Box 5.1.

9 Increased costs for industrial producers due to an increasing carbon price will impact the economic feasibility of New Zealand producers, especially if products are traded on the global market. Therefore, although the modelling shows that most natural gas users are likely to switch once the carbon price exceeds \$200 tCO_2e, some users may cease business if the carbon price rises significantly. The impact of high energy costs on industrial producers is discussed in Box 5.1.

10 Increasing investment in CCUS is consistent with the recommendations of the IEA and IPCC.

incurring the high costs of the additional generation and storage investment required to reach 100 percent renewable electricity.[11]

Utilise robust ETS with a binding cap and support carbon offset opportunities

A robust Emissions Trading Scheme (ETS) with a rising carbon price will incentivise reductions in natural gas demand, and therefore reductions in gross emissions. The amount of gross emissions reductions will depend on the carbon price. The modelling shows that some natural gas users are sensitive to carbon price changes, particularly once the carbon price exceeds \$200 tCO_2e. However, natural gas still appears to be the lowest cost source of energy for many sectors, even as energy costs rise because of the lack of viable low-carbon energy substitutes. As the carbon price rises, it may impact economic viability for industrial firms producing goods exposed to trade on global markets. Those natural gas users may stop production if the carbon price rises significantly and overseas competitors do not have the same climate obligations.[12]

Policy that supports using an ETS with a binding cap would provide emissions reduction opportunities that fully comply with the Climate Change Response Act in an efficient and predictable way. If the carbon price remains market-based and traded on the ETS, it can reflect the relative value of emitting compared to abating across the economy. This approach can ensure that abatement occurs first where it is cost-effective, thus incentivising emissions reductions across the whole economy.

Policymakers should commit to a market-traded ETS with a binding cap. GTP policymakers should also carefully consider the effect of 'complementary' and sector-specific policies on the carbon price.

Direct interventions are high risk and have high energy and economic costs, so these deterministic policies should be avoided

The modelled CCC Demonstration Pathway and the Direct Interventions Pathway illustrate the risks of deterministic policies targeting particular gas users or classes of users. Such policies can target the wrong users or technologies, or produce unintended consequences (such as marginal emissions reductions relative to other pathways, higher costs across the economy that cannot be sustained, and significant economic costs). For instance, the CCC Demonstration Pathway was prepared in 2021 and is already significantly out of date with actual events superseding the CCC's core assumptions. The Direct Interventions Pathway is expected to cost 21.2 percent more than the Reference Pathway over the modelled period. Rather than incur those costs, gas users will probably stop production, leading to negative economic impacts. Methanol production currently underpins New Zealand's gas market through long-term contracts[13] and ceasing it could cause supply uncertainty that might increase electricity prices to pay for new generation and infrastructure investment. This could delay electrification elsewhere in the economy.

The modelling did not explicitly consider how increases in New Zealand's energy costs may impact gas demand for trade-exposed energy users. Increases in domestic energy costs are likely to make the products of domestic firms less competitive with imports or with products on global export markets. Higher energy costs would probably cause domestic industrial firms

11 The modelled 100 Percent Renewable Electricity by 2030 Pathway is not cost-benefit justified.

12 Insight from stakeholder engagement.

13 OMV (2021), Submission on the 2021 Draft Advice for Consultation.

to close or reduce production. This could result in a significant impact on New Zealand's GDP and loss of strategic industry, job losses concentrated in particular regions, and higher global emissions due if substitute products are made in countries with more emissions intensive processes.

Renewable gases are more expensive but could play a role in preserving optionality, so renewable gas potential and pricing should be monitored and use of targets and certificates should be explored

There may be a case for integrating some renewable gases into the gas network, if renewable gas production costs fall significantly. Integrating renewable gases could be used to extend the lifespan of New Zealand's gas networks, and also provide energy choices to consumers, while achieving emissions reductions. This approach could preserve gas network infrastructure for future optionality, for example, when renewable gases can be produced at lower costs and integrated at higher volumes than is currently possible. If costs fall, the gas sector will require a coordinating mechanism so that natural gas producers, renewable gas producers, network operators, and gas users can integrate renewable gases. A renewable gas target, renewable gas certificates, and other coordinating policies should be considered in that case.

Retain LPG for some users and explore use of renewable LPG once available

LPG will remain an important energy source for commercial, residential, agriculture, and transport sectors into the future because switching to alternative energy sources is likely to be costlier than retaining LPG, even with a fully reflective carbon price. Other commentators, policymakers, and stakeholders[14] have concluded that LPG demand will remain a feature in New Zealand's energy supply. Renewable LPG could be the most effective decarbonization route for industrial and commercial LPG users that require a high burn temperature or a mobile energy source.

Additional impacts from pathways beyond 2035

The pathways modelled in this report provide some insights on other impacts on the three parameters of the energy trilemma beyond 2035. In the long run, the choices available to reduce emissions in an affordable way might be maximised if options remain available. Policymakers should seriously consider future optionality, path dependencies, and the impact of domestic policy choice on global net emissions impacts.

After 2035, most natural gas demand is likely to come from industrial users

Most natural gas demand will come from industrial users after 2035. Typically, these large-scale users emit from concentrated point sources, which could strengthen the economic case to carry out targeted CCUS.

Path dependencies matter beyond 2035 for commodity production using gas and for key infrastructure

Asset and infrastructure choices made by the large users of gas can create path dependencies, shut off future options, and lead to the same or higher global emissions if the production of commodities is displaced overseas.

Key industries may enable future decarbonisation options

Just over one third of New Zealand's annual natural gas supply is currently used for methanol production. Clean methanol could potentially contribute to decarbonising shipping and other

[14] Including CCC, Worley in analysis for Gas NZ, and sector stakeholders we engaged with for this Report.

transport options in the future. If methanol production were to cease before emissions reducing technology is developed and deployed (such as green hydrogen for e-methanol or CCS for blue methanol), it could be difficult to restart the industry. This would impose economic costs from lost income, jobs, and higher methanol prices for domestic consumers of methanol.

Loss of gas sector transmission and distribution infrastructure could reduce options beyond 2035

Gas transmission and distribution infrastructure could provide a valuable option to transmit renewable gases or captured carbon dioxide for storage. If gas demand is confined to a small number of large users after 2035, the network owners might choose to decommission the pipelines.

Emissions leakage from industry is possible

New Zealand's net zero by 2050 policy objective in the Climate Change Response Act supports its international commitments under the Paris Agreement. New Zealand's domestic objectives sit in the context of global efforts to reduce emissions.

Several large users of gas are exposed to downstream global markets for the commodity products produced using gas in New Zealand. For example, methanol, urea, and milk products produced in New Zealand are all tradeable commodities subject to a global price, determined by global supply and demand for the commodities. Policy decisions that change natural gas input costs may make domestic production of commodity goods uncompetitive with imports for domestic consumers or uncompetitive on global markets. This may force domestic trade-exposed firms to stop production. If global demand remains unaffected, and global emissions frameworks are not binding on overseas competitors, those overseas producers could keep using fossil fuels to meet demand for those commodities. This could cause higher global emissions.

1 Introduction

The New Zealand Government has set a target for New Zealand to reach national net zero emissions by 2050. The gas sector plays an important role in achieving this target. The Government is exploring policy choices for the gas sector and will publish documents that set out how the sector will transition toward net zero by 2050. The Emissions Reduction Plan signals that a Gas Transition Plan (GTP) will be published in 2023, which will inform a National Energy Strategy, to be published in 2024.

Energy Resources Aotearoa, Gas New Zealand, and Major Gas Users Group (MGUG) want to identify the most plausible pathways for the evolution of the sector, demonstrating the trade-offs between the energy trilemma—sustainability, affordability, and reliability. It is crucial that all plausible options are on the table and well-understood by the sector, policymakers, and the public.

To inform the development of the GTP and the National Energy Strategy, Castalia has estimated gas demand and gross emissions if New Zealand stays on its current policy and carbon price track—we call this the Reference Pathway. We modelled six other possible pathways between 2022 and 2035, and provided commentary on the implications of the model outputs out to 2050. The purpose of this pathway modelling is to highlight where key choices will have the most impact on the cost of energy and emissions, and how these choices might impact New Zealanders. The analysis and recommendations in this Report focus on the gas sector only. Decision-makers should also consider dynamics across the energy sector.

The Report is structured as follows:

- The context for this Report, including the role of natural gas in New Zealand's energy supply, a summary of the objectives of the forthcoming GTP, and the role of the Climate Change Commission (CCC) in monitoring New Zealand's emissions reduction targets are contained in section 2
- The Reference Pathway (that is, New Zealand's predicted gas demand and emissions if we stay on the current track) and six different policy pathways are described in section 3
- The modelling framework and approach are outlined in section 4, with modelling assumptions detailed in Appendix A
- The modelling results are presented in section 5, and the sensitivity analysis of key variables is in section 6
- Finally, we outline the conclusions and recommendations in section 7.

Pathways and modelling assumptions are grounded in evidence provided by sector stakeholders and previous modelling and forecasting work. Insights from engagement with sector stakeholders are summarised in Appendix B, while the list of literature reviewed is provided in Appendix C.

2 Context for this Report

Natural gas currently provides a significant amount of New Zealand's primary energy supply. It plays an important firming role in New Zealand's energy mix—a feedstock for industry, a reliable source of energy for domestic and commercial heating and cooking, and for electricity generation as a dispatchable energy source and an energy source for peaking. New Zealand's Ministry of Business Innovation and Employment (MBIE), together with the Gas Industry Company (GIC), the industry co-regulator, are preparing a Gas Transition Plan (GTP) for an "equitable phase out of fossil [natural] gas".[15] The GTP intends to set out the steps needed to phase out natural gas between now and 2035 (the first three emissions budgets out to 2035), and signal the longer-term direction for the sector out to 2050.

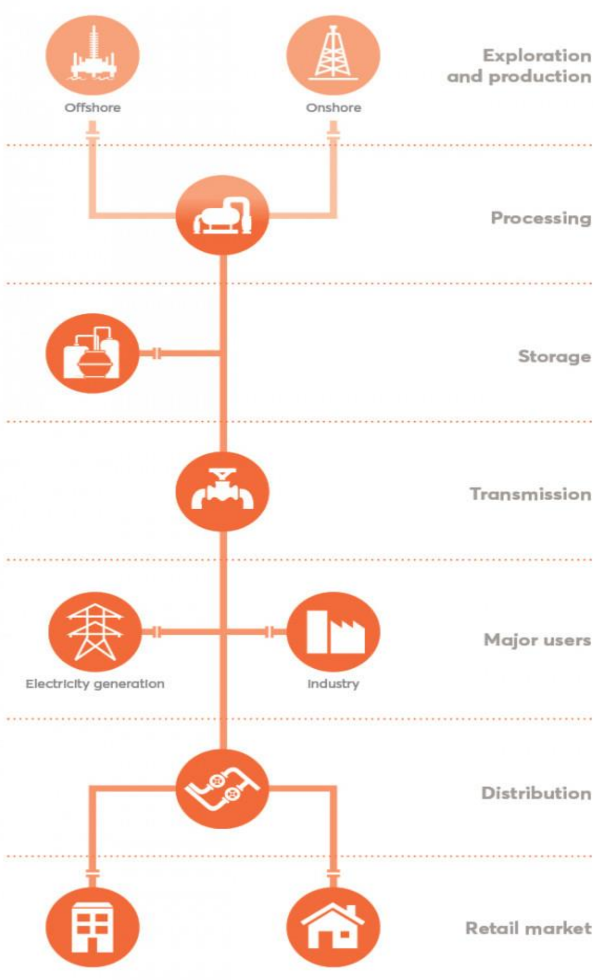
An overview of the role of natural gas in New Zealand's energy supply and for the industry is provided in section 2.1, while the GTP and the CCC analysis of New Zealand's carbon budget for the gas sector is discussed in section 2.2.

2.1 Natural gas plays an important role in New Zealand's energy supply and industry

New Zealand's gas sector meets the energy needs of many industrial, commercial, and residential consumers. Natural gas is also an important feedstock in chemical production, chiefly methanol and ammonia and urea production. New Zealand's natural gas is supplied solely through domestic sources. Figure 2.1 provides an overview of New Zealand's gas sector structure.

[15] MBIE use the term fossil gas, which refers to natural gas. MBIE, Gas Transition Plan, available: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/gas-transition-plan/

Figure 2.1: Structure of New Zealand's gas sector

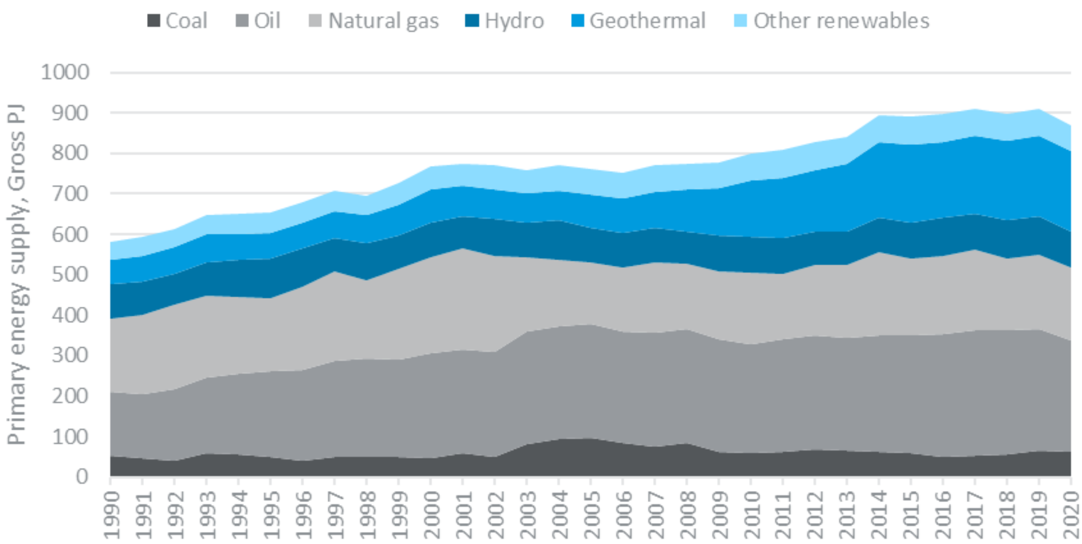


Source: Gas Industry Company

Natural gas is currently a significant part of New Zealand's energy supply

Natural gas provides about 18 percent of New Zealand's primary energy supply. This is lower than oil at 34 percent, which is used mainly in transportation and machinery, and higher than coal at 7.1 percent, which is used predominantly for electricity generation and process heat. Renewable sources (hydro, geothermal, solar PV, and wind) are growing as a share of New Zealand's energy mix, currently making up 41 percent. This is increasing as the cost of renewable energy (particularly from solar PV and wind) falls both in absolute and relative terms. Figure 2.2 displays New Zealand's primary energy supply by source.

Figure 2.2: New Zealand's primary energy supply by source



Note: Primary energy supply refers to energy that has not been transformed through human-engineered processes
Source: MBIE, Energy in New Zealand: Energy Overview Data Tables

Natural gas has many industrial, commercial, and residential users

Gas in New Zealand is utilised by industrial, commercial, and residential users, and it is also a key component of the electricity system. Industrial uses include steel and chemical manufacturing, especially methanol and fertiliser. Commercial and residential users largely use natural gas to power space and water heating, and household appliances (such as gas cooktops). Gas is supplied to residential customers as both piped natural gas and bottled liquified petroleum gas (LPG). Natural gas is also a key component of the electricity system by providing a firm energy source for peaking and dispatchable electricity generation plants. Figure 2.3 displays New Zealand's natural gas consumption by sector.

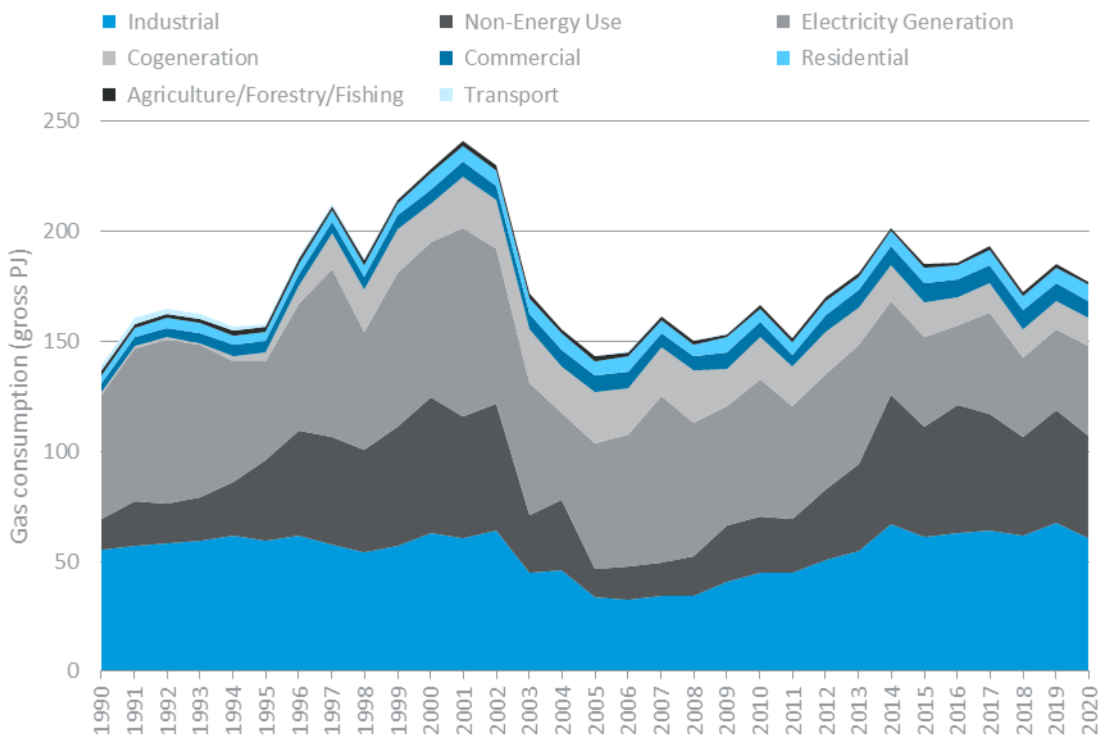
Some gas users will find it easier to transition to lower carbon alternatives than others. For industry, there is a lack of viable low-emissions alternatives for processes that use gas for high-temperature heat. These gas users will find switching technically difficult.[16] Low- and medium-temperature process heat (such as for food processing and wood, pulp and paper production) will be able to switch to energy sources such as wood-based biomass and grid-sourced renewable electricity.[17] Most residential and commercial customers will be able to switch to grid-sourced renewable electricity for cooking, and space and water heating. In theory, switching will largely occur whenever owning and operating gas appliances is no longer the least-cost option. However, gas demand is relatively sticky. For example, there are split incentives for rented properties, where the tenant pays the energy bill, but the landlord is responsible for chattels. Some people value the space saving that gas hot water and heating

16 Engagement with sector stakeholders in 2022.

17 The University of Waikato, 2019 Options to Reduce New Zealand's Process Heat Emissions; The Climate Change Commission, 2021, Ināia tonu nei: a low emissions future for Aotearoa, Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025, p.288

systems provide (over electricity solutions) or consider gas appliances more 'high end' than electric appliances. Cooking applications that require flame (for example, wok cooking) cannot easily switch to electricity.[18]

Figure 2.3: New Zealand natural gas consumption by sector



Source: MBIE Gas Production and Consumption Data Tables

2.2 New Zealand's Gas Transition Plan aims to reduce emissions in the gas sector

The GTP aims to provide a pathway to "phasing-out fossil [natural] gas"[19] in Aotearoa, New Zealand" as part of New Zealand's energy transition to a national net-zero carbon economy by 2050. MBIE and GIC are co-developing the GTP and expect to publish it by the end of 2023. It will contain two key pillars:

- Pillar 1 will set out the natural gas transition pathways across the first 3 emissions budgets to 2035, and signal the longer-term direction for the sector out to 2050[20]

18 Engagement with sector stakeholders in 2022.

19 Fossil gas refers to natural gas and is used to distinguish this source of gas from biogenic, renewable, or synthetic sources. MBIE, Gas Transition Plan, available: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/gas-transition-plan/

20 The first three emissions budgets are 2022–2025, 2026–2030, and 2031–2035. New Zealand's emissions budgets are discussed in more detail below.

- Pillar 2 will develop a cohesive view on renewable gas market developments, including how New Zealand could effectively reduce emissions and lower transition costs for gas consumers.[21]

The GTP aims to help New Zealand achieve the following outcomes—sustainability, energy security, energy equity, emissions reductions, and energy conservation and efficiency. The Government recognises that these outcomes may need to be balanced against each other over time, and it seeks an equitable transition for the natural gas sector. The GTP will align with relevant emissions reduction frameworks and targets, consider other relevant workstreams, such as the Bioeconomy Strategy and the Decarbonising Industry Plan, and take into consideration other relevant Government objectives, such as the aspirational target to achieve 100 percent renewable electricity by 2030.

The GTP will inform MBIE's development of New Zealand's Energy Strategy, which is expected to be published by the end of 2024. The Energy Strategy will set out a coordinated decarbonisation strategy for the energy sector (including the gas sector) that aligns with the government's 2050 vision for energy—"highly renewable, sustainable, and efficient energy system that is accessible and affordable, secure and reliable, and supports New Zealander's wellbeing."[22]

Climate Change Commission analysis of New Zealand's carbon budget for the gas sector

New Zealand does not currently have a specific gas sector or energy sector emissions reduction target. The Government publishes national emissions budgets, which set out the total quantity of emissions allowed to be released in New Zealand during a set period, and provide a pathway for New Zealand to meet its national net zero emissions targets by 2050. Each emissions budget covers a period of five years (except the first emissions budget, which covers a four-year period). The first three budgets cover the years 2022–2025, 2026–2030, and 2031–2035. The Government publishes an emissions reduction plan (ERP) for before the start of each emissions budget period, which outlines policies and strategies to meet the budget.

The CCC provides independent policy advice to the Government on climate change issues, including on how New Zealand should set its national emissions budgets and the preparation of the ERP. The CCC also monitors progress towards New Zealand's emissions reduction targets and budgets, as well as the country's climate adaptation goals.[23] On a periodic basis, the CCC is required to provide advice on the preparation of the next ERP (next scheduled for December 2023), and revisit the 2050 emissions target (next scheduled for December 2024).[24] This approach enables the CCC to provide advice that reflects technological developments that may influence its assumptions and advice to the Government.

21 Pillar 2 considers the role for renewable gases (including green hydrogen, biomethane and renewable Liquid Petroleum Gas (rLPG)) to help support the reduction in emissions from this sector.

22 MBIE, New Zealand Energy Strategy, available at: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/new-zealand-energy-strategy/

23 Climate Change Commission, Our Purpose, available at: https://www.climatecommission.govt.nz/who-we-are/our-purpose/#:~:text=We%20monitor%20and%20review%20progress,out%20until%202050%20and%20beyond

24 A timeline of the CCC's upcoming work is available here: https://www.climatecommission.govt.nz/our-work/our-upcoming-work/#:~:text=Due%20December%202024,-Currently%2C%20the%202050&text=The%20Commission%20will%20provide%20advice,provided%20by%2031%20December%202024

In 2021, the CCC published advice to the Government on its first three emissions budgets in a document called *Ināia tonu nei: a low emissions future for Aotearoa* (*Ināia tonu nei*).[25] This advice includes a 'demonstration path', which outlines measures and actions within each sector that would deliver the CCC's recommended emissions budgets to 2035. The demonstration path includes the following assumptions about gas use:

- No new natural gas heating systems installed after 2025
- Start phasing out existing natural gas use in buildings from 2031
- Phase out base-load generation from non-renewable resources from 2022
- Replace natural gas with biomass and electricity for industrial process heat from 2031.

In *Ināia tonu nei*, the CCC have modelled the emissions and some costs (including natural gas and LPG and electricity costs) associated with its demonstration path. The CCC's assumptions about gas use could be adopted in the GTP.

The Government published its first ERP in 2022, which responds to the CCC's recommendations in *Ināia tonu nei*.[26] The Government's main deviation from the CCC's recommendations is around the CCC's suggestion that the Government should 'set a date to end the expansion on pipeline connections [in residential, commercial, and public buildings]'. The Government did not adopt this recommendation. Instead, the ERP states that further work is required before decisions are made on how best to reduce natural gas use, and that the GTP will identify transition pathways for the natural gas sector.[27]

3 Pathways model potential gas sector futures

The Government and GIC's work to prepare a GTP will consider several future scenarios for the gas sector and consumers. Economic modelling of different future scenarios (defined as 'pathways' in this Report) can highlight where key choices will have the most impact on the cost of energy, emissions, and reliability (the energy trilemma). The modelling timeframe is 2022 to 2035. This Report also provides additional commentary on the implications of the model outputs for the period after 2035 and out to 2050.

First, it is necessary to understand what New Zealand's gas sector future will look like if current trends continue. We modelled a Reference Pathway that shows how gas demand and emissions should develop over to 2035. It is based on intensive consultations with the whole sector. The Reference Pathway reflects the 'business as usual' (BAU) approach, based on current expectations of policy and the carbon price change.

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[25] CCC (2021), Ināia tonu nei: a low emissions future for Aotearoa, available at: https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/

[26] Ministry for the Environment (2022), Te hau mārohi ki anamata Towards a productive, sustainable and inclusive economy, available at: https://environment.govt.nz/assets/publications/Aotearoa-New-Zealands-first-emissions-reduction-plan.pdf

[27] The Government's response to the CCC's recommendations can also be found here: https://environment.govt.nz/assets/publications/Files/The-Governments-response-to-He-Pou-a-Rangi-Climate-Change-Commissions-recommendations.pdf

We also developed six additional pathways which test how gas and energy demand respond to changes in key variables.

Figure 3.1: Gas sector transition pathways to 2035

Reference Pathway	BAU pathway for New Zealand gas demand and emissions, based on sector participants' views of likely government policy. It includes a carbon price that rises to $140 by 2030, and $160 by 2035
CCC Demonstration Pathway	Models gas demand using the CCC's 'demonstration path', developed as part of the CCC's 2021 advice in *Ināia tonu nei.* Gas demand is adjusted to account for actual (higher) gas demand in 2021. CCC's other assumptions affecting demand, including those that have been superseded by real events, are unchanged
100% Renewable Electricity by 2030 Pathway	Models how gas demand and emissions could evolve if New Zealand transitions to 100 percent renewable electricity by 2030. Gas-fired generation is phased out and investments are needed to improve reliability of electricity supply
Direct Interventions Pathway	Models how direct mandates could affect gas demand and emissions. It includes stopping gas use in low-medium heat industrial processes and banning new gas connections in commercial and residential buildings. Methanol production also switches to electricity for heat processes, and urea production switches to green hydrogen and biogenic carbon for feedstock and electricity for heat processes
High Carbon Price Pathway	Models the impacts of a high carbon price on gas demand and emissions. The carbon price rises to $300 per tCO_2e by 2035
Renewable Gas Pathway	Models how blending renewable gases in the natural gas network and in LPG could affect gas demand and emissions. The relevant least-cost gas (hydrogen, biogas, bioLPG, and DME) is blended
CCUS Pathway	Models the impact of capturing emissions of large emitters and storing or utilising the captured CO_2. CCUS technologies are available from 2026

The Castalia economic modelling of gas sector pathways explores the impact that key decisions relating to the gas sector could have on New Zealand's energy mix, emissions profile, and energy affordability. This modelling is explorative (not determinative). It seeks to develop an understanding of the space within which policy makers should operate. Economic modelling of this type (including models used by policymakers and other stakeholders) should not be used to predict the future. The future is 'radically uncertain'.[28] Modelling does not describe the world as it really is (or as it will actually turn out). Instead, modelling merely provides insights into the key factors that may influence future outcomes.

New Zealand's future gas sector could incorporate elements of many of the pathways. The purpose of using a discrete set of pathways is to illustrate how the choices of policymakers, gas sector participants, and gas and energy consumers could impact New Zealand's transition from natural gas and LPG. The pathways are varied to illustrate how plausible pathways might play

[28] Kay and King (2020), Radical Uncertainty.

out, and their impacts in terms of the energy trilemma. Sections 3.1 to 3.7 describe the pathways at a high level, their key assumptions and why they are relevant.

3.1 Reference Pathway

The Reference Pathway illustrates how the gas sector is already transitioning under existing policy settings and available technologies, consumers' responses to the energy prices, the carbon price, and how the sector is responding to policy signals. It was developed by undertaking extensive workshops with gas sector stakeholders (summarised below and discussed in detail in Appendix B). It provides a base case from which the other pathways build off, and pathways can be compared.

Key parameters under the Reference Pathway are:

- Current government policies continue, but no new policies are announced. For example, there is no ban on new gas connections, offsetting (through the purchase of New Zealand emission units (NZUs)) is available to a somewhat limited extent, and the carbon price will increase to $140 per tCO_2e by 2030 and $160 tCO_2e by 2035 to encourage behaviour change to reduce emissions[29]
- The gas sector continues to pursue planned investment and decarbonisation opportunities. For example, Tiwai Point Aluminium Smelter and Methanex remain open at least until 2035 and 2039, respectively
- There is no new significant industrial natural gas use over the modelled period[30]
- Renewable electricity increases to 95 percent in 2030 and 98 percent in 2035, and the price of electricity fluctuates but overall remains relatively flat (in real terms)
- Natural gas blending with renewable gases is not available at scale[31]
- CCUS technologies are not available
- New Zealand will have sufficient gas supply to meet future demand over the long-term.[32]

The Reference Pathway is relevant because it provides a realistic BAU, from which the other pathways build off, and a counterfactual from which the other pathways can be compared.

[29] The model does not include industrial allocations of emissions units, and assumes that all gas users purchase units at the full price. The allocation of units matters for competitiveness of gas users end products and services, particularly in trade-exposed sectors. We do not model the gas demand impacts of changes in prices of gas users' end products, so the inclusion of industrial allocations is only relevant for changes in energy demand based on energy costs.

[30] We understand that Methanex has a dormant plant in Waitara Valley that could be a significant future user of natural gas. For the purposes of the analysis in this report, we assume it does not resume production.

[31] Some renewable gas projects are currently underway, for example the biomethane project at the Reporoa Organics Processing facility. Under the Reference Pathway, these projects are expected to continue at small scale, but not at large scale, and therefore do not impact natural gas demand overall. No new projects are expected to eventuate.

[32] New Zealand has natural gas reserves, and resources will be sufficient to meet New Zealand's energy demands between 2022 and 2050. New Zealand has 2P natural gas reserves of 1,967 petajoule (PJ), and additional 2,915PJ of contingent resources could provide sufficient gas if partially developed. This assumption is aligned with MBIE's long-term projections of reserves developments, and the GIC's gas supply and demand projections, which suggest that there is sufficient gas in New Zealand's existing fields to meet future demand out to 2060. Modelling assumptions, including assumptions and references related to gas supply, are detailed in Appendix A.

Reference Pathway based on intensive sector-wide workshops and consultation with key government agencies

The Reference Pathway was developed following a series of six intensive cross-sector workshops with upstream, midstream, downstream (retail) stakeholders, as well as LPG users and wholesalers, and major and large natural gas users. Each workshop was approximately 90 minutes, during which stakeholders were asked to respond to a series of guiding questions about:

- Current annual gas demand and use
- Predicted gas demand and use in the future under current (or predicted) policy environment
- Actions and directions each organisation is taking or planning to take to support the transition under the current or predicted policy environment. For example:
  - Measures to reduce energy demand and improve energy efficiency
  - Switching to alternative energy sources or alternative technologies
  - Off-setting or carbon reducing and eliminating options (such as CCUS)
  - Infrastructure winddown and repurposing
- Policy, commercial, and technical barriers for the organisation to support the transition
- Plausible pathways and opportunities for the gas sector, particularly if barriers were removed.

The Reference Pathway incorporated the insights from this engagement. We then presented the Reference Pathway (and other key assumptions for the other Pathways) to MBIE, GIC, and EECA.[33] Feedback from these three organisations were integrated. Appendix B provides more detail about the stakeholder engagement undertaken to develop the pathways.

Reference Pathway informed by other gas and energy sector analysis

The Reference Pathway (and key interventions and assumptions in the six modelled policy pathways) was informed by modelling and forecasting work completed by other sector stakeholders. A list of literature and models reviewed for this assignment is contained in Appendix C. We reviewed the key assumptions and the analytical approach taken in analysis by CCC, Energy Resources Aotearoa, and Concept Consulting (in analysis for CCC and various clients in a BCG report). The analysis in this report is broadly consistent with those other reports, given the different assumptions made. Where there are differences, these are highlighted in our modelling assumptions in Appendix A.

[33] CCC were also invited to participate.

3.2 CCC Demonstration Pathway

The CCC Demonstration Pathway illustrates how the gas sector could evolve under the CCC's demonstration path (explored in *Ināia tonu nei*).[34] Key parameters under the CCC Demonstration Pathway are:

- The Tiwai Point Aluminium Smelter is closed at the end of 2024, with the electricity becoming available for alternative use, and Methanex is closed by 2040
- New policies will be introduced to aggressively phase out natural gas, requiring greater investment into electrification. For example, all new space heating and hot water systems installed after 2025 in new buildings are electric
- Phase-out of natural gas for existing buildings begins in 2030 with existing natural gas appliances switched to electric or biomass at end of life, and no further natural gas connections to the grid, or bottled LPG connections, occur after 2025
- Renewable electricity increases to 93 percent by 2035.

CCC Demonstration Pathway no longer reflects reality

The CCC's Demonstration Pathway was modelled in 2021. It is now out of date in several respects. Castalia made one key adjustment to the CCC's modelling to ensure fair comparison between the other five pathways, and draw conclusions on the validity of the CCC's modelling.

We adjusted CCC's underlying data, to correct for the actual gas demanded in the first year of the CCC's model, because actual consumption data is available. The CCC assumed that gas consumption in 2021 would be 149.8PJ. We adjusted it in our modelling for the CCC Demonstration Pathway to be 154.97PJ in 2021, in line with actual gas consumption in 2021.[35] We did not make adjustments in our CCC Demonstration Pathway modelling for three other key real world outcomes that contradict the CCC's 2021 demonstration path model:

- Methanex production: The CCC assumed that Methanex would curtain the production of methanol, and use less natural gas. However, in the intervening year since it published its advice, Methanex returned to full production and has indicated it intends to continue at these production levels
- Tiwai Point to keep operating: The CCC also assumed that Tiwai Point would ease the production of electricity, thus freeing up electricity generation capacity for the wider market. Tiwai Point is expected to keep operating for the foreseeable future
- Marsden Point refinery has ceased operating: CCC assumed that the Marsden Point oil refinery, which was a large consumer of natural gas, would continue to operate. That facility has now become a terminal for importing already refined fuels.

Relevance of CCC Demonstration Pathway

This pathway is relevant for two key reasons.

[34] CCC (2021), Ināia tonu nei: a low emissions future for Aotearoa: Chapter 7 Demonstrating emissions budgets are achievable, available at: https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Chapter-7-inaia-tonu-nei.pdf

[35] MBIE Gas statistics, available at: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/

First, the CCC's current demonstration path (that is, the path explored in *Ināia tonu nei*) is likely a key consideration in development of the GTP.[36] The CCC demonstration path may be adopted by Government in part or in full (that is, the Government may adopt some recommendations but not others). Therefore, it is important to understand its costs and benefits, especially against other plausible pathways.

Second, the CCC demonstration path establishes the basis for the Government's carbon budgets out to 2035. If the gas sector does not achieve CCC's modelled contribution, then policymakers may wish to impose policies that reduce more emissions from other fossil fuel use, or from other areas in the economy. Conversely, if the gas sector outperforms the CCC's modelled outcomes, then this could compensate for lower emissions reductions in other areas of the economy.

3.3 100 Percent Renewable Electricity by 2030 Pathway

The 100 Percent Renewable Electricity by 2030 Pathway illustrates how the gas sector could evolve if New Zealand transitions to 100 percent renewable electricity by 2030. Key parameters under this pathway are:

- 100 percent renewable electricity is achieved by 2030
- Electricity prices are higher relative to the Reference Pathway as New Zealand increases the share of renewable electricity[37]
- Additional renewable energy generation and storage investment is required to increase the reliability of supply[38]
- Additional cost of non-supply and unplanned outages (for the proportion of customers that are not covered by the additional generation and storage investment) is also included.

100 Percent Renewable Electricity Pathway assumes that all fossil-based electricity generation is removed

Greater investment into renewable energy will eliminate all fossil fuel-based generation. New renewable energy generation will mostly come from wind and solar PV, which is variable and correlated (sun and wind are correlated). The 100 Percent Renewable Electricity by 2030 Pathway is considered to provide less reliability than what New Zealand currently enjoys due to the high penetration of renewable and the uncertainty about the ability to keep power flowing when the hydro lakes are low—the 'dry year problem'.

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36 The CCC's demonstration path may change after the CCC revisits New Zealand's 2050 emissions target (next scheduled for December 2024). CCC's role in providing advice to the Government is discussed in section 2.2.

37 Literature states that replacing the last 1–2 percent of fossil fuel generation with renewable electricity would be costly, and prices would likely increase for residential, commercial, and industrial customers. For example, [The Interim Climate Change Commission, 2019, Accelerated electrification, Evidence, analysis and recommendations](); the Climate Change Commission, 2021, Ināia tonu nei: a low emissions future for Aotearoa, Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025, p.279; and Cole et. al., (2021), available at: https://www.sciencedirect.com/science/article/pii/S2542435121002464

38 ICCC's modelling of increased electricity prices does not cover costs of additional generation and storage investment required to increase reliability of supply. Therefore, additional investment has been included to increase energy reliability under this pathway.

Reliability adjustment is made to pathway

To improve the reliability of the energy supply under this pathway, additional renewable energy generation investment is required (often called 'overbuild'). Estimates of the overbuild and storage required have been used to identify the additional energy costs of $3.7 billion for 1,174MW of renewables and 500MW of batteries and extra demand response and shortage.[39] However, even with such overbuild, it is likely that some users will still experience non-supply and unplanned outages. The amount of non-supply is estimated at approximately 4,000MWh annually, and there is an annual need for over 8,000MWh of demand side response (DSR). Additional costs associated with non-supply or unplanned outages are estimated at $242.8 million per year. This additional cost is included in the total cost of the pathway. The non-supply in the modelling is due to a lack of available generating capacity, as additional investment in renewables would not be cost recovering.[40]

Alternative options to improve the reliability of the energy supply also considered in the modelling include Lake Onslow pumped hydro storage and hydrogen storage. Similar to the overbuild option, these options require large investments but do not necessarily eliminate the non-supply issue.[41]

100 Percent Renewable Electricity by 2030 Pathway is relevant as it is still a government aspiration

This pathway is relevant because the government has announced an aspirational target that 100 percent of New Zealand's electricity come from renewable sources by 2030. It is unclear what actions the Government's forthcoming Energy Strategy will include to achieve this aspirational target.[42]

3.4 Direct Interventions Pathway

The Direct Interventions Pathway illustrates how the gas sector could evolve if policymakers elected to direct investment decisions in the gas sector, as opposed to using the ETS as the primary policy mechanism to address emissions.

Direct Interventions Pathway includes policies that force gas users to switch to other energy or feedstock sources

This pathway forces gas users to switch to alternative energy or feedstock sources. The key direct interventions are:

- All low-medium heat process gas users[43] progressively switch from 2025 to 2030. This will affect food processing, pulp and paper, mining and quarrying, other industries and

39 The ICCC (2019), Electricity Market Modelling 2035, available at: available at: https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Advice-to-govt-docs/ICCC-electricity-modelling-reports.pdf

40 The ICCC (2019), Electricity Market Modelling 2035, available at: available at: https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Advice-to-govt-docs/ICCC-electricity-modelling-reports.pdf

41 The ICCC (2019), Electricity Market Modelling 2035, available at: available at: https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Advice-to-govt-docs/ICCC-electricity-modelling-reports.pdf

42 MBIE (2022), First Emissions Reduction Plan—Chapter 11: Energy and Industry, available at: https://environment.govt.nz/publications/aotearoa-new-zealands-first-emissions-reduction-plan/energy-and-industry/ According to the New Zealand Energy Strategy Terms of Reference, the development of the strategy should have regard to "the Government's aspirational target of 100% renewable electricity by 2030." MBIE (2022), New Zealand Energy Strategy Terms of Reference, available: https://www.mbie.govt.nz/dmsdocument/25373-terms-of-reference-new-zealand-energy-strategy

43 Low-medium heat users include food processing, other industry, mining and quarrying, pulp and paper. High heat users include Cement, steel, methanol, urea, electricity generation.

agriculture. Since there is insufficient biomass available to meet all low-medium heat process users' energy needs, we assume 50 percent of these users switch to biomass and 50 percent to electrification. This is in-line with the CCC's assumptions around available biomass resource, and energy users requiring certainty of energy supply

- Natural gas supply for large methanol and urea producers changes after 2030:
  - Natural gas supply for urea production (Ballance Kapuni) ceases after 2030. This producer switches to green hydrogen and biogenic carbon for feedstock, and electricity for heat processes
  - Natural gas supply used for heat processes in methanol production (Methanex) ceases after 2030, so electricity is utilised as the energy source instead. Natural gas is still used as a feedstock[44]
  - It is not assumed that Ballance and Methanex cease production (although this may be the case)[45]
- No new natural gas or LPG connections in residential and commercial sectors from 2025
- Natural gas use for electricity generation follows Reference Pathway (that is, 98 percent renewable electricity by 2035). It is assumed that there is sufficient electricity supply to support increased electricity demand from large users
- Green hydrogen supply (and a source of carbon dioxide for urea production) is available where demanded.

Relevance of Direct Interventions Pathway

The CCC[46] states that so-called "complementary policies" are required. Complementary policies are interventions that are imposed in addition to the ETS and emissions pricing. The government is actively considering how complementary policies in the gas sector can reduce emissions. These could include sector specific mandates, bans on certain fuels or technologies, or subsidies. For complementary policies to be effective and avoid unintended consequences, they require detailed knowledge of the impact of intervention.

3.5 High Carbon Price Pathway

The High Carbon Price Pathway illustrates how the gas sector could evolve with higher carbon prices, relative to the Reference Pathway. Key parameters under this pathway are:

- New Zealand has a higher carbon price relative to the Reference Pathway, increasing to \$300 per tCO_2e by 2035. This increase results in higher energy prices
- Investments in low-emissions alternatives are incentivised by the higher carbon price, which results in earlier fuel switching

[44] The carbon embedded in methanol from natural gas feedstock is mostly exported (and emitted outside New Zealand, if emitted at all) so does not contribute significantly to net emissions in New Zealand.

[45] The impact of Methanex and Ballance existing the market due to high energy costs or a lack of alternative energy sources is discussed in section 5.3.

[46] Climate Change Commission (2021), Draft Advice for Consultation, p 11.

- Investors have policy certainty on future carbon prices to de-risk investments.

Relevance of High Carbon Price Pathway

This pathway is relevant because NZUs under the ETS may help to incentivise behaviour, without other policy interventions. It is important to note that the CCC and Government express caution about rapidly increasing the carbon price because it may not reduce emissions effectively in the short-to-medium-term.[47]

Some experts think the social cost of carbon should be much higher than current traded prices. For instance, a recent study claims a mean price of US$185 per tCO_2e (NZ$292) is justified.[48]

3.6 Renewable Gas Pathway

The Renewable Gas Pathway illustrates how the gas sector could evolve by blending renewable gases, such as hydrogen, biogas, bio LPG, and DME. Key parameters under this pathway are:

- Renewable gas supply is available where demanded
- Policies and regulations enable blending hydrogen and biogas with natural gas, and bioLPG and DME with conventional LPG
- The gas sector transitions to renewable gases as technologies mature and enabling policies are developed. Gas blending is economic relative to other abatement options
- We assume 100 percent piped or distributed renewable gas is unavailable before 2035 due to feedstock and resource limitations[49]
- The Renewable Gas Pathway also models bioLPG as an LPG substitute.

Relevance of Renewable Gas Pathway

This pathway is relevant because blended natural gas and renewable gasses can be used as a feedstock or for heating without the need to change any pipeline infrastructure or end-user appliances.[50] Where the capital costs of switching to electricity (including network infrastructure investment) or biomass are high, renewable gas blending could allow gas users to reduce emissions while incurring incremental operating costs.[51] Renewable gases may also help New Zealand preserve existing gas infrastructure, which would support optionality in the future. This pathway is also relevant because renewable gases are the focus of Pillar 2 of the GTP.

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47 For example, it could incentivise excessive forestry planting and planting pines today would not generate substantial offsets by 2050. NZ Insight: Carbon markets, 29 July 2021

48 Rennert, et al. (2022), Comprehensive evidence implies a higher social cost of CO2, available at: https://www.nature.com/articles/s41586-022-05224-9

49 It is unlikely that 100 percent green gases will be used in the gas network before 2035. First Gas states that all gas networks will not be converted to 100 percent hydrogen before 2050. While biogas is constrained by the feedstock availability—biogas potential is only 15.6-19.9 PJ per year. Additionally, 100 percent hydrogen or biogas would also require appliance conversion. Beca (2021), Biogas and Biomethane in New Zealand, available: https://www.beca.com/getmedia/4294a6b9-3ed3-48ce-8997-a16729aff608/Biogas-and-Biomethane-in-NZ-Unlocking-New-Zealand-s-Renewable-Natural-Gas-Potential-Final.pdf; First Gas Group, Bringing Zero Carbon gas to Aotearoa

50 For example, the Reporoa Organics Processing Facility is New Zealand's first large-scale food waste-to-bioenergy facility. It opened in October 2022. https://www.ecogas.co.nz/reporoa

51 Energy Resources Aotearoa, 2022, Fuelling the Energy Transition, A low Emissions Energy Future for New Zealand, available at: https://www.energyresources.org.nz/assets/Uploads/Fuelling-the-Energy-Transition-Full-Report.pdf

3.7 CCUS Pathway

The CCUS Pathway illustrates how the gas sector could evolve if economic CCUS solutions were commercially available in New Zealand. Key parameters under this pathway are:

- Policies and regulations enable CCUS to be used
- CCUS technology is available after 2026
- CCUS technologies are adopted by parts of the gas sector as the least-cost abatement option. This includes gas users that use natural gas for high-heat processes[52], and are therefore unable to switch to alternative energy sources (including methanol, urea, steel, and cement producers), and some natural gas used for electricity generation.[53]

Relevance of CCUS Pathway

This pathway is relevant because CCUS technologies could be the least cost abatement option, especially for large users of natural gas in industry and power generation. CCUS technologies are expected to cost less than fully transitioning to renewables for some industrial processes in New Zealand, such as iron and steel, cement,[54] ammonia, and methanol production. Carbon captured from ammonia production could also be used to produce urea.[55]

[52] High heat users include cement, steel, methanol, urea, electricity generation. Low-medium heat users include food processing, other industry, mining and quarrying, and pulp and paper.

[53] CCUS used by natural gas production facilities is not included in the modelling in this Report.

[54] The use of fossil fuels for heating accounts for 35–40 percent of emissions from cement production. The remainder comes from the calcination of limestone, for which there is no close substitute. This makes CCUS more appealing because it can potentially remove nearly all emissions, not just those from heating.

[55] IRENA, 2021, Reaching Zero with Renewables: Capturing Carbon, available at: https://irena.org/-/media/Files/IRENA/Agency/Technical-Papers/IRENA_Capturing_Carbon_2021.pdf

4 Modelling framework for evaluating pathways

The modelling in this report uses a range of plausible pathways for the gas sector and assesses them against the energy trilemma of sustainability, affordability, and reliability (section 4.1). The energy trilemma framework used in this Report has been tailored to suit the New Zealand context and the scope of this Report (section 4.2). We model the pathways using an economic model that predicts gas demand based on the costs of gas and alternative energy sources for current and predicted potential future users of gas (section 4.3). The key assumptions in the model are detailed in Appendix A.

4.1 Energy trilemma framework

The energy trilemma is a well-understood framework for assessing energy systems against three important dimensions. It is used by the World Energy Council and is referenced by MBIE in GTP Terms of Reference as a guiding framework.[56] The three dimensions of the World Energy Council's trilemma are:

- **Environmental sustainability**—measures the transition of a country's energy system towards mitigating and avoiding potential environmental harm and climate change impacts, including focusing on productivity and efficiency of generation, transmission and distribution, decarbonisation, and air quality
- **Energy equity**—measures a country's ability to provide universal access to affordable, fairly priced, and abundant energy for domestic and commercial use
- **Energy security**—measures a country's capacity to meet current and future energy demand reliably, and withstand and recover from system shocks. This measure considers how effectively energy sources are managed, and the reliability and resilience of energy infrastructure.[57]

Figure 4.1 displays the energy trilemma, indicating how the three dimensions are linked.

[56] MBIE, Gas Transition Plan Terms of Reference, available at: https://www.mbie.govt.nz/dmsdocument/20265-terms-of-reference-gas-transition-plan

[57] Definitions adapted from World Energy Council, World Energy Trilemma Index, available at: https://www.worldenergy.org/transition-toolkit/world-energy-trilemma-index

Figure 4.1: Energy trilemma illustration

Source: Castalia, adapted from World Energy Council

4.2 Adaptations to the energy trilemma framework

We adapted the World Energy Council's framework to focus on affordability, reliability, and sustainability. The interpretations of these three elements for the purposes of this Report are provided below.

Sustainability is measured with reference to GHG emissions

'Sustainability' in this Report refers to the amount of greenhouse gas (GHG) emissions associated with gas use in New Zealand from 2022 to 2035 under each pathway. GHG emissions are expressed as carbon dioxide equivalent (CO_2e). Each pathway has a different emissions profile, based on available energy sources and the rate of switching to lower-cost renewable energy sources, such as renewable electricity, biomass, and renewable gases.[58]

To determine the emissions of each pathway:

- The amount of gas consumed for energy by sector[59] is quantified (in PJ)
- Total gas consumption is then multiplied by the relevant emissions factor—53.29ktCO_2e/PJ for natural gas and 60.43ktCO_2e/PJ for LPG[60]

58 Renewable gases are only available in the Renewable Gas Pathway.

59 Sectors considered are food processing, methanol production, urea production, other chemical production, synfuel production, steel production, cement and lime production, aluminium production, pulp and paper production, mining and quarrying, other industry, agriculture, forestry and fishing, commercial sector, residential sector, electricity generation, and transport.

60 The emissions factors used in this Report are in line with the CCC, Energy and Emissions in New Zealand (ENZ) model, available at: https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/modelling/.
We do not assume a reduction in emissions intensity of natural gas over modelled period, except where renewable gases are blended in the modelled pathways.

– Emissions from the consumption of LPG are not included in the total gas sector emissions,which is consistent with how CCC has treated LPG emissions.[61] However, LPG emissions are just as important for climate change policy objectives[62]
– Emissions from other sources of energy (such as coal and diesel) are not quantified
– Emissions from non-energy use (that is, as a feedstock for methane and urea production) are not included[63]
– Upstream emissions (those associated with natural gas extraction) are also not explicitly calculated due to differences in techniques adopted by each gas producer.[64] Nevertheless, scope one emissions from natural gas extraction, venting and flaring, contributes to New Zealand's gross emissions.[65]

Affordability is measured in terms of the total cost of energy and other costs associated with increasing reliability, blending renewable gasses, and capital costs of CCUS

'Affordability' in this Report refers to the total cost of energy under each pathway. Total costs include the total cost of the energy sources modelled (principally natural gas, biomass, and electricity)[66], any cost of increasing energy reliability to match the current level (see discussion below for 100 Percent Renewable Energy by 2030 Pathway), the costs of blending any renewable gases as well as the estimated costs of CCUS.

It is easier to make cost projections for established technologies than nascent technologies, such as CCUS and renewable gas. The costs for CCUS and renewable gases have been estimated based on detailed research (costs are provided in Appendix A). Renewable gas costs are particularly difficult to estimate because projects have multiple sources of revenue (for example, biogas projects earn money from waste tipping fees, biofertiliser sales, as well as biogas). The sensitivity analysis, provided in section 6, explores how changes to the costs of CCUS and renewable gases impact total energy costs under the CCUS Pathway and the Renewable Gas Pathway.

61 This approach is in line with the CCC's Energy and Emissions in New Zealand (ENZ) model. Using the same approach as the CCC enables pathways to be compared fairly.

62 LPG demand, emissions, and costs are mentioned separately in sections 5.1, 5.2, and 5.3, respectively. Annual LPG consumption is around 200,000t, which produces approximately 500,000t CO_2-e. Gas New Zealand, What We Do, available at: https://gasnz.org.nz/what-we-do#:~:text=LPG%20is%20available%20in%20both,tonnes%20of%20it%20each%20year.

63 Emissions associated with non-energy use are not included in this calculation of emissions from gas use because carbon is embedded in the products (for example, the emissions associated with the production of chemicals). Emissions from urea and methanol occur when the products are applied/used (or in some cases with methanol end-products, never). This approach is in line with the CCC's Energy and Emissions in New Zealand (ENZ) model. Using the same approach as the CCC enables pathways to be compared fairly.

64 Energy Resources Aotearoa's 2022 Report, reports on scope 1 emissions. ERA, Fueling the Energy Transition, available at: https://www.energyresources.org.nz/assets/Uploads/Fuelling-the-Energy-Transition-Full-Report.pdf

65 Fugitive emissions arise from the production, processing, transmission, storage, and use of fossil fuels, and from non-productive combustion. In 2020, fugitive emissions accounted for 4.3 percent of total emissions from the energy sector. Fugitive emissions from oil and natural gas contributed 1,286.1kt CO_2-e, equal to 95.4 percent of total fugitive emissions from the energy sector. Fugitive emissions from solid fuels accounted for 61.4kt CO_2-e, or 4.6 percent of total fugitive emissions from the energy sector, in the same year. Ministry for the Environment (2022), New Zealand's Greenhouse Gas Inventory 1990–2020, available at: https://environment.govt.nz/assets/publications/GhG-Inventory/New-Zealand-Greenhouse-Gas-Inventory-1990-2020-Chapters-1-15.pdf

66 Including the carbon price.

Reliability is measured relative to the current level of energy sector reliability and normalised

'Reliability' in this report refers to the ability of New Zealanders to access energy at the same rate, for the same purposes, and at the same level of reliability as they currently enjoy. In practical terms, this means that current preferences for heating levels and energy demand for cooking in the domestic and commercial sectors will continue. It also means that we assume New Zealand firms will seek to use energy in manufacturing and processing at the same rate, and at the same level of reliability as they currently do.

In the electricity system, natural gas continues to provide energy for dispatchable generation that firms the grid. It is a key energy source for peaking and dispatchable electricity generation plants. Gas-fired generation can be rapidly ramped up to meet peak demand (or provide load when other forms of generation, such as solar photovoltaic (PV) and wind, drop out).[67] Natural gas is also used as a feedstock to produce methanol, fertiliser, and other chemicals[68] , which are respectively key export industries and inputs into domestic agriculture and other industries.

A pathway with less energy reliability will not be a viable least-cost option for New Zealand. This is because New Zealanders are unlikely to accept a pathway that delivers less energy reliability than what is currently enjoyed, and additional unplanned outages and faults associated with less reliability are also likely to be more expensive than retaining current levels of reliability. The modelled pathways are therefore normalised for reliability (that is, delivering at least the same energy reliability as what New Zealanders currently enjoy). This approach focuses the modelling on sustainability and affordability, without compromising New Zealand's energy reliability.

To normalise the reliability variable of each pathway:

- The reliability standard of each pathway was determined and assessed against current standards
- The energy sources that were added to or subtracted from each pathway were reviewed (for example, replacing natural gas generation with new variable renewable solar PV or wind energy generation, or biomass in process heat applications)
- The additional investment (or incurred costs from lost load) needed to match current reliability was then estimated[69] and included in estimates of energy costs.

[67] The growing share of variable renewable electricity sources, such as solar PV and wind, increases the difficulty of balancing supply and demand and ensuring energy reliability.

[68] According to the CCC's modelling, approximately 58 percent (36.1PJ annually) of total natural gas consumed by methanol and urea producers is used for non-energy (i.e., as a feedstock).

[69] The method to estimate the investment required to equalise reliability across all pathways is based on knowledge of current technologies and proposed investments in the energy sector. In the future, however, it is possible that different technologies and a mix of generation, energy storage and demand management (for example, smart grid technology) may be used to improve energy reliability when the grid has a greater share of variable renewable generation. These other technologies and grid-stabilising options may be lower cost.

4.3 Modelling approach predicts gas demand, costs, and emissions

The Castalia Gas 2035 model for this assignment predicts gas demand, emissions, and energy costs for current and predicted future users of gas. The model assumes that gas users (with two sector exceptions) will choose the least-cost energy source each year, considering all economic costs, including capital, operating and carbon costs.

Data is sourced from the CCC's gas sector model, other New Zealand government sources, BusinessNZ's Energy Council, and credible international organisations. Where data is insufficient or not available, we outline our alternative modelling approach.

Step 1—Identifying gas demand

The model begins with recent actual natural gas and LPG consumption data. For the BAU Reference Pathway, we predicted future demand for all sectors and sub-sectors of gas users based on information from the sector workshops, assumptions about future climate and energy policy, and impacts on the sector's investment, production, and supply intentions.

Step 2—Modelling of switching to gas substitutes

We then assess whether different sub-sectors (such as industrial, agriculture, fishery and forestry, residential, and commercial) would switch to an alternative energy source. The switching behaviour depends on relative costs and other behavioural drivers. We use historical data, the econometric relationship between gas consumption and population growth, and relative cost of energy substitutes. The variables that drive switching decisions differ depending on the sector:

- For the industrial sector, switching is driven by the carbon price, capital costs, operational costs and fuel costs adjusted for the efficiency of the gas, biomass, electric and gas appliances (boilers and so on)
- For the agriculture, fishery and forestry sector, switching is driven by the cost of electricity plus the annualised capital costs of new electric appliances
- For residential and commercial sectors, switching is driven by price and non-price switching projections, including the cost of electricity plus the annualised capital costs of new electric appliances
- For electricity generation, switching is policy driven and based on long-run marginal cost (LRMC) of generation methods
- Forced switching under some pathways also occurs, which is not driven by relative costs and other behavioural drivers.

Step 3—Pathway-specific modelling of other mitigants that reduce gas demand

Once we identified the total gas consumption after switching, we applied other mitigants. These include:

- Renewable Gas Pathway—blending of renewable gases. The model replaces the amount of natural gas consumed by different sectors with a maximum of 6.3 percent hydrogen blending (by energy), and a maximum available biogas of 7.7PJ
- CCUS Pathway—application of CCUS. The model assumes that the decision to implement CCUS technology (once it is available) is a function of a carbon price.

Namely, once the carbon price becomes higher than the cost of implementing CCUS, large industrial polluters and energy producers would decide to implement CCUS

- There are no mitigants for the other pathways.

Step 4—Determine the final model outputs

We then calculate the final model outputs. These are provided for the three key impacts:

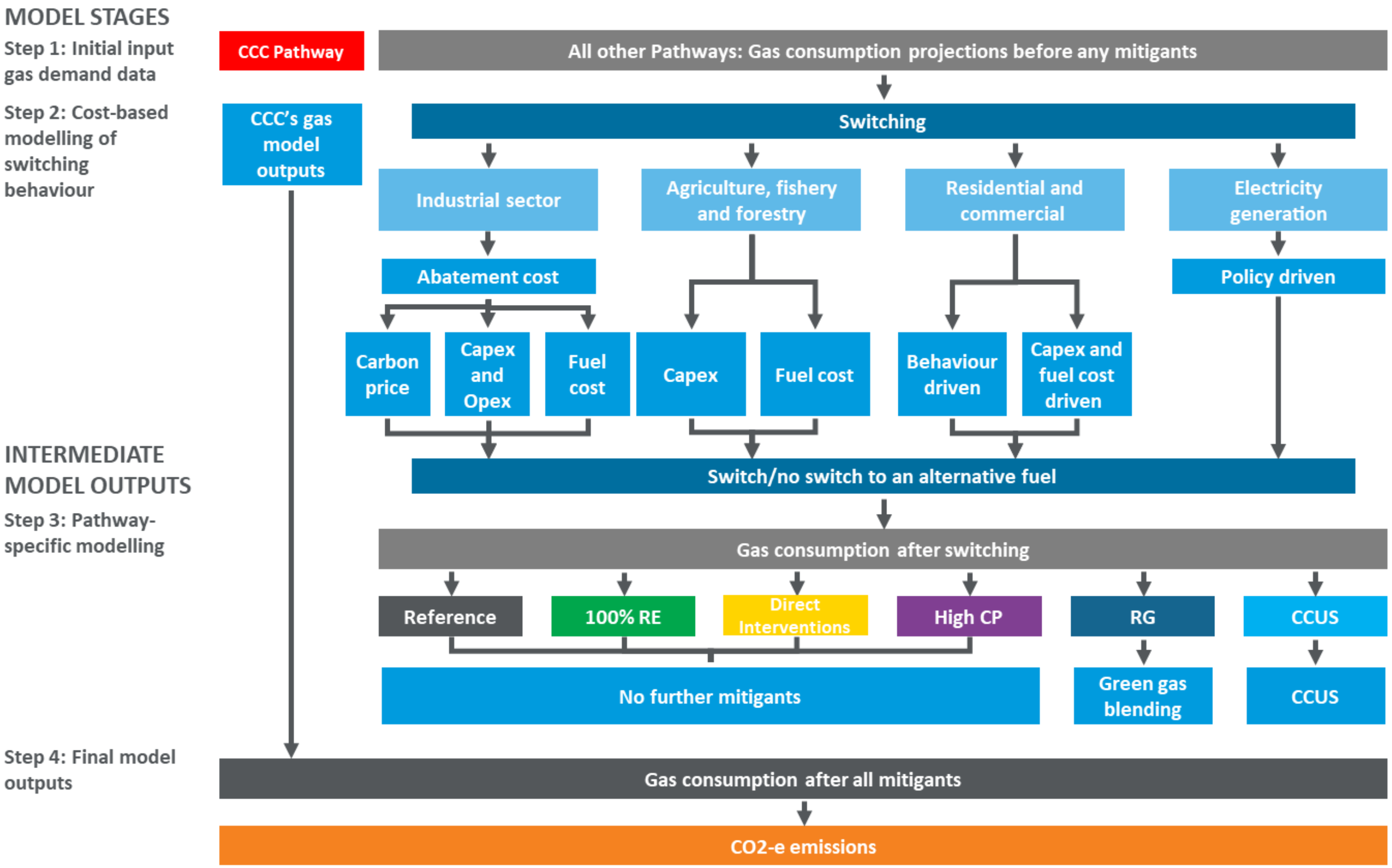
- We estimate the gas consumption for each pathway by summing the final gas consumption of each sector after we applied all mitigants under each pathway
- We calculate CO_2e emissions associated with the consumption of natural gas under each pathway by multiplying gas consumption by the emissions factor associated with the natural gas 53.29ktCO_2e/PJ for natural gas and 60.43ktCO_2e/PJ for LPG.[70] Emissions associated with gas consumption for non-energy use (that is, as a feedstock for methane and urea production) is not included[71]
- We also estimate the total energy costs and any additional costs for each pathway by estimating the total energy demand from gas, electricity, biomass, and other sources and multiplying it by the prevailing energy source cost in the model.

A diagram of the modelling approach is displayed in Figure 4.2. Further detail about the modelling approach, as well as modelling assumptions, is provided in Appendix A.

70 The emissions factors used in this Report are in line with the CCC, Energy and Emissions in New Zealand (ENZ) model, available at: https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/modelling/

71 This approach is in line with the CCC's Energy and Emissions in New Zealand (ENZ) model. Using the same approach as the CCC enables pathways to be compared fairly. Emissions associated with non-energy use are not included because carbon is embedded in the products (for example, the emissions associated with the production of chemicals).

Figure 4.2: Modelling approach diagram



Source: Castalia

Notes: 'Reference' refers to Reference Pathway, 'CCC' refers to CCC Demonstration Pathway, '100% RE' refers to 100 Percent Renewable Electricity by 2030 Pathway, 'Direct Interventions' refers to the Direct Interventions Pathway, 'High CP' refers to High Carbon Price Pathway, 'RG' refers to Renewable Gas Pathway, 'CCUS' refers to CCUS Pathway

5 Modelling results

The pathways modelling predicted gas demand, emissions from gas use, and the total cost of energy for current and potential future gas users.[72] All pathways are compared to the Reference Pathway, as the Reference Pathway represents how the gas sector is predicted to transition under existing and anticipated policy settings (that is, the expected BAU). Demand, emissions, and costs associated with LPG are treated separately, in line with the CCC's modelling.

5.1 Natural gas demand declines across all pathways

The model predicts natural gas demand based on the relative energy cost, including a carbon price and external policy factors in some pathways.

Reference Pathway

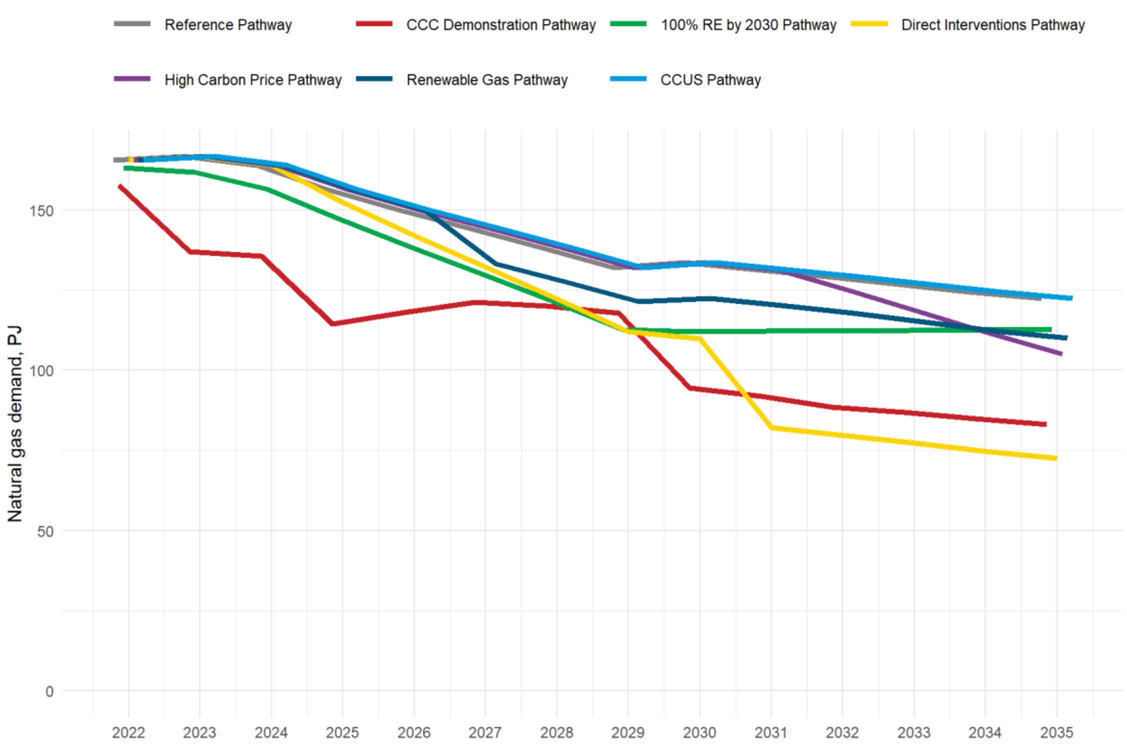
In the Reference Pathway, natural gas demand is 165.6PJ in 2022 and declines to 122.3PJ by 2035. Commercial and residential users and low-medium heat industrial users begin to rationally switch from natural gas when alternative energy sources cost the same or are cheaper than natural gas.[73] This switching occurs progressively as the carbon price increases. Natural gas demand for electricity generation also reduces as the relative cost of renewable electricity generation decreases. This decrease is due to the reduction in the cost of renewable electricity technologies (such as solar PV and wind electricity generation technologies) and the increasing carbon price.

Natural gas demand declines in the six pathways when specific policy choices are modelled. Natural gas demand declines most compared to the Reference Pathways, where natural gas demand is forced out of electricity generation early, or large natural gas users are forcibly switched off. Figure 5.1 illustrates natural gas demand across the six pathways, compared to the Reference Pathway.

[72] Total cost of energy includes the total cost of the energy sources modelled (principally natural gas, biomass and electricity), any cost of increasing energy reliability to match the current level (100 Percent Renewable Energy by 2030 Pathway), and the costs of blending any renewable gases (Renewable Gas Pathway) as well as the estimated costs of CCUS (CCUS Pathway).

[73] The modelling accounts for some stickiness by using a price buffer.

Figure 5.1: Comparison of natural gas demand across pathways from 2022 to 2035



Note: The data for each pathway was offset slightly to show overlapping data at the same time.
Source: Castalia modelling

CCC Demonstration Pathway results in a rapid decline in natural gas demand

CCC Demonstration Pathway results in a rapid decline in natural gas demand, relative to the Reference Pathway. However, the CCC's assumptions about natural gas demand in *Ināia tonu nei* are either outdated or unrealistic based on current information. The CCC predicts that natural gas demand in 2021 is 149.8PJ. However, actual demand in 2021 was 154.97PJ.[74] The CCC's other assumptions in its demonstration path were unchanged in the modelling. The reduction in natural gas demand in the CCC Demonstration Pathway hinges on the CCC's expectation that there will be a significant demand reduction from commercial and residential users. CCC also assumed that Methanex would reduce demand and close by 2040, that the Tiwai Point aluminium smelter will close by 2024, and that there will be restrictions on the sale or replacement of natural gas appliances. The CCC also assumed that Marsden Point oil refinery would stay open. These assumptions have been surpassed by actual events and corporate decisions.

[74] In our modelling, natural gas demand under the CCC Demonstration Pathway was adjusted upwards to 154.97PJ in 2021, in line with actual natural gas demand in 2021. However, the other assumptions in the CCC's demonstration path (outlined in Ināia tonu nei) remain unchanged.

MBIE Gas statistics, available at: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/

100 Percent Renewable Electricity by 2030 Pathway shows rapid decrease in natural gas demand to 2030, but levels off to 2035

Natural gas demand under the 100 Percent Renewable Electricity by 2030 Pathway rapidly decreases to 2030 because zero natural gas is used for electricity production after 2030. From 2030 to 2035, natural gas demand from industrial, commercial, and residential users is expected to be the same as the Reference Pathway, which includes some switching to biomass and electrification.

Direct Interventions Pathways has a similar gas demand profile to the Reference Pathway to 2024, but then diverges

The Direct Interventions Pathway has similar natural gas demand as the Reference Pathway until 2024, at which point low-medium heat industrial users switch to biomass and electricity for energy, and no new residential or commercial gas connections are permitted. Natural gas demand significantly decreases after 2030 as natural gas is phased out partially in methanol production (the largest consumer of natural gas) and entirely in urea production. Methanol production retains natural gas for feedstock but switches to electricity for process heat. Urea production switches to green hydrogen and biogenic carbon for feedstock, and electricity for process heat. After 2030, natural gas is only used as a feedstock for methanol production, in select high-temperature industrial applications (steel, cement, and lime production), for electricity generation, and by commercial and residential users (but with no growth in demand). Under this pathway, natural gas demand in 2035 is less than 72.5PJ, which is lower than that of all other pathways.

Natural gas demand under the High Carbon Price Pathway decreases relative to the Reference Pathway after the carbon price exceeds \$200 per tCO_2e

The High Carbon Price Pathway has the same natural gas demand as the Reference Pathway until 2030, after which natural gas demand declines as alternative energy sources become cheaper than the cost of natural gas and carbon for some users. Natural gas users can tolerate an increase in natural gas and carbon prices up to around \$200 per tCO_2e because natural gas is relatively competitive against alternative energy sources, and there is a high cost associated with switching. Abatement costs are cheaper than alternative energy sources for most users when the carbon price is around (or lower than) \$200 per tCO_2e.[75] After the carbon price exceeds \$200 per tCO_2e (which occurs in 2031), natural gas demand from low-medium heat processing decreases because biomass becomes cheaper.[76] Demand for natural gas from high-temperature industrial users continues after 2031, as these users are willing to pay higher costs, and there is a lack of alternatives. Demand from residential and commercial users also continues because the cost of electricity and capital costs associated with switching (such as for appliances) are higher than continuing to use natural gas.

[75] This finding is consistent with other modelling, such as by Transpower, which identified that 'a carbon price of \$200 per tonne of CO_2e is needed to replace a gas boiler for medium temperature heat (100-300°C) early.' Included in Energy Resources Aotearoa, 2022, Fuelling the Energy Transition, A low Emissions Energy Future for New Zealand, available at: https://www.energyresources.org.nz/assets/Uploads/Fuelling-the-Energy-Transition-Full-Report.pdf

[76] There is limited switching to electricity because the high carbon price increases the cost of electrification.

Gas demand decreases under the Renewable Gas Pathway after renewable gases are blended into the network

Renewable Gas Pathway

The Renewable Gas Pathway has the same natural gas demand as the Reference Pathway to 2026, after which renewable gases are blended with natural gas, and demand for gas subsequently declines. Demand for gas decreases because renewable gas costs increase the total cost of gas. Commercial and residential, and low-medium heat industrial users, therefore progressively switch to cheaper energy sources. This pathway also results in decreased demand for gas for electricity generation, as renewable electricity generation becomes more economical. After 2026, gas is largely used for electricity generation and high-temperature heat processes. High-temperature heat users (such as chemical and steel production) do not have viable alternatives and are therefore willing to pay higher costs.

CCUS Pathway results in the same gas demand as the Reference Pathway

CCUS Pathway

Under the CCUS Pathway, natural gas demand is the same as in the Reference Pathway. Natural gas demand does not decline, even when costs associated with CCUS technologies are factored into users' energy costs. CCUS is most viable for capturing point-source emissions from large users. When CCUS becomes available in 2026, large industrial users (such as Methanex and Ballance) start investing in CCUS technologies because investing in CCUS is cheaper than paying the carbon price associated with natural gas. Other large users (such as NZ Steel, and users of natural gas for cement production and electricity generation) start investing in CCUS technologies in later years as the carbon price rises.

LPG demand under the Renewable Gas Pathways deviates most significantly from the Reference Pathway

The model predicts LPG demand based on the relative cost of energy, including a carbon price, and in some pathways external policy factors.[77] Figure 5.2 illustrates LPG demand across the six pathways, compared to the Reference Pathway.

LPG demand under the Reference Pathway increases slightly across the modelled period, increasing from 9.4PJ in 2022 to 10.1PJ by 2035. Demand from high heat industrial processes remains consistent over the period. This is because biomass or electricity is only viable as an energy source for medium to low heat processes. LPG cannot be substituted easily for high-heat processes where a high burn temperature is needed, or where mobility of the energy source is prized. Providing high temperatures with electricity or biomass is very expensive and often impractical. However, low-medium heat processing switches from LPG to alternative energy sources such as biomass and electricity. This switching occurs quickly, as the cost of using electricity is already less than the cost of LPG for certain sectors.[78] LPG demand from other sectors increases slightly due to population growth and a lack of switching. Existing LPG users in the agriculture, fishing and forestry, residential and commercial, and transport sectors do not switch to alternative energy sources due to the higher costs (including the cost of new electric appliances) relative to the price of LPG.

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77 LPG demand is measured separately from natural gas demand and is therefore modelled separately.

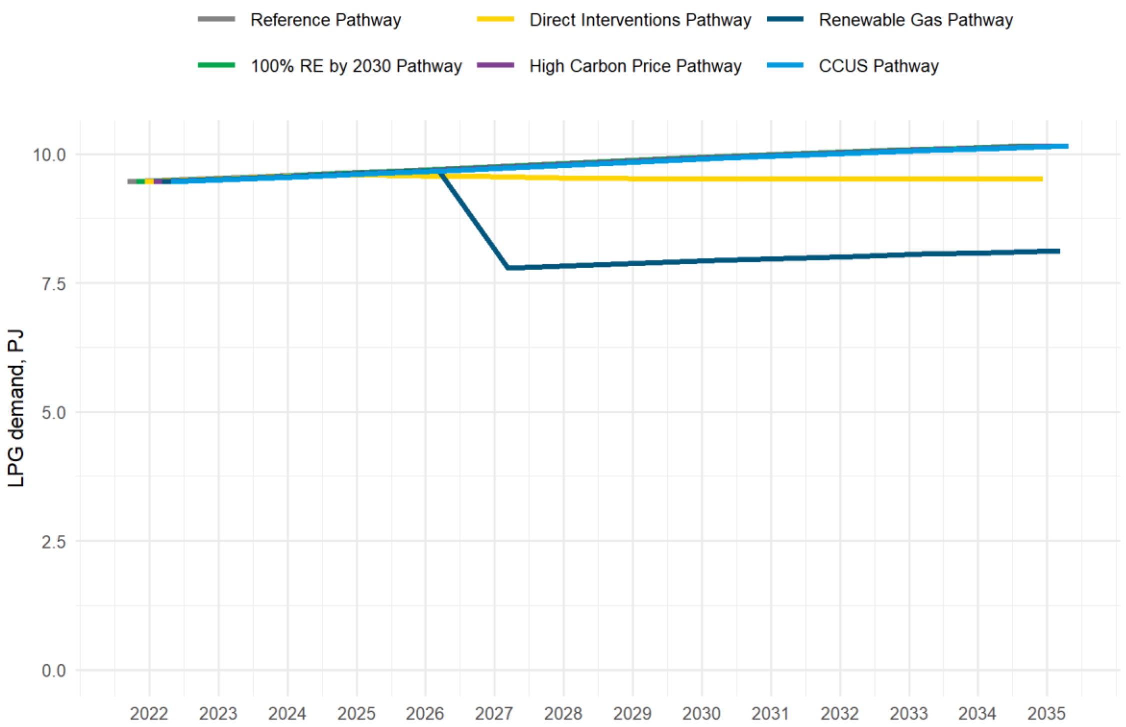
78 It is assumed that 26 percent of LPG demand is by low-medium heat processing. Source: EECA, Energy End Use Database, available: https://www.eeca.govt.nz/insights/data-tools/energy-end-use-database/

LPG demand under the 100 Percent Renewable Electricity Pathway, the High Carbon Price Pathway, and the CCUS Pathway is the same as the Reference Pathway. LPG users follow the same behaviour as users under the Reference Pathway. LPG demand is not included in the CCC's Demonstration Pathway, and is therefore not modelled.

LPG demand under the Direct Interventions Pathway is slightly lower than the Reference Pathway. The trajectory of LPG demand deviates from the Reference Pathway from 2025, as low-medium heat process users are progressively forced to switch to biomass and electricity for energy, and no new residential or commercial LPG connections are permitted from 2025. It is unclear from available data the exact proportion of LPG that is used by low-medium heat processes and the proportion that is used by high heat processes. LPG demand (and associated emissions) under the Direct Interventions Pathway may be higher or lower than the modelled results.

LPG demand under the Renewable Gas Pathway deviates most from the Reference Pathway (13 percent less than the total demand under the Reference Pathway). Demand for LPG under the Renewable Gas Pathway falls significantly after 2026, as bioLPG is blended with LPG. Blending makes LPG more expensive than biomass and electricity, which encourages more LPG users to switch to cheaper energy sources.

Figure 5.2: LPG demand under modelled pathways



Note: LPG demand is not included in the CCC's Demonstration Pathway, and is therefore not modelled.
Source: Castalia modelling

5.2 Emissions reductions appear greatest if large downstream gas users are forcibly switched off or targeted CCUS is available

The model predicts greenhouse gas emissions from gas consumption. This is driven by the gas demand model outputs. Emissions from natural gas used as a feedstock for methane and urea production are not included.[79] Emissions associated with the production of natural gas, fugitive emissions from natural gas transmission and distribution, emissions from other areas of the economy, or emissions removals from land-use change and forestry are also not included.

Reference Pathway

In the Reference Pathway, emissions are 6.7MtCO_2e in 2022 and decline to 4.3MtCO_2e by 2035. An increase in the carbon price and advances in renewable electricity technologies (such as the efficiency of solar PV and wind electricity generation technologies) make natural gas relatively more expensive than alternative energy sources. Commercial and residential users, and low-medium heat industrial users, rationally switch from natural gas when alternative energy sources cost the same or are cheaper than natural gas.[80]

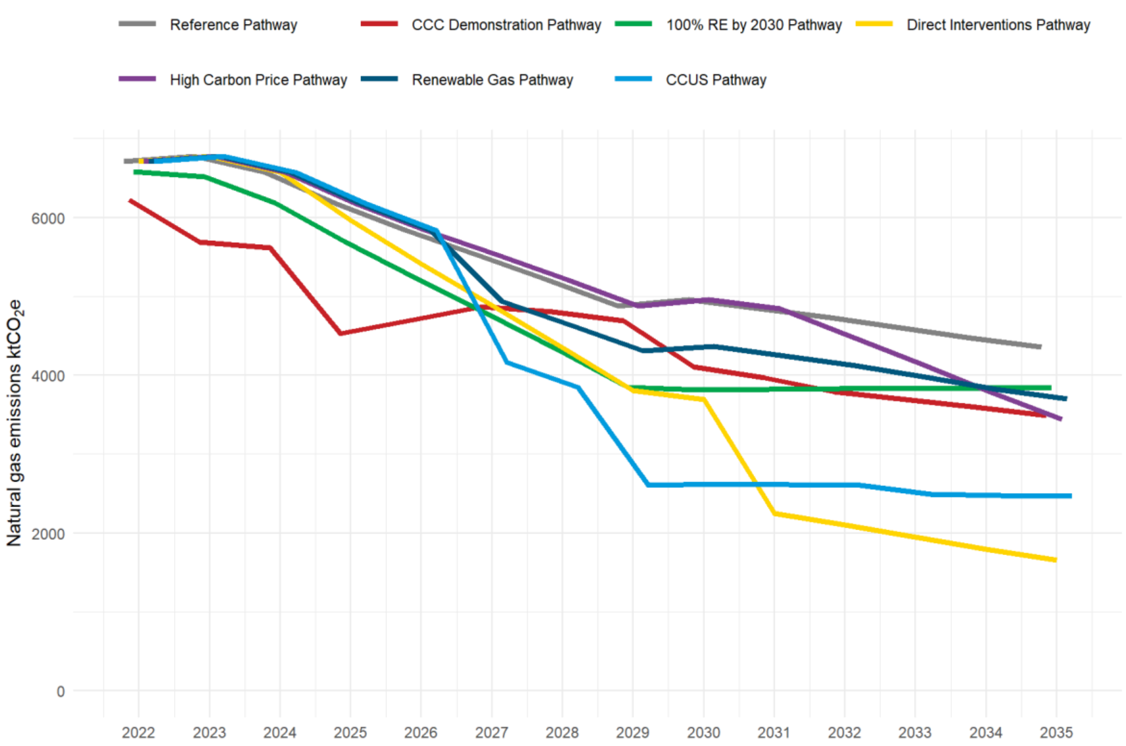
Emissions decline further than the Reference Pathway (in line with declining natural gas demand) in the six pathways, when specific policy choices are modelled. Emissions reduce much below the Reference Pathway where technological advances (CCUS) enable emissions from large downstream natural gas users to be captured, or where large users are forced to switch away from natural gas due to policy decisions. However, significantly higher costs are expected under some pathways (discussed in 5.3), so emissions reduction results should be interpreted carefully. Figure 5.3 below shows the emissions under the six pathways, compared to the Reference Pathway.

The analysis in this section acknowledges the time value of carbon. That is, reducing a tonne of emissions today has more impact than reducing a tonne of emissions at some point in the future. Sensitivity analysis on the time value of carbon (using a discount rate) is explored in section 6.6.

[79] Emissions associated with non-energy use are not included because carbon is embedded in the products (for example, the emissions associated with the production of chemicals). This approach is in line with the CCC's Energy and Emissions in New Zealand (ENZ) model. Using the same approach as the CCC enables pathways to be compared fairly.

[80] The modelling accounts for some stickiness by using a price buffer.

Figure 5.3: Comparison of emissions from natural gas use across pathways from 2022 to 2035

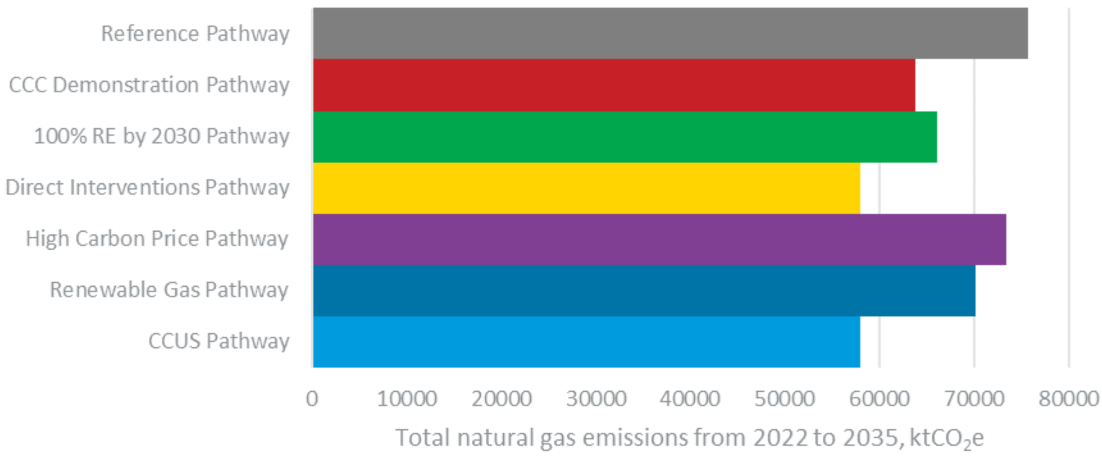


Source: Castalia modelling
Note: Emissions are directly correlated with downstream gas demand, and do not include emissions from upstream or midstream sectors. The data for each pathway was offset slightly to show overlapping data at the same time.

Figure 5.4 below shows the total amount of emissions under each modelled pathway between 2022 and 2035, compared to the Reference Pathway. The total amount of emissions is the key metric to evaluate a pathway's sustainability.[81]

[81] A discounted total amount of emissions could better reflect the actual impact of emissions due to the time value of carbon. However, for the purpose of this report, a simple sum is used to align with figures used by the CCC. Section 6 explores the impact of applying a discount rate to emissions.

Figure 5.4: Comparison of total emissions across pathways from 2022 to 2035



Source: Castalia modelling

CCC Demonstration Pathway results in rapid reduction in emissions

The CCC Demonstration Pathway results in the rapid reduction of emissions relative to the Reference Pathway (16 percent reduction over the modelled period). Emissions under the CCC Demonstration Pathway are modelled to peak in 2022, and then decline in line with the CCC's assumptions about declining natural gas demand (see section 5.1). The emissions reduction associated with the CCC Demonstration Pathway is implausible, given some of the CCC's assumptions are out of date (surpassed by actual events), or are unrealistic based on current information.

Emissions reduction occurs sooner in the CCC Demonstration Pathway relative to other pathways. Due to the time value of carbon, an earlier reduction in emissions could make the CCC Demonstration Pathway more effective at mitigating the impacts of emissions, as opposed to reducing the total amount of emissions over the whole period. However, accounting for the time value of carbon does not make the CCC Demonstration Pathway better for total emissions than the CCUS Pathway or the Direct Interventions Pathway. A discount rate is applied to the emissions under each pathway in section 6.6.

100 Percent Renewable Electricity by 2030 Pathway results in a steady decrease in emissions to 2030, but levels off to 2035

The 100 Percent Renewable Electricity Pathway results in a steady decline of emissions relative to the Reference Pathway (13 percent reduction compared to the Reference Pathway over the modelled period). Emissions steadily decline between 2022 and 2030, as renewable electricity generation increases, and demand for natural gas for electricity generation reduces to zero. After 2030, emissions under this pathway are attributed to ongoing demand from industrial, and commercial and residential natural gas users. This demand is expected to be the same as the Reference Pathway, that is, some rational switching occurs when alternative energy sources (biomass and electrification) cost the same or are cheaper than natural gas.

The 100 Percent Renewable Electricity Pathway reduces significant emissions associated with electricity generation. However, this pathway may result in higher national net emissions as it is expected to make electrification in other sectors more expensive.

Direct Interventions Pathway reduces emissions most, but results in high energy and economic costs

The Direct Interventions Pathway reduces the most amount of emissions, relative to the Reference Pathway (23.4 percent reduction) over the modelled period. Emissions are the same as the Reference Pathway to 2025, at which point gas demand from low-medium heat processes is progressively switched off until 2030, when all low-medium heat processes are using either biomass or electricity.[82] After 2030, emissions drop rapidly, as the natural gas supply to Ballance's Kapuni facility stops completely (and alternative feedstock and heat process technologies are used), and the natural gas supply for Methanex's heat processing also ceases (and electricity is used as a replacement).[83] In 2035, emissions are expected to decline by 40.8 percent relative to the Reference Pathway, with natural gas demand being less than 72.5PJ. More electricity is demanded under this pathway because electricity replaces natural gas for heat processes in methanol and urea production. This would increase gas used in electricity generation (given the assumed energy mix), which would increase emissions from electricity generation.

Emissions reduce under the High Carbon Price Pathway after 2031, when abatement costs exceed the cost of biomass

The High Carbon Price Pathway results in the same emissions reduction as the Reference Pathway until 2031, as natural gas demand remains consistent. After 2030, when the abatement costs associated with natural gas exceed the cost of alternative energy sources, natural gas demand declines, resulting in more rapid emissions reduction. Emissions after 2031 are predominantly associated with electricity generation and high-temperature industrial users, the latter of whom are willing to pay higher costs for natural gas due to a lack of alternatives. This pathway results in a three percent reduction of emissions relative to the Reference Pathway over the modelled period.

Emissions reduce under the Renewable Gas Pathway after 2026, relative to the Reference Pathway

The Renewable Gas Pathway results in the same emissions reduction as the Reference Pathway to 2026, after which emissions reduce rapidly. This results in commercial and residential, and low-medium heat industrial users to progressively switch to cheaper energy sources. Demand for gas for electricity generation also declines as renewable electricity generation becomes the cheaper option, but a large portion remains. Emissions after 2026 are predominantly associated with electricity generation and high-temperature industrial users. The latter see their share of total emissions rise because they are willing to pay higher costs for gas due to a lack of alternatives. This pathway results in a seven percent reduction of emissions relative to the Reference Pathway over the modelled period.

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82 Where switching is viable, the model switches 50 percent of users to biomass and 50 percent to electricity. This approach takes into account the limits on biomass supply as well as some users preferring the certainty that electrification provides.

83 It is assumed that Methanex continues to use natural gas as a feedstock after 2030 under the Direct Interventions Pathway.

CCUS Pathway reduces the second most amount of emissions, but does not incur significant GDP loss

The CCUS Pathway has the same natural gas demand profile as the Reference Pathway, however, emissions are significantly lower than the Reference Pathway because emissions from large natural gas users are captured and utilised and/or stored. Under the CCUS Pathway, emissions are 23.4 percent lower than the Reference Pathway over the modelled period. The CCUS Pathway results in lower emissions from industry and electricity generation, compared to the Reference Pathway, as CCUS is likely to be the most economical where point-source emissions can be captured. Large industrial users, such as Methanex, Ballance, NZ Steel, and electricity generators, start investing in and using CCUS technologies after 2026, once CCUS is available. Between 2022 to 2035, the CCUS Pathway has 30 percent less emissions from industry and 19 percent less emissions from electricity generation, compared to the Reference Pathway.

The emissions reductions potential of the CCUS Pathway is highly dependent on the availability of effective CCUS technology for large emitters. CCUS is not yet commercially demonstrated in New Zealand at the scale needed. Several New Zealand geothermal energy generators are preparing trials for CO_2 capture and injection.[84] Opinions vary on the readiness of CCUS, whether it is permanent, and the full costs of deploying it in New Zealand. The model uses a range of up-to-date information as inputs to provide a reasonable view of what could happen with CCUS technology. The modelling assumes that CCUS will be available from 2026. This is an ambitious assumption; however, it is not implausible, particularly if New Zealand has permissive policy settings. Box 7.1 provides more information on the state of CCUS technologies.

The CCUS Pathway has fewer emissions reduction benefits than the later CCUS is available. Section 6.3 provides a sensitivity analysis of how changes to the availability and cost of CCUS impact emissions and costs associated with this pathway. It shows that if CCUS were first available by 2030, 2031, and 2033, the CCC Demonstration Pathway, the 100 Percent Renewable Energy by 2030 Pathway, and the Renewable Gas Pathway could lead to lower emissions than that of the CCUS Pathway, respectively.

Renewable LPG could be an effective decarbonisation route

The model predicts greenhouse gas emissions from LPG consumption. This is driven by the LPG demand model outputs. Figure 5.5 shows LPG emissions under modelled pathways.

In the Reference Pathway, emissions from LPG consumption increase slightly over the modelled period, that is, 572ktCO_2e in 2022 and 613ktCO_2e by 2035. Emissions increase slightly due to increased demand (discussed in Section 5.1).

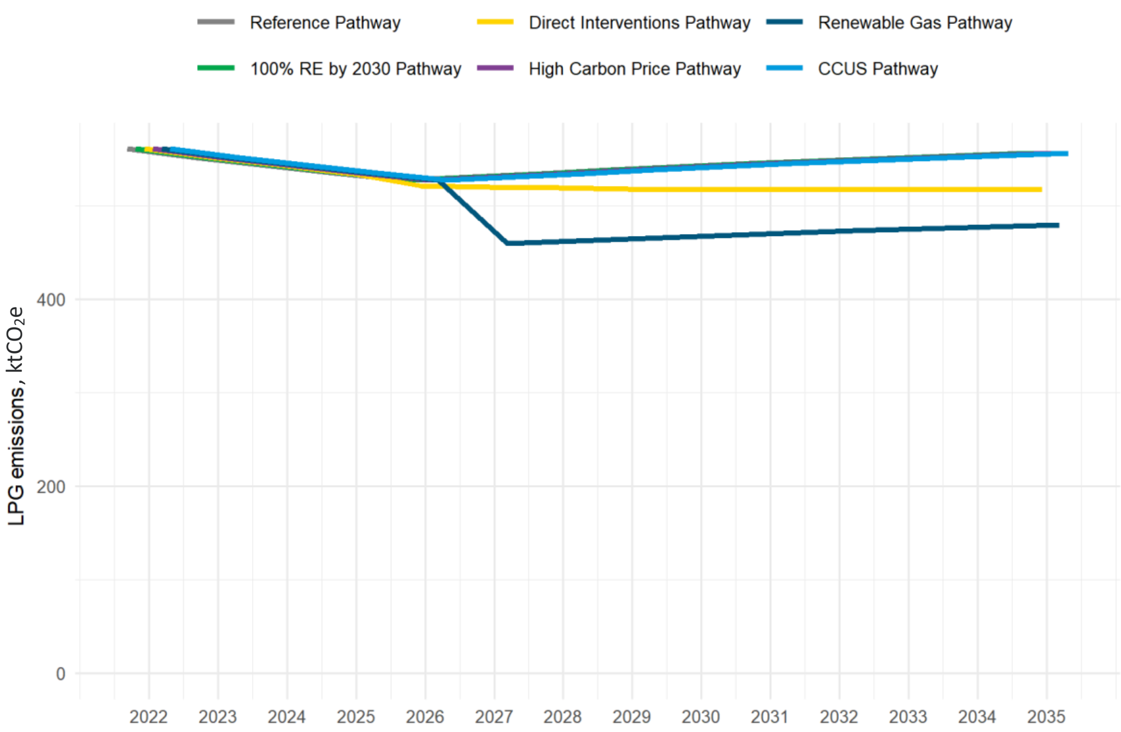
Emissions associated with LPG consumption under the 100 Percent Renewable Electricity by 2030 Pathway, the High Carbon Price Pathway, and the CCUS Pathway are the same as the Reference Pathway because LPG users follow the same consumption behaviour as users under the Reference Pathway. LPG demand is not included in the CCC's Demonstration Pathway, therefore, emissions are not included as part of emissions from natural gas users. Emissions from LPG consumption under the Direct Interventions Pathway are slightly lower than the

[84] Ara Ake (2022), Carbon Dioxide Removal and Usage in Aotearoa New Zealand, available at: https://www.araake.co.nz/assets/Uploads/Ara-Ake-Report-Carbon-Dioxide-Removal-and-Usage-in-Aotearoa-New-Zealand.pdf?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

Reference Pathway. This is due to forced switching and a ban on new residential or commercial LPG connections over the modelled period.

Emissions from LPG consumption under the Renewable Gas Pathway deviate most from the Reference Pathway (8.8 percent less than total LPG emissions under the Reference Pathway). Emissions under the Renewable Gas Pathway fall significantly after 2026, as bioLPG is blended with LPG. Blending makes LPG more expensive than biomass and electricity, which encourages more LPG users to switch to cheaper energy sources. The hurdles associated with substitution of LPG for its particular use cases suggest that using renewable LPG (such as bioLPG) could be the most effective decarbonisation route.

Figure 5.5: LPG emissions under modelled pathways



Source: Castalia modelling
Note: LPG demand is not included in the CCC's Demonstration Pathway.

5.3 Energy costs could be minimised by early investment in CCUS technologies

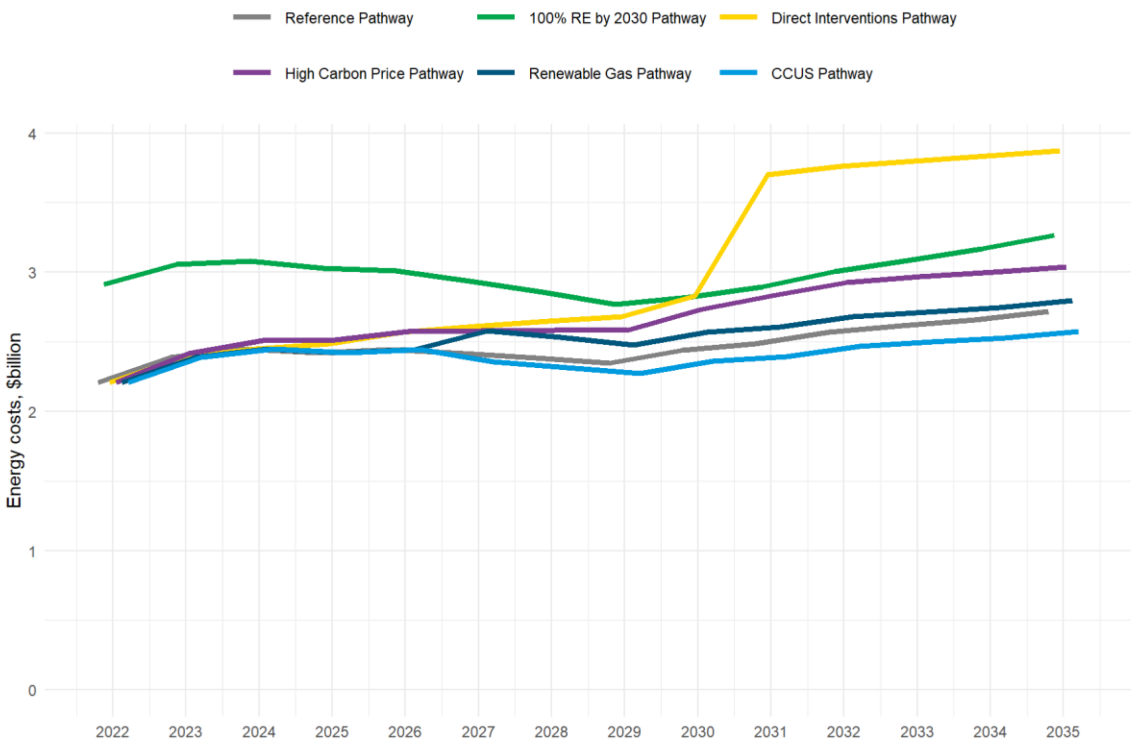
The model predicts energy costs based on the total cost of the energy sources modelled (principally natural gas, biomass, and electricity), any cost of increasing energy reliability to match the current level (100 Percent Renewable Energy by 2030 Pathway), the costs of blending any renewable gases (Renewable Gas Pathway), and the estimated costs of CCUS (CCUS Pathway). This analysis of costs does not consider the dynamic economic effects of increasing energy costs. For instance, a firm's rising energy costs due to a rising carbon price added to natural gas costs, or switching to alternative energy sources, might make it uncompetitive in global markets, meaning it reduces energy consumption or exists the market.

In the Reference Pathway, energy costs increase from $2.2 billion in 2022 to $2.7 billion in 2035. Total energy costs gradually increase over the modelled period as the carbon price rises, impacting both natural gas prices and electricity prices.

The cost of energy varies greatly across the six pathways when specific policy choices are modelled. Energy costs are higher compared to the Reference Pathway where significant investment is required to supplement reliability, when users are forced to switch to higher cost energy sources, and when the carbon price is higher. High energy costs under the Direct Interventions Pathway (due to forced switching to higher cost energy sources) and the High Carbon Price Pathway (due to an increasing carbon price) may result in industrial producers exiting the market, if the cost of decarbonisation makes products globally uncompetitive. A reduction in energy use and closure of strategic industry would have significant negative economic impacts on New Zealand (discussed in detail below). In the CCUS Pathway, the cost of deploying CCUS is lower than paying the carbon price for large emitters.

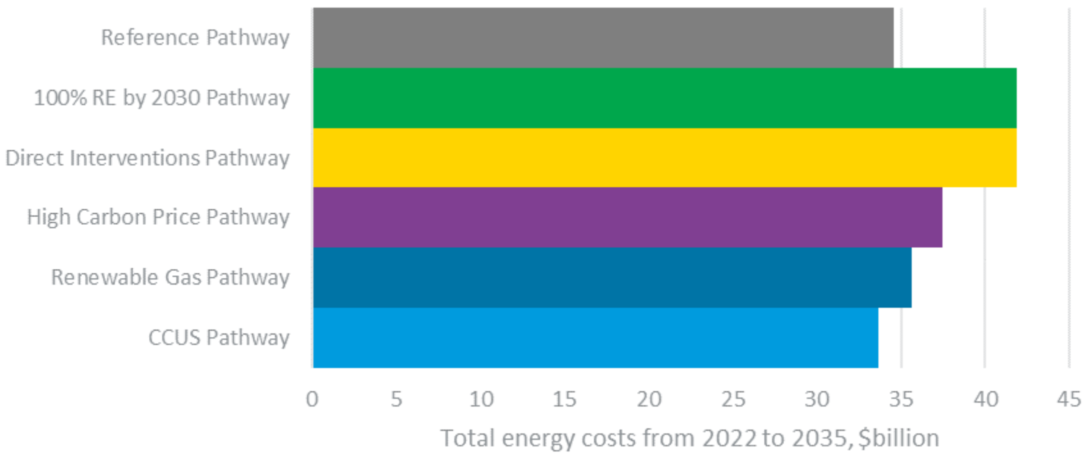
Figure 5.6 shows the pathways' energy costs over the modelled time period (2022 to 2035) compared to the Reference Pathway, with the exception of the CCC Demonstration Pathway. Figure 5.7 compares total costs across the pathways compared to the Reference Pathway.

Figure 5.6: Comparison of energy costs across pathways from 2022 to 2035



Note: Includes adjustment for reliability and CCUS costs. The data for each pathway was offset slightly to show overlapping data at the same time. The CCC Demonstration Pathway costs could not be modelled due to a lack of published data from CCC.
Source: Castalia modelling

Figure 5.7: Comparison of total energy costs across pathways from 2022 to 2035



Note: The cost associated with the CCC Demonstration Pathway was not modelled due to insufficient publicly available information.
Source: Castalia modelling

CCC Demonstration Pathway costs could not be modelled but are probably higher than most pathways modelled

The CCC did not disclose the full energy costs of its demonstration path of energy sector transition. Castalia is unable to replicate the modelling that would allow like for like comparison with other pathways, due to differences in assumptions and uncertainty about cost calculations.

However, the CCC Demonstration Pathway is likely to impose higher costs on New Zealand than most of the pathways modelled in this assignment. For instance, the CCC's final report *Ināia tonu nei* suggested that under its demonstration path, phasing out natural gas and LPG space and water heating systems (replaced with electric alternatives) by 2050 would incur a net cost averaging around $200 million per year out to 2050 (excluding the emissions reduction benefits). It also stated that a full transition away from using coal, natural gas, and diesel to generate heat in the food processing sector by 2050 would lead to net costs on the order of $200 million per year by 2035, largely due to higher fuel costs. This is because conversion to biomass or electric boilers means using a more expensive fuel without any significant energy efficiency gain.[85]

100 Percent Renewable Electricity Pathway is a high-cost pathway

100 Percent Renewable Electricity Pathway costs $41.9 billion between 2022 and 2035 (or 21.3 percent more than the Reference Pathway). It is the most expensive pathway modelled (closely followed by the Direct Interventions

[85] Climate Change Commission, 2021, 'Ināia Tonu Nei: A Low Emissions Future For Aotearoa', p.144-145 Available at: www.climatecommission.govt.nz/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf

Pathway) and is expected to increase energy costs for the country as a whole (rather than just for particular sectors).

The high cost of the 100 Percent Renewable Electricity by 2030 Pathway is primarily due to the cost of additional investments required to ensure energy reliability. Additional renewable energy generation investment is required (often called ‘overbuild’). Estimates of the overbuild and storage required have been used to identify the additional energy costs of $3.7 billion for 1,174MW of renewables and 500MW of batteries and extra demand response and shortage.[86] Even with such overbuild, it is likely that some users will still experience non-supply and unplanned outages, due to a lack of available generating capacity, as additional investment in renewables would not be cost recovering.[87] Additional costs associated with non-supply or unplanned outages are estimated at $242.8 million per year. This additional cost is included in the total cost of this pathway.

The modelling also considers alternative options to improve the reliability of the energy supply. These options include the Lake Onslow pumped hydro storage and hydrogen storage. Similar to the overbuild option, these options require large investments but do not necessarily eliminate the non-supply issue.[88]

Direct Interventions Pathway is also high-cost, especially after industrial users are forced to switch

The Direct Interventions Pathway costs $41.8 billion between 2022 and 2030, (or 21.2 percent more than the Reference Pathway). Total energy costs increase between 2022 and 2030 due to forced rapid switching to biomass and electrification for low-medium heat processes, which are more expensive than natural gas. After 2030, costs increase steeply because Methanex and Ballance’s Kapuni facilities are forced to switch to green processes. Both Methanex and Ballance switch to electricity for process heat. Ballance also switches from natural gas to green hydrogen and biogenic carbon for feedstock. The modelling suggests that, between 2031 and 2035, Methanex incurs costs averaging $1.49 billion per year while Ballance incurs costs averaging $270 million per year. For Methanex, the switch to electricity for process heat contributes around 70 percent of the cost, while natural gas feedstock contributes around 30 percent of the cost. For Ballance, the switch to using green hydrogen for feedstock contributes around half of the cost, while the switch to using electricity for process heat contributes the other half. The costs are estimates, informed by other Castalia modelling for the New Zealand government and assumptions about alternative (but as yet untested) production processes.

As methanol and urea are globally traded commodities, the products must match global prices. Very high energy costs for Methanex and Ballance may force them to reduce production, or exit the market rather than switching partially (Methanex) or fully (Ballance) to decarbonized energy and feedstock sources. A reduction in energy use and closure of strategic industry would have significant negative economic impacts on New Zealand. These negative impacts are difficult to quantify but are likely substantial. For example, foregone economic activity

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[86] The ICCC (2019), Electricity Market Modelling 2035, available at: https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Advice-to-govt-docs/ICCC-electricity-modelling-reports.pdf

[87] The ICCC (2019), Electricity Market Modelling 2035, available at: https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Advice-to-govt-docs/ICCC-electricity-modelling-reports.pdf
The amount of non-supply is estimated at approximately 4,000MWh annually, and there is an annual need for over 8,000MWh of DSR.

[88] The ICCC (2019), Electricity Market Modelling 2035, available at: https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Advice-to-govt-docs/ICCC-electricity-modelling-reports.pdf

(GDP) and employment, import substitution, undermining the role of key demand in underpinning gas supply, and emissions leakage. These impacts are discussed in Box 5.1 below. The Direct Interventions Pathway (and also the High Carbon Price Pathway, discussed below) should be viewed in the context of these likely economic impacts.

Box 5.1: Economic impacts of the Direct Interventions Pathway on New Zealand

The Direct Interventions Pathway may result in Methanex closing its three methanol production plants and Ballance closing its Kapuni urea production plant. This is due to forced switching after 2030 to electrification for heat processes for all four facilities, and forced switching to green hydrogen and biogenic carbon for feedstock for Kapuni. These four plants are all located in Taranaki.

While these closures would lead to lower domestic emissions and cost of energy for gas users, they are also likely to lead to lower economic outputs than other modelled pathways. Loss of strategic industry is also possible under the High Carbon Price Pathway, but is not expected under the other modelled pathways.

Measuring the foregone economic output is difficult because the economy is dynamic. A Methanex-commissioned report estimated that Methanex contributes $834 million per year to New Zealand's GDP.[89] No equivalent figure is available for Ballance.

If Methanex and Kapuni close, the following five factors may contribute to lower GDP for New Zealand:

Lower wages

Existing workers would become redundant, reducing wages. While some workers may be able to earn a similar amount at another job, most workers are likely to earn less. According to Energy Resources Aotearoa, oil and gas sector workers earn twice New Zealand's average salary.[90] In the absence of gas sector jobs, workers are likely to see their income drop. Between 2018 and 2022, Ballance paid personnel expenses averaging $86.2 million per year.[91] Methanex has over 240 full time equivalent employees in New Zealand,[92] while Ballance has over 700.

Skilled labour may leave New Zealand, leading to lower productivity and innovation. The concentration of impacts in Taranaki is likely to increase regional inequities.

Higher import costs

Urea and methanol would not be produced domestically, increasing import costs. Domestic users of urea and methanol would need to import urea, methanol, or their substitutes. The import cost includes both the international market price for urea and methanol as well as the transport costs required to ship them to New Zealand. Users of urea, including ammonia-based fertilisers, would bear the brunt of this cost because all urea produced in New Zealand is consumed domestically.[93] There would likely be a smaller impact on methanol users because 95 percent of all domestic methanol production is exported.[94]

Lower corporate profits

Profits created by Methanex and Ballance would be lost or reduced. Between 2018 and 2022, Ballance made an average pre-tax profit of $24.3 million per year.[95] The closure of Kapuni would reduce these

[89] Methanex, About Methanex in NZ, available: https://www.methanex.com/location/new-zealand/about-methanex-nz

[90] Energy Resources Aotearoa, The importance of oil and gas to New Zealand, available: https://www.energyresources.org.nz/oil-and-gas-new-zealand/the-importance-of-oil-and-gas-to-the-new-zealand-economy/

[91] Ballance, Annual Reports, available: https://ballance.co.nz/annual-report

[92] Methanex, New Zealand: working in NZ, available: https://www.methanex.com/location/new-zealand/working-nz

[93] Rural Delivery (2013), Kapuni Urea Plant, available: https://www.ruraldelivery.net.nz/posts/Kapuni-Urea-Plant-2017-04-03-23-47-22Z

[94] Methanex, About Methanex in NZ, available: https://www.methanex.com/location/new-zealand/about-methanex-nz

[95] Ballance, Annual Reports, available: https://ballance.co.nz/annual-report

profits. Between 2018 and 2022, Methanex made an average pre-tax profit of US$398 million per year—a substantive part of this could be attributed to New Zealand.[96]

Higher uncertainty in the natural gas market

The exit of Methanex would increase uncertainty in New Zealand's natural gas market due to Methanex's size. Methanex currently underpins New Zealand's gas market through long-term contracts.[97] This could increase the cost of natural gas. Potential supply uncertainty may also threaten energy security, requiring further investment into electricity infrastructure. The closure of Kapuni is likely to have a similar but smaller effect.

Lower natural gas consumption

Natural gas consumption would be reduced, decreasing GDP from natural gas extraction. Natural gas previously used by Methanex and Ballance would likely not be extracted. Assuming a wholesale natural gas price of $8.5/GJ, this represents around $580 million per annum worth of natural gas foregone.[98]

Emissions leakage

Methanol and urea produced in New Zealand are all tradeable commodities subject to a global price, determined by global supply and demand for the commodities. Changes in natural gas input costs can make domestic production of commodity goods uncompetitive with imports for domestic consumers or uncompetitive on global markets. This may force domestic trade-exposed firms to stop production. If global demand for the commodity goods remains unaffected, and global emissions frameworks are not binding on overseas competitors, those overseas producers could keep using fossil fuels to meet demand for those commodities. This may result in increased global emissions.

High Carbon Price Pathway is significantly more costly than the Reference Pathway

The High Carbon Price Pathway costs $37.5 billion between 2022 and 2030, or 8.5 percent more than the Reference Pathway. The higher cost associated with this pathway is due to the increased cost of carbon. After 2031, as the carbon price exceeds $200 tCO2e (reaching $300 per tCO2e by 2035), natural gas becomes increasingly expensive. This cost is predominantly incurred by high-temperature industrial users, who continue to use natural gas even as the carbon price increases, due to a lack of alternatives.[99] Under the High Carbon Cost Pathway, residential, commercial, and agricultural sectors incur cost increases of up to 11.1, 19.8, and 14 percent per annum, respectively. This is predominantly due to users paying a higher carbon price rather than switching to alternative fuels.

An increasing carbon price may also result is lower production or closure of production facilities for trade-exposed industrial users, particularly if the products are a global traded commodity. Closure of industrial businesses is likely to have significant negative economic impacts for New Zealand. These impacts are discussed in Box 5.1 above.

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[96] While Methanex does not report New Zealand-specific profits, New Zealand accounts for a quarter of its global production capacity. Source: Methanex, Financial Reports, available: https://www.methanex.com/investor-relations/financial-reports

[97] OMV (2021), Submission on the 2021 Draft Advice for Consultation.

[98] Methanol production consumes 60.8PJ of natural gas per year while urea production consumes around 7.3PJ of natural gas per year.

[99] Although the modelling shows that most natural gas users are likely to switch once the carbon price exceeds $200 tCO_2e, some users may not be in business by this point if the carbon price rises significantly.

Renewable Gas Pathway is only three percent more expensive than the Reference Pathway

The Renewable Gas Pathway costs $35.6 billion between 2022 and 2035, or 3.1 percent more than the Reference Pathway. This increase in costs is due to the increasing uptake of renewable gases from 2027 onwards. Between 2027 and 2035, the total cost from renewable gases is $3.41 billion, with roughly $2 billion from hydrogen and $1.4 billion from biogas. Industrial users face disproportionally higher energy costs in Renewable Gas Pathway. Most industrial sectors face higher energy costs compared to the Reference Pathway. For example, the steel and cement industries face annual energy cost increases of up to 30 percent relative to the Reference Pathway. This is because the modelled price of hydrogen and biogas is equal across the industrial, residential, and commercial sectors. The industrial sector is, therefore, more impacted by the higher costs of hydrogen and biogas than the residential and commercial sectors because the industrial sector pays a lower natural gas price. For the commercial and residential sectors, the marginal cost increase of hydrogen and biogas is less significant. The residential sector of gas users faces slightly lower costs in later years as renewable gas costs fall, compared to natural gas.

CCUS Pathway is less expensive than the Reference Pathway as the cost of investing in CCUS technologies for large users is less costly than the cost of carbon

The CCUS Pathway costs $33.7 billion between 2022 and 2035, or 2.5 percent less expensive than the Reference Pathway. Costs under the CCUS Pathway are the same as the Reference Pathway to 2026. After 2026, costs decrease relative to the Reference Pathway as CCUS technologies are introduced for large gas users (including electricity generation). For most large users that are able to implement CCUS, investing in CCUS technologies is less costly than paying the cost of carbon to use natural gas. Between 2027 and 2035, the total cost of deploying CCUS is just over $1.2 billion. As per the Reference Pathway, other natural gas users rationally switch from natural gas when alternative energy sources cost the same or are cheaper than natural gas.

LPG energy costs are impacted by early adoption of higher cost energy sources, carbon price, and renewable gases

LPG energy costs were modelled separately from the total energy costs for natural gas users.[100] This is consistent with the approach taken by the CCC in its national energy sector modelling. Figure 5.8 displays LPG energy costs under each pathway.

In the Reference Pathway, LPG energy costs are $441 million in 2022, which increases to $538 million in 2035. LPG energy costs gradually increase over the modelled period as the carbon price rises, impacting the cost of LPG. LPG energy costs total $6.9 billion from 2022 to 2035. The modelling shows that LPG remains the least costly energy source for existing LPG users in the commercial, residential, agriculture, fishery and forestry sectors, despite changes in costs under the Reference Pathway. Some low-medium heat process users switch to biomass as it becomes cheaper compared to LPG.

LPG energy costs under the 100 Percent Renewable Electricity by 2030 Pathway and the CCUS Pathway are the same as those under the Reference Pathway. LPG users follow the same consumption behaviour as users under the Reference Pathway. LPG demand is not included in the CCC's Demonstration Pathway, therefore, associated costs are not modelled. The CCC

[100] 'LPG energy costs' refers to the cost of LPG, bioLPG, and the cost of biomass and electricity that is used instead of LPG.

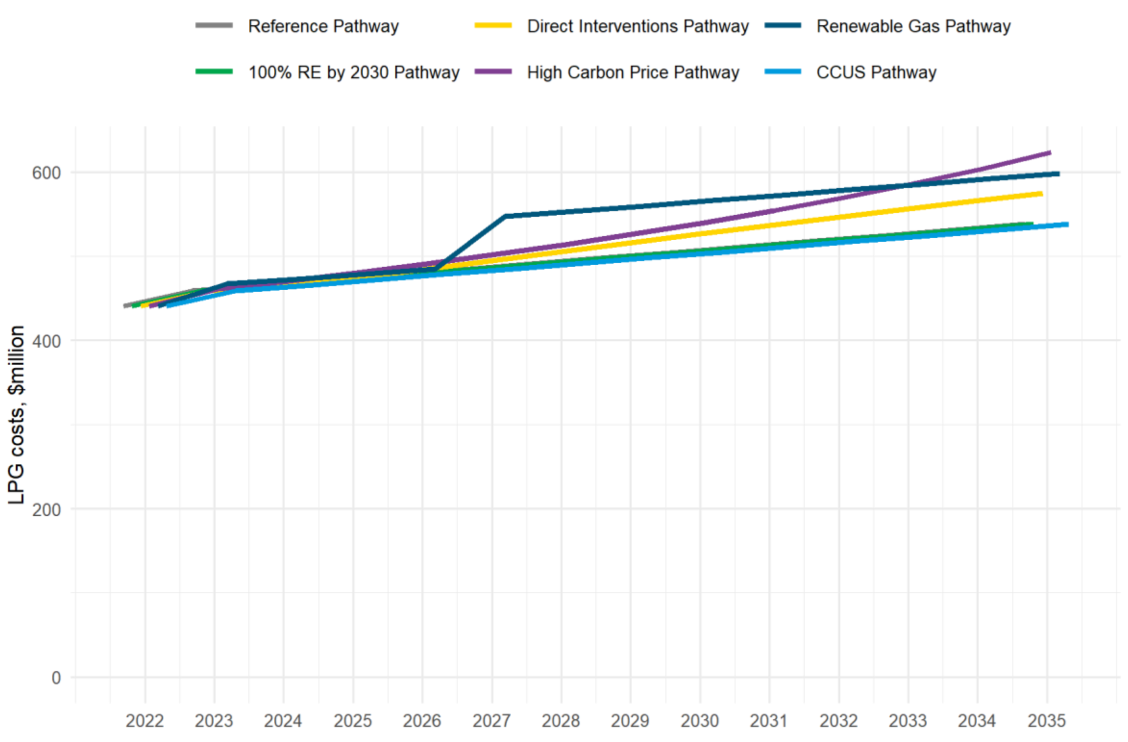
considers LPG as part of the liquid fuels stream and does not separate cost of liquid fuels out by fuel type (that is, costs attributed to LPG).

LPG energy costs under the Direct Interventions Pathway are higher than the Reference Pathway (a total of two percent higher than the Reference Pathway over the modelled period). This is due to forced switching to, or adoption of (due to LPG connection bans), higher cost energy sources.

Although demand for LPG under the High Carbon Price Pathway is the same as the Reference Pathway, LPG energy costs are higher. This is because both the cost of electricity and the cost of LPG are higher under the High Carbon Price Pathway compared to the Reference Pathway. LPG energy cost quickly rises from $441 million in 2022 (the same as the Reference Pathway) to $623. million in 2035. This is a total increase of 4.6 percent over the modelled period, relative to the Reference Pathway.

LPG energy costs under the Renewable Gas Pathway deviates most from the Reference Pathway (9.8 percent more than total costs under the Reference Pathway). This is because the blending of LPG with renewable LPG (that is, bioLPG) occurs after 2026, which makes LPG more expensive than biomass and electricity.

Figure 5.8: LPG costs across modelled pathways



Source: Castalia modelling
Note: LPG is not included in the CCC's Demonstration Pathway.

5.4 Reliability is equalised across all pathways

It is assumed that total energy demand from 2022 to 2035 is consistent with today's living standards. Although there will be some developments in energy efficiency, demand will remain stable overall. In addition, it is assumed that firms that use energy to produce goods do not curtail production due to rising energy costs. It is beyond the scope of this assignment to model demand sensitivity to changes in the prices of products and services that some firms sell.

A reduction in reliability would therefore be a reduction in living standards for New Zealanders. To overcome this, all pathways are normalised for reliability to ensure that energy reliability is the same as the Reference Pathway (normalisation approach is outlined in section 4.2). After detailed analysis, only the 100 Percent Renewable Electricity by 2030 Pathway required additional investment in generation assets (overbuild) in addition to a cost adjustment non-supply and unplanned outages.

6 Sensitivity analysis

This section summarises the sensitivities of key variables for the modelled pathways. We test how sensitive the baseline[101] modelled outputs for each pathway (presented in section 5) are to changes in key variables. The key variables tested are changes to the wholesale natural gas price and carbon price, the availability and cost of CCUS technology, the cost of renewable gases, and the wholesale price of electricity. A discount rate is also applied to energy costs and carbon emissions.

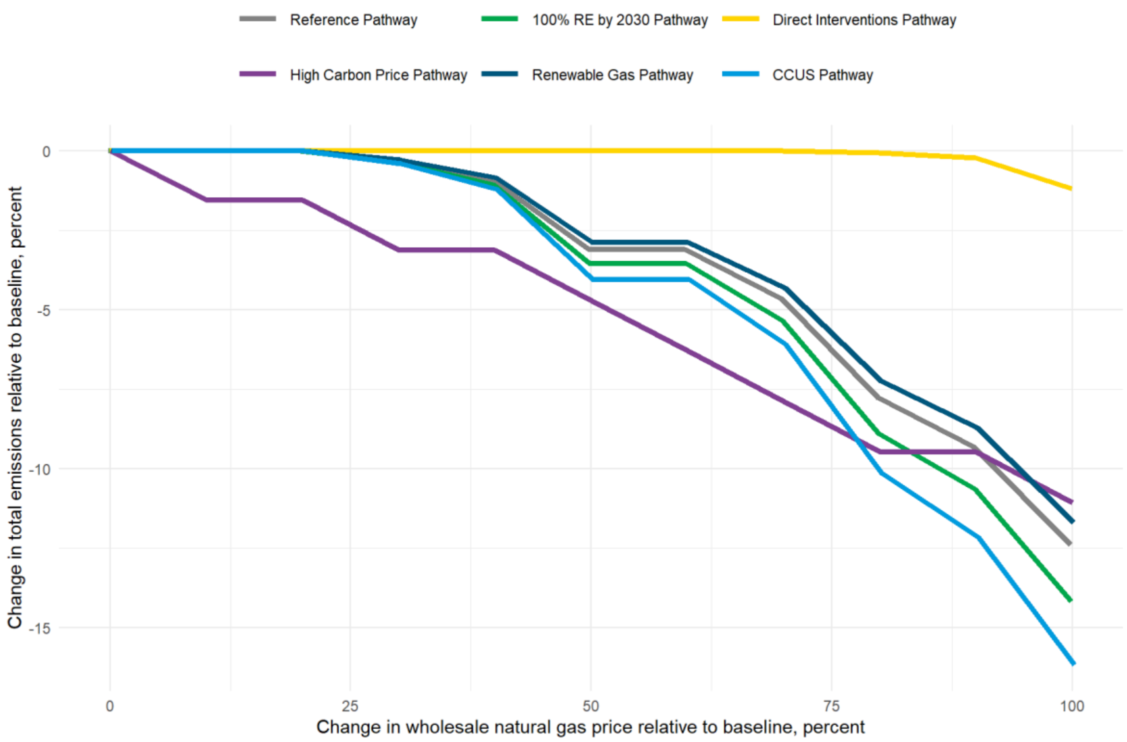
6.1 Wholesale natural gas price changes

Changes to the wholesale natural gas price have a large impact on emissions and costs, though it does not significantly impact the relative performance of pathways. Under the Reference Pathway, if wholesale natural gas prices were to increase by 50 percent, then between 2022 and 2035, the total energy costs would increase by 18 percent, and total emissions would decrease by three percent. For the six other pathways, increasing the wholesale natural gas price also reduces emissions while increasing costs relative to the baseline. Changes to the wholesale natural gas price are unlikely to significantly impact the relative performance of pathways, detailed in section 5.

Figure 6.1 displays the sensitivity of total emissions against changes in the wholesale natural gas price. The High Carbon Price Pathway is the most sensitive, while the Direct Interventions Pathway is the least sensitive to changes in the wholesale natural gas price.

[101] The baseline refers to original modelling assumptions as outlined in Section 5. The baseline does not refer to the Reference Pathway (that is, the BAU).

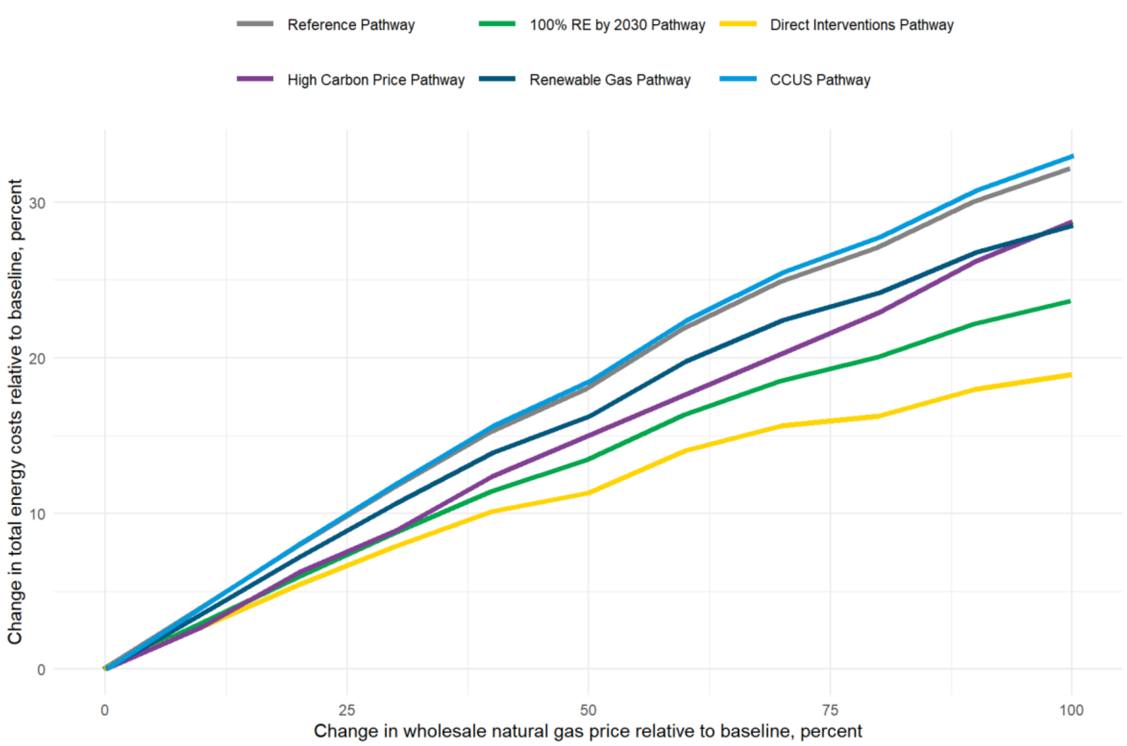
Figure 6.1: Sensitivity of emissions against changes in the wholesale natural gas price



Note: CCC Demonstration Pathway is not included because demand under the CCC Demonstration Pathway is not modelled by Castalia. Instead, demand is taken directly taken from CCC modelling, and emissions are calculated using the relevant emissions factor.
Source: Castalia modelling

Figure 6.2 below displays the sensitivity energy costs against changes in the wholesale natural gas price. The CCUS Pathway is the most sensitive, while the Direct Interventions Pathway is the least sensitive to changes in the wholesale natural gas price.

Figure 6.2: Sensitivity of energy costs against changes in the wholesale natural gas price



Note: CCC Demonstration Pathway is not because the CCC did not provide energy costs in its modelling.
Source: Castalia modelling

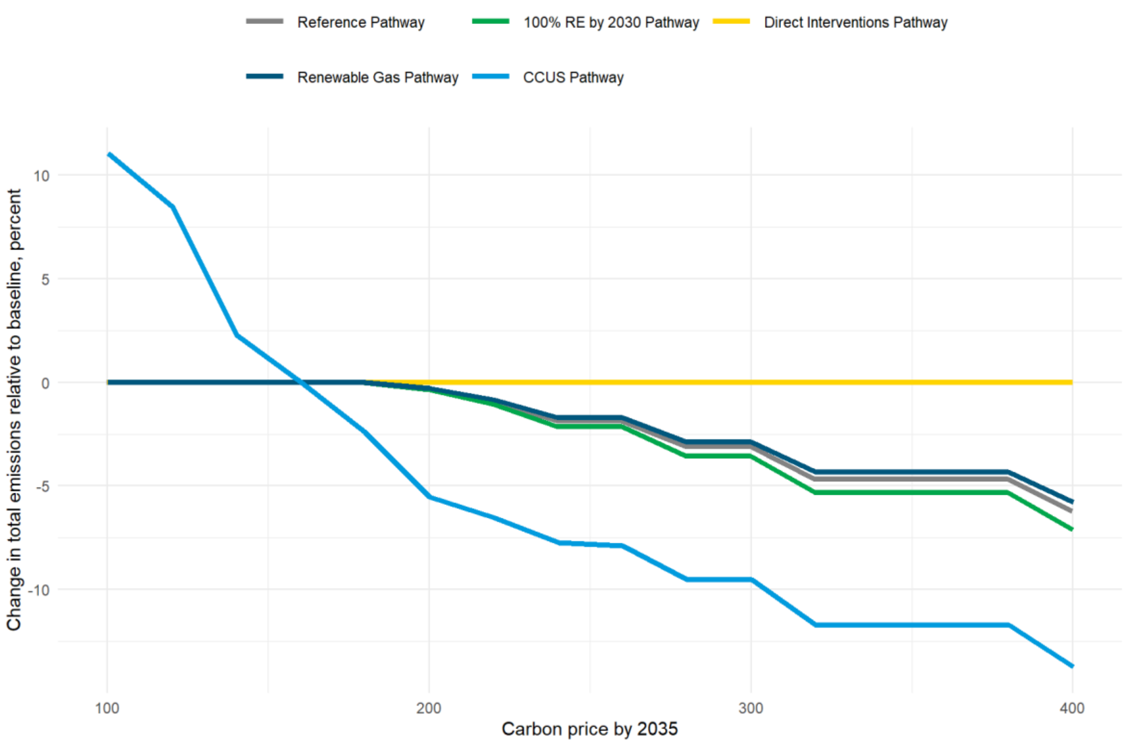
6.2 Carbon price changes

Changes to the wholesale carbon price have a moderate impact on energy costs and emissions for most pathways. For all pathways, increasing the carbon price decreases emissions but increases costs relative to the baseline.

Other than the CCUS Pathway, the cost of energy is more sensitive to changes in the carbon price than the amount of emissions. That is, for every dollar increase in the carbon price by 2035, energy costs increase more than emissions decrease. This is because increasing (and incurring) the carbon price does not always induce switching due to the high cost of alternatives. For the CCUS Pathway, the reverse is true because CCUS allows users to reduce their exposure to the carbon price. This means that once the carbon price exceeds around \$155/tCO_2e, energy costs increase slower than the carbon price for all sectors using CCUS. The sensitivities for the Reference Pathway and the High Carbon Price Pathway (not shown) are the same because the pathways share the same assumptions other than the carbon price.

Figure 6.3 below displays the sensitivity of total emissions against changes in the carbon price. The amount of emissions under the CCUS Pathway is highly sensitive to the carbon price. Between \$120 and \$160, every dollar increase in the carbon price (per tCO_2e) by 2035 leads to a 122ktCO_2e decrease in emissions over the 2022–2035 period under the CCUS Pathway. The CCUS Pathway could be less effective in terms of emissions reduction if the carbon price were to be lower than the carbon price in the baseline (that is, \$140 per tCO_2e by 2030 and \$160 per tCO_2e by 2035). For other pathways, the amount of emissions is not likely to decrease significantly unless the 2035 carbon price exceeds $200, and even then changes are not substantial.

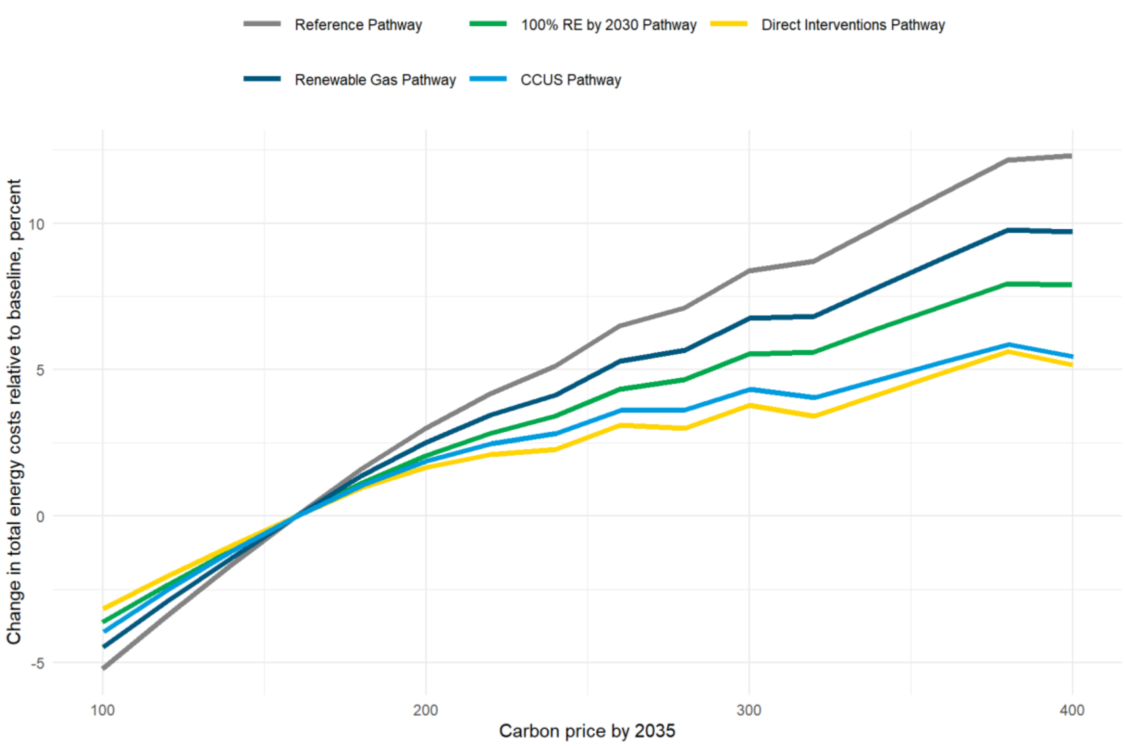
Figure 6.3: Sensitivity of emissions against changes in the carbon price



Note: CCC Demonstration Pathway is not included because the CCC did not provide energy costs in its modelling.
Source: Castalia modelling

Figure 6.4 below displays the sensitivity of total energy costs against changes in the carbon price. The cost of energy is somewhat sensitive to changes in the carbon price. Between $100 and $300, changes to the carbon price are unlikely to impact costs by more than ten percent. Energy costs change more as the carbon price increases to $400, but only energy costs under the Reference Pathway changes by more than ten percent. Overall, as the carbon price rises, energy costs increase at a slower rate than the carbon price, because some natural gas users switch to less emission-intensive fuels, predominantly biomass.

Figure 6.4: Sensitivity of energy costs against changes in the carbon price

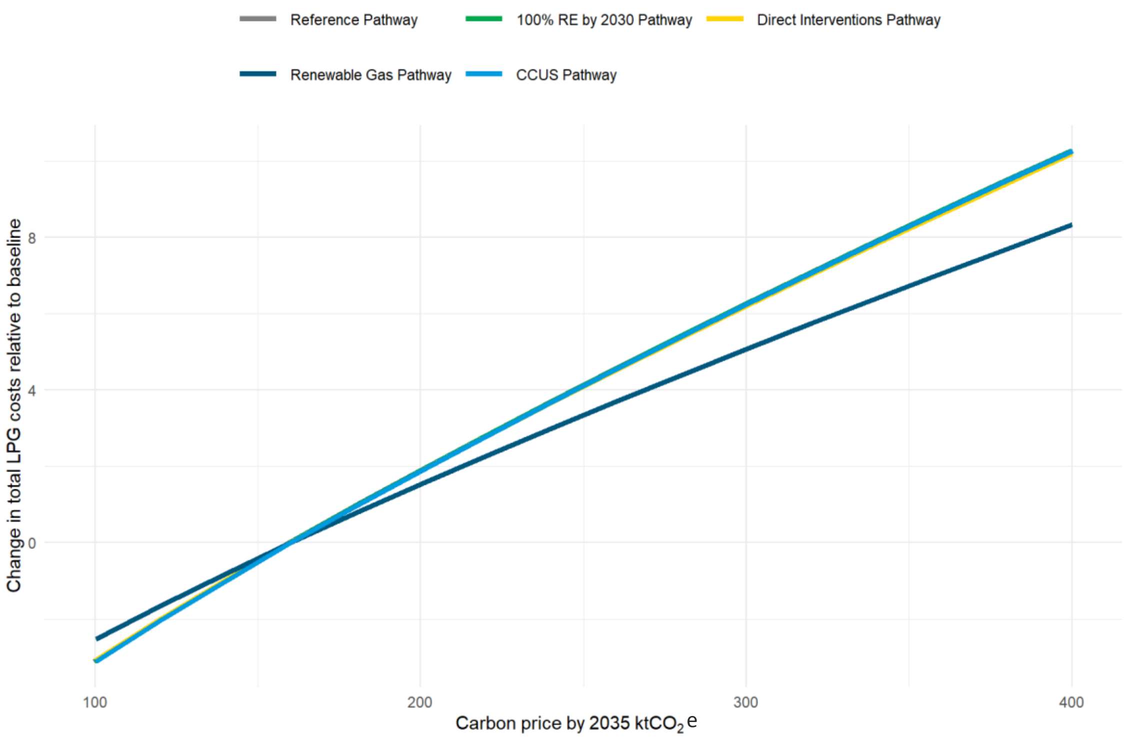


Note: CCC Demonstration Pathway is not included because the CCC did not provide energy costs in its modelling.
Source: Castalia modelling

6.2.1 LPG cost is not sensitive to changes in carbon price

The cost of energy for LPG users is not highly sensitive to changes in the carbon price. Changes to the carbon price from $100 to $400 appear to not impact LPG users' energy costs by more than ten percent across all pathways. Figure 6.5 below illustrates the sensitivity of total costs against changes in the carbon price.

Figure 6.5: Sensitivity of LPG costs against changes in the carbon price



Note: CCC Demonstration Pathway is not included because the CCC did not provide energy costs in its modelling.
Source: Castalia modelling

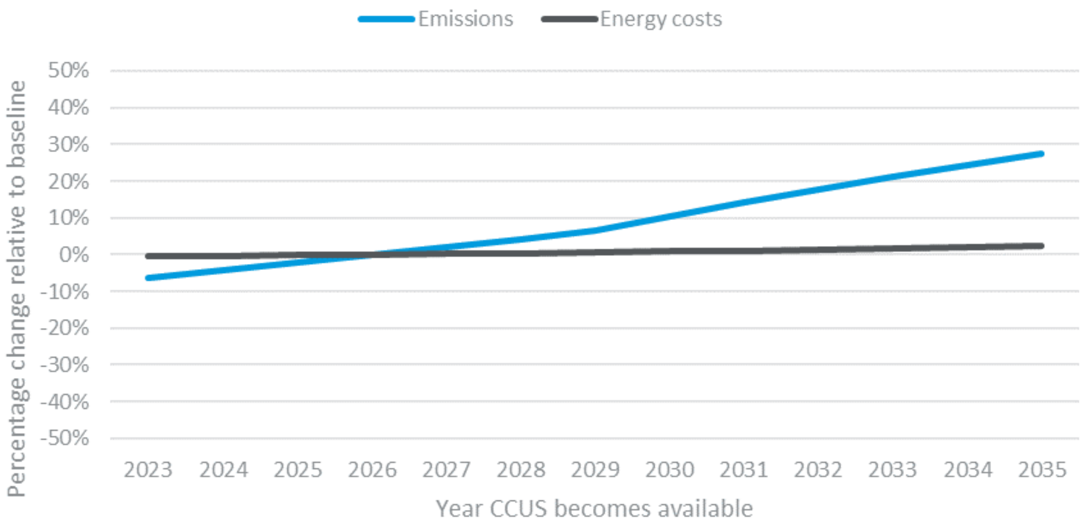
The analysis suggests that the amount of emissions from LPG under all pathways will not be sensitive to the carbon price. This is because even with a substantial increase in carbon price, the cost of switching to electric appliances in the modelling is significantly higher than the cost of retaining LPG and appliances. Moreover, an increase in carbon price has an impact on both LPG and electricity energy sources, as the carbon price increases the cost of both energy sources (although it increases the cost of LPG more, given LPG's higher carbon content relative to electricity in New Zealand).

6.3 CCUS technology timing and cost

Under the CCUS Pathway, changes to the availability and cost of CCUS have a large impact on emissions and a negligible impact on costs. The earlier CCUS technology is available (and supported by the regulatory environment), the lower the emissions and the lower the costs of the CCUS Pathway. The lower the cost of CCUS, the lower the emissions and the lower the energy costs of the CCUS Pathway.

Figure 6.6 below shows how the emissions and costs under the CCUS Pathway could change if CCUS were available earlier or later. If CCUS were first available by 2030, 2031, and 2033, the CCC Demonstration Pathway, the 100 Percent Renewable Energy by 2030 Pathway, and the Renewable Gas Pathway could lead to lower emissions than that of the CCUS Pathway, respectively.

Figure 6.6: Sensitivity of emissions and cost against changes in timeline of CCUS technology availability (CCUS Pathway only)

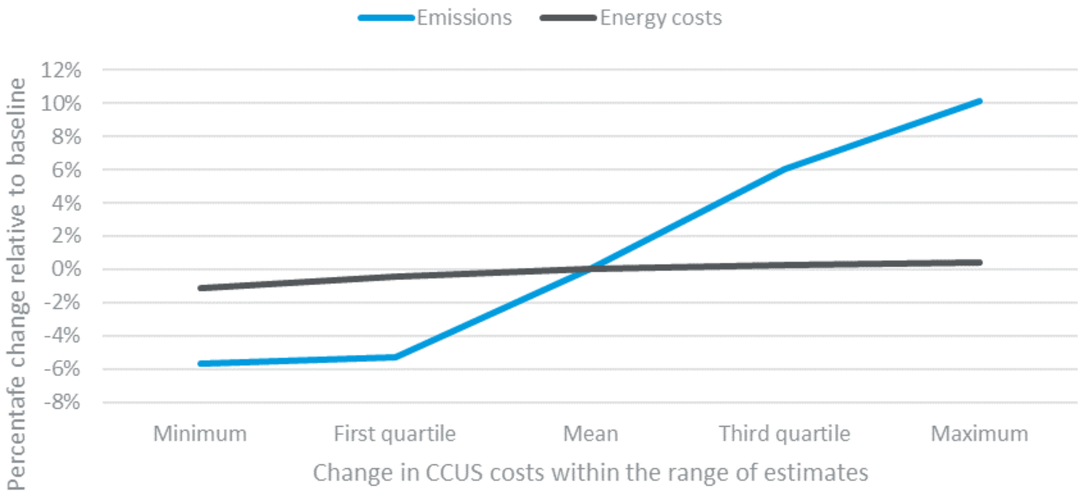


Source: Castalia modelling

Figure 6.7 shows how the emissions and costs under the CCUS Pathway could change if CCUS were less or more expensive. If CCUS costs were close to the top end of estimates, then the CCUS Pathway would produce similar emissions as the CCC Demonstration Pathway. This is because the steel sector would defer using CCUS relative to the baseline, which increases emissions slightly. However, within the range of estimates for CCUS costs,[102] the CCUS Pathway is modelled to have the highest emissions reduction potential out of all pathways.

[102] The cost of carbon capture ranges from US$50/tCO2e to US$100/tCO2e for power generation, US$60/t$CO_2$e to US$120/tCO_2e for cement, US$40/t$CO_2$e to US$100/tCO_2e for iron and steel, and US$25/t$CO_2$e to US$35/tCO_2e for ammonia. The cost of carbon capture generally reduces as the concentration of CO_2 increases. The cost of carbon storage is around US$10/t$CO_2$e. IEA, Is carbon capture too expensive? available at: https://www.iea.org/commentaries/is-carbon-capture-too-expensive

Figure 6.7: Sensitivity of emissions and cost of energy against changes in cost of CCUS (CCUS Pathway only)



Note: The cost of carbon capture ranges from US$50/tCO$_2$e to US$100/tCO$_2$e for power generation, US$60/tCO$_2$e to US$120/tCO$_2$e for cement, US$40/tCO$_2$e to US$100/tCO$_2$e for iron and steel, and US$25/tCO$_2$e to US$35/tCO$_2$e for ammonia. The cost of carbon capture generally reduces as the concentration of CO$_2$ increases. This sensitivity analysis does not vary the cost of carbon storage, which is around US$10/tCO$_2$e.
Source: Castalia modelling

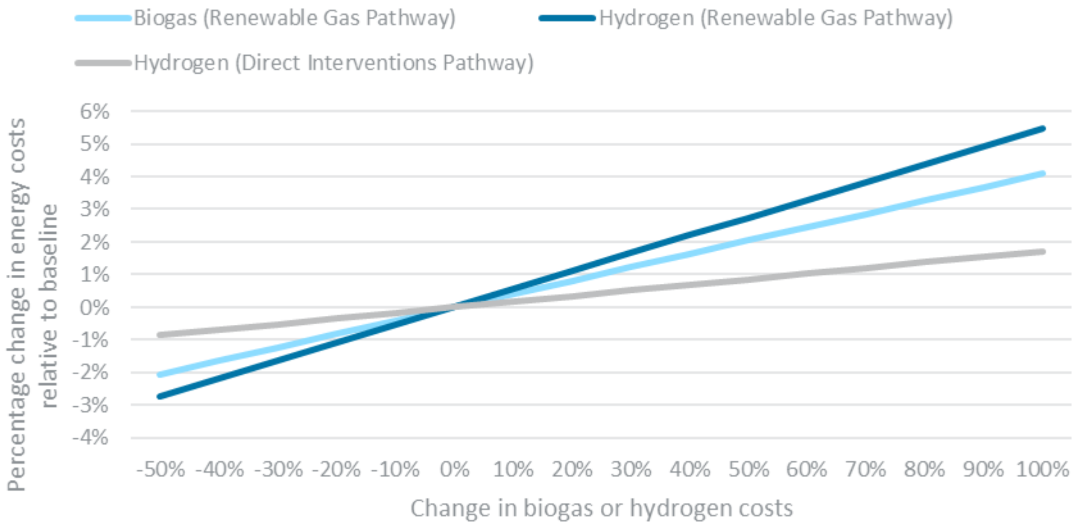
6.4 Renewable gas costs

Changes to the cost of renewable gases could impact the costs but not the emissions associated with the Renewable Gas Pathway and the Direct Interventions Pathway. Under the Renewable Gas Pathway, changes to the cost of biogas and green hydrogen (which is blended with natural gas) has a moderate impact on energy costs. Under the Direct Interventions Pathway, changes to the cost of green hydrogen (consumed as a feedstock for urea production) has a small impact on energy costs. Section 6.4.1 separately discusses the sensitivity of bioLPG demand to bioLPG costs. The modelling does not consider other renewable gases, such as DME, because existing production of DME is limited, and costs are highly uncertain.

Figure 6.8 shows how energy costs under the Direct Interventions Pathway and the Renewable Gas Pathway could change if biogas or green hydrogen were more or less expensive. Relative to the baseline, every one percent increase in the cost of biogas increases energy costs by $14.6 million in the Renewable Gas Pathway.[103] Relative to the baseline, every one percent increase in the cost of green hydrogen increases energy costs by $7.18 million in the Direct Interventions Pathway and $19.5 million in the Renewable Gas Pathway. Changes in the cost of biogas or green hydrogen do not impact emissions because both the Direct Interventions Pathway and the Renewable Gas Pathway assume uptake of biogas and green hydrogen independent of costs.

[103] Biogas is not consumed under the Direct Interventions Pathway, so the cost of biogas does not change the cost of the pathway.

Figure 6.8: Sensitivity of energy costs against changes in the price of biogas and hydrogen (Direct Interventions Pathway and Renewable Gas Pathway only)

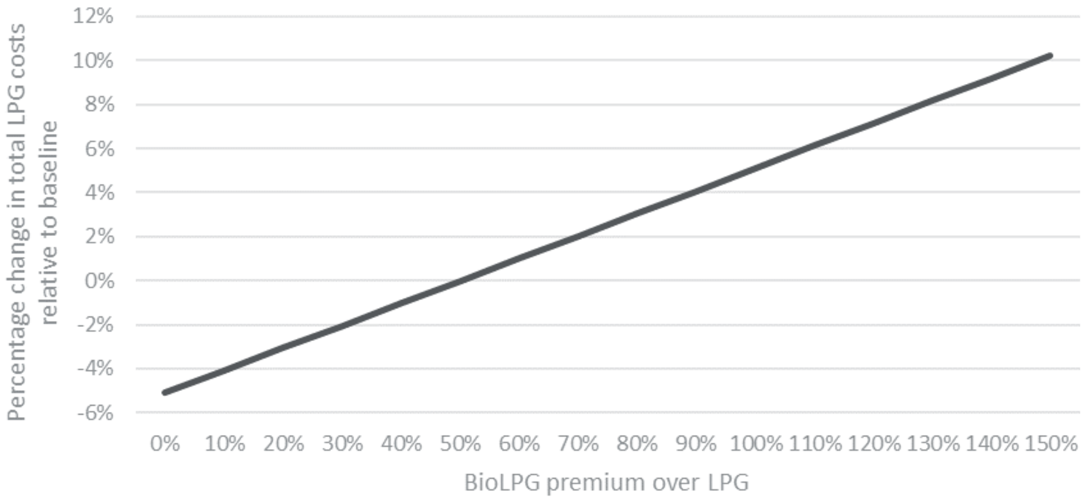


Note: The baseline biogas cost increases linearly from $20/GJ in 2021 to $50/GJ in 2050, as modelled in section 5.3.
Source: Castalia modelling

6.4.1 LPG costs are moderately sensitive to changes in the bioLPG price

Under the Renewable Gas Pathway, bioLPG becomes available from 2026 at 20 percent of total LPG demand. Relative to the baseline, every one percent premium of bioLPG over LPG increases the total cost of LPG by 0.10 percent, or $7.05 million. Figure 6.9 below shows the sensitivity of total LPG costs against changes in the bioLPG price.

Figure 6.9: Sensitivity of LPG costs against changes in the bioLPG price (Renewable Gas Pathway only)



Note: The baseline refers to a bioLPG premium of 50 percent over LPG, as modelled in section as modelled in section 5.3. The cost of LPG varies across sectors.
Source: Castalia modelling

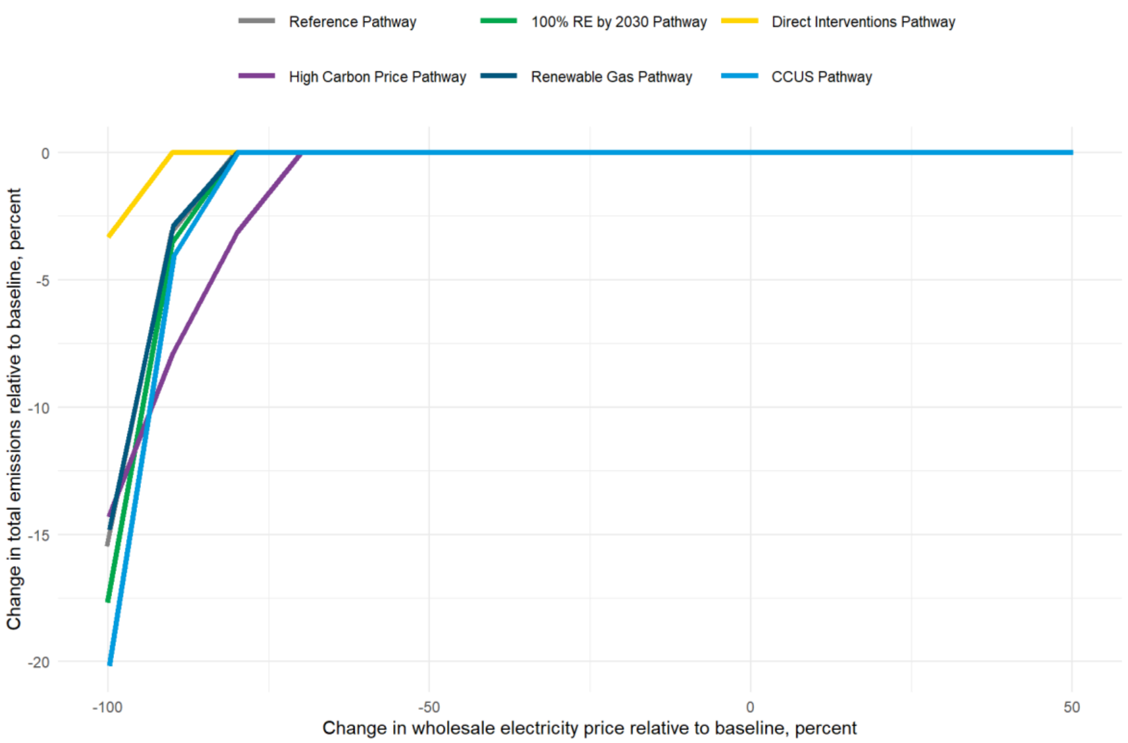
6.5 Wholesale electricity price

Changes to the wholesale electricity price have a minor impact on emissions and costs in the modelled pathways. The Castalia model uses the same wholesale electricity price as the CCC uses.

The wholesale electricity price would have to drop over 80 percent from the baseline before significantly impacting emissions and costs in all pathways. This is because the capital costs associated with switching from gas to electric energy are high, so large decreases in electricity prices are needed (assuming other factors remain constant) to incentivise switching from natural gas. These capital costs are also sourced from CCC's publicly released models.

Figure 6.10 below shows how emissions change across the modelled pathways as the wholesale electricity price changes. The sensitivity curve is flat near the baseline, suggesting that minor to moderate changes to the wholesale electricity price does not impact emissions. However, the curve is steep when wholesale electricity prices reduce by more than 80 percent (although such an outcome is highly unlikely).

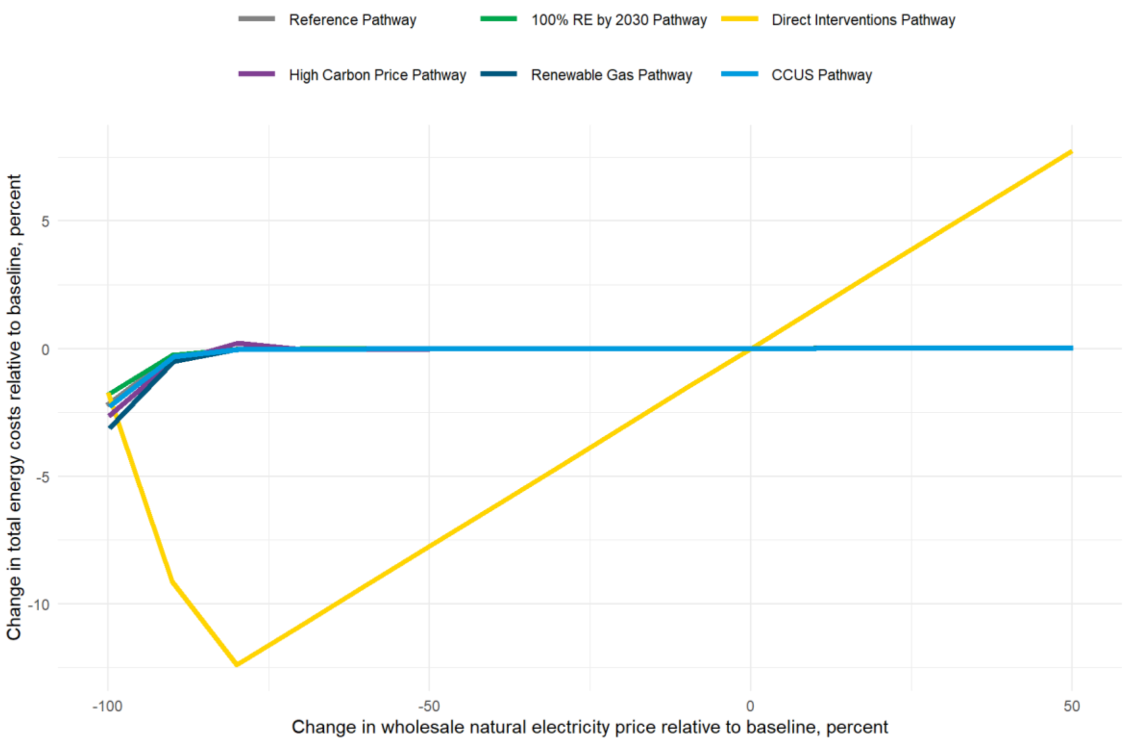
Figure 6.10: Sensitivity of emissions against changes in the wholesale electricity price



Note: CCC Demonstration Pathway is not included in the sensitivity analysis because the CCC did not provide energy costs in its modelling.
Source: Castalia modelling

Figure 6.11 below shows how energy costs change across the modelled pathways as the wholesale electricity price changes. The sensitivity curve is flat near the baseline, suggesting that minor to moderate changes to the wholesale electricity price would not impact energy costs. However, the curve is steep when wholesale electricity prices reduce by more than 80 percent (although such an outcome is highly unlikely).

Figure 6.11: Sensitivity of energy costs against changes in the wholesale electricity price



Note: CCC Demonstration Pathway is not included in the sensitivity analysis because the CCC did not provide energy costs in its modelling.
Source: Castalia modelling

6.6 Discount rates for costs and emissions

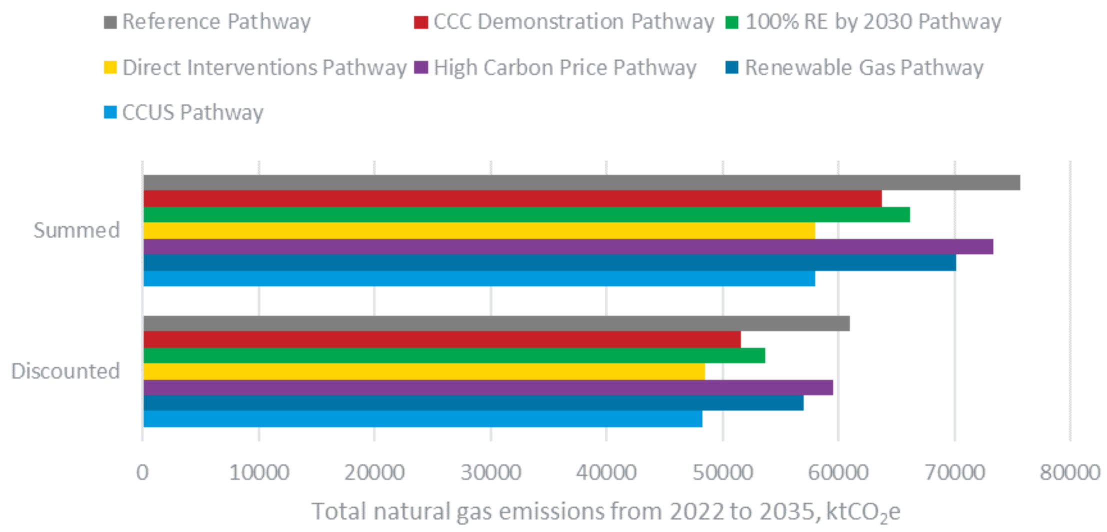
Both money and emissions have time value. A unit of money is worth more today than in the future because the money could be invested today to produce returns. Similarly, a unit of emissions has more impact on the climate if released today than if released in the future because the GHG remains in the atmosphere for longer. Therefore, it is preferable for both energy costs and emissions of GHGs to be deferred into the future.

Applying a discount rate to emissions does not impact the findings in Section 5.[104] Figure 6.12 compares the discounted emissions against the summed emissions for each pathway between 2022 and 2035 using a 3.3 percent per annum discount rate.[105] The relative performance of pathways for sustainability is largely preserved, though the CCUS Pathway surpasses the Direct Interventions Pathway to become the most sustainable pathway by a small margin (0.05 percent).

[104] Higher discount rates could changes the analysis in section 6.6, but they are likely unrealistic and incompatible with policy and economic analysis in New Zealand.

[105] A 3.3 percent per annum discount rate for emissions is consistent with the 100-year global warming potential metric. M. C. Sarofim, M. R. Giordano (2018), A quantitative approach to evaluating the GWP timescale through implicit discount rates, Earth Syst. Dynam., 9, 1013–1024, 2018, https://doi.org/10.5194/esd-9-1013-2018

Figure 6.12: Impact of discounting on emissions

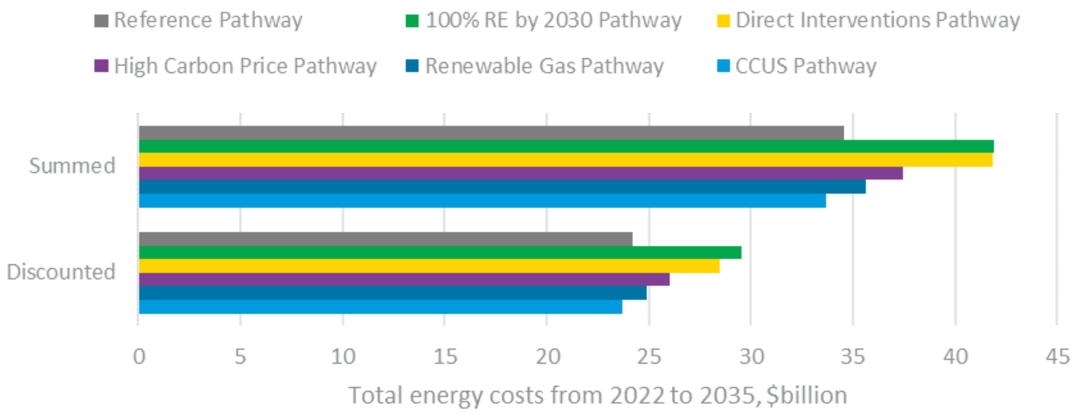


Notes: Discounted refers to a "net present value of carbon" with an annual discount rate of 3.3 percent.
Source: Castalia analysis

Applying a discount rate to energy costs does not impact the relative performance of the pathways. Figure 6.13 compares the discounted energy costs against the summed energy costs for each pathway between 2022 and 2035 using a discount rate of five percent per annum.[106] After discounting, the relative performance of pathway for affordability is also preserved.

[106] The Treasury, Discount Rates, available: https://www.treasury.govt.nz/information-and-services/state-sector-leadership/guidance/financial-reporting-policies-and-guidance/discount-rates

Figure 6.13: Impact of discounting on energy costs



Notes: Discounted refers to a net present value of costs with an annual discount rate of five percent. Costs include adjustment for reliability and CCUS costs.
Source: Castalia analysis

7 Conclusions and recommendations

We used the energy trilemma framework to evaluate the relative financial costs and emissions impacts of six pathways (holding reliability constant) compared to the 'business as usual' Reference Pathway. The Reference Pathway shows falling gas consumption and emissions over the 13 years to 2035 and beyond. The six additional pathways modelled show how critical policy and technology choices can significantly affect energy costs and emissions in the GTP.

Emissions reductions in the gas sector will contribute to New Zealand achieving the net zero policy goal, but there will be trade-offs. Evaluating the emissions reduction benefits against the additional energy costs of each pathway shows where policymakers should focus most effort. Where costs increase, policymakers can focus on where the most emissions reduction gain is possible for the cost. In addition, some pathways provide options that could assist future decarbonisation.

We explicitly applied a framework that evaluates potential policy choices according to the level of emissions reductions for the cost. We held reliability constant. This means we assumed New Zealanders will require the same level of energy for industrial, commercial and residential uses as they currently require, at the same level of security of supply. The energy trilemma is a well-established framework used by governments and international organisations to guide policy. The energy trilemma is insightful because all energy policy decisions involve trade-offs among the three parameters. The optimal pathway will balance emissions impacts and costs and meet an energy reliability standard acceptable to New Zealanders.

7.1 Key recommendations for GTP to 2035

The optimal GTP pathway will probably include a combination of choices and options considered in this report. It will probably also include some technological innovations and changes that are currently unknown. Based on our modelling analysis and acknowledging these limitations, the optimal pathway appears to be a combination of CCUS for large-scale emissions, and using the carbon price to incentivise net emissions reductions. Flexibility to adapt to changes in technology and new information in the future (which a dynamic carbon price would promote) is important.

7.1.1 Investment in CCUS technologies and adoption should be prioritised, so ensure regulatory regime is supportive

CCUS technologies and adoption should be a key component in efforts to achieve net-zero emissions through gas sector changes. CCUS can capture scope one emissions from upstream oil and natural gas producers, as well as point source emissions from industrial, chemical, electricity generation and process heat users of natural gas. Increasing investment in CCUS is consistent with the recommendations of the IEA[107] and IPCC.[108] Box 7.1 provides more information about the state of CCUS technologies.

The CCUS Pathway shows that CCUS technologies have the potential to significantly decrease emissions for the lowest cost. However, sensitivity analysis shows that the earlier CCUS is

107 IEA (2022), https://www.iea.org/reports/about-ccus and https://www.iea.org/fuels-and-technologies/carbon-capture-utilisation-and-storage

108 IPCC Working Group III (2022), Climate Change 2022: Mitigation of Climate Change, available at: https://www.ipcc.ch/report/ar6/wg3/

available, the greater the gross emissions impact will be. CCUS technology is not yet in use in New Zealand at the scale necessary to realise the emissions reductions estimated in the CCUS Pathway. Scale CCUS technology is being increasingly used overseas in the same sectors responsible for most gas-related emissions in New Zealand (gas processing and production, fertiliser, chemicals, synfuel, and power generation). Costs still need to fall to the IEA's estimated range for it to become economically viable. Technical feasibility in New Zealand's geography needs to also be certain for CCUS to be effective as a long-term and stable decarbonisation option. Sites with sufficient carbon dioxide storage capacity that do not leak significantly need to be identified.

CCUS adoption in New Zealand will require regulatory certainty to support investment and technically viable sites. An MBIE-funded study dating from 2013 identified areas of law and regulatory reform needed to enable CCS.[109] Some research has been carried out to identify potential storage sites and assess the feasibility of different CCUS technologies. Ara Ake recently recommended the government explore CCUS, test the public support for it, and if there is support, then it should fund or otherwise support pilot projects for different CCUS options.[110]

Box 7.1: State of CCUS technologies

CCUS technologies are recognised as having an important role in achieving global and domestic emissions reduction targets. The latest Intergovernmental Panel on Climate Change (IPCC) report (2022) states that CCUS technologies are likely to be a necessary part of the transition to net zero.[111] The International Energy Association (IEA) also considers CCUS technologies to play an 'important and diverse role in meeting global energy and climate goals'.[112]

The development of CCUS technologies has been slower than anticipated, but technology is advancing. CCUS technologies are being used and tested globally. There are around 35 operational commercial facilities using CCUS in industrial processes, fuel transformation, and energy generation. Around 300 other projects are in various stages of development across the CCUS value chain, and additional projects have been announced by developers, many of which are expected to be operating by 2030.[113]

The New Zealand Government last explored the use of CCUS in 2010. The study found that New Zealand's legislative and regulatory framework provided barriers to the application of CCUS, but several opportunities are worth further investigation.[114] Several New Zealand geothermal energy generators are preparing trials for CO_2 injection.[115]

109 Barton, B, et al, (2013) Carbon Capture and Storage: Designing the Legal and Regulatory Framework for New Zealand, University of Waikato, available at: https://researchcommons.waikato.ac.nz/bitstream/handle/10289/8530/Carbon.pdf?sequence=1&isAllowed=y

110 Ara Ake (2022), Carbon Dioxide Removal and Usage in Aotearoa New Zealand, available at: https://www.araake.co.nz/assets/Uploads/Ara-Ake-Report-Carbon-Dioxide-Removal-and-Usage-in-Aotearoa-New-Zealand.pdf?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

111 IPCC (2022), Climate Change 2022: Mitigation of Climate Change, available at: https://www.ipcc.ch/report/ar6/wg3/

112 IEA (2021), About CCUS, available at: https://www.iea.org/reports/about-ccus

113 IEA (2022), Legal and Regulatory Frameworks for CCUS, available at: https://www.iea.org/reports/legal-and-regulatory-frameworks-for-ccus

114 Transfield Worley (2010), CCS in New Zealand—Case Studies for Commercial Scale Plant Final Report, available at: https://www.mbie.govt.nz/dmsdocument/2868-ccs-case-studies-commercial-scale-plant-report-2010-pdf

115 Ara Ake (2022), Carbon Dioxide Removal and Usage in Aotearoa New Zealand, available at: https://www.araake.co.nz/assets/Uploads/Ara-Ake-Report-Carbon-Dioxide-Removal-and-Usage-in-Aotearoa-New-Zealand.pdf?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

Key challenges for effective use of CCUS include the availability of underground storage options and changes to the physical, chemical, or biological conditions of storage facilities.[116]

7.1.2 Reduce but retain natural gas as part of New Zealand's electricity system and ensure policy settings support investment confidence

Natural gas could continue to play a smaller but more important role in electricity generation. As more variable renewable electricity generation is added to the grid, responsive dispatchable generation will be needed. Natural gas can provide a reliable and cost-competitive energy source for New Zealand's electricity generation needs, albeit with emissions. Natural gas can provide energy for flexible dispatchable generation, for example, in open cycle gas turbine generation.

The contrast in costs between the 100 Percent Renewable Electricity by 2030 Pathway and other pathways that retain natural gas fired generation is stark. The former pathway is not cost-benefit justified using publicly available cost estimates of the investment needed to improve electrical system reliability. The 100 Percent Renewable Electricity by 2030 Pathway would impose significantly higher costs for moderate emissions reduction benefits within the gas sector. It reduces gas sector emissions, thus scoring well on the 'sustainability' dimension, but would increase electricity costs for New Zealand as a whole. This would probably delay electrifying transport, increasing national net emissions. The 100 Percent Renewable Electricity by 2030 Pathway scores poorly on the 'affordability' dimension. New Zealand can still shift to lower electricity costs with a higher share of renewable electricity generation than is currently the case, but in order to reach a 100 percent renewable target, significant high-cost generation and storage investment will be required.

7.1.3 Utilise robust ETS with a binding cap and support carbon offset opportunities

A robust ETS will incentivise reductions in natural gas demand, and therefore gross emissions. The amount of gross emissions reductions will depend on the carbon price. Some users of natural gas are sensitive to changes in the carbon price. However, natural gas still appears to be the lowest cost source of energy for many sectors, even as energy costs rise for users with changes in the cost of carbon. Gas demand reduces under the Reference Pathway (the BAU) as the carbon price approaches $160 by 2035. In the High Carbon Price Pathway, as the carbon price rises to $300, natural gas demand reduces as users are incentivised to switch to other energy sources. Natural gas demand appears to be sensitive to a carbon price above $200. Using the purchase of NZUs to reduce net emissions from the gas sector, however, requires a well-functioning ETS market that matches carbon removal and mitigation options (in New Zealand and overseas) with buyers.

Policy that supports using an ETS with a binding cap would provide emissions reduction opportunities that fully comply with the Climate Change Response Act in an efficient way. The ETS can be kept effective by ensuring the cap-setting mechanism is predictable. The

[116] Transfield Worley (2010), CCS in New Zealand—Case Studies for Commercial Scale Plant Final Report, available at: https://www.mbie.govt.nz/dmsdocument/2868-ccs-case-studies-commercial-scale-plant-report-2010-pdf

institutional design should keep emissions prices free from short-term policy drivers. For instance, complementary policies that have the effect of reducing emissions in a sector or activity covered by the ETS will free up NZUs in other sectors or activities, lowering the cost of emitting GHGs (known as the waterbed effect). Governments have a mixed track record of designing effective complementary policies that reduce emissions and work alongside an ETS that covers the same sectors.

Using an ETS with a binding cap can ensure that cost-effective abatement is realised across the economy. If the carbon price remains market-based and traded on the ETS, it can reflect the relative value of emitting compared to abating across the economy. The High Carbon Cost Pathway shows natural gas demand (and therefore emissions) is sensitive to a carbon price around $200 and above. This suggests natural gas demand will be ‘sticky’, and lower cost abatement options might exist elsewhere in the New Zealand economy (for example, in transport). However, increased costs for industrial producers due to an higher carbon price may impact the economic feasibility of trade-exposed New Zealand firms. Some natural gas users may reduce production or go out of business if the carbon price rises significantly compared to international competitors.

7.1.4 Direct interventions are high risk and have high energy and economic costs, so these deterministic policies should be avoided

Both the CCC Demonstration Pathway and the Direct Interventions Pathway illustrate the risks of deterministic policies targeting particular gas users or classes of users. Such policies can target the wrong users or technologies, or produce unintended consequences. This can mean emissions are not reduced, or costs are higher than can be sustained.

The modelling did not explicitly consider the effect on gas demand of increases in New Zealand energy costs for trade-exposed energy users. Increases in domestic energy costs would probably make the products of domestic firms less competitive with imports or with products on global export markets.

The CCC’s Demonstration Pathway was produced in mid-2021 and is already out of date. The CCC’s expectations for the future have been proven incorrect on three important drivers of gas demand and overall energy costs. The CCC’s modelling assumed the Marsden Point refinery (a large natural gas user) would keep operating, Methanex would reduce production, and the Tiwai Point aluminium smelter would cease production in 2027. However, these three assumptions have already been superseded by events or public announcements.

The Direct Interventions Pathway would lead to emissions reductions, but at significant cost to industrial and commercial energy users. The forced switching of methanol and urea production plants from natural gas for process heat, and also as a feedstock for urea production, would impose large economic costs on New Zealand, with limited or no effect on global demand for those commodities. In the modelling, we show the energy cost impact by estimating the cost of decarbonizing energy and feedstock sources used in methanol and urea production. This pathway would cost 21.2 percent more than the Reference Pathway over the modelled period. Rather than incur those costs, gas users would likely cease production. The loss of these industries from New Zealand would result in negative economic impacts, such as foregone GDP, loss of higher-paying jobs, and a loss of export income (detailed in Box 5.1). Furthermore, Methanol production currently underpins New Zealand’s gas market through long-term contracts[117] and ceasing it could cause supply uncertainty that might increase electricity prices to pay for new generation and infrastructure investment. This could delay electrification elsewhere in the economy. De-industrialisation is also a potential consequence of the High Carbon Price Pathway, if overseas producing countries do not match New Zealand's climate policy settings.

7.1.5 Renewable gases are more expensive but could play a role in preserving optionality, so renewable gas potential and pricing should be monitored and use of targets and certificates should be explored

If renewable gas production costs were to fall significantly, there might be a case for integrating some renewable gases into the gas network. However, current price forecasts are too high for renewable gases to be any cheaper than other emissions abatement options. If integrating renewable gases can extend the lifespan of gas networks (while achieving emissions reductions), this might preserve future infrastructure options for when renewable gases can be produced at lower costs than forecast, and at higher volumes than is currently possible. Preserving infrastructure also provides energy choices to consumers, while achieving emissions reductions. However, policymakers, network owners, and investors would need to carefully weigh the option value of preserving infrastructure against the likelihood of renewable gas costs falling.

If costs fall, the gas sector will require a coordinating mechanism so that natural gas producers, renewable gas producers, network operators and gas users can integrate renewable gases. A renewable gas target and other coordinating policies should be considered in that case.

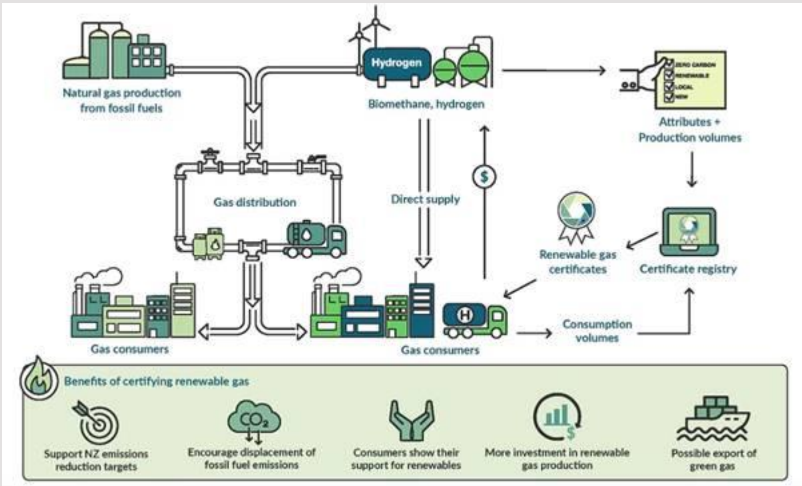
In the intervening period, renewable gas certificates could be a mechanism to integrate higher-cost renewable gases for gas users with a higher willingness to pay. For instance, some gas users may be prepared to pay for higher-cost renewable gases, and through a certificate system, could pay for the renewable gases blended into the network. This could help close the viability gap for renewable gases. Box 7.2 provides further detail about Renewable Gas Certificates in New Zealand.

[117] OMV (2021), Submission on the 2021 Draft Advice for Consultation.

Box 7.2: Renewable Gas Certificates in New Zealand

Certified Energy, which operates the New Zealand Energy Certificate System (NZECS), has established a system of certification of renewable gas.[118] The certification has been available within the NZECS from 1 October 2022. Eligible gases under the NZECS are green hydrogen, biomethane, biogas, and bioLPG. The certification system aims to incentivise new renewable gas production by providing a revenue stream for producers, while enabling gas users to make a statement about the types of gas they are supporting and generate goodwill. Certified Energy is also exploring how the NZECS can support the export of renewable gases.[119]

The system works in a similar way to renewable electricity certificates. Renewable gas producers issue a certificate for every unit of renewable gas they produce, which is logged on the NZECS Certificate Registry. Both gas that is produced and distributed via the network, and gas that is delivered to users directly (such as liquified petroleum gas (LPG)) are eligible under the certification system.[120] Gas users then purchase issued certificates, and the units are matched against a users' consumption (via a processed called 'redemption').[121] Certificates can be transferred between users. The diagram below provides an overview of the system for gas certificates.



Source: Certified Energy

Renewable gases have some potential for reducing emissions from LPG consumption. Modelling shows that under the Renewable Gas Pathway, blending bioLPG to replace 20 percent by volume would reduce the greatest amount of LPG emissions relative to other pathways. However, the costs of bioLPG are uncertain in New Zealand, and gas is not yet available. Again, a policy mechanism that coordinates between producers, suppliers, and consumers, such as a target, could be considered if the costs of bioLPG fall.

118 Certified Energy, The New Zealand Energy Certificate System

119 Certified Energy proposes that New Zealand Energy Certificates (NZECs) corresponding to the volume of gas to be exported be redeemed against a storage device, ensuring that those attributes do not leak into the domestic market. NZECs would be converted into the local certificate class once received. It will engage with international system providers to ensure acceptance of NZECs, and further develop this idea.

120 Certified Energy, The New Zealand Energy Certificate System, 2021, Response To Submissions, Renewable gas certification

121 Certified Energy, The New Zealand Energy Certificate System, 2021, Designing A Renewable Gas Certificate System

7.1.6 Retain LPG for some users and explore use of renewable LPG once available

The modelling of LPG demand suggests that LPG will remain an important energy source into the future. Switching to alternative energy sources is costlier than retaining LPG (even with a fully reflective carbon price). Other commentators, policymakers and stakeholders[122] have concluded that LPG demand will remain a feature in New Zealand's energy supply, providing up to 8PJ. Those conclusions appear to have been reached without modelling LPG demand and potential switching behaviour. Castalia's sensitivity analysis shows a high carbon price is required to make LPG use uneconomic compared to other energy sources for industrial and commercial users.

Commercial, residential, agriculture, and transport sectors will probably continue to use LPG due to the higher cost of electric substitutes. While biomass is viable in theory, substitution with biomass will likely be limited by feedstock supply, the cost of equipment, and concerns around poorer burn properties. Given these hurdles, renewable LPG could be the most effective decarbonization route for industrial and commercial LPG users that require a high burn temperature or a mobile energy source.

7.2 Additional impacts from the pathways beyond 2035

The pathways modelled in this report provide some insights on other impacts on the three parameters of the energy trilemma beyond 2035. Path dependencies are important to consider after 2035, as are the global net emissions impacts of New Zealand policy choices.

7.2.1 After 2035, most gas demand is likely to come from industrial users

The gas sector choices made in the short and medium term can limit the options available to reduce emissions after 2035. In the long-run, the choices available to reduce emissions in an affordable way might be maximised if options remain available.

When we extend the modelling out to 2050 using the same assumptions, natural gas demand decreases by around 30 to 50 percent compared to 2022. Remaining demand in most of the pathways is in the industrial sector. A large proportion of remaining demand is from Methanex (at least until 2039, consistent with other commentators' assumptions) and gas fired power plants. Since many industrial users typically emit GHGs from a small number of point sources, this could strengthen the economic case to carry out targeted CCUS. Assuming that by 2050 all medium and low heat processes will switch to an alternative energy source, the cost of distributing gas to the residential and commercial sectors will become very high, which would induce these users to switch too. This would leave only high heat processes, meaning that by 2050 gas demand would fall to around 82PJ per year.

7.2.2 Path dependencies matter beyond 2035 for methanol production and key infrastructure

Asset and infrastructure choices made by the large users of gas can create path dependencies and shut off future options.

[122] Including CCC, Worley in analysis for Gas NZ, and sector stakeholders we engaged with for this Report.

Key industries may enable future decarbonisation options

Just over one third of New Zealand's annual natural gas supply is currently used for methanol production. Methanol is clean burning fuel that is being promoted for use in shipping. If green[123] or blue methanol[124] can be produced, it could contribute to decarbonising shipping. If methanol production were to cease before emissions reducing technology is developed and deployed (such as green hydrogen or CCS), it could be difficult to restart the industry. This would impose economic costs from lost income, jobs, and higher methanol prices for domestic consumers of methanol.

Loss of gas sector transmission and distribution infrastructure could reduce options beyond 2035

Gas transmission and distribution infrastructure is a sunk investment. It could provide a valuable option to transmit renewable gases or captured carbon dioxide for storage (as outlined in section 3.6). If gas demand is confined to a small number of large users after 2035, the national transmission and distribution network may no longer be viable because the fixed costs of the network must be shared among a much smaller number of consumers of far less gas. Without enough customers, the network owners might choose to decommission the pipelines. If renewable gases become economically and technically viable in future (which would require significant falls in costs from today), the gas network might provide a valuable option for transmission and distribution. The existence of a network could be important to transmit biogas. A recent Beca report suggests biogas could replace significant volumes of gas but would need to be sourced from diverse and geographically widespread sources (farms, landfill, food waste depots).[125] Many of those biogas sources may be already close to the current gas network.

Emissions leakage from industry is possible

New Zealand's net zero by 2050 policy objective in the Climate Change Response Act supports its international commitments under the Paris Agreement. New Zealand's domestic objectives sit in the context of global efforts to reduce emissions.

Some policies that reduce domestic emissions may contribute to higher global emissions, especially if New Zealand emissions are from the production of goods or services that trade on global markets. For example, methanol, urea, and milk products produced in New Zealand are all tradeable commodities subject to a global price, determined by global supply and demand for the commodities. Changes in natural gas input costs can make domestic production of commodity goods uncompetitive with imports for domestic consumers or uncompetitive on global markets. This will force domestic trade-exposed firms to stop production. If global demand for the commodity goods remains unaffected, and global emissions frameworks are not binding on overseas competitors, those overseas producers could keep using fossil fuels to meet demand for those commodities.

Over 95 percent of methanol produced by Methanex in New Zealand is traded on global commodity markets. It competes with methanol produced in China, Russia, USA, Saudi Arabia,

[123] Green methanol includes: biomethanol, produced from the gasification of sustainable biomass sources such as livestock, agricultural and forestry residues and municipal waste; and e-methanol, produced from green hydrogen and captured carbon dioxide. Iberdrola, Green Methanol, available at: https://www.iberdrola.com/about-us/what-we-do/green-hydrogen/green-methanol

[124] Blue methanol is produced by using natural gas and capturing and storing the carbon generated during production.

[125] Beca (2021), Biogas and Biomethane in New Zealand, available at: https://www.beca.com/ignite-your-thinking/ignite-your-thinking/july-2021/biogas-and-biomethane-in-nz-report

Trinidad and Tobago, Iran, Germany, Venezuela, and Oman. If methanol production ceased in New Zealand, without a corresponding and enforced commitment from overseas producers to reduce emissions-intensive production, any change in global emissions would be much smaller than the emissions reduction in New Zealand from methanol production. This is because global demand is not influenced by New Zealand's methanol production. Indeed, global emissions may even increase since some methanol produced in China comes from coal, which has a significantly higher emissions profile than natural gas.[126] In such a situation, New Zealand's GDP would fall, and emissions would be unchanged or worsen. Methanex's recent submission to the Ministry for the Environment on proposed changes to the ETS,[127]as well as internal government advice,[128] highlights that global emissions are expected to increase if Methanex ceases domestic production.

Similarly, New Zealand's domestic producer of urea, Ballance, produces a globally traded commodity. It competes with importers of urea and must match the global price. Ballance's Kapuni plant is constructing a wind powered green hydrogen electrolyser to partially decarbonise its production process. If Ballance ceased producing urea in New Zealand as a result of domestic gas sector or climate policies, this would not affect local or global demand (unless fully coordinated with other urea producing countries). As a result, global emissions would not be affected, or might even increase slightly.

[126] Methanol produced from coal has an estimated carbon footprint of 300g CO_2e/MJ compared to 110g CO_2e/MJ for methanol from natural gas. Methanol Institute (2022), Carbon Footprint of Methanol, available at: https://energycentral.com/c/og/carbon-footprint-methanol

[127] Methanex's 2022 response to the consultation document issued by the Ministry for the Environment on 9 September 2022 ("Proposed changes to New Zealand Emissions Trading Scheme limit and price control settings for units 2022") discusses emissions leakage implications of increased NZU prices on Methanex. It states that "the likely impact of significantly elevated carbon pricing will have the effect of reducing domestic emissions but materially increasing global emissions." Methanex (2022), Methanex New Zealand Limited—consultation on proposed changes to NZ ETS limit and price control settings for 2022.

Recent press coverage also highlights emissions leakage implications. RNZ (2021), Methanex to mothball Waitara Valley plant in Taranaki, available at: https://www.rnz.co.nz/news/business/437055/methanex-to-mothball-waitara-valley-plant-in-taranaki

[128] A 2018 MBIE aide memoire about methanol applications (received through OIA) states that "The direct consequence of Methanex scaling back its operations in New Zealand is that this global supply is met by higher cost, and significantly higher emitting, methanol produced from coal in China." MBIE (2018), Aide Memoire: Methanol Applications, available at: https://www.beehive.govt.nz/sites/default/files/2018-06/07_Methanol%20Applications.pdf

Appendix A: Modelling approach and assumptions

The modelled pathways have common and specific assumptions, which are used in each model module. A detailed description of the modelling approach and common assumptions for each pathway is provided in A.1. Pathway-specific modelling approaches and assumptions are provided in A.2.

A.1 Modelling approach and common assumptions for energy demand and energy source switching

The model predicts energy demand based on the marginal levelised cost of energy for a user over time. The energy price assumptions and fuel switching behavioural drivers are set out as follows.

A.1.1 Natural gas price modelling approach and assumptions

A summary of the approach to developing the natural gas price is set out below.

Category	Approach
Wholesale price of natural gas	The wholesale price (before transmission, distribution and any retail or other costs are included) is flat and the same for all pathways at around \$6.50-7 per GJ. This is because falling demand for gas over the long-term is balanced by diminishing supply as the offshore gas exploration ban means no new fields are brought into production. It is assumed that the wholesale price of gas will continue to be driven by the balance between supply and demand and remain relatively close to its average historical levels of approximately \$6.5 to \$7 per GJ.[129] Supply and demand of wholesale gas are estimated to generally be in balance in the long-term. The government will not grant new offshore oil and gas exploration permits, which caps the available gas for supply (excluding additional supply that can be unlocked through onshore exploration, and through ongoing development of existing gas fields).[130] Gas demand is likely to decrease as consumers switch to alternatives. This is because of increasing retail gas prices, rising carbon costs, and higher average network and distribution costs, which further increase the retail price of gas and contribute to switching to alternative energy sources (electrification or other). Demand from Methanex is one of the key drivers of gas demand. It is assumed that Methanex will remain open throughout the modelled period, providing long-term contracts and steady demand for gas producers. As a result, certainty about the future demand would assure continued investment in future resources, resulting in a sufficient supply of gas to meet the demand and a balanced wholesale price.
Supply of natural gas	We assume New Zealand will have sufficient gas supply to meet future demand from large-scale gas users over the long-term New Zealand has natural gas reserves, and resources will be sufficient to meet New Zealand's energy demands between 2022 and 2050. New Zealand has 2P[131] natural gas reserves of 1,967

[129] MBIE, Energy prices, The wholesale annual natural gas prices between 1999 and 2021. The wholesale price excludes the New Zealand Emissions Trading Scheme (ETS).

[130] Although natural gas supply is unlikely to be constrained in the modelled timeframe (2022-2035).

[131] 2P reserves are the total of proven and probable reserves. Proven reserves are likely to be recovered, whereas probable reserves are less likely to be recovered than proved reserves. The sum of proved and probable reserves is represented by 2P.

	petajoule (PJ), and additional 2,915PJ of contingent resources could provide sufficient gas if partially developed.[132] This assumption is aligned with MBIE's long-term projections of reserves developments[133], and the GIC's gas supply and demand projections, which suggest that there is sufficient gas in New Zealand's existing fields to meet future demand out to 2060.[134]
Carbon price component	Changes depending on the pathway, calculated based on the carbon price and the emissions intensity of natural gas. Industrial allocations of free emissions units are not included in the modelled cost of energy for gas users. We assumes that gas users purchase units at the full price. The allocation of units matters for competitiveness of gas users end products and services, particularly in trade-exposed sectors. We do not model the gas demand impacts of changes in prices of gas users' end products, so the inclusion of industrial allocations is only relevant for changes in energy demand based on energy costs.
Network cost	Cost of transmission and distribution (T&D) network services will increase annually due to current regulatory expectations and rising average costs as connection numbers fall. This assumption is based on the Commerce Commission's decisions to apply accelerated depreciation to gas network assets, which aims to ensure that infrastructure can meet safety and reliability obligations during New Zealand's transition to a net-zero economy in 2050. This decision is expected to increase T&D costs which will be recovered by increasing customer prices. ▪ We include transmission (Tx) and distribution (Dx) costs ▪ We calculated pipeline demand for Tx and Dx based on the projected total gas consumption ▪ We also projected maximum allowed revenue (MAR), which is assumed to increase by 44% by 2050 ▪ We then calculated the Tx and Dx charge per GJ based on the corresponding pipeline demand ▪ The Dx charge is adjusted depending on user classification (for Agriculture, forest & fish, Commercial, Residential and Other Industry).
Retail and metering cost	Data taken from CCC's ENZ model.[135]

A.1.2 Electricity prices approach and assumptions

The electricity price path is taken from the CCC's "Tiwai stays with certainty" scenario. We then make assumptions about the impact of transmission, distribution and retail costs, impact of the carbon price, and discuss how the carbon price affects electricity prices.

Category	Approach
Wholesale price	Wholesale electricity price projections are taken from the CCC's "Tiwai stays with certainty" scenario. The wholesale price is then adjusted for the Industrial, Commercial and Residential sectors based on the scaling factor using the following formula: $Adjusted\ wholesale\ price = R_s * H_s * L_s * P_{TW}$

[132] MBIE, 2021, Markets – Evidence And Insights, Energy In New Zealand 22, Comprehensive information on and analysis of New Zealand's energy supply and demand
[133] MBIE, 2021, Markets – Evidence And Insights, Energy In New Zealand 22, Comprehensive information on and analysis of New Zealand's energy supply and demand
[134] Concept Consulting, 2022, Gas supply and demand projections
[135] Climate Change Commissions, Modelling and data, Emissions in New Zealand (ENZ) Model, available at: https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/modelling/

	where, ▪ P_{TW} is the time-weighted average wholesale electricity price ▪ R_s is the ratio between demand-weighted average price and time-weighted average price for ▪ customer segment ▪ H_s iis the hedge contract for customer segment ▪ L_s is a factor to account for distribution losses for customer segments. Total scaling factor for Residential sector is 1.21, Commercial – 1.2, Industrial – 1.14[136]
Transmission, distribution, retail and metering costs	We include a fully variable Tx and Dx cost, plus retail and metering costs depending on the sector in question. The sectors are Industrial, Agriculture, Forestry, and Fishing, Commercial and Residential. The data for these network costs are sourced from the CCC's ENZ model.
Impact of different carbon prices on electricity prices	We used data from BusinessNZ Energy Council that quantifies the impact of carbon prices on electricity prices. We then calculated the price elasticity of electricity depending on changes in carbon price. Overall, our analysis suggests that in 2022, an increase of carbon prices by $1 would increase electricity prices depending on the sector as follows: ▪ Industrial sector by 0.1 percent ▪ Commercial sector by 0.14 percent ▪ Residential sector by 0.15 percent However, since electricity generation is increasingly coming from renewable resources, changes in the carbon price will have less of an effect over time. We therefore adjust the 2022 impact of the carbon price on electricity prices at the same rate at which the share of fossil generation falls.

A.1.3 LPG price approach and assumptions

The approach to estimating the LPG price, and underlying assumptions are as follows:

Category	Approach
Wholesale price	We adopt the CCC's forecast LPG prices. CCC uses the diesel price to derive the LPG price: LPG price = Diesel price minus diesel transport in diesel costs plus non-wholesale costs for residential/commercial/industrial users plus carbon price
Diesel transport in diesel costs ($/GJ)	$1.004/GJ sourced from CCC's ENZ modelling.
Non-wholesale costs ($/GJ)	The LPG price to users includes non-wholesale costs such as primary and secondary transport, retail cost-to-service (CTS) and a retail margin for the Residential, Commercial and Industrial sectors.
Carbon price ($/GJ)	The carbon price component of LPG changes depending on the pathway in our model, and is calculated based on the carbon price and the emissions intensity of LPG sourced from the CCC's ENZ modelling.
Formula ($/GJ)	LPG price=Diesel price-Diesel transport in diesel costs+ Non-wholesale costs for residential/commercial/industrial users + carbon price

[136] ICCC, 2019, Modelling Retail Electricity Prices Under High Renewables, And Low emissions Scenario

A.1.4 Biomass price approach and assumptions

We assume a biomass price of approximately $11.7 per GJ remains flat across the analysed period.

Category	Approach
Biomass price delivered	The biomass cost to users is taken as an average price of the forest residues, pulp chips, wood pellets, process residues and billetwood, and in-forest residues (including collection).[137] The same biomass price is applied across all gas consumers, including industrial, commercial, residential, and so on. Woody biomass is considered a cost-effective fuel alternative for many industries that use boilers, and is therefore an important low-carbon fuel source. There are three main sources of biomass for use as boiler fuel—forest-based residues, wood chips, and processed wood pellets. The proposed price of biomass used for the pathway modelling is based on the average price of three main biomass sources because users have different preferred choices (forest residue ($9-12 per GJ), pulp chip ($12.8 per GJ), and pellets ($14.8 per GJ)).[138]

A.1.5 Energy source switching to low-emissions alternatives

Fuel or energy source switching to low-emissions alternatives is one of the key factors driving the reduction in natural gas consumption and emissions. Fuel switching will occur across all pathways. However, the extent to which, and the timeline of when, users will switch to low-emission alternatives will vary depending on the cost of carbon, the level of the renewable electricity mix, capital costs, operational costs, alternative fuel costs and policy and regulations. Fuel switching is divided into three categories:

- Industrial
- Commercial and residential, and agricultural sectors
- Electricity generation.

The approach and assumptions that underpin the fuel switching in the model are set out below. The same approach was applied to natural gas users and LPG users (adjusting for the higher energy content of LPG).

Fuel switching for industrial and food processing sectors

The modelling approach and key assumptions for fuel switching are modelled as follows.

Category	Approach
Natural gas and LPG:	
Industrial sector	Fuel switching in the industrial sector with low to medium heat processes is determined by the relative capital and variable (fuel) costs of different energy types adjusted for the efficiency of the gas, electric and gas equipment. For the pulp and paper sector, fuel switching is only based on the fuel price. The modelling assumes no CAPEX cost for increasing use of biomass, as some sector boilers are multi-fuel capable.

[137] EECA, 2022, Government Leadership Regional Energy Transition Accelerator (RETA) Southland - Phase One Report. Available at: https://www.eeca.govt.nz/assets/EECA-Southland-RETA-Report.pdf; The Climate Change Commission, Modelling and data, Emissions in New Zealand (ENZ) Model; EECA, 2022, Government Leadership, Regional Energy Transition Accelerator (RETA), Southland - Phase One Report

[138] The Climate Change Commission, Modelling and data, Emissions in New Zealand (ENZ) Model; EECA, 2022, Government Leadership, Regional Energy Transition Accelerator (RETA), Southland - Phase One Report

	We also assume that a maximum of 20 percent of industrial users can switch from gas in any year. This reflects the constraints on engineering expertise and equipment and capital goods required to switch industrial users from gas to alternative energy sources. Fuel switching for the industrial sector becomes cost-effective when the relative costs of continuing to operate gas assets is greater than converting to an alternative low-emissions asset. Switching is generally price driven, and the price includes the cost of fuel, capital costs (including transmission and distribution network upgrade cost) and carbon cost. The difference in fuel price typically makes up about 60-80 percent of the total life-cycle cost.[139] Capital costs and carbon costs also play a significant role in the economic viability of switching decisions to lower-emission fuels. Natural gas is currently used for process heat (mainly in boilers) and as a feedstock in the industrial sector. It is assumed that processes that use natural gas for high-temperature heat and as a feedstock will continue to use gas, due to the lack of viable low-emissions alternatives. It is assumed that industry using low-medium process heat (such as for food processing and wood, pulp and paper production) will progressively switch to wood-based biomass and grid-sourced renewable electricity.[140]

Fuel switching in commercial, residential and agricultural sectors

Fuel switching in commercial and residential, and agricultural sectors is modelled as follows.

Category	Approach
Natural gas:	
Commercial and Residential	Gas is used in households and businesses mainly for cooking, and space and water heating. Provided there are no connections, bans and other mechanisms impacting decision-making, it is assumed that: ▪ Households that currently use gas will continue to do so because it is typically not economical to replace these before end-of-life[141] ▪ Consumers will want choices when building new homes (or replacing old appliances), and will largely make decisions based on what is most economic[142] ▪ Some switching will occur in existing homes, but at a slower rate than in new homes ▪ Overall, it is expected that the number of new customer connections will decrease compared to historical averages.[143] To estimate commercial and residential switching behaviour, we reviewed modelling by EnergyConsult[144] that predicts gas use based on historical sales of appliances, energy use, demand and energy efficiency. This showed that commercial and residential demand for gas was relatively inelastic to changes in price. We then applied a fuel-switching approach as in the agriculture, forestry and fishing sectors. However, we assumed that in addition, commercial and residential users of gas would have a 30 percent price rise tolerance above electrification costs to account for inertia, as well as time and search costs of switching.

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[139] The University of Waikato, 2019 Options to Reduce New Zealand's Process Heat Emissions

[140] The University of Waikato, 2019 Options to Reduce New Zealand's Process Heat Emissions; The Climate Change Commission, 2021, Ināia tonu nei: a low emissions future for Aotearoa, Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025, p.288
Switching will largely occur whenever owning and operating gas appliances is no longer the least-cost option. When the switching will occur will be determined when the modelling is undertaken.

[141] NZ Gas Infrastructure Future, Findings report, 2021: the weighted average retrofit costs for consumers switching their gas appliances to electricity today would be around $4,000 per household. A consumer with the full range of appliances – a water heater, hobs, and central or radiator heating – may face an average retrofit cost of $8,000 -$10,400.

[142] Energy Resources Aotearoa, 2022, Fuelling the Energy Transition, A low Emissions Energy Future for New Zealand, p.66
Switching may not be a fully least-cost decision for the commercial and residential sector. Some users, such as restaurants, may be willing to pay more to use gas. Information provided through consultations with stakeholders and https://firstgas.co.nz/wp-content/uploads/16098-First-Gas_Future-of-Gas-Report-Dec18-FINAL-high-res.pdf

[143] Vector Gas Distribution Asset Management Plan Update – 2022-2032

[144] Energy Consult (2021), Residential Energy Baseline Study: Australia and New Zealand, available at: https://www.energyrating.gov.au/document/report-2021-residential-baseline-study-australia-and-new-zealand-2000-2040

	This approach was applied to both commercial and residential because we assume commercial users will largely follow the pattern of the residential sector.
Agriculture, forestry and fishing	We assume that switching is driven by the cost of electricity plus the annualised capital costs of new electric appliances relative to the cost of existing gas use. A maximum of 20 percent of sector users can switch from gas in any year. This reflects the constraints on engineering expertise and equipment and capital goods required to switch industrial users from gas to alternative energy sources.
LPG:	
Commercial and residential	Similar to the projections of natural gas consumption changes, we used EnergyConsult modelling results to project LPG consumption. Switching from LPG to electric appliances is assumed to be driven only by the price. No capital costs of new appliances were taken. We also assume that even if LPG prices increase by 30%, users will still prefer using LPG rather than switching to electricity. A maximum of 20 percent of sector users can switch from gas in any year. This reflects the constraints on engineering expertise and equipment and capital goods required to switch industrial users from gas to alternative energy sources

Switching energy sources for electricity generation

Natural gas plays an important role in supporting electricity generation in New Zealand, particularly to balance the system during peak demand and to meet growth in electricity demand across the economy. It is assumed that baseload gas use for electricity is likely to reduce due to an increased integration of renewable generation into the electricity mix. However, due to the decommissioning of coal generation, gas generation would still be required to provide flexibility during the peak demand and dry years. The modelling approach to estimating the use of gas and other energy sources in the electricity system is as follows.

Category	Approach
Natural gas demand in electricity generation	In the Reference Pathway, and all other Pathways except the 100 Percent Renewable by 2030 Pathway, we assume that renewables will provide 98 percent of total electricity generation by 2035. The remaining 2% will be provided by gas fired generation. We also assume that peaking thermal capacity will be met exclusively by gas-fired open-cycle gas turbine (no combined cycle gas turbine or co-generation). This is consistent with Concept Consulting's analysis for the report "Climate Change in New Zealand: The Future is Electric".[145] We used the total demand for electricity projections from the CCC's "Tiwai point stays with certainty" scenario. We then calculate how much of the total electricity demand will be generated by gas-fired power plants (that is, 2% times total demand for electricity). We then converted the electricity demand into a total gas demand by using the heat rate of OCGT (peakers) of 9.6 GJ/MWh (consistent with the CCC assumption).
Retirement of coal generators	We assume that coal-fired generators will retire by 2025.

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

A.2 Pathway-specific modelling approaches and assumptions

We make a range of assumptions that are specific to individual Pathways. In particular, assumptions there are material assumptions used in the 100 Percent Renewable Electricity by 2030 Pathway, Direct Interventions Pathway, Renewable Gas Blending Pathway, and the CCUS Pathway (aside from the common assumptions outlined in section A.1).

A.2.1 Reference Pathway

The specific assumptions of the Reference Pathway are provided below. These assumptions provide the base case, from which the other pathways build off and adjust, depending on the parameters of the pathway.

Carbon price trajectory

Assumption: Carbon price trajectory of \$140/tCO_2e in 2030 and \$160 tCO_2e by 2035

The price of carbon is one of the key instruments used by the government to encourage behaviour change to reduce emissions. New Zealand's carbon price is expected to rise in the future to meet the country's 2050 emissions reduction target.

The CCC indicates that New Zealand emission units (NZUs) would need to be priced at around \$140 per ton in 2030 to achieve the target. The CCC points out that this is not a forecast price. However, it will help to drive the expectations that carbon prices will continue to rise.

Electricity price

Assumption: Price of electricity is assumed to be fluctuating, but overall will remain relatively flat

An increase in natural gas prices would have minimal impact on wholesale electricity prices, given that a significant amount of gas power generation would be displaced by renewable generation under the Reference Pathway. In addition, retailers often remove wholesale electricity price variations when determining how to pass these costs onto households, which would flatten retail price fluctuations.

Hydrogen, biogas, bioLPG, DME blending

Assumption: Natural gas and LPG blending with hydrogen, biogas, bioLPG, or DME is not available at scale[146]

The literature review and stakeholders' feedback suggest that blending natural gas with renewable gasses is unlikely to be competitive with other emissions reduction options under New Zealand's current policy settings. This is because natural gas and LPG blending with hydrogen, biogas, bioLPG, or DME have higher costs than other abatement options, and there is no explicit government support for green gas blending. Policy and technology improvements would be required to make green gas blending viable.

[146] Some renewable gas projects are currently underway, for example the biomethane project at the Reporoa Organics Processing facility. Under the Reference Pathway, these projects are expected to continue at small scale, but not at large scale, and therefore do not impact natural gas demand overall. No new projects are expected to eventuate.

Availability of CCUS

Assumption: CCUS technology is not viable

It is assumed that carbon capture and storage (CCS) and CCUS technologies will not be available in the analysed period due to the ambiguity around the prospects of CCS and CCUS in New Zealand.

The government does not currently see a rationale to adopt the technology because New Zealand's emissions are relatively dispersed, which makes CCS and CCUS less viable for reducing emissions. MBIE states that it supports the international development of CCS and CCUS, but "does not prejudge any decision on whether or when CCS might be undertaken in New Zealand."[147] Additionally, if the regulatory framework becomes available for stakeholders to implement the technology, it will take 3-5 years to set up from the time of the permit.[148]

Offsetting

Assumption: Available, but complementary policies used

It is assumed that offsets (removals and offshore mitigation) are available to a somewhat limited extent. This is because so-called 'complementary policies' are chosen in addition to offsets within the Emissions Trading Scheme (ETS). Complementary policies generally subsidise emissions reductions, or penalise emissions, beyond those driven solely by the ETS. Policymakers in government think that such policies are needed in addition to the ETS to address market failures and drive efficiency.[149] Governments have also demonstrated a tendency to select complementary policies rather than rely solely on the price signal under the ETS to support emissions reductions (for example, the clean car feebate policy).

Increase in renewable electricity

Assumption: A gradual increase in renewable electricity to 95-98 percent by 2035 from approximately 82 percent in 2021

It is assumed that the share of renewable electricity will increase to 95 percent by 2030 and 98 percent by 2035. The assumption will avoid a higher electricity price than New Zealand currently has. Achieving 100 percent renewable electricity would require overbuilding of renewable generation such as wind and solar to ensure sufficient electricity is available in dry years. This would also require increasing battery storage and demand response. However, this costly solution will likely result in higher electricity prices.

The CCC's report also suggests that the government should consider replacing the 100 percent target by 2030 to 95-98 percent target by 2030.[150]

Closure of Tiwai Point Aluminium Smelter and Methanex

Several large industrial players significantly impact energy consumption in New Zealand, including Tiwai Point Aluminium Smelter and Methanex.

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147 MBIE, Carbon capture and storage

148 Energy Resources Aotearoa, 2022, Fuelling the Energy Transition, A low Emissions Energy Future for New Zealand, p.66

149 New Zealand Treasury (2022), The Value of Taking a Portfolio Approach to Climate Policy. https://www.treasury.govt.nz/sites/default/files/2022-10/an22-06.pdf; Climate Change Commission (2022), New advice on NZ ETS unit limits and price control settings. https://www.climatecommission.govt.nz/news/new-advice-on-nz-ets-unit-limits-and-price-control-settings/

150 The Climate Change Commission, 2021, Ināia tonu nei: a low emissions future for Aotearoa, Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025, p.272

Continuing to supply to large industrial players is a major incentive for natural gas producers to continue to supply all users across the economy. Closure of large industry would impact gas consumption by gas-fuelled peaking power plants and would significantly impact the amount of available electricity. Tiwai Point Aluminium Smelter consumes 10-14 percent of the electricity generated in New Zealand. Methanex consumes around 40 percent of the total domestic gas supply to produce methanol from natural gas.

Tiwai Point Aluminium Smelter

Assumption: Tiwai Point Aluminium Smelter will remain open at least until 2035

It is assumed that Tiwai Point Aluminium Smelter will continue to operate after 2024, and that changes in the smelter's operations would not result in decreased gas consumption in the analysed period. This assumption is based on recent public statement by the smelter, which states its intention to secure a new electricity contract.[151] If the smelter does decide to close, it is assumed that management would provide early signals to the market.

Continued baseload thermal generation and new natural gas peaker plants may be required to meet growth in electricity demand in New Zealand, if the smelter stays open beyond its earlier signalled closure in 2024. However, an early and certain signal of continued operations may also bring forward the construction of renewable generation projects and minimise the increase in fossil fuel electricity generation.

Methanex

Assumption: Methanex will remain open until at least 2039

It is assumed that Methanex will remain open until at least 2039 because Methanex's investment in emission reduction technologies indicates its objective to continue operations in New Zealand. Methanex has recently made a multi-million-dollar investment to reduce its carbon emissions over the next 12 months, with an economic payback within two years. Methanex expects the project to potentially reduce the site's carbon emissions by over 50,000 tons per annum.[152]

It is also assumed that there is no new significant industrial natural gas use over the modelled period[153]

No ban on new gas connections

Assumption: No ban on new gas connections (both natural gas and LPG)

Gas connections will be driven by consumer preferences on capital and operating costs of gas and alternative (electric) appliances. It is assumed that the government will not ban new gas connections. A ban might limit the opportunity to repurpose the existing gas network infrastructure for green gas blending (one viable supply is available). The CCC's draft report discussed a possible ban on gas connections, but its final report did not include this recommendation.

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151 RNZ, 2022, Tiwai Point aluminium smelter begins talks to continue operating after 2024

152 Methanex Invests in Technology To Reduce Emissions at New Zealand Site by Over 50,000 Tonnes

153 We understand that Methanex has a dormant plant in Waitara Valley that could be a significant future user of natural gas. For the purposes of the analysis in this report, we assume it does not resume production.

A.2.2 CCC Demonstration Pathway

Assumptions for the CCC Demonstration Pathway are:

- The Tiwai Point Aluminium Smelter will be closed at the end of 2024, with the electricity becoming available for alternative use
- All new space heating and hot water systems installed after 2025 in new buildings are electric
- Phase-out of gas for the existing building will begin in 2030, and no further natural gas connections to the grid, or bottled LPG connections, will occur after 2025
- Methanex is assumed to decrease level of production from 2023
- Gas demand in the refining sector continues
- Share of renewable electricity is 93 percent by 2035
- Other assumptions are consistent with the Reference Pathway.[154]

A.2.3 100 Percent Renewable Electricity by 2030 Pathway

Assumptions for the 100 Percent Renewable Energy by 2030 Pathway are:

- 100 percent renewable electricity will be achieved by 2030, resulting in higher electricity prices relative to the Reference Pathway
- Additional renewable energy generation (1,174MW) and storage (500MW) investment is required to increase reliability of supply[155]
- Additional cost of non-supply and unplanned outages (for the proportion of customers that are not covered by the additional generation and storage investment) is also included in total costs. The amount of non-supply is estimated at approximately 4,000MWh annually, and there is an annual need for over 8,000MWh of demand side response (DSR)
- Other assumptions are consistent with the Reference Pathway.

Higher electricity prices are expected as New Zealand increases the share of renewable electricity. Literature states that replacing the last 1–2 percent of fossil fuel generation with renewable electricity would be costly, and prices would likely increase for residential, commercial, and industrial customers.[156] This pathway is adjusted for reliability to enable a fair comparison between pathways.

The modelling approach adopted in this pathway is explained in the table:

[154] The Reference Pathway assumes Methanex will close after 2039, while the CCC Demonstration Pathway assumes it will close after 2040.

[155] ICCC's modelling of increased electricity prices does not cover costs of additional generation and storage investment required to increase reliability of supply. Therefore, additional investment has been included to increase energy reliability under this pathway.

[156] For example, The Interim Climate Change Commission, 2019, Accelerated electrification, Evidence, analysis and recommendations; the Climate Change Commission, 2021, Ināia tonu nei: a low emissions future for Aotearoa, Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025, p.279; and Cole et. al., (2021), available at: https://www.sciencedirect.com/science/article/pii/S2542435121002464

Category	Modelling approach
Impact of 100% renewable electricity	In order to estimate the impact on electricity prices of 100 percent renewable energy, we used the Interim Climate Change Commission's (ICCC's) estimate of how 100 percent renewable electricity generation by 2035 will impact electricity prices relative to 2018 actuals. The price impact of achieving 100 percent renewable by 2035 on electricity prices is: ▪ Residential—increase of 17 percent ▪ Commercial—increase of 32 percent ▪ Industrial—increase of 44 percent. In addition, capital investment is needed. While the electricity price increases described above would cover the costs of new generation, transmission and distribution (assuming cost reflective pricing), some extra capital investment is required to provide responsive dispatchable generation to match current reliability standards. Therefore, we estimated the capital cost of additional generation required to improve the reliability of the grid. These costs include:[157] ▪ The average cost of three additional generation/capacity options includes a significant overbuild of renewables, the Onslow pumped hydro scheme and large-scale hydrogen storage. ▪ Demand side response costs ▪ Non-supply cost (value of lost load)

A.2.4 Direct Interventions Pathway

Assumptions for the Direct Interventions Pathway are:

- Natural gas is progressively phased-out from 2025, with no further gas consumption from 2030 for low-medium heat processes
- Natural gas supply for methanol production (Methanex) is available only for feedstock after 2030. Methanex switches to electricity as an energy source for process heat
- Natural gas supply for urea production (Ballance Kapuni) ceases after 2030. Ballance Kapuni switches to green hydrogen and biogenic carbon for feedstock, and electricity for process heat.
- Natural gas use for electricity generation follows Reference Pathway (that is, 98 percent renewable electricity by 2035). It is assumed that there is sufficient electricity supply to support increased electricity demand from large users
- No new natural gas or LPG commercial or residential connections after 2025
- Green hydrogen and carbon dioxide supply for urea production is available where demanded.

The Direct Interventions Pathway makes various modelling assumptions to reflect the deliberate policy choices and interventions affecting gas users. The modelling approach adopted in this pathway is explained in the table:

[157] This data was sourced from: ICCC, 2019, Modelling Retail Electricity Prices Under High Renewables, And Low emissions Scenario. Available at: https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Advice-to-govt-docs/ICCC-electricity-modelling-reports.pdf; EnergyLink, 2022, Hydrogen Storage as a Dry-year Solution. Available at: https://static1.squarespace.com/static/62de1246a51eee1bf53f34e6/t/638fd2b2f97caf09e09390ba/1670369984302/First+gas+hydrogen+storage+modelling+Nov-22+FINAL.pdf

Natural gas phase-out assumptions and modelling approach

Category	Modelling approach
Natural gas use by low-medium heat processes	Gas is progressively phased-out from 2025 in the model with no further gas consumption from 2030 for low-medium heat processes. This affects the following sectors: ▪ Food processing ▪ Pulp & paper ▪ Mining & quarrying ▪ Other industry ▪ Agriculture, forestry and fishing. There will not be enough biomass resource for all of these users to consume it in low-medium heat processes. The Direct Interventions Pathway, therefore, switches 50 percent of these users to biomass and 50 percent to electrification. This is in-line with the CCC's assumptions around available biomass resource, and the certainty of energy supply for electrification. Costs associated with switching to alternative fuels include: ▪ Fuel cost (biomass and electric) ▪ Marginal capital and operating costs of a new boiler (biomass and electric) ▪ Transmission upgrade for electric boilers.
Natural gas use in methanol and urea production	The model assumes that Methanex (methanol production) continues to use natural gas as a feedstock but switches to electricity for process heat (discussed below). The model assumes natural gas supply for Ballance Kapuni (urea production) stops entirely after 2030. balance Kapuni switches to green hydrogen (and captured carbon dioxide) as the only alternative feedstock (discussed below). Electricity is used for process heat (discussed below). It is not assumed that these producers cease production (although this may be the case). The economic impact of ceasing methanol and urea production is estimated outside of the model.
Electrification, and hydrogen and carbon use in methanol and urea production	We assume that from 2031, Methanex and Kapuni continue to produce methanol and urea. Volumes produced are the same as that of 2022. Natural gas remains a feedstock for methanol production. Green hydrogen (from electrolysis) and captured carbon dioxide (from biogenic sources) replace natural gas as a feedstock for green urea. For both methanol and urea production, electricity replaces natural gas as an energy source for heat processes because biomass supply is limited. The entire production capacity is assumed to switch in at once between 2030 and 2031. For methanol, we assume additional capital costs to electrify production. For urea, we assume additional capital costs to electrify production and additional capital costs for hydrogen electrolysers. Capital costs are assumed based on comparable new plant in New Zealand and is sourced from another modelling assignment for the New Zealand government. The capex component of hydrogen is included in the levelized cost of green hydrogen. The model assumes no other capital costs because the synthesis process is the same, independent of the source of hydrogen or carbon dioxide.[158] In the model, the cost of biogenic carbon declines from \$31.9/ktCO_2e in 2031 to \$30.7ktCO_2e by 2035[159] while the cost of green hydrogen declines from \$4.86/kg in 2031 to \$4.51/kg in 2035.[160]

[158] The hydrogen and carbon dioxide feedstock is currently produced through steam reforming of natural gas. To produce green methanol and green urea, the steam reforming step can be skipped; hydrogen and carbon dioxide can be directly provided. Some minor capital costs could be required for the storage and transport of hydrogen and carbon dioxide, but the model assumes that these costs are negligible.

[159] The cost of carbon is consistent with a cost of US\$22.5 in 2023, declining at a rate of one percent per year due to technological improvements. Source: IEA (2022), Simplified levelised cost of competing low-carbon technologies in long-distance transport, available: https://www.iea.org/data-and-statistics/charts/simplified-levelised-cost-of-competing-low-carbon-technologies-in-long-distance-transport

[160] Castalia modelling of green hydrogen costs.

Category	Modelling approach
	The amount of green hydrogen and biogenic carbon needed for urea production is the amount required to sustain the same production volumes as 2022.
Natural gas use in commercial and residential sectors	We assume no new natural gas or LPG commercial or residential connections after 2025. Even though population growth occurs, new houses and commercial premises do not connect to gas or LPG. We assume that gas consumption remains flat in these sectors (that is, we assume existing households and commercial premises do not increase gas demand). The cost of energy impact after this policy is applied a simple calculation of gas and electricity costs. No additional capital costs are assumed.
Natural gas use in high-heat processes	Industries using high-heat processes are assumed to continue using gas due to a lack of viable alternative technologies or energy sources.

LPG phase out

LPG is phased on in the Direct Interventions Pathway in a similar manner to natural gas. The modelling approach and key assumptions are outlined:

Category	Approach
Industrial LPG use	The use of LPG in the industrial sector is largely unallocated in statistics and data. We could not locate precise estimates for the industrial processes in which LPG is used. We therefore, assume that the proportion of LPG use in different industrial processes is the same as for natural gas. Therefore, we assume that approximately 26 percent of the total LPG consumption in the industrial sector will be used for low-medium heat processes (for example, in the dairy processing industry). Our analysis shows that these users will switch to biomass due to the high cost of electricity relative to biomass. The remaining user will continue consuming LPG. Meaning that no LPG phase-out is applied for this sector.
Agriculture, Forestry and Fishing sector LPG use	Assumes 50%/50% switching to biomass and electricity. Similar to the natural gas phase-out approach.
Commercial and Residential LPG use	Same as for the natural gas phase-out approach.
Transport LPG use	No switching or phasing out is assumed. LPG consumption in the transportation sector is approximately 1% of total LPG demand.

A.2.5 High Carbon Price Pathway

Assumptions for the High Carbon Price Pathway are:

- The carbon price rises steadily from 2022 up to $300 per ktCO2e by 2035
- Other assumptions are consistent with the Reference Pathway.

A higher carbon price could incentivise more investments in low-emissions alternatives and result in earlier fuel switching. However, lack of certainty on pricing policy could result in volatile emissions prices and make investments to reduce emissions riskier, which may result in under-investment.

This pathway would require certainty from the policy perspective on future carbon prices. The CCC and government express caution about rapidly increasing the carbon price. It could result in unintended consequences. For example, it could incentivise excessive forestry planting, which would provide only a temporary offset of emissions and is unlikely to reduce emissions effectively in the short-to-medium-term. For example, planting pines today would not generate substantial offsets by 2050.[161]

A.2.6 Renewable Gas Pathway

Assumptions for the Renewable Gas Pathway are:

- Renewable gas supply will be available
- Policies and regulations will enable the blending of hydrogen, biogas, bioLPG, and DME with natural gas and LPG
- Gas blending is economic relative to other abatement options (but utilising pure renewable gas is unlikely to be economic before 2035)[162]
- Other assumptions are consistent with the Reference Pathway.

Blended natural gas and renewable gasses can be used as a feedstock or for heating.[163] Where the capital costs of switching to electricity or biomass are high, renewable gas blending could allow gas users to gradually reduce emissions while incurring incremental operating costs.[164]

The cost of renewable gases would need to decrease over the short to medium term for renewable gases to be competitive with alternative decarbonisation options.

We also assume that renewable gases can be substituted for conventional LPG. We considered two renewable gases, bioLPG and rDME. We only modelled BioLPG because it is a more mature technology. The available supply and the cost associated with bioLPG and rDME are uncertain. We also assume there would be around 50 percent green premium over the conventional LPG price, however, in reality, it could be higher.

BioLPG

Bio-LPG refers to LPG produced through a renewable feedstock. It is chemically identical to conventional LPG and can be delivered, stored and used exactly the same way. The fuel could be integrated directly into the current supply and distribution pathways and would not require any change of end-use appliances.

There is currently no renewable LPG available in New Zealand. However, bioLPG is well-established overseas, with 460,000 tonnes already being produced each year globally – an amount that would more than cover New Zealand's current LPG needs. However, it is unclear

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161 NZ Insight: Carbon markets, 29 July 2021

162 It is unlikely that 100 percent green gases will be used in the gas network before 2035. First Gas states that all gas networks will not be converted to 100 percent hydrogen before 2050. While biogas is constrained by the feedstock availability—biogas potential is only 15.6-19.9 PJ per year. Additionally, 100 percent hydrogen or biogas would also require appliance conversion. Beca (2021), Biogas and Biomethane in New Zealand, available: https://www.beca.com/getmedia/4294a6b9-3ed3-48ce-8997-a16729aff608/Biogas-and-Biomethane-in-NZ-Unlocking-New-Zealand-s-Renewable-Natural-Gas-Potential-Final.pdf; First Gas Group, Bringing Zero Carbon gas to Aotearoa

163 For example, the Reporoa Organics Processing Facility is New Zealand's first large-scale food waste-to-bioenergy facility. It opened in October 2022. https://www.ecogas.co.nz/reporoa

164 Energy Resources Aotearoa, 2022, Fuelling the Energy Transition, A low Emissions Energy Future for New Zealand

how much of this can be available for export to New Zealand, given the high local demand for bioLPG as a renewable fuel to reduce emissions.

BioLPG is also more expensive than conventional LPG. However, the price premium is difficult to estimate.

rDME

DME is a methanol derivative, while renewable DME is made from renewable feedstock such as dairy manure. rDME is a competitive LPG substitute up to a 20% by volume blend limit or around 16.4% by energy. Several rDME plants have been built overseas. However, there is currently no rDME production in New Zealand. There are also no cost indications that we know of.

Modelling approach for Renewable Gas Pathway

The modelling approach for blending renewable gases in the model is as follows:

Category	Approach
Overall	Both biogas and hydrogen can be blended simultaneously with natural gas.
Biogas	▪ Biogas blending by energy = by volume ▪ Biogas blending is limited between 3% and 9% due to the supply constraint ▪ Biogas price is assumed to increase by an average 3.5% per year, based on BCG's projections ▪ Biogas is more costly than natural gas. Thus, there will be additional costs associated with this pathway ▪ The same biogas price is applied across all sectors, i.e. industrial, agriculture, commercial, residential
Hydrogen	▪ Up to 20% of hydrogen blend can displace around 6.3% of natural gas. ▪ Castalia projects hydrogen prices ▪ Hydrogen is more costly than natural gas. Thus, there will be additional costs associated with this pathway. We calculate an incremental cost of hydrogen consumption.
The year when green gas blending becomes available	▪ After 2026

A.2.7 CCUS Pathway

Assumptions for the CCUS Pathway are:

- CCUS technology will be viable from 2026
- Policies and regulations will enable CCUS use
- Other assumptions are consistent with the Reference Pathway.

CCUS is expected to cost less than fully transitioning to renewables for some industrial processes in New Zealand, such as iron and steel, cement,[165] ammonia, and methanol production. Carbon captured from ammonia production could also be used to produce urea.[166]

The availability of economical CCUS in New Zealand will be assumed. Because of uncertainty around timeframes, the modelling will assume a specific year for commercial scale adoption. This is not a prediction of the future, rather the pathway is a tool to illustrate possibilities.

CCUS Pathway modelling approach

The modelling approach for availability of CCUS and the natural gas users that can access it is as follows:

Category	Approach
CCUS application	Applied to natural gas consumed by heavily polluting industries, such as: ▪ Methanol ▪ Urea ▪ Steel ▪ Cement & Lime ▪ Electricity generation. The decision to invest in CCUS is assumed to be driven by the capital costs of CCUS relative to carbon cost. We used the IEA's estimated of the levelised cost of CO2 capture by sector and initial CO2 concentration. CCUS efficiency is assumed to be 85%.
The year when CCUS becomes available	After 2026
Cost associated with CCUS pathway	The total cost of the CCUS investment is calculated by multiplying the total emission captured by the CCUS technology by the levelised cost of CO2 capture ($/t$CO_2$)

165 The use of fossil fuels for heating accounts for 35–40 percent of emissions from cement production. The remainder comes from the calcination of limestone, for which there is no close substitute. This makes CCUS more appealing because it can potentially remove nearly all emissions, not just those from heating.

166 IRENA, 2021, Reaching Zero with Renewables: Capturing Carbon

Appendix B: Stakeholder engagement

The pathways (and pathway assumptions) were developed following a series of six intensive workshops with stakeholders from different parts of the gas sector, as well as feedback from policymakers from MBIE, GIC, and EECA.[167] These insights and feedback provided an evidence base for the modelling. This Appendix provides a summary of the stakeholder engagement, including detailing organisations that participated in and key insights from the workshops.

Six workshops were undertaken with upstream, midstream, and downstream gas stakeholders

The six workshops were held between late September and early October 2022. The workshops were:

- Upstream Workshop
- Midstream Workshop
- Downstream Retail Workshop
- Major Gas Users Workshop
- Large Gas Users Workshop
- LPG Workshop.

Each workshop was approximately 90 minutes. Castalia provided background to the project, approach to the analysis, and outlined the purpose of the workshop. Stakeholders were then asked to respond to guiding questions. The insights provided below are purposefully not assigned to any individual organisation.

Upstream Workshop

The Upstream Workshop was held on 29 September and sought the perspective of organisations that identify, extract, or produce natural gas. The following organisations attended—Beach Energy, New Zealand Oil & Gas, OMV, Todd Energy, Westside Corporation, as well as Castalia, Energy Resources Aotearoa, and Gas New Zealand.

Key insights gathered at the meeting are summarised below:

- Organisations have implemented projects to reduce scope one emissions, for example electrification, reducing flaring, compression efficiency, and replacing gas boilers with biomass. Other support, such as for tree planting (offsetting) and energy efficiency in homes,[168] has also been provided. These projects are considered 'low hanging fruit'
- To further reduce emissions, organisations are exploring:
  - CCUS—considered a promising emissions reduction option, particularly once lower cost emissions reductions opportunities (mentioned above) have been exhausted. However, there is no regulatory framework for CCUS
  - Electrification to supplement power supply at natural gas processing plants—exploring solar panels, and onshore and offshore wind power. However, it is possible that New Zealand will compete with Europe for turbine supply

[167] CCC were also invited to participate.

[168] For example, window installations through the Curtain Bank.

  - Hydrogen, including blending—this option is less certain
- Investment in the sector is being disincentivised, due to:
  - Demand uncertainty, such as around the future of Methanex
  - Demand destruction, for example because of electrification projects and other possible projects such as Lake Onslow. It is unclear whether Transpower will be able to support increased grid electricity
  - Resource Management Act (RMA) and Crown Minerals Act (CMA) make it harder and slower to implement projects
  - Lack of policy clarity, and lack of a supportive regulatory regime and framework
    - Organisations need policy clarity and a structured path to work towards, including through the election cycle
    - The sequencing of events is more important than the timing of the events
  - Uncertainty around the carbon price, but organisations expect it to increase
- Organisations stated that policy changes and uncertainties have negative impacts outside of Upstream organisations, for example:
  - Increased living costs for New Zealanders, particularly energy costs
  - Impact on industry—phasing out demand and supply of gas, when industry is still dependent on gas
  - Loss of jobs and strategic industries in New Zealand
  - Impact on iwi
  - Impact on New Zealand Inc
  - Emissions leakage.

Midstream Workshop

The Midstream Workshop was held on 30 September and sought the perspective of organisations that transport and store gas. The following organisations attended—First Gas, GasNet, Liquigas, Port Taranaki, Powerco, and Vector, as well as Castalia, Energy Resources Aotearoa, and Gas New Zealand.

Key insights gathered at the meeting are summarised below:

- Organisations have different opinions on the future of the gas supply and customer base. Some organisations are more optimistic than others. Key assumptions from different organisations include:
  - Natural gas supply will continue until at least 2030, maybe 2035. Beyond that, supply is unclear
  - Natural gas supply will not exist after 2050
  - A higher proportion of residential customers to drop off as gas prices increase
  - Customer size will remain similar to what it is now, and it is important to provide customers with energy choices

  – Gas supply may continue, but the delivery method might be different in 2050. For example, it could be via LPG
  – Industrial customers likely to remain until there are viable alternatives
  – Industrial customers will use other fuel sources, or will move production out of New Zealand (emissions leakage)
  – Methanex will continue to operate in New Zealand, which will mean a base load natural gas supply
- Due to the uncertainty on the future of gas infrastructure and supply, organisations are building strategies that accounts for uncertainty. For example:
  – Some organisations are starting to slow down investment in long-term assets, such as pipe replacement
  – Organisations are not actively decommissioning the network. However, accelerated depreciation is impacting investments in the network
  – Key focus is on recovery of debt and recovery of capital. Recovery costs tend to be shifted to the customer
  – Organisations are starting to invest in renewable gases, including biomethane and hydrogen (including blending). There is uncertainty around the costs of these possible alternatives (costs are often highly project-specific)
- Organisations have little confidence in New Zealand's current policy settings. This makes investments challenging. Organisations require continuous policy that enable 'back tracking' if needed. However, there are points of no return that present particular risks. For example:
  – Closure of Methanex
  – Customer death spiral (that is, as the number of customers decreases, the proportion of the costs associated with gas transmission in consumers' gas bills increases, causing more customers to switch to alternatives)
  – Some customers are looking to switch from gas. However, when customers are presented with the full costs of switching from gas to electricity (including cost of electricity connection), many customers continue with gas. Articulating the whole cost of switching from gas is important
- Midstream organisations can support emissions reduction efforts by reducing gas leakage (fugitive emissions) and changing the fuel used for compression processes.

Downstream Retail Workshop

The Downstream Retail Workshop was held on 3 October and sought the perspective of organisations that provide gas to end users. The following organisations attended—Contact Energy, Elgas, Genesis Energy, Liquigas, Mercury, Rinnai, and Vector, as well as Castalia, Energy Resources Aotearoa, and Gas New Zealand.

Key insights gathered at the meeting are summarised below:

- Organisations indicated that there is less appetite for gas connections from residential customers. However, it is expected that the majority of existing customers will continue using gas in the short-term, as alternatives are expensive:

  - Builders want to continue connecting houses to the gas network (and installing gas appliances) because it saves spaces and makes a house more resalable. However, heat pumps are becoming popular
  - Architects encourage electrification of houses
  - Less gas fitters are finishing courses—installers have uncertainty around the future
  - Trade allies are receiving a lot of questions from customers about the future of gas
  - One organisation shared that, in a recent survey, 45 percent of customers stated they are willing to switch from gas if the cost of gas increases by 30 percent
  - There are hidden costs with converting to electricity, including appliance costs and connections costs. These costs are not well understood in New Zealand
- Demand from industry is more stable. This is predominantly because industry is more difficult to electrify:
  - Some industry is asking for carbon neutral products, and many have emissions reduction plans
  - Ban on coal boilers for process heat, but industry still finding it difficult to decarbonise
  - More money may be available for decarbonisation efforts through the GIDI Fund and State Sector Decarbonisation Fund
- Organisations are exploring alternative gasses, for example:
  - Biomass
  - Hydrogen
  - Renewable LPG
  - rDME, which is probably 10-15 years away. Some organisations were sceptical about the viability of rDME
- Alternative gasses can be supported by existing appliances, with some upgrades. However, renewable gases face challenges such as:
  - Regulatory and policy barriers, including for blending
  - Demand and supply uncertainty
- GIC is considering transferrable certification, which could support gas use, and could change the trajectory of the market
- Other challenges in the sector include:
  - Accelerated depreciation, and recovering assets and uncontrolled decline
  - Lack of policy clarity
  - Policy is not considering what the existing gas infrastructure could be used for in the future. This takes away from option value
  - It is harder to argue that natural gas is lower emissions than other energy options because New Zealand's grid is highly renewable.

Major Gas Users Workshop

The Major Gas Users Workshop was held on 4 October. The following organisations attended—Ballance, Methanex, Oji Fibre Solutions, Fonterra, as well as Castalia, Energy Resources Aotearoa, Gas New Zealand, and MGUG.

Key insights gathered at the meeting are summarised below:

- Organisations are exploring low-carbon options, but still see a role of gas in the future. This is because gas is available, less expensive, and is required to make some products (for example, for high-temperature heat and carbon used as an input)
- Organisations have reduced emissions for 'low hanging fruit'. For example, by:
  - Progressively electrifying where possible, such as heat pumps and hot water boilers
  - Investing in decarbonisation
  - Focusing on changing from coal first (required by 2037), then will focus on shifting from gas where possible
- Other decarbonisation options being considered by major gas users are:
  - Increased electrification, but these alternatives are expensive (both capital and operating costs)
  - Hydrogen may be used by some organisations (but there are issues with affordability), while some organisations are not expecting to utilise hydrogen
  - CCUS
  - Biomass, but this is not effective for high-temperature process heat (but is effectively used for pulp and paper processing), and there are issues with supply and capacity constraints to gather biomass materials
  - Biogas, particularly as a drop-in fuel
  - Biocrude
  - Renewable energy certificates are also promising
- Organisations face challenges to decarbonise:
  - There are no incentives in the regulation to explore low carbon options
  - There are no incentives to export excess renewable electricity to the grid
  - Lack of certainty around future policy
  - Current policy environment rewards contraction and not growth
  - Experience high carbon prices compared to competitors
  - Cost of energy inputs are important to be competitive on global stage
  - ETS allocation is going to unwind over time
  - Limited number of boilers in production
  - The market is not willing to pay for green products, such as green methanol
- Organisations are, overall, expecting demand for products to grow. Emissions leakage is expected if products are not made in New Zealand

- Organisations have varying gas supply contracts, and some organisations have one contract, while others have split contracts. Longer contracts (5-10 years) are considered more beneficial by most organisations.

Large Gas Users Workshop

The Large Gas Users Workshop was held on 5 October. The following organisations attended—Auckland University, Dominion Salt, Hospitality New Zealand, Open Country Dairy (OCD), Plumbers and Gasfitters and Drainlayers Board, Restaurant New Zealand, Sanitarium, Vegetables New Zealand, Horticulture New Zealand, as well as Castalia, Energy Resources Aotearoa, and Gas New Zealand.

Key insights gathered at the meeting are summarised below:

- There is continued demand for gas from most end-users due to lack of viable alternatives:
  - 95 percent of restaurants are using gas and see it hard to switch to electricity cooking due to the temperature requirements and high switching costs
  - Other industrial processes require the high-temperature heat that gas provides
  - Some processes benefit from carbon in gas (for example, utilising carbon increases vegetable output by 25 percent
- Organisations are investing in projects and initiatives to reduce emissions. These include:
  - Electrification where possible (such as hot water), but these options have expensive capital and operating costs, and can require the implementation of new electrical lines to facilities. Organisations predict that electricity prices will decrease over the next five years
  - Carbon capture, which is already done for vegetable growing
  - Biomass, but some organisations do not have the space or the capacity to implement this and capital costs are high
  - Wood pellets, but these have capital and operating costs, and are only suitable for some appliances (gas boilers are not able to run on wood so would need to be replaced)
  - Windfarms
  - Efficiency designs in production and use
  - Carbon calculations to support organisations in understanding where their emissions are coming from
  - Hydrogen is also being explored, but this is in early stages
- Organisations face other challenges to decarbonising. These include:
  - Most organisations do not have money to switch to alternative options (such as electricity) after a challenging few years of trading due to COVID-19
  - An increasing carbon price is likely to push many companies out of business. Competing organisations in other countries do not experience such high carbon taxes. Emissions leakage is expected if products are not made in New Zealand

  - Early adopters of electric boilers are penalised because there is no infrastructure
  - GIDI Fund is useful, but is not enough for most organisations to switch to alternative low-carbon options
  - Technology supply constraints of alternatives (such as boilers) and limited number of contractors to implement technology
- Organisations have varying gas supply contracts, normally between 1-3 years in length.

LPG Workshop

The LPG Workshop was held on 11 October. The following organisations attended—Elgas, First Gas, Genesis Energy, Liquigas, Rinnai, and Rockgas, as well as Castalia, Energy Resources Aotearoa, and Gas New Zealand.

Key insights gathered at the meeting are summarised below:

- There are nearly as many LPG customers as there are natural gas customers (about 300,000 customers each). Sales volumes are relatively steady. Organisations expect some customers to drop off (possibly around 15 percent), but there is likely to be increased demand from hard to abate customers
- LPG is particularly useful when there is electricity and energy constraints. In addition, connection costs are relatively low, and long-term infrastructure requirements are limited. LPG can also be stored for long period of time and import facilities are not expensive
- Organisations see renewable gas as a future pathway for New Zealand. But the pathway is still in development:
  - Renewable LPG is being tested in places such as Italy, but it is probably 3-5 years away
  - rDME is considered promising by some organisations. It is being trialled, and is slightly closer to being 'ready' than renewable LPG
  - Biomethane is promising, and it can be blended into the pipeline with no regulatory changes (whereas rDME requires regulatory changes to enable mixing). Biomethane could be an option in the short-term
  - Hydrogen is also being explored
- Modifications to appliances required to utilise alternative gases are mostly straightforward
- Renewable gas certificates are expected to speed up decarbonization of LPG
- Challenges to the decarbonisation are predominantly around:
  - Capacity and technology constraints
  - Regulatory barriers and policy uncertainty
  - Readiness of alternative gasses—organisations warned about being 'locked in' to a pathway before alternative gases are viable.

Draft pathways were then presented to policymakers, who provided feedback

Draft pathways were developed based on the engagement with stakeholders from different parts of the gas sector. The draft pathways were then presented to policymakers from MBIE, GIC, and EECA at three separate meetings.[169] Castalia provided background to and the objective of the project, outlined the process taken to develop the pathways, and then detailed the pathways and proposed modelling assumptions. Feedback from MBIE, GIC, and EECA on the were integrated into the final modelled pathways.

[169] CCC were also invited to participate.

Appendix C: List of reviewed literature

The literature list below records the previous modelling and forecasting work that Castalia reviewed.

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