NZ Gas Infrastructure Future

Gas Transition Analysis Paper

The New Zealand Government is looking to take decisive action to address climate change, including through work on a Gas Transition Plan – and this will have a profound impact on the use of natural gas.

A Working Group was established in May 2021 to consider the potential impacts from a gas infrastructure perspective.

This Gas Transition Analysis Paper reports on work commenced in October 2022 to provide more detailed conceptual quantitative and qualitative analysis to inform work on the Gas Transition Plan.

16 June 2023

Note: the paper was developed without consideration of the draft Gas Transition Plan being developed by the Gas Industry Company and the Ministry for Business, Innovation, and Employment. The Working Group may undertake further analysis in light of that plan.

Contents

SNAPSHOT

Start with scenarios

Analysis looks at four scenarios advised by the Gas Industry Company that reflect alternative futures for gas networks: (1) **business as usual**, (2) **biomethane blending**, (3) **conversion to LPG**, or (4) **full winddown**. These are assessed to see their potential impact on networks, consumers, infrastructure owners, and emissions.

Network impacts

- Expenditure needs will align with future use of networks
- Disconnection and decommissioning costs could be sizeable if networks are wound down

Disconnection[1] ▶ $364M

$158M ◀ **Decommissioning**[1]

Consumer impacts

- Gas prices could increase a lot if networks are wound down
- Biomethane could be price competitive with alternatives
- Consumers could face significant conversion costs

Conversion[1] ▶ $7.9B

Owner impacts

- A future with biomethane blending reduces asset stranding risk
- A winddown could lead to significant unrecovered revenue and stranded assets

$973M ◀ **Potential loss if full winddown occurs by 2050**[1]

Emission impacts

- Emissions likely to reduce in the longer term as natural is gas phased out
- But short to medium term this will depend on the emissions intensity of alternative energy sources and the efficiency of appliances that consume them

Future analysis

Trading off cost and emissions reductions would be worth exploring further. Potential extensions could also look at the impact on electricity networks, labour and resource markets, and vulnerable consumers. It would also be wise assessing how acute the cash flow concerns are that face infrastructure owners and how consumers may respond to alternative wholesale price projections.

[1] Values are indicative.

NZ Gas Infrastructure Future

EXECUTIVE SUMMARY

The Gas Transition Analysis Paper reports on work commencing in November 2022 to assess four gas transition scenarios advised by the Gas Industry Company (GIC).

The work drew on conceptual financial model and model inputs previously developed by the Working Group to analyse potential impacts on gas consumers, gas pipeline businesses and Government of alternative gas futures. The model and inputs to it were updated to incorporate more recent information and to consider the gas transition scenarios over the period out to 2050.

The conceptual analysis considers four alternative scenarios that align with those considered in the Working Group's Initial Analysis Paper:

- **Business as usual** – whereby pipelines remain operational, albeit with a lower level of gas throughput and fewer connections
- **Biomethane blending** – like the business as usual scenario, except with biomethane blending introduced and meeting 20% of residential and commercial demand by 2035
- **LPG conversion** – a winddown scenario whereby some gas consumers switch to LPG as an alternative to electricity and the pipelines largely shut down by 2040
- **Full winddown** – a winddown scenario whereby the pipelines shut down by 2050 and consumers switch to alternative energy sources.

The analysis and this paper were prepared without direct consideration of the Gas Transition Plan (GTP) that the GIC is developing jointly with the Ministry for Business, Innovation, and Employment (MBIE).

This initial analysis is preliminary and conceptual. Although care has been taken to prepare the modelling and inputs to it, the analysis is based on many assumptions and projections that are unlikely to reflect real world outcomes that will be more dynamic and responsive than can be reflected through modelling. Nor does this analysis seek to assess the financial performance or position of any specific gas pipeline business.

The analysis conclusions should be read together with the relevant qualifications and caveats. The analysis should not be attributed to individual participants in the Working Group, nor those that have helped the Working Group prepare it.

The analysis presents results and makes preliminary findings on four interrelated questions. These are summarised over the next three pages.

KEY MESSAGES

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This Gas Transition Analysis Paper builds on previous work look at potential future outcomes, taking a more direct look at potential transition pathways (or scenarios).

Care should be taken when interpreting the results.

Question 1 | *What do the alternative gas transition scenarios mean for future gas network expenditure and revenue requirements and how might these vary over time?*

- The expenditure that gas pipeline businesses need to make over the period out to 2050 will differ across the scenarios, both in terms of levels and type. These differences translate into differences in the revenue required under each scenario to provide gas transportation services in a safe, reliable, and efficient way.
- Projected operating and capital expenditure under the business as usual and biomethane blending scenarios reduce from recent highs to a relatively steady state by 2050.
- Pipeline decommissioning costs and disconnection costs ramp up for distribution pipelines over time under both the LPG conversion and full windown scenarios as consumers disconnect and decommissioning kicks in. By way of illustration, over the period to 2050, the full winddown has estimated decommissioning costs of $158 million and disconnection costs of $364 million based on rudimentary assumptions.
- Under those scenarios, gas pipeline businesses are expected to substitute operating expenditure for capital expenditure to ensure that can provide a safe and reliable service during the transition period without over-investing in long-lived assets that are only required for a short period of time.
- Reductions to required expenditure will drive lower projected required revenue across all four scenarios. The profile of that revenue is also affected by how capital is recovered over the horizon, with the accelerated depreciation adopted by the Commerce Commission in its 2022 default price path decisions leading to a profile that broadly aligns with reductions in gas consumption, assuming that the Commission continues to accelerate depreciation in future decisions.

Question 2 | *What are the potential implications to gas consumers in terms of the impact on consumer prices and other costs and how do these vary across gas consumers (e.g., residential vs commercial vs industrial)?*

- A winddown of gas pipelines exposes the remaining gas consumers to substantial price increases as other consumers defect up until the infrastructure is shutdown. After that point, consumers lose the choice to consume reticulated gas to meet their energy needs and are required to invest in alternative appliances.
- The Working Group's earlier analysis showed that the pace of the winddown will clearly affect that risk – with a faster winddown leading to faster price increases that will encourage more rapid defection of consumers through the winddown.
- Blending biomethane may help reduce that price risk to gas consumers, although further work is needed to better understand what demand may look like under such a scenario.
- As well as price increases, winddown of gas pipelines will lead to significant conversion costs being incurred by gas consumers. Initial estimates suggest that across all consumers this could be $7.9 billion if full winddown occurs by 2050 or $7.3 billion if conversion to LPG occurs by 2040.

KEY MESSAGES

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Decommissioning and disconnection costs would be significant if pipelines are wound down.

Given their capital-intensity, depreciation has a significant impact on revenue profile/

Under a winddown scenario, consumers that remain on gas could face significant price increases, while those that switch to alternative energy sources could face significant conversion costs.

Question 3 | *What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?*

- A winddown of regulated gas pipelines exposes gas pipeline businesses to material cost recovery risk – both in terms of unrecovered allowed revenue while the pipeline is operating and unrecovered capital when it ceases operating (i.e., as reflected in the regulated asset base, or RAB, at that time).
- Initial analysis indicates that a winddown of regulated gas pipelines exposes gas pipeline businesses to material cost recovery risk:
  - $973 million if full winddown occurs by 2050, and
  - $568 million if conversion to LPG occurs by 2040,

  both in present value terms ($2022) and assuming no further regulatory or policy levers (or mitigations) are applied beyond those reflected in the recent DPP decisions.
- Given this, initial analysis suggests that the financial viability of GPBs is at risk under the full winddown and LPG conversion scenarios, assuming no change to current regulatory settings or Government intervention.
- Key drivers of the size of this risk are gas consumers' future demand and willingness to pay for gas transportation services, which largely drives GPB's net cash flows. Declining cash flows under both scenarios reduces projected returns on investment (ROIs). Cash flow and ROI projections suggest that changes will need to be made to regulatory and policy settings for privately financed gas pipelines to remain financially viable under a winddown or LPG conversion scenario.
- Faced with that outlook it may be rational for gas pipeline businesses to shutdown uneconomic sections of their infrastructure sooner than is socially desirable. If shutdown did occur, then energy consumers would lose the option to choose reticulated gas as an energy source.
- Alternatively, it may also be rationale for gas pipeline businesses to actively pursue biomethane blending as a way of mitigating the risk of under-recovery under a winddown scenario. Such incentives, however, are undermined by uncertainty over the future viability of biomethane and other green gases transported by gas pipelines.
- Any investment to preserve the option of future green gases will need to balance the risk that that investment will not be recovered – e.g., because re-purposing does not occur – with the potential reduction in cost recovery risk from undertaking it, which could be done via a probability-based assessment.

KEY MESSAGES

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Pipelines face significant cost recovery risk if winddown incurs, almost $1 billion over the period to 2050.

Biomethane blending could help mitigate this risk somewhat, but demand remains uncertain.

Question 4 | *How might carbon emissions vary across the gas transition scenarios?*

- The key driver for the gas transition plan being developed by MBIE and the GIC is the aim to reduce carbon emissions in Aotearoa New Zealand. The gas transition scenarios were designed to test alternative pathways that could contribute to that outcome.
- Unsurprisingly, reducing natural gas consumption is expected to lead to lower carbon emissions over the period out to 2050, led by significant reductions in consumption by large transmission-connected consumers.
- There is some potential for higher emissions in the shorter term under the LPG conversion and full winddown scenarios. However, whether this occurs in reality will depend on what fuels consumers convert their energy consumption to, the emissions intensity of those fuels, and – importantly – the energy efficiency of the appliances that use them.
- An important next step for the Working Group's analysis will be to compare projected emissions reductions to the financial implications for gas consumers, gas pipeline businesses, and the wider economy.

Future analysis

This Gas Transition Analysis paper provides a baseline from which to identify further and more targeted questions to explore.

To this end, the Working Group has identified six areas of interest for potential future analysis:

- the impact on resources and the labour force from consumers switching to alternative energy sources
- the impact on vulnerable consumers if gas pipelines are wound down
- acuteness of cash flow concerns facing gas pipeline businesses under the winddown scenarios
- trade-offs between affordability and emissions reductions across the four scenarios
- sensitivity of consumer impacts to alternative energy price projections, and
- impacts on electricity networks from consumers switching their gas energy needs to electricity.

The Working Group is currently updating its conceptual financial model and model inputs so that it can explore these areas further.

KEY MESSAGES

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Emissions should reduce if natural gas consumption does.

Timing and extent of reductions will depend on the emissions intensity of what fuels consumers switch to and the energy efficiency of the appliances used.

Working Group is undertaking further target analysis, including to look at how alternative scenarios may affect labour markets, vulnerable consumers, and electricity networks.

1. INTRODUCTION

The New Zealand Government is committed to taking decisive action to address climate change. A carefully managed transition will be required to ensure continuity of a safe, reliable, and affordable energy supply as gas and LPG consumers transition their consumption to zero carbon 'green gases' or alternative renewable energy sources.

The Gas Infrastructure Future Working Group[1] (Working Group) was established in May 2021 to offer constructive input[2] to the Government's response to the Climate Change Commission advice with a focus on the future of gas infrastructure in New Zealand and potential solutions that could meet the objectives of Government, infrastructure owners and consumers.

As set out in the Emissions Reduction Plan, the Government is developing a Gas Transition Plan (GTP) that will set out the immediate steps on a long-term pathway to phasing-out fossil gas in Aotearoa New Zealand.[3] The GTP will focus on actions through to 2035 for the fossil gas sector to reduce emissions, and support the transition to a net zero carbon economy by 2050. The Ministry of Business, Innovation, and Employment (MBIE) and the Gas Industry Company (GIC) are working together to develop the GTP. As part of its work, GIC asked the Working Group to consider evolving its earlier modelling to assess alternative scenarios for the future transition of gas in New Zealand (the Gas Transition Scenarios). This paper is only one of several inputs that the GIC and MBIE may consider when developing the GTP.

This **Gas Transition Analysis Paper** builds on the Working Group's earlier modelling work.[4] It seeks to provide more detailed – albeit conceptual, quantitative, and qualitative – analysis to inform policy decisions related to the future of gas infrastructure. It is not intended to inform business or consumer decisions.

The paper reports on the outcomes of a simplified model and inputs – including demand, pricing and expenditure assumptions – developed to analyse the potential impacts on gas consumers, gas infrastructure businesses, and Government over a 35-year horizon under the Gas Transition Scenarios. In doing so, it extends from the winddown and re-purposing scenarios considered in the Working Group's earlier modelling work.

The Working Group's initial analysis is preliminary, conceptual, and will likely evolve. The initial conclusions should be read together with the relevant qualifications and caveats. The analysis should not be attributed to individual participants in the Working Group, nor used to inform financial or commercial decisions. The initial analysis was prepared before MBIE has published the draft GTP, and so does not consider the potential impacts of that draft plan. The Working Group may undertake further analysis after that plan becomes available.

The rest of this paper is structured as follows:

- **Section 2** sets out the context and analysis framework for this analysis
- **Section 3** describes the Model, the scenarios and limitations
- **Section 4** reports on the initial analysis of the Gas Transition Scenarios, and
- **Section 5** sets out the further analysis that the Working Group intends to undertake.

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1 See Solutions Scoping Paper, Appendix B for the updated Working Group Charter and membership.

2 See the following reports: Gas Infrastructure Future Working Group, *New Zealand Gas Infrastructure Future Findings Report*, August 2021; and Solutions Scoping Paper, November 2021.

3 See: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/gas-transition-plan/.

4 See: Gas Infrastructure Future Working Group, *Initial Analysis Paper*, 14 March 2022; and Gas Infrastructure Future Working Group, *Further Analysis Paper*, 29 March 2022.

The first paper is available here: https://comcom.govt.nz/__data/assets/pdf_file/0036/278991/Gas-Infrastructure-Future-Working-Group-Submission-on-Gas-DPP3-draft-decision-14-March-2022.pdf.

The second paper is available here: Gas-Infrastructure-Working-Group-on-behalf-of-Firstgas2C-Powerco-and-Vector-Cross-submission-on-Gas-DPP3-draft-decision-Further-analysis-paper-29-March-2022.pdf (comcom.govt.nz).

2. CONTEXT AND ANALYSIS FRAMEWORK

2.1. Summary

Gas pipeline infrastructure is expected be used less – or differently – in the future due to the impact of Government climate change policies, including the GTP. As part of this transition, the potential exists to repurpose gas infrastructure in a way that supports those policies but the evolution of a market for green gases in New Zealand is far from certain.

The initial analysis undertaken by the Working Group considers four key questions: how the transition will affect gas network expenditure and revenue requirements, consumer bills and conversion costs, infrastructure owner financial viability, and emissions. The questions are set out in section 2.4.

To assess these questions, the analysis considered four scenarios: business as usual, biomethane blending, LPG conversion, and full winddown. These scenarios are described in section 3.3.

2.2. Context

New Zealand has committed to reaching net zero emissions of long-lived greenhouse gasses by 2050. The operation of emission budgets and the Emissions Trading Scheme (ETS) are expected to cause natural gas and LPG (along with other fossil fuels) to become increasingly expensive, resulting in the eventual phasing out of natural gas and LPG. Clearly this will have profound impacts on the future of the natural gas and LPG supply industry in New Zealand. Achieving this transition requires a view across New Zealand's gas value stream, including the upstream and downstream markets, as well as the national and regional energy mix.

The Working Group was established in May 2021 to consider the future of the downstream gas industry, including as to potential scenarios for the end state and transition options; and potential solutions to achieve the objectives of Government, gas pipeline businesses, and gas consumers.

Initially its focus was to offer constructive input to the Government's response to the Climate Change Commission advice. Overtime it has also provided input to the Commerce Commission decisions and it is currently providing input into the GTP being developed by the Government.

Earlier work that provides context for this **Gas Transition Analysis Paper** are:

- an initial **Findings Report** to the Minister of Energy and Resources in August 2021,[5] which was undertaken over a short period to provide a starting point for policy development and dialogue between the Government and affected stakeholders
- an **Initial Analysis Paper**, dated 14 March 2022, [6] which was submitted to the Commerce Commission as part of its work developing the default price paths (DPPs) for gas pipeline businesses and report on modelling work that commenced in October 2021 to provide more detailed conceptual quantitative and qualitative analysis
- a **Further Analysis Paper**, dated 29 March 2022, [7] which updated the analysis from the Initial Analysis Paper in light of the Commerce Commission's draft DPP decision.

These outputs from the Working Group are described below. The subsequent subsection briefly describes the other key piece of context, namely, the GTP being developed by MBIE and the GIC.

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5 Gas Infrastructure Future Working Group, *New Zealand Gas Infrastructure Future Findings Report*, August 2021.

6 Gas Infrastructure Future Working Group, *Initial Analysis Paper*, 14 March 2022.

7 Gas Infrastructure Future Working Group, *Initial Analysis Paper*, 14 March 2022.

2.2.1. Findings Report

This report reported on initial work undertaken over a short period to provide a starting point for policy development and dialogue between the Government and affected stakeholders. It set out two high level scenarios namely, gas infrastructure winddown and repurposing.

Key findings include:

- there was significant interest in the potential for green gasses – green hydrogen has a role for 'hard to abate' energy uses, but production cost uncertainty means that hydrogen's role in other energy uses is unclear
- there are a range of technical options that could facilitate repurposing gas pipelines to transport hydrogen
- any winddown of gas pipelines will need to be undertaken safely and in a coordinated manner, and significant electricity distribution investment will be required, and
- there was a need to analyse the impact of falling demand, revenues, and the impact on financial sustainability and to consider the future economic regulation arrangements.

2.2.2. Initial and Further Analysis Papers

These papers built on the *Findings report* and involved developing a conceptual financial model and model inputs – including demand, pricing and expenditure assumptions – to enable analysis of the potential impacts on gas consumers, gas infrastructure businesses, and Government over a 35 year horizon. It considered alternative scenarios that built on the two conceptual scenarios developed in the Findings Report.

The analysis presented results and makes preliminary findings on seven interrelated questions:

- **Question 1** | What is the extent and trajectory through time of cost recovery risk faced by gas pipeline businesses and what are the key drivers of this risk under the various scenarios, assuming no mitigations adopted?
- **Question 2** | How is the extent and trajectory through time of cost recovery risk faced by gas pipeline businesses affected by the potential for re-purposing and differences in willingness to pay across consumer classes?
- **Question 3** | What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?
- **Question 4** | What are the potential implications to gas consumers in terms of the impact on consumer prices and other costs and how do these vary across gas consumers (e.g., residential vs commercial vs industrial)?
- **Question 5** | How could the implications for gas pipeline businesses and consumers be affected by future policy and regulatory decisions? What impact could different levers have (e.g., regulatory settings, government support)?
- **Question 6** | Ignoring accelerated depreciation, how do the draft default price path (DPP) assumptions affect the insights and conclusions identified in the Initial Findings Report?
- **Question 7** | How might the accelerated depreciation adopted in the draft DPP affect the cost recovery risk faced by gas pipeline businesses and prices and other costs faced by gas consumers?
- The work reported on in the *Initial Analysis Paper* and the *Further Analysis Paper* were considered by the Commerce Commission when making its May 2022 DPP decision to accelerate depreciation for gas pipeline businesses assets to migrate the risk of asset stranding.

2.2.3. Gas Transition Plan

MBIE and the GIC are working together to develop a GTP. MBIE intends to initiate public consultation on the GTP in mid 2023.

As part of its work program, in mid 2022 GIC asked the Working Group to consider evolving the modelling used to develop the Initial and Further Analysis Papers to assess four alternative Gas Transition Scenarios, which reflect alternative future configurations of the New Zealand's reticulated gas infrastructure. These scenarios are further described in Section 3.3.

2.3. Analysis scope

Consistent with standard economic regulation approaches, the scope of the initial conceptual analysis undertaken in the Gas Transition Analysis Paper considers only private costs and benefits to gas infrastructure owners and consumers under winddown or re-purposing scenarios. No account is taken of externalities – such as spill over costs and benefits – that would be considered in a broader social cost benefit analysis.[8,9] Whether or not broader social costs and benefits should be assessed could be considered further in future.

2.4. Analysis questions

This Gas Transition Analysis Paper considers the following four questions:

1. **Transition of gas networks |** *What do the alternative gas transition scenarios mean for future gas network expenditure and revenue requirements and how might these vary over time?*

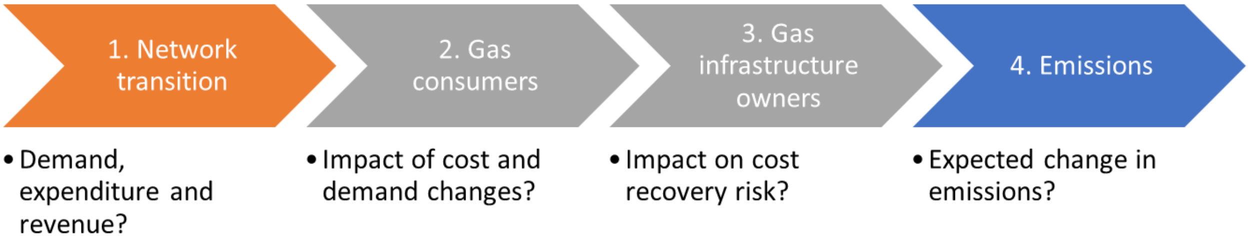
2. **Implications for consumers |** *What are the potential implications to gas consumers in terms of the impact on consumer prices and other costs and how do these vary across gas consumers (e.g., residential vs commercial vs industrial)?*

3. **Implications for infrastructure owners |** *What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?*

4. **Impact on emissions |** *How might carbon emissions vary across the gas transition scenarios?*

Figure 4.1 sets out these analysis questions and the relationship between them.

FIGURE 2.1: ANALYSIS QUESTIONS



8 See NZ Treasury, Guide to Social Cost Benefit Analysis, 27 July 2015 https://www.treasury.govt.nz/publications/guide/guide-social-cost-benefit-analysis

9 Possible examples of externalities that could be considered in a social cost benefit include for example: the environmental, amenity and safety benefits of distributing green gasses by way of pipelines compared to, say, by road; avoidance of amenity disbenefits arising from the decommissioning of pipelines, changes in security of energy supply, and so on.

At the outset, it is worth noting that this **Gas Transition Analysis Paper** – and the modelling underpinning it – has only scratched the surface of the questions being considered by the Working Group. Further questions that the Working Group is considering are discussed in section 5.

2.5. Approach

The **Gas Transition Analysis Paper** starts with the Excel model that was used to prepare the Initial and Further Analysis Papers (the Model). To streamline the analysis, the Working Group largely retained the modelling approach and only updated where appropriate to reflect more recent information and to consider the Gas Transition Scenarios and analysis questions noted above.

The Model was first updated to incorporate actual data from 2022, including from the Commerce Commission's final DPP decision[10] and information disclosures by the gas pipeline businesses. This included updates to the weighted average cost of capital (WACC), inflation, and capital and operating expenditure, as well as the accelerated depreciation adopted in that DPP decision.

To explore the 4 analysis questions, the Model was refined so that it could assess the impact on gas consumers and gas pipeline businesses of the Gas Transition Scenarios advised by the GIC. The steps involved were:

- **Model refinement** – with support from PricewaterhouseCoopers New Zealand (PwC), the Working Group refined the model to analyse the analysis questions and the Gas Transition Scenarios
- **Model populated** – drawing from input provided by Concept Consulting and the gas pipeline businesses, initial inputs to the model were generated that aligned with the Gas Transition Scenarios, including demand and price projections and expenditure forecasts
- **Model refined** – after an initial review of the inputs and outputs, key model inputs and assumptions were further refined to better reflect real world expectations
- **Model outputs analysed** – the model outputs (e.g., charts and present values) were analysed and used to prepare the initial analysis discussed in section 4.

As this is only an initial analysis, the Working Group expects to undertake further work refining the model (and inputs or assumptions to it) and to use it to assess other questions. Section 2.6 below describes in further detail how the modeling was planned and developed.

2.6. How the analysis was planned and developed

Box 1 describes how the analysis was planned and developed.

Box 1: How the analysis was planned and developed

The Working Group previously engaged:

- PwC to help design and build the model for analysis undertaken in late 2021 and early 2022
- Concept Consulting to produce indicative pipeline demand projections and associated consumer prices (for pipeline gas, and alternatives to pipeline gas) for scenarios considered at that time.

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10 Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2022 Final Reasons Paper*, 31 May 2022.

The Working Group had also established a modelling subgroup comprising representatives from each of the gas pipeline business to enable discussion with PwC on the model structure, design, and development. The gas pipeline businesses completed templates provided by PwC setting out expenditure forecasts consistent with each of the scenarios and assuming that the cost of all new connections were, for the most part, fully funded by connecting consumers (i.e., ensuring that those costs were not spread across existing consumers).

With that starting point, the modelling subgroup was re-established and PwC and Concept Consulting re-engaged to undertake new analysis that looked at the Gas Transition Scenarios. That new analysis involved:

- PwC updating the model to reflect more recent information, including actual data from 2022, the Commerce Commission's final default price path decision for gas pipeline businesses, and various inputs from Concept Consulting and the gas pipeline businesses
- Concept Consulting providing indicative pipeline demand projections and associated consumer prices (for pipeline gas, and alternatives to pipeline gas) for the Gas Transition Scenarios – as would be expected given the complex nature of demand and pricing dynamics, questions remain over how realistic these projections are (see discussion in section A.6).
- The gas pipeline businesses completing templates provided by PwC setting out expenditure forecasts consistent with each of the Gas Transition Scenarios.

PwC then populated the model with expenditure and demand input data, performed sense checks on outputs, and performed a full review of model logic and quality assurance checks.

This work was then considered by the Working Group and further refined.

3. MODEL DESCRIPTION

3.1. Summary

Core to the initial analysis undertaken by the Working Group is an Excel model that assesses the potential financial impact on gas consumers and gas pipeline businesses of future scenarios for gas infrastructure in New Zealand (the Model).

The Working Group used the Model to test how the Gas Transition Scenarios may affect outcomes faced by gas consumers and infrastructure owners.

The Model is summarised below. A more detailed description of the model is set out in **Appendix A**.

3.2. Model

The Model contains three core modules:

- a building blocks allowable revenue (BBAR) module that projects the revenue that gas pipeline businesses are allowed to recover *assuming* that economic regulation continues to apply
- a consumer impacts module that projects the annual revenue recovered from gas consumers
- a carbon emissions model that projects the annual emissions from gas consumption.

Outputs from these modules is used to project net cash flows and proxy credit measures for gas pipeline businesses, and costs or prices faced by gas consumers.

To drive these two modules, the model relies on projected demand, wholesale gas prices, alternative energy prices, energy conversion costs, pipeline capital and operating expenditure, and other inputs, including those needed for the BBAR calculations (e.g., weighted average cost of capital (WACC), inflation, asset lives). It also relies on current regulatory inputs, such as the regulatory asset base (RAB) values for each regulated gas pipeline business.

3.3. Scenarios

A key capability of the model is the flexibility to test Gas Transition Scenarios and sensitivities, including:

- **Market scenarios** – which are four[11] defined scenarios relating to the overall market outcomes for gas, including 2 business as usual scenarios (base and biomethane blending) and 2 winddown scenarios (LPG conversion, full winddown)
- **Model scenarios** – which are five customisable scenarios used to test a range of regulatory and policy levers (and other factors).

The initial analysis considered in section 4 was developed using different combinations of the *market* scenarios. Although the *model* scenario capability was retained from the earlier work reflected in the Initial and Further Analysis Papers, it was not used to inform the analysis in this **Gas Transition Analysis Paper**.

The four market scenarios are described in Table 3.1.

11 Note that GIC had initially identified a further gas transition scenario that looked at converting gas distribution networks to import liquefied natural gas. After investigation, this scenario was not modelled.

TABLE 3.1: MARKET SCENARIOS (SCENARIO 3 OMITTED)

Market scenario	Description
1. Business as usual scenario	Gas pipelines remain operational with some decline to a lower level of gas throughput and connections due to the impact of carbon pricing and other emissions reduction measures
2. Biomethane blending scenario	As per the business as usual scenario, except that biomethane blending up to 20% of current gas throughout by residential and commercial consumers by 2030 with blending costs reflected in wholesale gas prices
4. LPG conversion	Gas distribution networks gradually winddown by 2040, with gas consumers switching either to LPG or alternative energy sources (e.g., electricity), incurring relevant conversion costs; gas transmission networks winddown as gas distribution networks disconnect, leaving a 'Taranaki rump' for continued supply to gas generation power plants and large transmission connected consumers in Taranaki
5. Full winddown (i.e., counterfactual) scenario	Gas throughput and connections reduce gradually, with gas consumers transitioning to alternative energy sources (e.g., residential and commercial users switch to electricity, no new connections), incurring relevant conversion costs with pipeline use ceased by 2050

3.4. Willingness to pay

As with the earlier analysis, an important component of the modelling is forecast willingness to pay (WTP), which is a prediction as to how much consumers are willing to pay for delivered gas before they would choose not to consume gas. This could occur where consumers switch to alternative energy sources or cease operation (e.g., where a business closes down).

For each scenario, WTP was projected for each consumer type by combining:

- the projected price of alternative energy sources (such as electricity and biomass)
- the cost of converting from gas to alternative energy, including any make good costs
- an assumed markup (of 10%) to reflect non-price factors, such as consumer stickiness,[12] amenity value, and other desirable characteristics of using gas appliances (e.g., instantaneous hot water).

Of these, the markup for non-price factors is likely to be most uncertain. The points above and anecdotal evidence of gas consumer behaviour suggest that the mark-up is likely to be positive. However, a precise estimate is difficult to determine. A 10% markup assumption was adopted as a placeholder intended to align with historical observations – whereby, for some gas consumers it would appear to make sense, economically, to switch to alternative energy sources, they do not actually behave in this way. For a residential consumer a 10% margin implies a margin of around $150 per year on current annual gas bills of around $1,500 per year. However, this assumption is not based on any empirical analysis.

12 Consumer stickiness is the phenomenon whereby consumers tend to be slow to switch from one supplier to another even though it is economically sensible to do so (e.g., switching energy retailers or telecom providers).

Further work could be done to better understand how non-price factors have historically affected demand for gas and what this may mean for gas demand in the future.

This is discussed further in section A.7 of Appendix A.

3.5. Limitations

This analysis is preliminary and conceptual in nature. Although care has been taken to prepare the modelling and inputs to it, the analysis is based on many assumptions and projections that are unlikely to reflect real world outcomes. The analysis has not been undertaken to a specific accounting or other standard.

The Working Group has not sought to assess the financial performance or position of any specific gas pipeline business, nor quantify the risks that they face. The analysis should not be relied on to inform financial or commercial decisions.

Specific limitations for the analysis undertaken on each of the analysis questions are discussed in each subsection in the next section below. Section A.6 of Appendix A outlines key model assumptions and limitations.

4. INITIAL ANALYSIS

4.1. Overview

The Working Group has constrained its initial analysis to just 4 questions:

1. **Transition of gas networks |** *What do the alternative gas transition scenarios mean for future gas network expenditure and revenue requirements and how might these vary over time?*

2. **Implications for consumers |** *What are the potential implications to gas consumers in terms of the impact on consumer prices and other costs and how do these vary across gas consumers (e.g., residential vs commercial vs industrial)?*

3. **Implications for infrastructure owners |** *What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?*

4. **Impact on emissions |** *How might carbon emissions vary across the gas transition scenarios?*

Moreover, this analysis is only a first look at these questions based on a preliminary set of inputs and assumptions and an initial model build. The Working Group expects to refine and evolve this analysis over time, including to consider other questions that may arise and further input from stakeholders. For this reason, the Working Group cautions against drawing inappropriate or incomplete conclusions from this analysis at this early stage.

The rest of this chapter steps through initial analysis for each of the 4 questions, discussing relevant context and predictions, before exploring the outputs from the modelling. Key initial insights are identified throughout. A more detailed description of the modelling and assumptions is set out in **Appendix A**

4.2. Question 1: Transition of gas networks?

What do the alternative gas transition scenarios mean for future gas network expenditure and revenue requirements and how might these vary over time?

Box 2: Gas network transition | Summary

- The expenditure that gas pipeline businesses need to make over the period out to 2050 will differ across the scenarios, both in terms of levels and type. These differences translate into differences in the revenue required under each scenario to provide gas transportation services in a safe, reliable, and efficient way.
- Projected operating and capital expenditure under the business as usual and biomethane blending scenarios reduce from recent highs to a relatively steady state by 2050.
- Pipeline decommissioning costs and disconnection costs ramp up for distribution pipelines over time under both the LPG conversion and full winddown scenarios as consumers disconnect and decommissioning kicks in. By way of illustration, over the period to 2050, the full winddown has estimated decommissioning costs of $158 million and disconnection costs of $364 million based on rudimentary assumptions. It remains unclear who will face the burden of those costs as well as any residual unrecovered capital costs incurred by the gas pipelines (as reflected in the RAB).
- Under those scenarios, pipelines are expected to substitute operating expenditure for capital expenditure to ensure that can provide a safe and reliable service during the transition period without over-investing in long-lived assets that are only required for a short period of time.
- Reductions to required expenditure will drive lower projected required revenue across all four scenarios. The profile of that revenue is also affected by how capital is recovered over the horizon, with the accelerated depreciation adopted by the Commerce Commission in its 2022 default price path decisions leading to a profile that broadly aligns with reductions in gas consumption, assuming that the Commission continues to accelerate depreciation in future decisions.

4.2.1. Context

The future of natural gas in New Zealand is unclear. Alternative pathways, or scenarios, exist that will lead to different outcomes for gas consumers and gas pipeline businesses. The expenditure that gas pipeline businesses will need to make will differ across the scenarios, as will the revenue required to provide gas transmission and distribution services in a safe, reliable, and efficient way.

With this in mind, the GIC asked the Working Group to extend its existing modelling to consider 5 potential scenarios. These scenarios were subsequently narrowed down into the 4 alternative Gas Transition Scenarios outlined in section 3.3.

4.2.2. Focus of analysis

The analysis in response to Question 1 focuses on what the scenarios suggest about future expenditure and revenue requirements. To inform this, the analysis starts with an initial look at projected connections and consumption across both the distribution and transmission networks. Across all scenarios, new connections are assumed to be largely funded by connecting consumers.

4.2.3. Prediction

Required revenue and expenditure is greatly reduced under the LPG conversion and distribution scenarios, albeit with conversion expenditure required as networks are shut down and consumers convert to alternative energy sources. Expenditure will be driven by the need to maintain public safety, with the impact likely varying across gas networks. Some reduction is also expected even where the pipelines remain operational under the business as usual and biomethane blending scenarios.

4.2.4. Initial quantitative analysis results

The initial quantitative analysis undertaken by the Working Group confirms the prediction that required expenditure and revenue reduces under all four scenarios driven by reductions in gas connections and consumption.

Gas connections and consumption

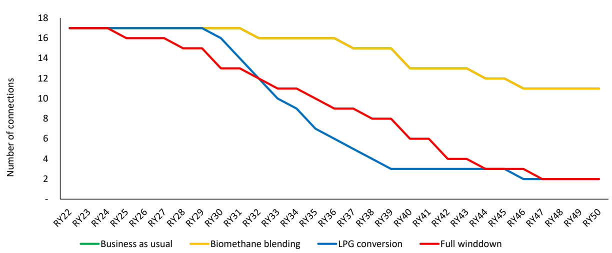
Forecast gas connections and consumption are projected to reduce under all four scenarios. As shown in FIGURE 4.1, consumption and connections are projected to reduce to a new sustainable level under both the business as usual and biomethane blending scenarios. This recognises that some defection from the gas networks is expected even if the pipelines remain operational.

The reductions are starker under the LPG conversion and full winddown scenarios as gas consumers switch from reticulated natural gas to alternative energy sources, such as electricity or LPG. Consumers are projected to convert to LPG by 2040 under the LPG conversion scenario, or to electricity by 2050 under the full winddown scenario.

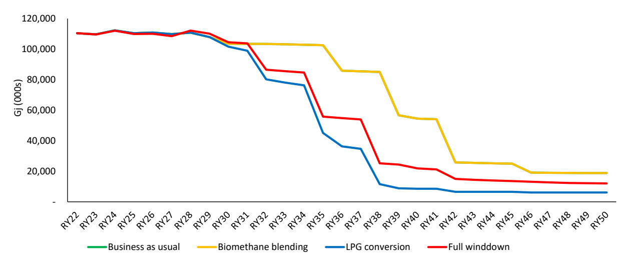
The stepwise reduction in connections and consumption for the transmission network under all four scenarios highlights the impact that a few large transmission-connected consumers can have on network utilisation.

FIGURE 4.1: GAS CONNECTIONS AND CONSUMPTION

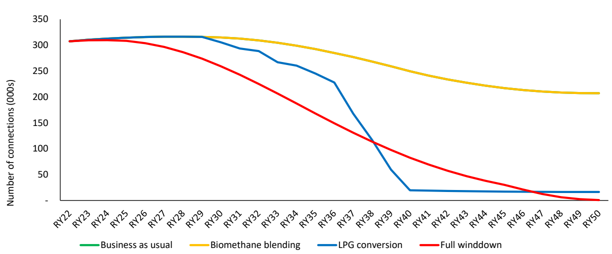
Connections
Transmission



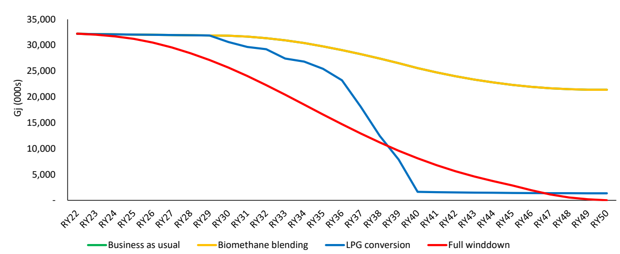
Consumption
Transmission



Distribution (excluding LPG and electricity connections)



Distribution (excluding LPG and electricity connections)



Required expenditure

Expenditure requirements largely follow projected gas connections and consumption. Gas pipeline businesses and others are expected to incur costs as consumers disconnect and pipelines are decommissioned. They are also expected to avoid unnecessary investment in certain capital assets where they can without compromising safety and reliability if they expect certain pipeline sections to eventually be decommissioned.

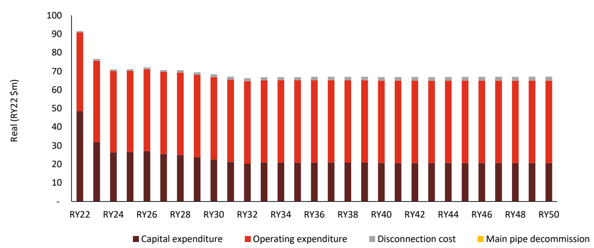
As shown in FIGURE 4.2 and FIGURE 4.3, projected operating and capital expenditure under the business as usual and biomethane blending scenarios reduce from recent highs to a relatively steady state by 2050. The drop in transmission capital expenditure in the biomethane scenario is due to an assumed scaling back of the transmission network under that scenario with some biomethane sourced locally.

As suggested by FIGURE 4.2, pipeline decommissioning costs (yellow) and disconnection costs (grey) are expected to ramp up for distribution networks over time under both the LPG conversion and full winddown scenarios as consumers disconnect and decommissioning kicks in. To illustrate this, the distribution and transmission pipeline decommissioning costs are estimated as $158 million over the period out to 2050 under the two scenarios based on rudimentary assumptions. The disconnection costs are estimated as $301 million and $364 million over the period out to 2050 under the two scenarios, respectively. Those networks also substitute operating expenditure for capital expenditure in order to minimise total costs while continue providing a safe and reliable service during the transition period.

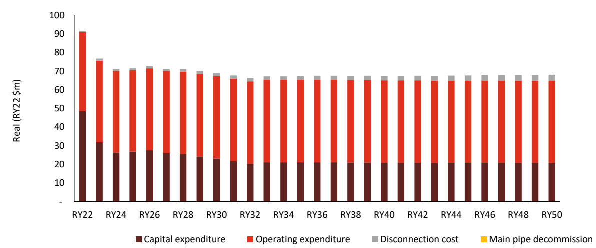
Importantly, the analysis makes no assumption as to who will ultimately face the burden of any decommissioning or disconnection costs, nor any residual unrecovered capital costs incurred by the gas pipelines (as reflected in the RAB).

FIGURE 4.2: DISTRIBUTION EXPENDITURE

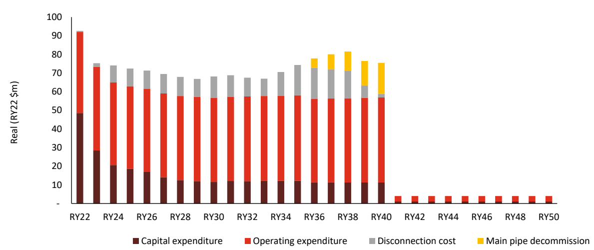
Business as usual



Biomethane blending



LPG conversion



Full winddown

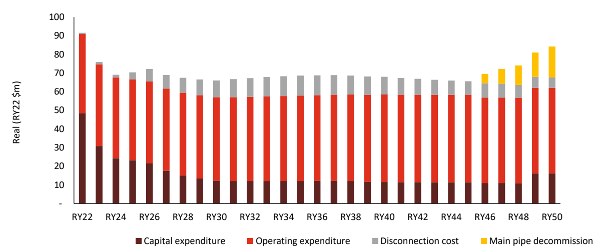
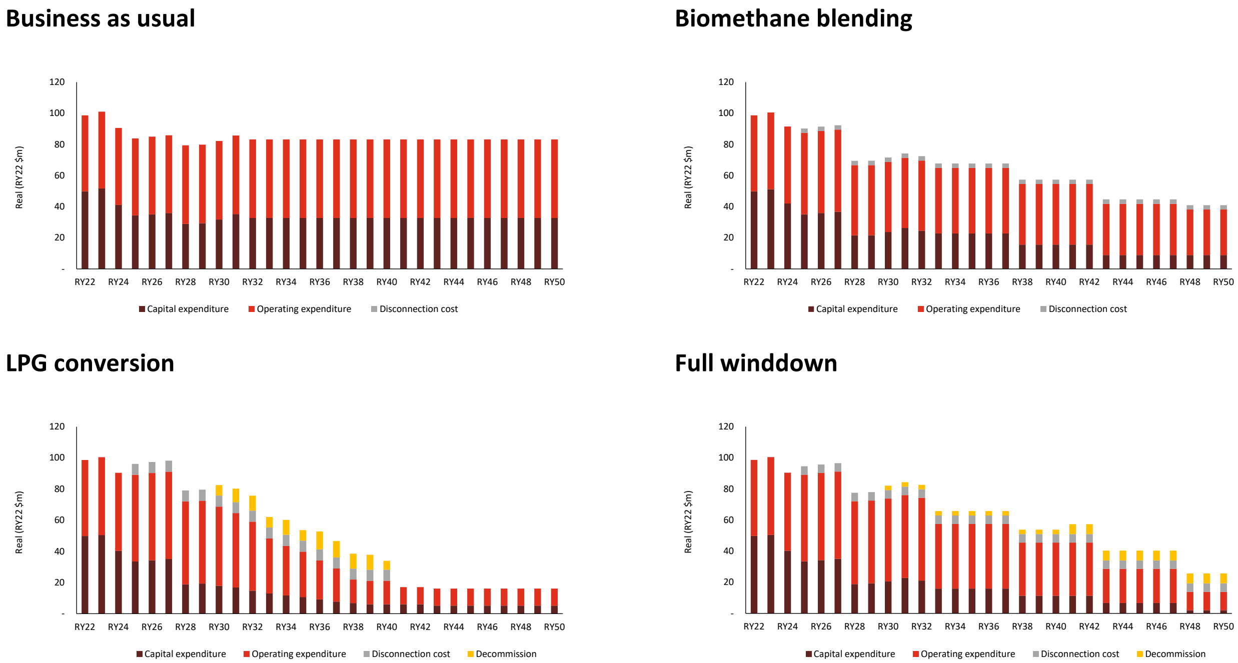


FIGURE 4.3: TRANSMISSION EXPENDITURE



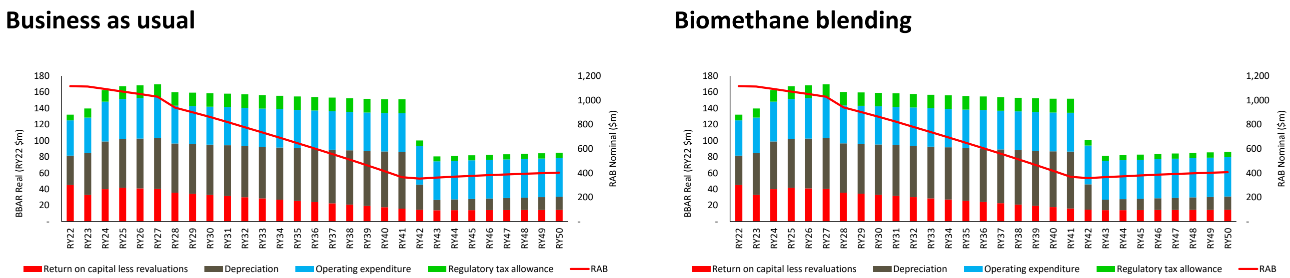
Required revenue

Reductions to required expenditure are driving lower projected required revenue across all four scenarios. The profile of that revenue is also affected by the depreciation assumptions, which align with those adopted in the Commerce Commission's 2022 DPP decisions for gas pipelines.

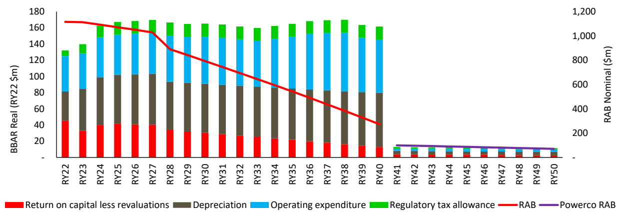
As shown in FIGURE 4.4 and FIGURE 4.5, those assumptions are driving a significant drop in the depreciation component of the revenue (the grey bars) from 2041 and 2042 and reduction in the regulated asset base (RAB) values (the red lines). The lower RAB values lead to lower return on capital component (the red bars).

Importantly, even with accelerated depreciation, some residual unrecovered RAB value is projected to remain once the gas pipelines are decommissioned under the LPG conversion and full winddown scenarios. This highlights the potential cost recovery risk facing gas pipeline businesses under those scenarios, which is further explored in response to Question 3 in section 4.4 below.

FIGURE 4.4: DISTRIBUTION REQUIRED REVENUE



LPG conversion



Full winddown

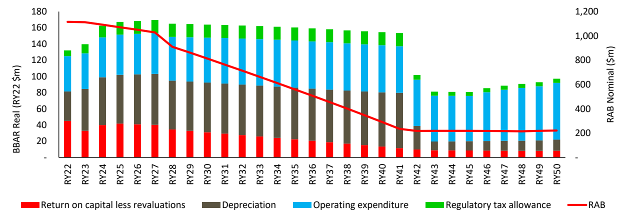
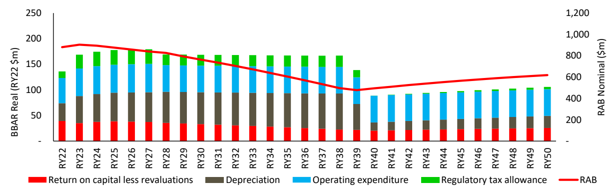
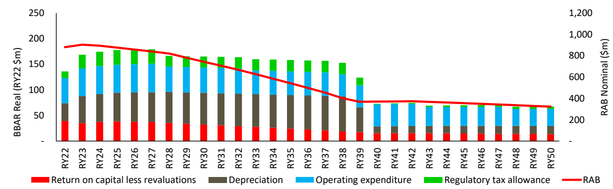


FIGURE 4.5: TRANSMISSION REQUIRED REVENUE

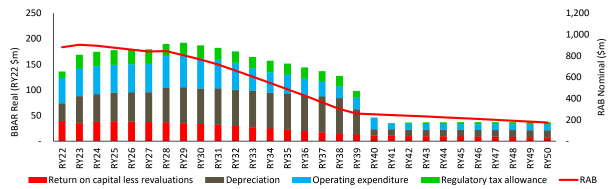
Business as usual



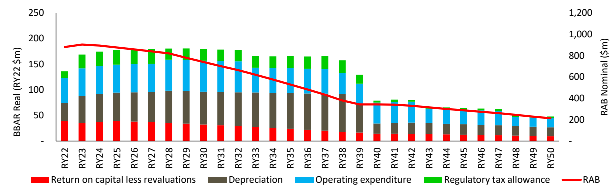
Biomethane blending



LPG conversion



Full winddown



Limitations

This analysis is subject to the limitations noted in section 3.5.

Given the inherent uncertainty over gas connection and consumption projections out to 2050, the analysis in response to Question 1 is indicative. Although useful to understand potential outcomes, it is not possible to say how realistic they are based on available information and so care should be taken when interpreting the outputs. The same applies to the assumed expenditure projections, including future disconnection and decommissioning costs.

Informed by recent Commerce Commission decisions, assumptions have been made to translate projected expenditure into required revenue. Depreciation assumptions are particularly important to the analysis because they affect how capital cost recovery is profiled over the modelling horizon. This is relevant because depreciation is an important regulatory tool that can be used to help align cost recovery with consumer use of gas pipelines. Alternative depreciation or other assumptions could lead to quite different required revenue profiles over the model horizon and 2050 residual RAB values.

4.2.5. Key insights

Unsurprisingly, projected expenditure needs differ materially depending on whether the pipelines are expected to remain operational or not.

Disconnection and decommissioning costs appear to be a material component of future expenditure (around 14%) in scenarios where there are significant gas consumer disconnections and pipeline decommissioning. It remains unclear who will face the burden of those costs as well as any residual unrecovered capital costs incurred by the gas pipelines (as reflected in the RAB).

As previously explored by the Working Group, depreciation assumptions will have a significant impact on how required revenue is spread over time.

4.3. Question 2: Implications for consumers?

What are the potential implications to gas consumers in terms of the impact on consumer prices and other costs and how do these vary across gas consumers (e.g., residential vs commercial vs industrial)?

Box 3: Consumer implications | Summary

- Given the operation of the economic regulation model, a winddown of gas pipelines exposes the remaining gas consumers to substantial price increases as other consumers defect up until the infrastructure is shutdown. After that point, consumers lose the choice to consume reticulated gas to meet their energy needs and are required to invest in alternative appliances.
- The pace of the winddown will clearly affect that risk – with a faster winddown leading to faster price increases that will encourage more rapid defection of consumers through the winddown. Although not modelled here, that prediction was shown in the Working Group's earlier analysis.
- Blending biomethane may help reduce that price risk to gas consumers, although further work is needed to better understand what demand may look like under such a scenario.
- As well as price increases, winddown of gas pipelines will lead to significant conversion costs being incurred by gas consumers. Initial estimates suggest that across all consumers this could be:
    - $7.9 billion if full winddown occurs by 2050, and
    - $7.3 billion if conversion to LPG occurs by 2040.
- This analysis is preliminary and conceptual. Although care has been taken to prepare the modelling and inputs to it, the analysis is based on many assumptions and projections that are unlikely to reflect real world outcomes. Further work is needed to better refine the modelling and inputs.
- It also remains unclear what if any steps Government may take to mitigate this cost to consumers, especially vulnerable consumers.

4.3.1. Context

Core to understanding whether a potential gas transition pathway is equitable or not is understanding the potential impact on gas consumers. This was a focus of the Working Group's earlier analysis and remains a focus when analysing potential gas transition pathways.

Gas consumers will be affected by the costs of the energy they consume, the appliances they acquire and replace through time, and any conversion from one energy source to another – ultimately affecting energy affordability (before considering any potential government support).

Energy costs include wholesale costs of gas or alternative energy sources, energy transportation costs, and retail costs. Appliance costs will generally be incurred periodically when they are up for replacement. However, where a consumer switches from one energy source (e.g., natural gas) to another (e.g., LPG or electricity), then it may incur conversion costs (e.g., acquiring and installing new appliances, making good).

The level and profile of costs incurred by gas consumers will depend on whether gas infrastructure is wound down or remains operational. It will also be affected by the revenues that regulated gas pipelines are allowed to recovery under either scenario.

Question 1 looks at these implications for gas consumers. Conversion costs are factored into gas consumers' assumed willingness to pay.

4.3.2. Focus of analysis

This analysis focuses on the projected implications to gas consumers under the various gas transition scenarios being considered. It considers the same horizon as the analysis in the previous section and ignores steps that the Government or the Commerce Commission may take to mitigate cost recovery risk or the implications to gas pipeline businesses and gas consumers.

Although the analysis considers many of the costs faced by gas consumers, it is not exhaustive. As noted in section 3.4, the costs of converting from gas to alternative energy sources, including any make good or appliance switching costs, are reflected in projected willingness to pay. In reality, these costs will vary significantly across consumers. Further work could be undertaken to better understand how these costs may differ and how they may influence gas consumer consumption decisions.

4.3.3. Prediction

The *first premise* is that – somewhat obviously – consumers will be affected by and adjust their behaviour in response to changes in the price of gas compared with alternatives. This is a similar prediction to that made in the Working Group's earlier analysis.

- Under the **full winddown scenario**, those consumers will increasingly face the costs of alternative energy sources such as electricity or LPG as reticulated natural gas is phased out – and so their energy demand decisions will be affected by cost differences between natural gas and electricity (or other alternatives).
- Under the **biomethane scenario**, consumers that continue to use gas will be affected by differences between green gas and natural gas prices – and may adjust their behaviour in response to price differences between green gas and alternatives.

The quantitative analysis described below does not model consumer behaviour directly (given the significant challenges in undertaking such modeling). The demand projection assumptions used in the analysis do reflect assumed consumer behavior decisions in response to changes in relative energy costs.

Consumer price impacts (and consumption decisions) will depend on:

- projected distribution and transmission network revenues
- projected natural gas, green gas, and alternative energy source costs (or prices), and
- non-price factors, which are captured in willingness to pay measures and are likely to be more important for residential consumers than other types of consumers.

The *second premise* is that consumers will incur significant costs converting from gas to an alternative energy source if gas infrastructure is wound down or consumers defect as it is economic to do so and that these costs will vary across consumer types.

In some cases, there may be no viable non-gas energy alternatives for some consumer types (e.g., industrial consumers with specific processing requirements) that currently consume natural gas. If they can no longer use gas in New Zealand, then those consumers may need to either cease operations or shift operations to overseas jurisdictions.

4.3.4. Initial quantitative analysis results

The initial quantitative analysis suggests that a winddown of gas infrastructure will lead to an accelerating increase in the cost of delivered natural gas for most gas consumers as allowed pipeline revenues are spread over a declining consumer base, *assuming* that:

- all revenues are passed through to consumers
- regulatory settings remain as they do now (i.e., there is no re-profiling of allowed revenue over the forecast horizon), and
- there is no rebalancing of revenue between consumer types.

In reality, such an increase will likely encourage consumers to defect faster (i.e., a death spiral) as alternative energy sources increasingly become more attractive. Similarly, it will encourage networks and regulators to rebalance prices and adjust regulatory settings to mitigate this. The Working Group's earlier analysis looked at some of those mitigations.

The analysis also suggests that biomethane blending and continued operation of the gas infrastructure will likely keep annual consumer charges lower as more consumers are assumed (as an input) to be consuming biomethane. *If* this assumption were relaxed, then it may be that more gas consumers defect than is currently reflected in the modelling. Further work could be done to look at this. But for now it is assumed away.

The flipside to consumers defecting is that they must incur costs to convert from one energy source to another. When looked at in aggregate across all consumers, these costs could be significant.

These dynamics are best shown by considering annual natural gas charges per user and total consumer conversion costs.

Annual natural gas charges per user

FIGURE 4.6 shows that annual natural gas charges – on a per user basis – increase strongly under the LPG conversion (blue line) and full winddown (red line) scenarios for residential and commercial distribution consumers. They eventually reach an inflection point where they rise rapidly to astronomically high levels. This largely reflects fixed costs being borne by a rapidly decreasing number of connected consumers.

In contrast, alternative energy charges (the dotted and dashed blue and red lines) remain much more stable under those two scenarios, falling below natural gas charges for a substantial part of the period for residential and commercial distribution consumers.

Under the biomethane blending scenario, annual charges (in yellow) for residential and commercial consumers initially jump above those for the LPG conversion and full winddown scenarios as the costs of biomethane production are incorporated into consumer bills. However, as the pipelines remain operational into the future, charges under that scenario – as well as under the business as usual scenario – avoid the impact of spreading fixed costs over a decreasing number of connected consumers (i.e., they avoid the spike).

As well as the alternative energy cost, willingness to pay incorporates conversion costs as well as non-price factors through an assumed 10% mark-up. As such, annual willingness to pay sits somewhat above the annual alternative energy costs shown in **FIGURE 4.6**. As discussed in section 3.4, in practice, gas consumers are assumed to switch to alternative energy sources once projected prices exceed their willingness to pay.

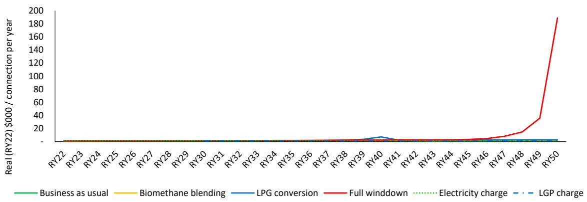
Interestingly, for industrial distribution consumers, alternative energy charges increase gradually over time and are significantly higher than natural gas charges in most years under all scenarios. The exception, however, is where the annual energy charge increases significantly around 2046 under the full winddown scenario.

An important limitation of these comparisons, however, is that the initial analysis has not sought to rebalance charges from one consumer group to another – which is a mitigating action commercial gas pipeline business could be expected to adopt. Doing so will affect the charges faced by those groups and their comparison to alternative energy charges.

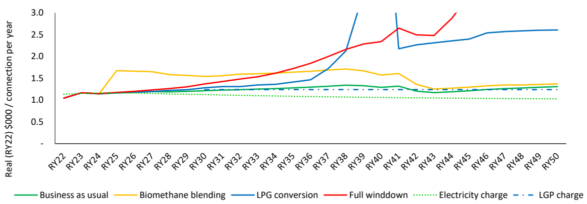
FIGURE 4.6: ANNUAL CHARGES PER CONSUMER BY TYPE

Residential

Unconstrained vertical axis

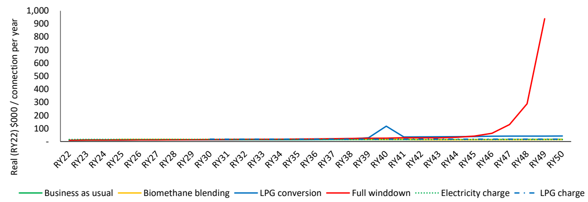


Truncated vertical axis with alternative enery prices

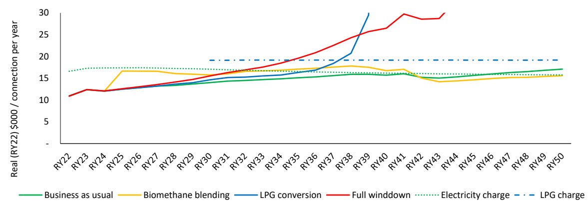


Commercial

Unconstrained vertical axis

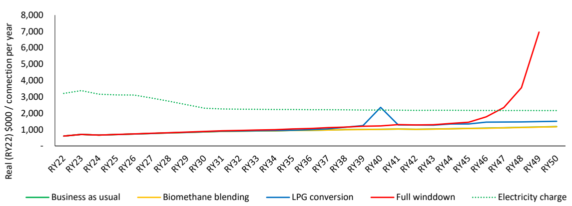


Truncated vertical axis with alternative enery prices

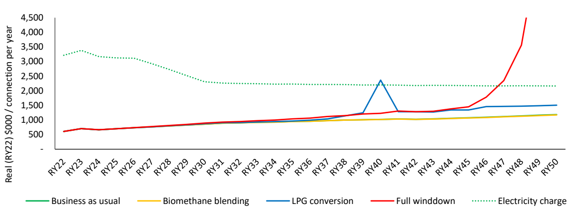


Industrial

Unconstrained vertical axis



Truncated vertical axis with alternative enery prices



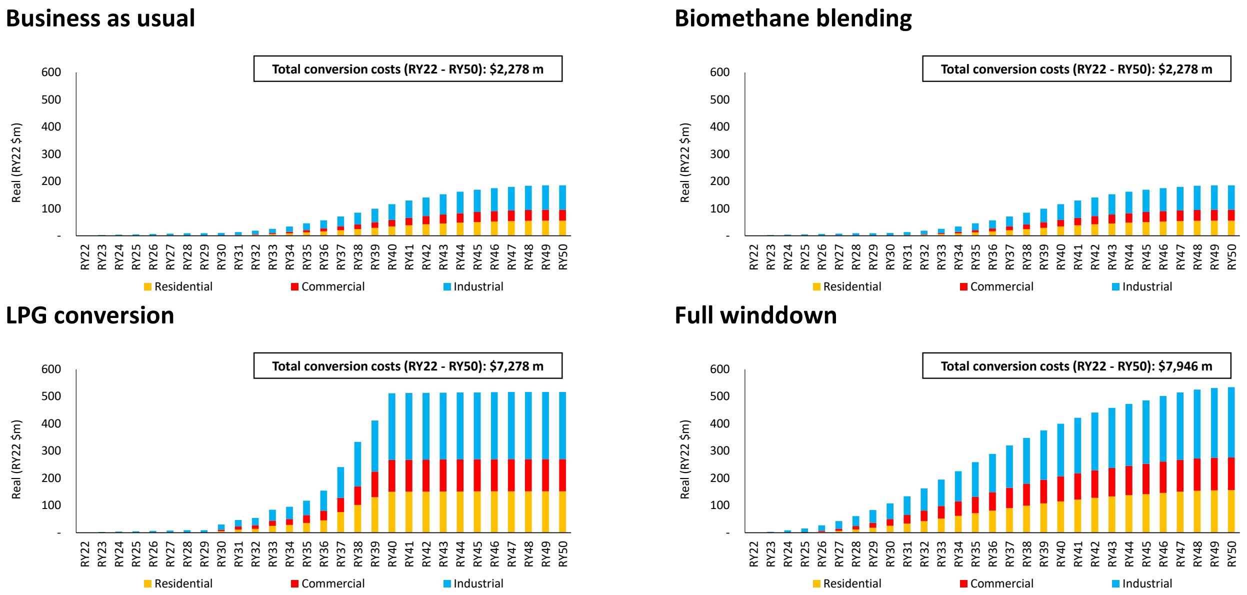
Conversion costs

FIGURE 4.7 shows that aggregate consumer conversion costs are expected to be significant under the LPG conversion and full winddown scenarios as consumers convert to alternative energy sources. Over the period out to 2050 these come to

$7.3 billion and $7.9 billion, respectively, which compares to the $5.3 billion in aggregate conversion costs estimated by the Climate Change Commission.[13]

Much less significant are the projected conversion costs incurred by consumers that convert to alternative energy sources under the business as usual and biomethane blending scenarios. In aggregate, these are $2.2 billion under both scenarios.

FIGURE 4.7: CONVERSION COSTS



Note: as a simplification, conversion costs per consumer assumed to be the same for those converting to LPG as those converting to electricity. In practice, converting to LPG may well be cheaper than converting to electricity.

Limitations

This analysis is subject to the limitations noted in section 3.5.

Importantly, the model logic for allocating revenue received from end gas consumers between transmission and distribution businesses, wholesale gas producers and retailers has a significant impact on results (including recoverable/unrecoverable revenue). Currently, this is being allocated between transmission businesses, distribution businesses and retailers based on their relative target revenues. It is assumed that gas wholesalers fully recover their revenue. This model logic can be adjusted.

Gas connection assumptions are particularly important to the analysis because they affect the consumer base that allowed revenue can be spread over. Further work to understand what demand and gas connections may look like under alternative scenarios would be sensible.

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13 Conversion costs include the costs of acquiring and installing new appliances as well as the costs of removing old appliances (including make-good costs). See: CCC, 24 June 2021, *Data for figures in the Commission's 2021 final advice to Government, Ināia tonu nei: a low emissions future for Aotearoa*, 'Chapter 8' sheet. Link: https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Modelling-files/Charts-and-data-for-2021-final-advice.xlsx.

Similarly, assumed conversion costs faced by gas consumers are also important to the analysis. Further work could be undertaken to better understand these costs, including by learning from experience in Australia or via other workstreams (e.g., the Working Group's desktop study into tactical decommissioning).

4.3.5. Key insights

The initial analysis above suggests that a winddown of regulated gas pipelines exposes the gas consumers that remain at any point in time to meaningful price increases as other consumers defect. Consistent with the Working Group's earlier analysis, the pace of the winddown will clearly affect that risk – with a faster winddown leading to a faster price increases, which will in turn encourage more rapid defection of consumers through the winddown.

Blending biomethane may help reduce or avoid that risk, although further work is needed to better understand what demand may look like under such a scenario (e.g., to assess how biomethane and natural gas costs compare). Changes to regulatory settings or government support will also affect the price risk faced by gas consumers.

Moreover, if decisions are made to defect, then the costs consumers face to convert to alternative energy sources could be significant, both individually and in aggregate. Any decision to provide government support to help fund conversion costs would affect where the burden of those costs fall within the economy.

4.4. Question 3: Implications for infrastructure owners?

What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?

Box 4: Infrastructure owner implications | Summary

- A winddown of regulated gas pipelines exposes gas pipeline businesses to material cost recovery risk – both in terms of unrecovered allowed revenue while the pipeline is operating and unrecovered capital when it ceases operating (i.e., as reflected in the regulated asset base, or RAB, at that time).
- Initial analysis indicates that a winddown of regulated gas pipelines exposes gas pipeline businesses to material cost recovery risk:
    - $973 million if full winddown occurs by 2050, and
    - $568 million if LPG conversion occurs by 2040,

  both in present value terms ($2022) and *assuming* no further regulatory or policy levers (or mitigations) are applied beyond those already reflected in the recent DPP decisions.[14]
- Given this, initial analysis suggests that the financial viability of GPBs is at risk under the full winddown and LPG conversion scenarios, *assuming* no change to current regulatory settings or Government intervention.

[14] The $973 million for the full winddown scenario is the sum of unrecovered revenue over the period to 2050 for transmission and distribution pipelines of $289 million and $540 million and the residual RAB values as at 2050 of $71 million and $73 million respectively. Likewise, the $568 million for the LPG conversion scenario is the sum of unrecovered revenue of $202 million and $285 million and residual RAB of $58 million and $23 million for transmission and distribution pipelines, respectively.

- Key drivers of the size and timing of this risk are gas consumers' future demand and willingness to pay for gas transportation services, which largely drives GPB's net cash flows. Declining cash flows under both scenarios reduces projected returns on investment (ROIs). Cash flow and ROI projections suggest that changes will need to be made to regulatory and policy settings for gas pipelines to remain financially viable under a winddown or LPG conversion scenario.
- Faced with that outlook it may be rational for gas pipeline businesses to shutdown uneconomic sections of their infrastructure sooner than is socially desirable. If shutdown did occur, then energy consumers would lose the option to choose reticulated gas as an energy source.
- Alternatively, it may also be rationale for gas pipeline businesses to actively pursue biomethane blending as a way of mitigating the risk of under-recovery under a winddown scenario. Such incentives, however, are undermined by uncertainty over the future viability of biomethane and other green gases.
- Any investment to preserve the option of future green gases will need to balance the risk that that investment will not be recovered – e.g., because re-purposing does not occur – with the potential reduction in cost recovery risk from undertaking it, which could be done via a probability-based assessment.
- Further work could be undertaken to better understand the drivers of the cash flow projections under both winddown and repurposing scenarios, including as to what revenue gas pipeline businesses may be able to realise from gas consumers and what mitigations could be taken (e.g., changes to regulatory settings go offset the risk faced). Modelling how future investment decision may occur could also provide useful insight.
- This analysis is preliminary and conceptual. Although care has been taken to prepare the modelling and inputs to it, the analysis is based on many assumptions and projections that are unlikely to reflect real world outcomes. Further work is needed to better refine the modelling and inputs.

4.4.1. Context

The current regulatory approach to setting allowed revenues and prices for regulated gas pipelines is to plan and implement expenditures – investment and operating costs – to meet forecast demand efficiently; and then spread the recovery of long-lived capital investments over long periods (e.g., typically at least 50 years) reflecting the expected technical life of the pipeline assets. This approach spreads the recovery of much of the investment to future generations of consumers who will benefit from use of the assets over their life.

Planning for meeting demand efficiently and spreading of costs in this way is predicated on the market for gas transportation services remaining at similar levels as today. If that market were to significantly reduce in size or cease entirely due to Government action to mitigate climate change, then it is unlikely that investment costs and associated operating costs could be recovered in full because there will be insufficient demand for regulated gas transportation services and related to this, limits on the willingness to pay by consumers higher prices resulting from the reduced demand available to recover past costs.

Cost recovery risk is related to the financial viability of gas pipeline businesses. This is because the financial obligations (debt and other liabilities) of those businesses can be expected to have been entered into assuming that they could recover their efficient costs, including past investment in pipeline infrastructure. Higher cost recovery risk implies worsening financial viability because it suggests that future cash flows to infrastructure owners are riskier (and vice versa).

4.4.2. Focus of analysis

The analysis focuses on the projected implications to gas pipeline businesses under the various gas transition scenarios being considered. It considers the same horizon as that in sections 4.2 and 4.3 and ignores steps that the Government or the Commerce Commission may take to mitigate cost recovery.

Cost recovery risk will be affected by whether Government action seeks to achieve a winddown of gas pipeline infrastructure or to repurpose it to transport green gases, such as blend with biomethane. Question 3 focuses on how cost recovery risk differs across the scenarios and what this might mean in terms of financial viability of gas pipeline businesses.

Given the long-lived nature of gas pipeline infrastructure, the initial analysis is concerned with how cost recovery risk changes over the medium to long term, both in terms of materiality and trajectory. The Government's target of net zero by 2050 provides a useful starting point for this horizon, and so the analysis focuses on the period from 2022 out to 2050.

To provide a baseline, the initial analysis ignores steps that the Government or the Commerce Commission may take to mitigate cost recovery risk in the future.

4.4.3. Prediction

The *premise* is that a winddown of gas infrastructure will increase cost recovery risk and worsen financial viability as gas pipeline businesses are unable to fully recover the revenue required to maintain and operate their pipelines. Although the Commerce Commission's 2022 decisions to accelerate depreciation for gas pipeline businesses reduces this risk, it remains material in outer years.

If biomethane blending occurs – and is economic to both gas pipeline businesses and gas consumers – then this should reduce cost recovery risk and improve financial viability relative to a winddown or LPG conversion scenario because it implies that those businesses will continue to generate cash inflows that can cover financial obligations.

Financial viability of gas pipeline businesses will depend on:

- projected cash flows – which will be affected by how future revenues and costs compare,[15] and
- current debt and future debt and equity raising needs (e.g., to support future expenditure).

Financial viability may be better assessed by longer term cash flows rather than shorter term cash flow fluctuations, which can be driven by large expenditure outlays that are paid back over time.

4.4.4. Initial quantitative analysis results

Initial analysis

The initial quantitative analysis undertaken by the Working Group confirms the prediction that a winddown of gas infrastructure will lead to a material risk of cost under recovery, although this is partially mitigated by Commerce Commission action. Consequentially, the analysis suggests that a winddown will reduce the financial viability of the GPBs.

Biomethane blending appears to mitigate that risk, largely because of the ongoing operation of the gas pipelines. If the demand assumed for that scenario does not eventuate, then financial viability will be undermined.

The key drivers of this are:

- cash flows being put under pressure due to projected cost under recovery under both scenarios as demand reduces, and
- meaningful levels of expenditures needing to continue even under a winddown or LPG conversion scenario.

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15 A company's ability to create value for shareholders – and therefore to have incentive to invest and stay in business – is fundamentally determined by its ability generate long-term positive free cash flow. A company may choose to stay in business through a period of negative cash flows, but only if it has expectations that net cash flows will turn positive.

These drivers and their consequences for financial viability and projected returns can be illustrated by considering:

- recoverable and unrecoverable revenue
- net cash flows
- return on investment, and
- present value of cash flows and residual value.

Recoverable and unrecoverable revenue

FIGURE 4.8 compares the recoverable and unrecoverable revenue under all four scenarios, with transmission and distribution combined. It shows that the proportion of allowable revenue (i.e., BBAR) that is unrecovered increases over time for the LPG conversion and full winddown scenarios. However, consistent with the projected demand profiles, the decline in recoverable revenue occurs over a longer period under those scenarios.

This increase in unrecoverable revenue occurs because forecast revenue that is recoverable from gas consumers is projected to decline noticeably faster than allowable revenue. Forecast revenue falls because demand is projected to decline almost to zero by the time the pipelines are assumed to stop operating (i.e., either 2040 or 2050), while willingness to pay per consumer remains relatively stable. Allowed revenue is projected to decline more slowly largely because the RAB is depreciated over a longer horizon and because of costs incurred as consumers disconnect and pipelines are decommissioned.

Importantly, FIGURE 4.8 also shows that – if retained – the accelerated depreciation adopted by the Commerce Commission helps mitigate under-recovery somewhat by allowing for greater capital recovery at the present time when demand is the greatest. Although some unrecovered revenue remains under the business as usual and biomethane blending scenarios, that action by the Commerce Commission and the continued operation of the pipelines reduces projected unrecoverable revenue significantly.

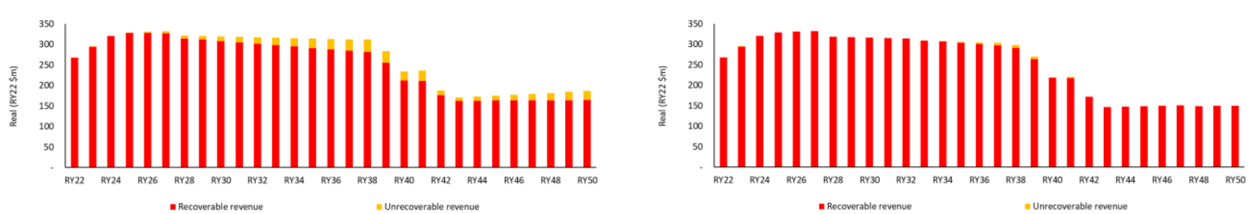
As a simplification, the analysis assumes that the share of allowable revenue recovered from different consumer types remains fixed. Similarly, producers are assumed to retain their existing margins rather than absorb some of the unrecoverable revenue.[16]

Over the period to when winddown is completed unrecoverable revenue sums to $289 million and $540 million in present value terms (2022 dollars) for transmission and distribution businesses respectively under the LPG conversion scenario, and $202 million and $285 million respectively under the full winddown scenario.

FIGURE 4.8: RECOVERABLE AND UNRECOVERABLE REVENUE

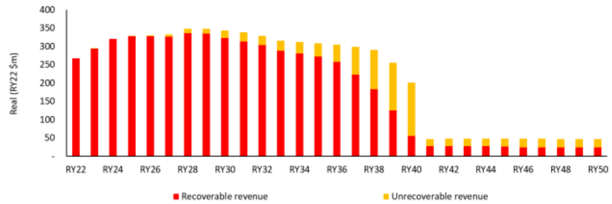
Business as usual *Transmission + distribution combined*

Biomethane blending *Transmission + distribution combined*

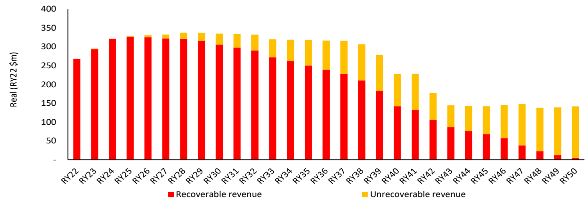


[16] Relaxing these assumptions may reduce projected unrecoverable revenue. For instance, gas pipelines could rebalance tariffs so that consumers that have greater willingness to pay face higher prices. Alternative, they could negotiate with producers to share some of the unrecoverable revenue.

LPG conversion
Transmission + distribution combined



Full winddown
Transmission + distribution combined



Net cash flows

Net cash flows are an important measure of business viability. Although businesses can operate with negative cash flows in some instances (e.g., a period when there are large capital outlays), over extended period this is simply not sustainable as it means that insufficient cash is coming in to pay outgoings. As such, understanding whether and if so for how long a business is expected to face negative or declining cash flows provides insights into whether it is financially viable.

FIGURE 4.9 compares the net cash flows in aggregate across gas distribution and transmission businesses for each of the four scenarios. It shows that, under the full winddown scenario, net cash flow tends to remain positive for the initial years. Cash flow then gradually trends downward before dropping strongly and becomes negative in the years leading up to full winddown as decommissioning costs are incurred, consumer numbers fall and consumer willingness to pay is insufficient to recover required revenue.

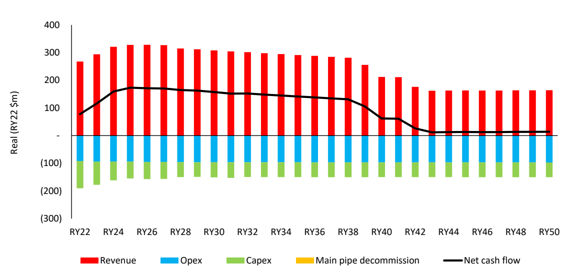
Under the business as usual and biomethane blending scenarios, net cash flows remain positive and less volatile over the modelling period relative to the full winddown scenarios. However, cash flows show a drop towards the end of the period. This suggests that those businesses may not be financially viable under the scenarios modelled even though net cash flows are positive. This is particular so for the business as usual scenario whereby net cash flows are only slightly positive.

FIGURE 4.9 also shows that net cash flows dip negative under the LPG conversion scenario by 2040 due to the impact of pipeline decommissioning costs. They then rebound to around zero over the period where the 'Taranaki rump' remains operational.

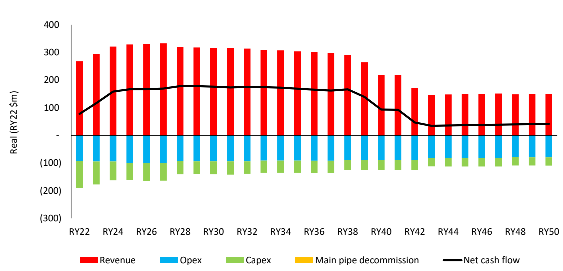
As shown in Table 4.1, the present value of net cash flows for transmission and distribution businesses are $999 million and $921 million respectively under the LPG conversion scenario, and $944 million and $789 million respectively under the full winddown scenario.

FIGURE 4.9: NET CASH FLOWS (BEFORE INTEREST AND TAX)

Business as usual
Transmission + distribution combined

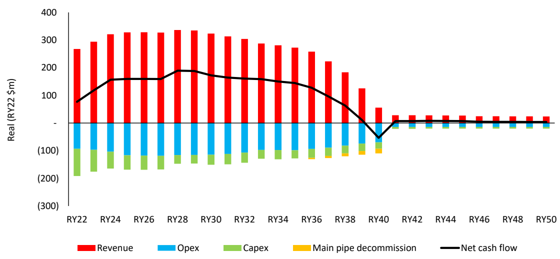


Biomethane blending
Transmission + distribution combined



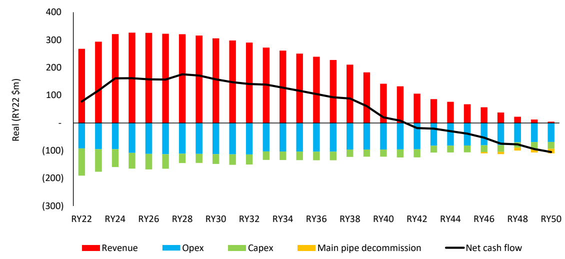
LPG conversion

Transmission + distribution combined



Full winddown

Transmission + distribution combined



Return on investment

The cash flow trajectories affect the estimated ROI of the GPBs. For simplicity, **Figure 4.8** compares the projected ROI for the gas distribution and transmission pipelines in aggregate against the assumed regulated WACC for the 4 gas transition scenarios.

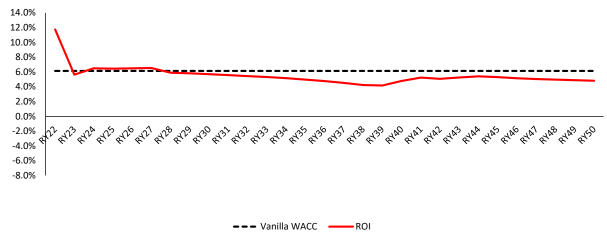
Assuming that the model assumptions are valid it shows that under both the LPG conversion and the full winddown scenarios the ROI declines gradually over time in proportion to the revenue being recovered and – critically – fall below the cost of capital and become negative. If this persists, then it suggests that the future financial viability of the GPBs is at risk under either scenario.

Importantly, **Figure 4.8** suggests that the project ROI will align with regulated WACC under the business as usual and biomethane blending scenarios. Although the ROI dips below the WACC under both scenarios, the RIO remains positive. Further work could be undertaken to better understand how much of a concern the RIO projections are under the two scenarios.

Figure 4.10: Return on investment

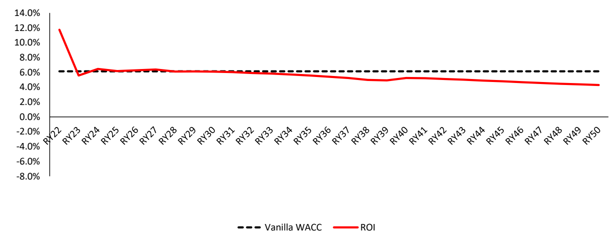
Business as usual

Transmission + distribution combined



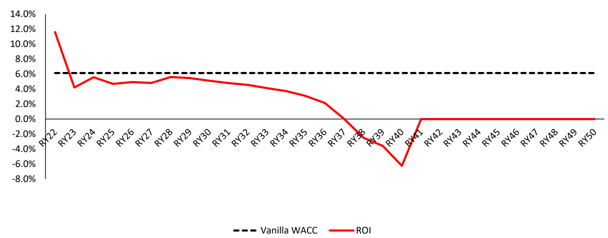
Biomethane blending

Transmission + distribution combined



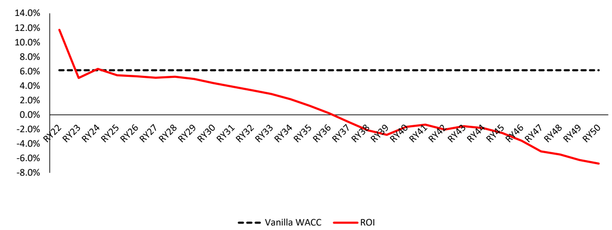
LPG conversion

Transmission + distribution combined



Full winddown

Transmission + distribution combined



Present value of cash flows and residual value

Table 4.1 compares the present value of future cash flows and residual RAB values for transmission and distribution pipelines across the 4 gas transition scenarios. It shows that the present value to gas pipeline businesses is greatest under the biomethane scenario and lowest under the LPG conversion scenario.

The table also shows that accelerated depreciation, if retained, would help reduce the present value of the residual RAB – an observation consistent with the RAB projections shown above in FIGURE 4.4 and FIGURE 4.5.

Importantly, the table assumes that gas pipeline businesses *will* recover the present value of the residual RAB in 2050. If they do not, then any under-recovery of the RAB represents a loss to those businesses. This is particularly relevant to the LPG conversion and full winddown scenarios whereby gas consumers are assumed to have defected from the gas pipelines.

TABLE 4.1: PRESENT VALUE OF NET CASH FLOWS AND CLOSING RAB

Sector	Scenario	Present value of net cash flows (RY22 $m)	Present value of residual RAB (RY22 $m)	Total present value (RY22 $m)
Transmission	Business as usual	950	204	1,155
	Biomethane blending	1,110	106	1,216
	LPG conversion	941	58	999
	Full winddown	874	71	944
Distribution	Business as usual	1,070	133	1,203
	Biomethane blending	1,198	134	1,332
	LPG conversion	897	23	921
	Full winddown	716	73	789

Note: Figures may not sum due to rounding

Financeability

The cash flow trajectories outlined above would – if realised – materially adversely affect the ability of GPBs to raise capital to continue investing in and operating gas infrastructure (i.e., financeability). To support that, two financeability measures – leverage ratios and operating cash to debt across the GPBs – for the different market scenarios were assessed. For simplicity these results are not presented here.

Limitations

This analysis is subject to the limitations noted in section 3.5.

However, notwithstanding these limitations, it appears that under all scenarios considered that cost under recovery will occur. Modeling uncertainties being about the speed and timing for when this risk will crystallize and the magnitude of it.

Importantly, the model logic for allocating revenue received from end gas consumers between transmission and distribution businesses, wholesale gas producers, and retailers has a significant impact on the results (including recoverable/unrecoverable revenue). Currently, this is being allocated between transmission businesses, distribution businesses and retailers based on their relative target revenues. It is assumed that gas wholesalers fully recover their revenue. This model logic can be adjusted and is being reviewed.

Willingness to pay assumptions are particularly important to the analysis because they affect the amount of allowed revenue that regulated gas pipelines are projected to recover. Further work to better understand willingness to pay is recommended, including to better assess non-price factors that influence gas consumer decisions to use gas or alternative energy sources. Another related question is to explore supply chain impacts, such as the possibility of cost pressures leading to lower margins for gas producers and retailers.

As noted above this initial conceptual analysis considers only private costs and benefits. Consideration could be given to whether there are further is whether are material external costs and benefits that would warrant undertaking a broader social cost-benefit analysis, such as the impact on electricity networks and to vulnerable consumers.

4.4.5. Key insights

The initial analysis above suggests that a winddown of regulated gas pipelines exposes gas pipeline business to material cost recovery risk even following the Commerce Commission decision to accelerate depreciation (i.e., the speed of capital recovery). That risk undermines the financial viability of GPBs.

The pace of winddown will affect that risk – however it appears to remain material under the two scenarios considered in this paper (i.e., the LPG conversion and full winddown). And although alternative assumptions (e.g., as to the ability to recover allowed revenue) will affect that risk, current regulatory settings (e.g., depreciation of long-lived assets) – if maintained – will appear to lead to sizable unrecovered capital once the pipelines no longer service gas consumers.

Absent further mitigation (i.e., beyond the accelerated depreciation adopted in the DPP decisions), such projections suggest that the gas pipelines will not remain financially viable under an LPG conversion or full winddown scenario. Faced with that outlook it may be rational for gas pipeline businesses to shutdown uneconomic sections of their infrastructure sooner than gas consumers may want.

Further work could be undertaken to better understand cost recovery risk under an LPG conversion or full winddown scenario. Although this may not affect the observations above, this work could assess what revenue gas pipeline businesses could realistically recover from gas consumers and what mitigations could be taken to help mitigate cost recovery risk (e.g., changes to regulatory settings or offset the risk faced). The model logic for allocating revenue received from end gas consumers across the supply chain could also revised.

4.5. Question 4: Impact on emissions?

How might carbon emissions vary across the gas transition scenarios?

Box 5: Emission impact | Summary

- The key driver for the gas transition plan being developed by MBIE and the GIC is the aim to reduce carbon emissions across New Zealand. The gas transition scenarios were designed to test alternative pathways that could contribute to that outcome.
- Unsurprisingly, reducing natural gas consumption is expected to lead to lower carbon emissions over the period out to 2050, led by significant reductions in consumption by large transmission-connected consumers.
- There is some potential for higher emissions in the shorter term under the LPG conversion and full winddown scenarios. However, whether this occurs in reality will depend on what fuels consumers convert their energy consumption to, the emissions intensity of those fuels, and – importantly – the energy efficiency of the appliances that use them.
- An important next step for the Working Group's analysis will be to compare projected emissions reductions to the financial implications for gas consumers, gas pipeline businesses, and the wider economy.

4.5.1. Context

The key driver for the gas transition plan being developed by MBIE and the GIC is the aim to reduce carbon emissions across New Zealand. The gas transition scenarios were designed to test alternative pathways that could contribute to that outcome.

The analysis in responses to Questions 1, 2 and 3 all focus on the financial implications to gas consumers and gas pipeline businesses from those four scenarios. The analysis in response to Question 4 focuses instead on the emissions impact.

As outlined in section 5, the Working Group is looking at further work that will assess the trade-off between those financial implications (i.e., costs) and emission reductions.

4.5.2. Focus of analysis

Simply put, the analysis looks at projected emissions over time for each of the scenarios. It translates forecast natural gas, LPG, and electricity consumption (i.e., from those that switch from natural gas) into tonnes of carbon dioxide (CO^2) emissions using assumed emissions intensity factors for each energy source.

Emissions from LPG and electricity consumption from gas consumers that switch away from reticulated natural gas are included in the analysis to ensure a like-for-like comparison. If either were excluded, then the projections would inherently suggest that consuming those fuels does not emit carbon dioxide, which is not accurate.

As a starting simplification, the analysis assumes the energy efficiency of appliances is the same across all fuels. In reality, energy efficiency differs across appliance types and fuel sources and so this simplification is intended to help illustrate the potential direction of emissions under the scenarios rather than provide accurate projections.

4.5.3. Prediction

The *premise* is that carbon emissions will reduce under all scenarios as consumers defect from gas pipelines to alternative energy sources (e.g., electricity). This driven by lower assumed emissions from electricity consumption than natural gas and LPG. Although there may be some temporary increases under the LPG conversion scenario, reductions will be permanent across both transmission and distribution pipelines.

4.5.4. Initial quantitative analysis results

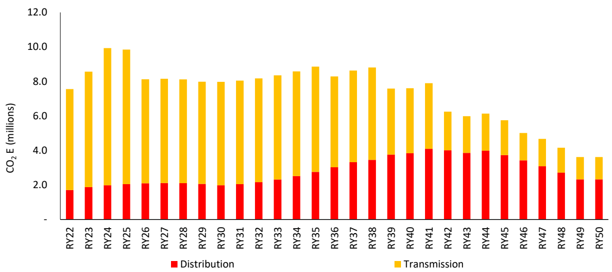
FIGURE 4.11 shows projected emissions under the four scenarios for natural gas delivered by transmission and distribution pipelines, combined and separately. The initial analysis confirms that emissions are projected to reduce under all four scenarios, with the largest contributor coming from reductions in consumption by transmission-connected consumers.

Somewhat more surprisingly, the initial analysis suggests the potential for emissions to be higher in the shorter term under the LPG conversion and full winddown scenario as consumers switch to alternative fuels. The reason for this is that incremental electricity and LPG consumption is assumed to have greater emissions intensity than natural gas during that period, which – when combined with the energy efficiency simplification noted above – means that consumers emit more for an equivalent energy output. Emissions intensity of electricity is projected to reduce as renewable generation substitutions for coal and gas fired power plants.

FIGURE 4.11: EMISSIONS

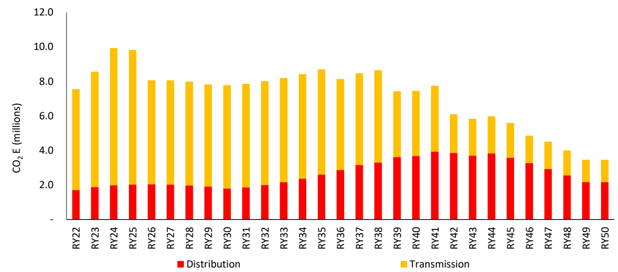
Business as usual

Transmission + distribution combined

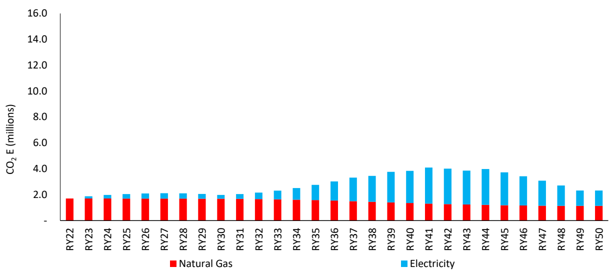


Biomethane blending

Transmission + distribution combined



Distribution



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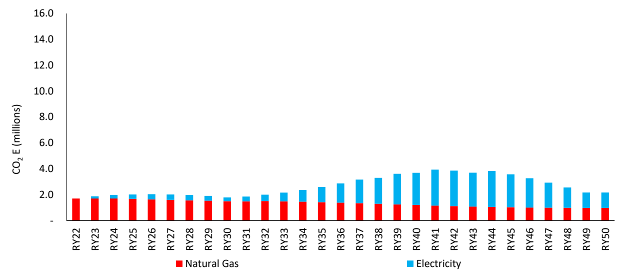
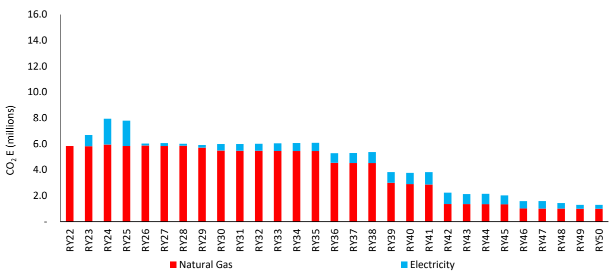
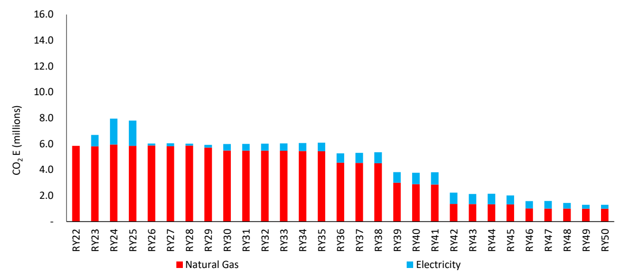


Transmission

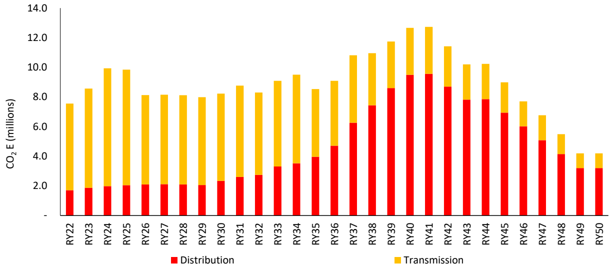


Transmission

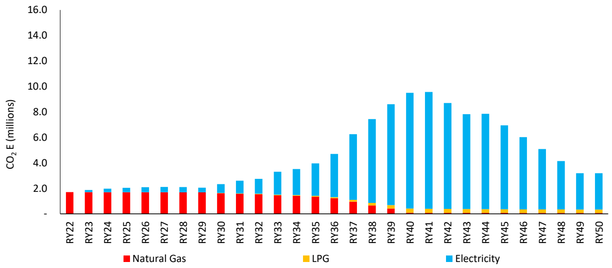


LPG conversion

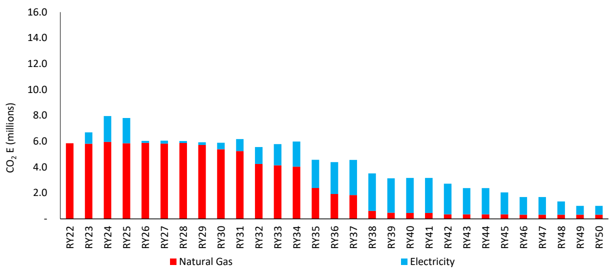
Transmission + distribution combined



Distribution

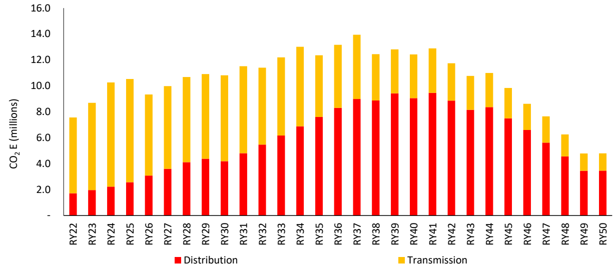


Transmission

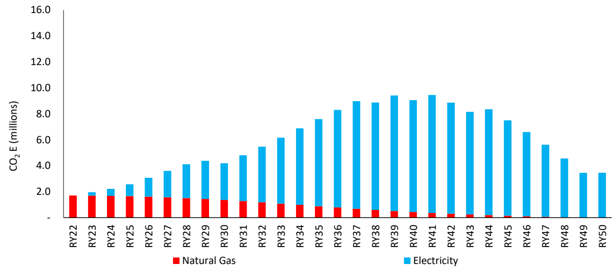


Full winddown

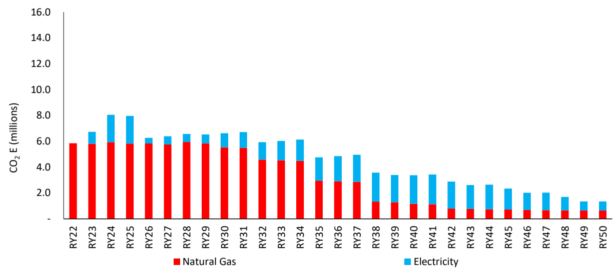
Transmission + distribution combined



Distribution



Transmission



Limitations

This analysis is subject to the limitations noted in section 3.5.

Projected natural gas, LPG, and electricity consumption is inherently uncertain, which directly affects projected emissions. If consumption projections turn out to be wrong, then so too will those for emissions.

Moreover, emissions intensity and energy efficiency assumptions are used to translate that consumption into emissions. There are differing views on what are the ‘right’ assumptions to use and in what circumstances. Sensitivity analysis could be used to assess how important these assumptions are to the projections.

4.5.5. Key insights

Unsurprisingly, reducing natural gas consumption is expected to lead to lower carbon emissions over the period out to 2050, led by significant reductions in consumption by large transmission-connected consumers.

There is some potential for higher emissions in the shorter term under the LPG conversion and full winddown scenarios. However, whether this occurs in practice will depend on what fuels consumers convert their energy consumption to, the emissions intensity of those fuels, and – importantly – the energy efficiency of the appliances that use them.

An important next step for the Working Group’s analysis will be to compare projected emissions reductions to the financial implications for gas consumers, gas pipeline businesses, and the wider economy.

5. FUTURE ANALYSIS

This **Gas Transition Analysis Paper** presents some initial conceptual analysis undertaken of four key questions about the transition scenarios explored by the Working Group. But it is by no means complete or exhaustive – further analysis is undoubtably warranted.

The conceptual analysis rests on a model and preliminary inputs developed by the Working Group, including demand, pricing, and expenditure assumptions. The model analyses potential impacts on gas consumers, gas infrastructure businesses, and Government over a horizon out to 2050 under alternative scenarios.

Although the initial conceptual analysis provides useful insight, it's more important role is to provide a baseline from which to identify further and more targeted questions to explore. To this end, the Working Group has identified six areas of interest for potential future analysis:

- impact on resources and the labour force from consumers switching to alternative energy sources
- impact on vulnerable consumers if gas pipelines are wound down
- acuteness of cash flow concerns facing gas pipeline businesses under the winddown scenarios
- trade-offs between affordability and emissions reductions
- sensitivity of consumer impacts to alternative energy price projections
- impacts on electricity networks switching their gas energy needs to electricity.

Potential questions, insights sought, and modelling approach for the six areas are set in the sections below. The Working Group is currently looking into this work further.

5.1. Resources and labour force

TABLE 5.1: RESOURCE AND LABOUR FORCE IMPLICATIONS

Component	Description
Question	*What are the potential resource and labour force implications of a full network winddown?*
Insight sought	Exploring this question should provide insight into the scale of resources and timeframes that may be required if there is a full network winddown. This may include insights on the cost to consumers, demand on trades (e.g., electricians, plumbers, gas fitters, builders), and the need for coordination among the various stakeholders involved. It may also allow an initial look at what timeframe may be realistic (e.g., if there is a material need to draw from New Zealand's already constrained pool of trades people). Initial analysis may look at these implications in aggregate across networks. Future refinements could consider these implications on a more regional or localised basis, to the extent that is possible.
Modelling approach	The modelling would likely involve: • focusing on the counterfactual and LPG scenarios (4 and 5) • developing new calculations that: – estimate aggregate conversion costs

Component	Description
	– estimate trade requirements, potentially drawing on insights from the tactical decommissioning study • outputting charts and tables that show estimated cost and resource requirements • comparing projected resource requirements against separate estimates of those available in New Zealand (i.e., as an implied constraint on each resource type). The outputs should allow the Working Group to draw inferences as to the need for coordination and realistic timeframes, potentially leading into further work (e.g., time in motion studies).

5.2. Vulnerable consumers

TABLE 5.2: VULNERABLE CONSUMERS

Component	Description
Question	*What may be the impact be on vulnerable consumers if there is a network winddown?*
Insight sought	Exploring this question will provide insight into what the impact of a winddown may be on vulnerable gas consumers who may be less able to transition of their own accord from gas to alternative energy sources. An extension could look at how negative impacts could be mitigated (e.g., government funding, rebalancing revenue between consumer groups).
Modelling approach	The modelling would likely involve: • focusing on the counterfactual and LPG scenarios (4 and 5) • translating revenue and volume projections into those components that relate to vulnerable consumers • comparing projected conversion costs per consumer to disposal income for vulnerable consumers.

5.3. Cash flow concerns

TABLE 5.3: CASH FLOW CONCERNS

Component	Description
Question	*How acute are the projected cash flow concerns to GPBs if there is a full network winddown? And what can be done to address these?*
Insight sought	Exploring this question will provide insight into how GPBs may respond to projected cash flow outcomes under a full network winddown, and the consequential impact on gas services (e.g., safety, reliability, and affordability of gas). Testing alternative revenue and price profiles (e.g., with different depreciation projections, or rebalancing across consumers) may give insight into how far economic regulation can or cannot

Component	Description
	go to address potential cash flow concerns (e.g., can accelerated depreciation avoid a death spiral?).
Modelling approach	The modelling would likely involve: • focusing on the counterfactual and LPG scenarios (4 and 5), potentially compared to the BAU scenarios (1 and 2) • testing the sensitivity of cash flow projections to alternative assumptions (e.g., depreciation profiles, rate of return, demand, revenue rebalancing across consumers) • assessing alternative profiles for the speed of winddown (e.g., a slower winddown if constrained due to difficulty securing trade and other resources).

5.4. Trade-off between affordability and emissions

TABLE 5.4: TRADE-OFF BETWEEN AFFORDABILITY AND EMISSIONS

Component	Description
Question	*Across the scenarios considered, what is the potential trade-off between affordability and emissions reductions?*
Insight sought	Exploring this question will provide insight into the cost of carbon abatement from gas consumption. This could be compared to the equivalent cost from other abatement opportunities in New Zealand. Combining this with insights from the earlier question as to the resource impact might also give some sense of the likely timing for that potential abatement compared with other 'lower hanging fruit' that may be cheaper and more timely. Further analysis could also provide insight into how important assumed changes in energy efficiency (e.g., from gas to electric appliances) are to estimated changes in emissions.
Modelling approach	The modelling would likely involve: • developing comparisons across the scenarios and consumer segments that look at both the cost implications and emissions reduction from the various scenarios (noting that some metrics will need to be developed) • outputting these comparisons in simple to understand charts that ultimately allow for sensitivity testing, including of the potential change in energy efficiency from gas appliances to those used by alternative energy sources (e.g., electricity).

5.5. Sensitivity of consumer impacts

TABLE 5.5: SENSITY OF CONSUMER IMPACTS

Component	Description
Question	*How sensitive are the projected consumer impacts across the scenarios to alternative energy price projections?*

Component	Description
Insight sought	Exploring this question will give insight into how consumers may respond across the scenarios if base assumptions turn out to be wrong.
Modelling approach	The modelling would likely involve: • starting with existing analysis for all scenarios (1, 2, 4 and 5) • testing how key projections change under alternative energy price projections • drawing insights as to the point in time when alternative energy prices fall below projected gas prices by consumer group • building in automated revenue rebalancing (i.e., that is targeted at using up available willingness to pay).

5.6. Impact on electricity networks

TABLE 5.6: IMPACT ON ELECTRICITY NETWORKS

Component	Description
Question	*What might be the projected impact on electricity network costs under a full network winddown?*
Insight sought	Exploring this question will help identify the potential cost to electricity consumers from gas consumers switching their energy needs to electricity. This will need to consider how that switching will affect localised peak demand across relevant electricity networks in Auckland, Wellington and elsewhere in the North Island. Depending on available information, the analysis could also look into the impact on wholesale electricity prices as well as electricity network costs. The current regionally aggregated model could be modified to enable average marginal electricity network costs, which would be useful to understand. In practice, the marginal impact on electricity network costs may vary by location, depending on factors such as existing network capacity, growth rates, scope for demand side management etc.
Modelling approach	The modelling would likely involve: • focusing on the counterfactual and LPG scenarios (4 and 5) • developing new calculations that: – translate the reduction in gas consumption from relevant consumers (e.g., residential and commercial) into peak electricity consumption – assess the marginal impact on network costs (e.g., drawing from LRMC or other cost measures publicly available) • outputting charts that project the aggregate impact on electricity network costs • assessing how sensitive these costs are to faster and slower winddowns • translating peak time electricity consumption impact into wholesale price estimates.

Appendices

Summary

This part of the Gas Transition Analysis Paper includes two appendices:

Appendix A: Model description

Appendix B: Glossary and Abbreviations

APPENDIX A. MODEL DESCRIPTION

This appendix describes the Model used by the Working Group to undertake its gas transition analysis.

A.1. Summary

At its core, the Model is a cash flow model. It assesses the cash flows to gas pipeline businesses and gas consumers over a 36-year forecasting period. It relies on a range of inputs and assumptions. It also simplifies some of the real-world dynamics that will play out in practice to approximate the potential cash flow impacts.

As with all modelling, there is always room to improve. Further work could be done to improve the quality of inputs and assumptions. The model could be refined to model, dynamically, relationships:

- between projected demand and prices faced by gas consumers, and
- between projected expenditure by and cash flows or returns to gas pipeline businesses.

However, the Working Group considers that the Model provides an appropriate starting point for an *initial* foray into the analysis questions identified in 2.4 and considered in section 4.

The remainder of this appendix briefly outlines the Model purpose, scope, and structure. It also notes the scenario capability and key limitations. The Model is supported by a model user guide, which has not been included in this paper.

A.2. Purpose

The overarching purpose of the Model is to help understand the financial impact on gas consumers and GPBs of future scenarios for gas infrastructure in New Zealand. The Model can be used to helps analyse key policy, regulatory and pricing questions related to the future of GPBs such as:

- What is the extent and trajectory through time of cost recovery risk faced by gas pipeline businesses and what are the key drivers of this risk?
- How is the cost recovery risk affected by the potential for re-purposing and differences in willingness to pay for consumer groups?
- How is cost recovery risk affected by regulatory levers (e.g., alternative depreciation, stranding allowance, regulatory WACC, etc.) and policy levers (e.g., Government support to networks and/or consumers)?
- How do these implications vary by distribution and transmission?
- What are the financial implications to gas consumers across consumer groups (residential, commercial and industrial)?
- How do carbon emissions compare across scenarios, consumer types, and transmission or distribution pipelines?

A.3. Scope

To achieve the purpose, the Model assesses cash flows to gas pipeline businesses and gas consumers over a 36-year forecasting period, starting with regulatory year 22 plus an additional 35 years. [17] Although not presented in this Gas Transition Analysis Paper, it can be used to assess the consequences of various potential regulatory and policy decisions (or levers) on each gas pipeline business' revenue, net cash flows (before financing and tax), and regulatory metrics (e.g., RAB, RIV or ROI).

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17 The 'regulatory year' concept is drawn from the economic regulation practice and adopted as a modelling convenience. This does not imply that the modelling analysis is solely focused on economic regulation questions. Rather it is also focused on broader commercial and policy questions.

The Model allows outcomes to be compared under different scenarios by applying specific flexes on:

- regulatory levers – such as, alternative depreciation, asset stranding allowance, RAB indexation, WACC
- policy levers – such as, Government support to consumers and networks, deregulation
- consumer connection profile
- expenditure profile (capex and opex)
- other consumer impacts – such as, BBAR allocation to consumer group, wholesale gas prices, alternative energy pricing.

The Model also incorporates further sensitivity testing on inputs including capex/opex, consumer connections/demand. It produces outputs for each gas pipeline business individually and in aggregate.

A.4. Structure

The Model is made up of three core modules which are dynamically linked and contained within the same workbook:

- **BBAR module**: estimates the regulatory asset base (RAB), regulatory tax asset value (RTAV) and regulatory investment value (RIV) and building blocks allowable revenue (BBAR) of a chosen GBP.
- **Consumer Impacts module**: calculates the annual cost recovered per consumer, as a combination of transmission and distribution BBAR, wholesale gas costs and a retailer margin, capped at the annualised alternative energy costs. This module also calculates the GBPs' revenue, cash flows, regulatory tax allowances and return on investment (ROI).
- **Emissions module**: calculates the emissions profile for distribution and transmission under each scenario based on emissions for natural gas, electricity, LPG, and biomethane.

Each module has three components, consisting of inputs, calculations, and outputs.

The Model also contains:

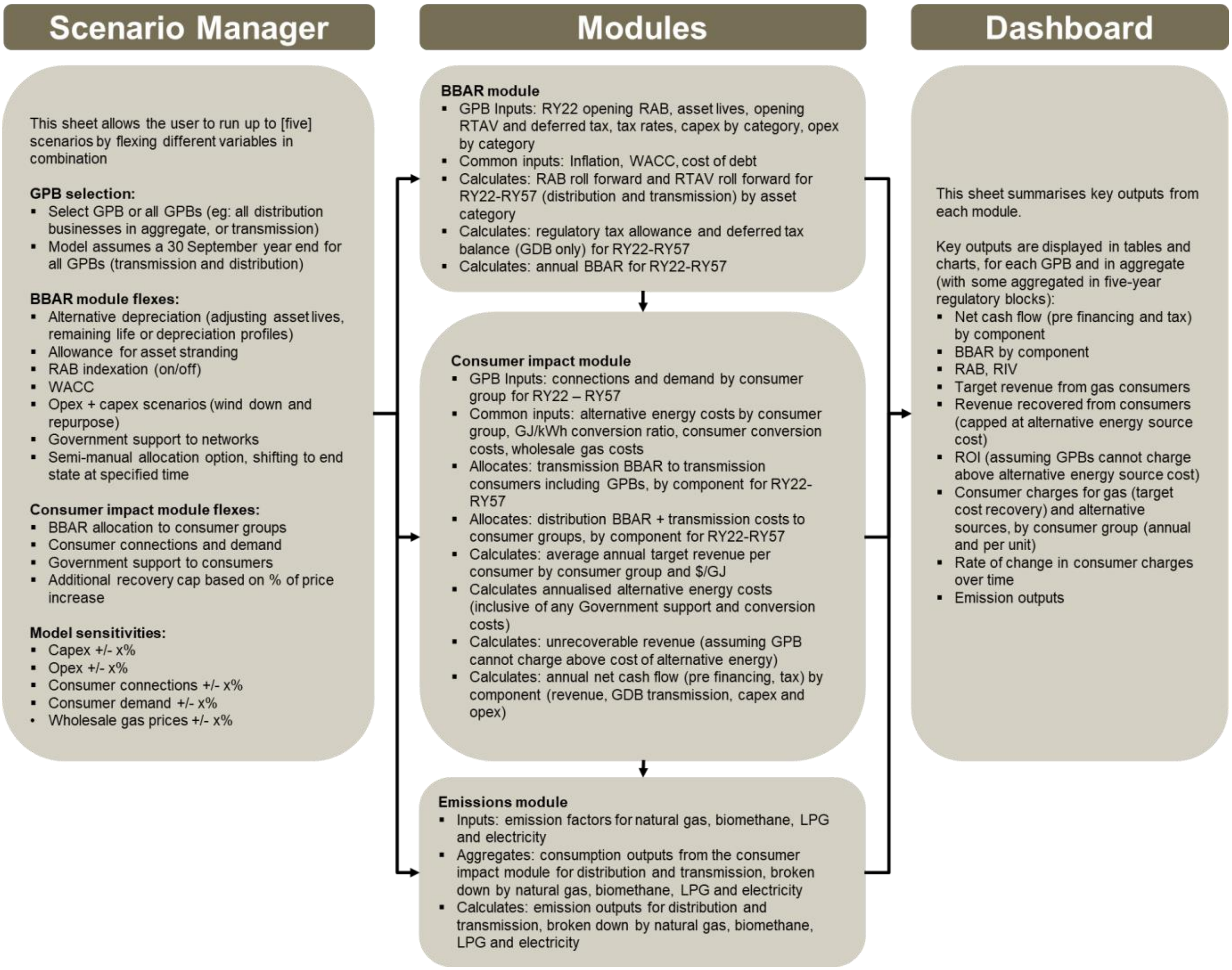
- **Scenario manager** – which allows the user to select from a comprehensive range of scenarios, flexes and sensitivities and a dashboard which displays key model outputs
- **Maximum allowed revenue (MAR) calculation capability** – which can be used to assess alternative options for smoothing BBAR revenues.

The Model start date is 1 October 2021 to align with the most recent published GPB regulatory data. The model forecasts annual cash flows over a 36-year period, with a 30 September year-end to align with the DPP. Four or five-year regulatory periods are identified in the Model, to allow for any changes in regulatory settings that apply from the beginning of a regulatory period.[18]

Figure A.4.1 illustrates the high-level structure of the Model (excluding certain modules and logic recently added such as MAR and financing calculations).

18 A four-year regulatory period is adopted for the first to align with the Commerce Commission's 2022 decision on the default price path for gas pipeline businesses.

FIGURE A.4.1: MODEL STRUCTURE



A.5. Scenarios and sensitivities

A key part of the model's capability is functionality to test the impact of a range of scenarios and sensitivities on the results.

This capability is managed within the scenario manager and there are four different categories of scenarios/sensitivities that can be changed:

- **Market scenarios** – four defined scenarios relating to the overall market outcome for gas.
- **Model scenarios** – five customisable model scenarios based on a range of regulatory and other factors.
- **Sensitivities** – percentage-based increases or decreases applied to specific inputs.
- **GPB selection** – choice of whether outputs should be calculated for a specific GDB (First Gas, GasNet, Powerco or Vector) or for the total distribution market.

The scenario manager lets the Working Group easily switch between any combination of scenarios and sensitivities under the above categories.

The market and model scenarios considered by the Working Group as part of the initial analysis are discussed in the next two sub-sections.

A.5.1. Market scenarios

The Model contains four different market scenarios relating to the overall market outcome for gas. Two scenarios involve a wind-down of gas infrastructure and four scenarios relate to re-purposing natural gas infrastructure for green gas or hydrogen. The key inputs that differ across market scenarios are gas throughput and number of connections as well as expenditure forecasts provided by GPBs.

The four market scenarios are described in Table A.5.1 below. A scenario (3) – a liquefied natural gas (LNG) conversion scenario – was considered initially, but was not incorporated into the Model.

TABLE A.5.1: MARKET SCENARIO DESCRIPTIONS (SCENARIO 3 OMITTED)

Market scenario	Description
1. Business as usual scenario	Gas pipelines remain operational with some decline to a lower level of gas throughput and connections due to the impact of carbon pricing and other emissions reduction measures
2. Biomethane blending scenario	As per the business as usual scenario, except that biomethane blending up to 20% of current gas throughout by residential and commercial consumers by 2030 with blending costs reflected in wholesale gas prices; transmission network remains operational but is scaled back
4. LPG conversion	Gas distribution networks gradually winddown by 2040, with gas consumers switching either to LPG or alternative energy sources (e.g., electricity), incurring relevant conversion costs; gas transmission networks winddown as gas distribution networks disconnect, leaving a 'Taranaki rump' for continued supply to gas generation power plants and large transmission connected consumers in Taranaki
5. Full winddown (i.e., counterfactual) scenario	Gas throughput and connections reduce gradually, with gas consumers transitioning to alternative energy sources (e.g., residential and commercial users switch to electricity, no new connections), incurring relevant conversion costs with pipeline use ceased by 2050

A.5.2. Model scenarios

Separate from the market scenarios described above, the Model allows the Working Group to compare outputs across up to five model scenarios. The model scenarios can be created within the scenario manager by assigning and flexing different scenario design variables in combination. This functionality was added to support the Initial and Further Analysis Papers.

The design variables impact either the BBAR module or the consumer impact module and relate to a wide range of factors including regulatory settings, government subsidies and market parameters. The full set of design variables built into the Model are described in the Table A.5.2 below.

TABLE A.5.2: MARKET SCENARIO DESCRIPTIONS

Module impacted	Design variable	Description
BBAR module	WACC	Ability to switch between a weighted average cost of capital (WACC) based on current regulatory settings and an alternative WACC.
BBAR module	Government subsidy	On/off switch for government subsidy to networks. The amount of the subsidy (as a percentage of RAB) for any given year can be specified as an input. When the switch is turned to on, GPBs are assumed to receive a cash payment equal to the value of the specified portion of RAB in the specified year. RAB is reduced by the same value and RAV is also reduced by an equivalent proportion. The after-tax cash flow impact is accounted for in net cash flows.
BBAR module	Ex-ante allowance for asset stranding	On/Off switch to apply an ex-ante allowance for asset stranding. Calculated as a customisable percentage rate applied to mid-period RAB, allowing GPBs to recover a portion of RAB in a regulatory year as BBAR.
BBAR module	Alternative Depreciation	On/Off switch for a customisable percentage of RAB depreciation (with a default 100% being equivalent to depreciation based on an asset's remaining useful life profile). Contains functionality to treat existing and commissioned assets separately.
BBAR module	Main pipe decommissioning	Functionality to choose if main pipe decommissioning costs are treated as opex or capex.
BBAR module	RAB revaluations	On/Off switch for RAB revaluations based on CPI, with the functionality to choose in which regulatory year revaluations are turned off.
BBAR module	Escalators	Functionality to choose how opex and capex are inflated over the forecast period, with the option to use a Consumer Price index, a weighted Labor Cost index/Producer Price index, or a Capital Goods Price index.

Module impacted	Design variable	Description
Consumer Impact Module	MAR allocation	Functionality to calculate MAR matched to consumption profile, or matched to a manually inputted profile.
Consumer Impact Module	BBAR allocation	Functionality to choose how BBAR is allocated to consumer groups. Includes a custom (manual) option, an option based on existing revenue allocation, and a recovery led option (distribution only)
Consumer Impact Module	Government support to consumers	Functionality to reduce the conversion cost component of alternative energy charges through a government subsidy, at a customisable percentage.
Consumer Impact Module	Annual recovery cap	Functionality to cap annual increases in consumer charges to a customisable percentage, for both transmission and distribution charges.
Consumer Impact Module	Allocation of unrecoverable revenue	Functionality to reallocate a portion of distribution unrecoverable revenue to transmission.
Consumer Impact Module	Willingness to pay margin	A customisable percentage that functions as a margin on top of the total alternative energy charge, signifying consumer preference towards gas.

A.6. Key assumptions and limitations

The Model and conceptual analysis depend on a wide range of assumptions and inputs – these are subject to important limitations.

Key assumptions and limitations include:

- **Interaction between demand and prices** – the Model is static in that it does not endogenously model the relationship between demand for gas and prices, which means that it may miss important insights that could be gained if projected demand were to update automatically within the Model if there were a change in projected prices. Nor does the model specifically analysis approaches to structuring gas transmission and distribution prices, which means that the model cannot provide assess the commercial reality facing any individual gas consumer.
- **Interaction between cash flows and pipeline expenditure** – the Model also does not model the relationship between projected cash flows and returns to infrastructure owners and the expenditure decisions that they make, which means that it may also miss important insights that could be gained if projected expenditure were to update automatically within the model if there were a change in projected cash flows (e.g., because infrastructure owners assessed that such expenditure was not economic).
- **Decommissioning and disconnection costs** – the Model relies on top-down assumptions to illustrate the potential materiality of decommissioning and disconnection costs. Decommissioning costs, for instance, are assumed to equate

to 5% of total RAB value across all assets, which can only ever be a rough estimate. Further work is needed to better understand what activities are required to decommission or disconnect and who will ultimately face the burden of the costs involved.

- **Revenue allocation** – the Model logic for allocating revenue received from end gas consumers between transmission and distribution businesses, wholesale gas producers and retailers has a significant impact on results (including recoverable/unrecoverable revenue). Currently, this is being allocated between transmission businesses, distribution businesses and retailers based on their relative target revenues. It is assumed that gas wholesalers fully recover their revenue. This logic means that the revenue obtained when modelling results for an individual GPB may not match that GPB's share of revenue when modelling the sector as a whole. This model logic can be adjusted in future versions. This model logic can be adjusted in future versions.
- **Regulatory period length** – the Model assumes regulatory (DPP) periods of 5 years, except for the current 4 year period. This may change in future.
- **Willingness to pay** – an additional margin was added to projected to economic willingness to pay for gas to ensure that unrecoverable revenue is zero or close to zero for the first three modelling years for all GPBs to approximate the impact of non-price factors, including consumer switching 'stickiness'. This is further discussed in section A.7 below.
- **Net debt approximation** – the Model calculates a proxy measure for 'net debt'. This measure is not meant to forecast actual debt levels for a given GPB, but rather illustrate financing impacts and trends under a given scenario. More detailed financing modelling capabilities can be built into future versions of the model.
- **Price limits** – the 10% annual price increase cap feature has currently been switched off in the model so that the impact of different regulatory settings can be more easily observed.
- **Forecast inflation** – forecast inflation has been set to 2% for all years to reduce short-term inflation forecast volatility.
- **Regulated WACC** – the WACC has currently been set to be consistent with the Commerce Commission's cost of capital determination for disclosure year 2023 for information disclosure regulation for all model years.
- **Emissions intensity** – natural gas and LPG are assumed to have emissions factors of 0.053 and 0.060 tonnes of CO^2 per GJ of gas consumed respectively, while electricity is assumed to have between 0.02 to 0.29 tonnes of CO^2 per MWh of electricity consumed depending on the appliance used. These assumptions may differ from those used by others or from what may be observed in the future. The assumptions were advised by Concept Consulting and are consistent with separate advice provided to the GIC.
- **Energy equivalence** – as a starting assumption, the Model assumes that consumption of natural gas is 1 for 1 with the consumption of electricity when consumers switch. This assumption is used to estimate the emissions from gas consumers that convert their energy consumption to electricity. In reality, the efficiency of gas and electricity appliances differ. If electricity appliances are more efficient than gas appliances, for instance, then they would require less energy and would mean that the Model is overstating estimated emissions from those consumers that convert.

A.7. Willingness to pay

As noted in section 3.4, an important component of the modelling is WTP – which is a prediction as to how much consumers are willing to pay for delivered gas before they would choose not to consume (e.g., to take up alternative energy sources or otherwise cease using cease).

Concept Consulting has been doing some work to look at the WTP of various types of gas consumers by comparing the costs that they may face for different energy sources, including gas. However, WTP is notoriously difficult to assess, let alone forecast accurately – which means that estimates are generally based on a suite of assumptions.

For the initial analysis, the Working Group has modelled the WTP for each consumer type, under each scenario as the sum of:

- the projected price of alternative energy provided by Concept Consulting

- the cost of converting from gas to alternative energy, including any make good costs, also provided by Concept Consulting, and
- an assumed markup (of 10%) to reflect non-price factors, such as consumer stickiness,[19] amenity value, and other desirable characteristics (e.g., instantaneous hot water).

Conversion costs are assumed to be spread evenly over a period of time – namely, 5 years for distribution consumers and 10 years for transmission direct connect consumers. An equal annual payment amount is set so that the total present value is equal to the total conversion cost provided by Concept Consulting.

Of the three components listed above, the markup for non-price factors is likely to be most uncertain. Anecdotal evidence of gas consumer behaviour indicates that the mark-up is likely to be positive. For example, historical observation suggests that some gas consumers continue to use gas even though it would appear to make sense, economically, to switch to alternative energy sources.

However, a precise estimate is difficult to determine. A 10% assumption was adopted as a placeholder intended to align with the intuition mentioned above, but it is not based on any empirical analysis.

A further limitation of applying a single mark-up for non-price factors is that variation between consumer groups is not captured. For example, it is possible that factors such as consumer stickiness are stronger for residential versus commercial or industrial consumer types.

Further work could be done to derive a more precise estimate of the WTP, especially around the uncertain mark-up for non-price factors. For example, analysis could be performed to better understand how non-price factors that have historically affected demand for gas (including differences across consumer groups) and what this may mean for gas demand in the future. Such analysis is likely to involve significant complexity.

[19] Consumer stickiness is the phenomenon whereby consumers are tend to be slow to switch from one supplier to another even though it is economically sensible to do so (e.g., switching energy retailers or telecom providers).

APPENDIX B. GLOSSARY AND ABBREVIATIONS

Term	Definition
BBAR	Building Blocks Annual Revenue
CPI	Consumer Price Index
DPP	Default Price Path
GDPs	Gas Distribution Businesses
GIC	Gas Industry Company
GJ	Gigajoules
GPBs	Gas Pipeline Businesses
GTP	Gas Transition Plan
LNG	Liquefied Natural Gas
LPG	Liquified Petroleum Gas
MBIE	Ministry of Business, Innovation, and Employment
PwC	PricewaterhouseCoopers
PV	Present Value
RAB	Regulatory Asset Base
ROI	Return on Investment
RY	Regulatory Year
WACC	Weighted Average Cost of Capital
WTP	Willingness To Pay