NZ Gas Infrastructure Future

Refreshed Analysis Paper

Financial implications of stylised gas network winddown and retreat scenarios

New Zealand's domestic gas landscape is evolving in response to supply constraints, consumer preferences, and climate change policy, both domestically and internationally.

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

This Refreshed Analysis Paper reports on work commenced in October 2025 to provide conceptual, quantitative and qualitative analysis to inform policy and regulatory decisions related to the future of gas infrastructure. It builds on early work undertaken in 2021, 2022 and 2023.

12 February 2026

Disclaimer: the views expressed in this paper reflect the culmination of initial analysis, research and discussion undertaken by the Working Group for the purpose of exploring regulatory and policy questions. That analysis is indicative and conceptual in nature and is not intended to assess the circumstances of any specific gas pipeline business, nor assess the financial performance or position of such businesses. Actual outcomes will inevitably differ and the differences could be very material The paper does not comprehensively assess or quantify the many uncertainties that may affect the future financial position of those businesses. The analysis should not be relied on to inform financial or commercial decisions.

The views in the paper do not necessarily reflect those of the organisations represented in the Working Group. The views may also differ from those that the Working Group includes in future outputs.

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NZ Gas Infrastructure Future

EXECUTIVE SUMMARY

Refreshed analysis suggests that cost recovery risk poses challenges for gas consumers and infrastructure owners under stylised gas network winddown and demand retreat scenarios even with current regulatory settings, including accelerated depreciation

This is a refresh of earlier work

The refreshed analysis builds on the Working Group's earlier modelling undertaken between 2021 and 2023. That earlier work developed a conceptual financial model and associated input assumptions – covering demand, wholesale gas prices, alternative energy prices, and expenditure forecasts – to explore how different gas futures could affect gas consumers, gas infrastructure owners, and Government over a 35-year horizon.

For this updated work, the model has been refreshed to incorporate more recent information, including updated demand projections, revised expenditure forecasts, and the Commerce Commission's draft default price-quality path (DPP4) regulatory settings.

It focuses on downside scenarios

This analysis focuses on three winddown and demand-retreat scenarios: (1) a supply-driven winddown of gas infrastructure by 2040, (2) demand retreat to a small gas network, and (3) demand retreat with renewable gas and imported LNG gas.

These scenarios are not forecasts; rather, they are structured stress-tests designed to explore the potential impacts to gas consumers and infrastructure owners of material volume decline and the associated risks of cost under-recovery and asset stranding. They are intended to bracket the bounds of potential downside outcomes rather than represent the base-case asset-planning strategies of any individual gas pipeline business.

It also starts with the draft DPP4 decision

The analysis adopts the Commerce Commission's draft DPP4 decision as a starting point, including accelerated depreciation, expenditure allowances, the allowed rate of return, and inflation assumptions. It then examines how the three scenarios affect cost recovery, financial viability, and consumer outcomes under these regulatory parameters.

Projected capital and operating expenditure vary across the scenarios and are forecast to decline in line with projected winddown and retreat, with a shift from capital investment to operating and maintenance activities. They do not reflect actual business forecasts.

The modelling also incorporates a simplified representation of consumer willingness to pay based on alternative-energy costs, amortised net conversion costs, and an allowance for non-price factors such as amenity value and consumer stickiness.

KEY MESSAGES

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This Refreshed Analysis Paper builds on the earlier analysis by the Working Group

It looks at gas consumer and infrastructure owner impacts if there is a winddown or demand retreat, starting with the draft DPP4 decision

The analysis has limitations

The purpose of the work is to support policy and regulatory conversations by providing an indicative understanding of the scale, timing, and drivers of risk under alternative downside scenarios.

The refreshed analysis is *conceptual*. Although a quantitative model underpins the results, the analysis relies on high-level assumptions and simplified relationships that have not been tested against real-world outcomes. Actual market behaviour – particularly consumer switching responses, the evolution of wholesale gas pricing, and network expenditure decisions – is likely to be more dynamic and interdependent than can be captured in the model. The outputs illustrate potential directional impacts. They are not predictive forecasts or assessments of the financial performance of any specific gas pipeline business.

As with earlier Working Group papers, this *Refreshed Analysis Paper* should be read in light of these limitations and the accompanying qualifications. The results reflect the model structure, the chosen scenarios, and the assumptions applied. They should not be attributed to any individual participant in the Working Group. Nor should they be used to inform commercial, financial, or investment decisions.

Initial findings align with previous work

The analysis presents results and makes initial findings on three interrelated questions:

Question 1 | What is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners and what are the key drivers of this risk under the various scenarios, assuming no mitigations adopted?

Cost recovery risk is the risk that gas infrastructure owners cannot recover the efficient costs incurred to provide gas transmission and distribution services.

The focus of this analysis is on cost recovery risk linked to supply and demand decline. Cost recovery risk raises questions about the ongoing willingness and ability of gas infrastructure owners and lenders to continue investing in the infrastructure that supports those services and the willingness of consumers to pay for the costs incurred.

The initial analysis shows:

- Infrastructure owners are exposed to potential material cost recovery risk of **$1,012 million** in present value terms ($2026) in unrecovered revenue and residual unrecovered capital if there is demand retreat with no additional regulatory or policy levers (or mitigations) are applied.
- Notwithstanding modelling limitations, there is little doubt that declining volumes expose gas infrastructure owners to material cost recovery risk across all scenarios, even if the pipelines remain operational with a smaller footprint. However, unrecovered costs can be lower in scenarios where gas networks take decisions to scale back their network footprint.

KEY MESSAGES

Care should be taken when interpreting the results.

Unmitigated demand retreat exposes gas infrastructure owners to material cost recovery risk, potentially as high as **$1 billion**

- Accelerated depreciation helps reduce asset stranding risk but does not eliminate risks to cost recovery. As volumes continue to decline, the scope to bring forward recovery is increasingly constrained by willingness-to-pay limits. Absent mitigation, declining cash flows and under-recovery are likely to weaken financeability and may incentivise reduced investment or earlier shutdown of assets, potentially ahead of socially desirable outcomes.
- This updated analysis is consistent with earlier work. Estimated under-recovery aligns with that shown in the Working Group's *Initial Analysis Paper* ($948–$1,222 million, present value $2022) and *Further Analysis Paper* ($526–$644 million, $2022). Under-recovery now emerges earlier due to steeper volume decline and tighter willingness-to-pay constraints.

Question 2 | What are the potential financial viability implications to infrastructure owners and how do these vary across infrastructure owners (e.g., distribution vs transmission)?

- Financial viability of GPBs appears at risk under all modelled scenarios, assuming no change to current regulatory settings or Government intervention. This will raise questions about the willingness and ability of shareholders to keep investing.
- Declining and increasingly uncertain cash flows are expected to weaken creditworthiness, constrain refinancing options, and limit access to new debt well before assets reach the end of their operating lives.
- Faced with that outlook it may be rational for gas infrastructure owners to shutdown 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.

Question 3 | 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 rapid supply-driven winddown of gas pipelines exposes remaining gas consumers to meaningful price increases up until the infrastructure is shutdown, as both wholesale gas prices and average network charges increase in that scenario. After that point, consumers lose the choice to consume reticulated gas to meet their energy needs.
- Scenarios in which the gas system persists at reduced scale result in more gradual but sustained affordability pressures. While the introduction of biomethane can improve competitiveness in the near term, it does not materially change longer-term consumer outcomes once volumes supplied stabilise at lower levels and more expensive imported LNG is introduced.
- Absent mitigation, rising charges are likely to reinforce volume decline and place pressure on affordability, highlighting the importance of regulatory and policy responses in shaping consumer outcomes during the transition.

KEY MESSAGES

Financial viability of GPBs appears at risk under all three winddown and retreat scenarios

A winddown of gas pipelines exposes the remaining gas consumers to meaningful price increases as other consumers defect

1. INTRODUCTION

New Zealand's domestic gas landscape is evolving in response to supply constraints, consumer preferences, and climate change policy, both domestically and internationally. With an evolving outlook, a carefully managed transition to any future state is needed to ensure continuity of a safe, reliable, and affordable energy supply.

It is within this context, that the Gas Infrastructure Future Working Group[1] (Working Group) was established in May 2021 to offer constructive input to government policy and regulatory decision-making with a focus on the future of gas infrastructure in New Zealand.

This **Refreshed Analysis Paper** builds on the Working Group's earlier modelling work.[2] It incorporates more recent information, including changes in gas demand and supply since that work. As with that earlier work, it provides conceptual,[3] quantitative and qualitative analysis to inform policy and regulatory decisions related to the future of gas infrastructure. It is not intended to inform business or consumer decisions.

It 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 alternative scenarios. In doing so, it incorporates refreshed scenarios that differ from the earlier work.

The working group's refreshed analysis is conceptual and may continue to 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 refreshed analysis was prepared after the Commerce Commission published its draft DPP4 decision for GPBs; where appropriate, it incorporates components from that decision, including allowed revenues over the DPP4 period.

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 sensitivities and limitations, and
- **Section 4** reports on the refreshed analysis.

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

2 See: Gas Infrastructure Future Working Group, *Initial Analysis Paper*, 14 March 2022 (link); Gas Infrastructure Future Working Group, *Further Analysis Paper*, 29 March 2022 (link); and Gas Infrastructure Future Working Group, *Gas Transition Analysis Paper*, 16 June 2023 (link).

3 'Conceptual' is used here and throughout the Refreshed Analysis Paper to mean that the analysis has not been tested against real-world outcomes and relies on simplified assumptions leading to illustrative rather than predictive results. Although the underlying modelling is detailed, many of the calculations within it reflect assumed relationships (e.g., willingness to pay) and inputs that may not reflect reality.

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 reduced domestic gas supply, Government climate change policies, and changing consumer preferences. The potential exists to repurpose gas infrastructure in a way that supports those government policies and consumer preferences, but the evolution of a market for green gases in New Zealand is far from certain.

The refreshed analysis undertaken by the Working Group considers three key questions: how transition of the gas sector will affect gas network expenditure and revenue requirements, consumer bills and conversion costs, and infrastructure owner financial viability, and the potential impact of network rightsizing. The questions are set out in section 2.4.

To assess these questions, the analysis considered three scenarios: supply driven winddown, demand retreat to a smaller network, and renewable gas and/or LNG import. These scenarios are described in section 3.4.

2.2. Context

New Zealand's domestic gas landscape is evolving in response to supply constraints, consumer preferences, and climate change policy, both domestically and internationally.

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.

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

- an initial **Findings Report** to the Minister of Energy and Resources in August 2021,[4] 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, [5] 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, [6] which updated the analysis from the Initial Analysis Paper in light of the Commerce Commission's draft DPP decision, and
- a **Gas Transition Analysis Paper**, dated 16 June 2023,[7] which explored the potential impacts on gas consumers, gas pipeline businesses, and Government of alternative gas futures as an input to the then Government's Gas Transition Plan consultation.

This Refreshed Analysis Paper is essentially an update to the analysis included in the Further Analysis Paper.

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4 Gas Infrastructure Future Working Group, *New Zealand Gas Infrastructure Future Findings Report*, August 2021 (link).

5 Gas Infrastructure Future Working Group, *Initial Analysis Paper*, 14 March 2022 (link).

6 Gas Infrastructure Future Working Group, *Further Analysis Paper*, 29 March 2022 (link).

7 Gas Infrastructure Future Working, *Gas Transition Analysis Paper*, 16 June 2023 (link).

The outputs from each of the earlier analysis papers are described in **Appendix D**. The subsections below briefly describe the other key context, including the Commerce Commission's draft DPP4 decision and more recent gas market dynamics.

2.2.1. Draft gas DPP4 decision

The Commerce Commission's draft DPP4 decision provides important context for the refreshed analysis in this paper. As with its DPP3 decision, the Commission has retained two key winddown scenarios to underpin its analysis: one assuming a network winddown by 2050, the other assuming 2060. These scenarios are used by the Commission to inform its asset stranding risk analysis and its draft decision to retain accelerated depreciation for the DPP4 regulatory period, with a one-third weighting given to the 2050 scenario and a two-thirds weighting given to the 2026 scenario.

The Refreshed Scenarios adopted for this paper effectively straddle those two scenarios, with one assuming a supply-driven winddown by 2040, and the other two assuming some ongoing use of the networks indefinitely but modelling reduced network scale and scope. These scenarios are described in section 3.4.

The analysis in this paper takes as given the draft DPP4 decision. As well as the position on accelerated depreciation, this analysis adopts the Commission's draft views on expenditure allowances, expected rates of return, inflation assumptions, and revenue requirements over the forthcoming DPP4 regulatory period.

2.2.2. Evolving gas market dynamics

Recent developments in New Zealand's gas sector have highlighted significant changes in both supply and demand. Gas consumption and new connections have begun to decline, with networks such as Vector, Powerco, and Firstgas experiencing reduced volumes and a peak in connections as early as 2023. Recent projections suggest a substantial drop in gas usage by 2050,[8] while industrial consumers increasingly explore electrification and some major users scale back or cease operations. On the supply side, gas security has become a growing concern, with some retailers unwilling to accept new consumers due to constrained supply and electrification objectives, and forecasts suggesting domestic reserves may be depleted before 2030 unless new fields are developed or imports such as LNG are secured. The Ministry of Business, Innovation and Employment (MBIE) observes that reserves data shows that New Zealand's gas supply is falling faster than previously expected.[9]

These dynamics are further complicated by policy uncertainty, with the government's direction on natural gas transition still evolving, and a focus on energy security and affordability remaining central to current discussions. 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 combined effect of these trends underscores the need for a carefully managed transition to ensure continued reliability and affordability of energy supply in an environment of declining domestic gas resources and shifting consumer preferences.

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[8] Concept Consulting projects that gas throughput on gas distribution pipelines will reduce by about 40% from 2024 to 2033. EY projected around a 66% reduction in gas throughput across both distribution and transmission pipelines over the same period in a low intervention scenario, around 50% under scenarios where Methanex exists immediately, and around 20% if there are LNG imports.

See: Concept Consulting, Gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses, 22 August 2025 (link); and EY, Gas Supply and Demand Study 2024, 28 November 2024 (link).

[9] See: MBIE, Energy in New Zealand 2025, August 2025, pp.28–29 (link).

2.3. Analysis scope

The analysis only considers the impact to gas pipeline owners and gas consumers under alternative winddown and retreat scenarios.[10] It is designed to test these impacts using current and assumed regulatory settings, including the accelerated depreciation adopted by the Commerce Commission in its draft DPP4 decision. However, the analysis does not explore other scenarios that may be pursued by gas pipeline owners, such as full transition to renewable gases, which may maintain long-term network viability.

2.4. Analysis questions

This Refreshed Analysis Paper considers the following three questions:

1. **Cost recovery risk |** *What is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners and what are the key drivers of this risk under the various scenarios, assuming no mitigations adopted?*
2. **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)?*
3. **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)?*

Figure 4.1 sets out these analysis questions.

FIGURE 2.1: ANALYSIS QUESTIONS



2.5. Approach

The **Refreshed Analysis Paper** starts with the Excel model that was used to prepare the Initial and Further Analysis Papers and the Gas Transition Analysis Paper (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 Refreshed Scenarios and analysis questions noted above.

[10] The analysis only considers private costs and benefits to gas pipeline owners and consumers. It does not factor in externalities, except to the extent these are reflected in those private costs and benefits (e.g., carbon prices).

The Model was first updated to incorporate actual data from the 2026 regulatory year, including from the Commerce Commission's draft DPP4 decision[11] 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 three analysis questions, the Model was refined so that it could assess the impact on gas consumers and gas pipeline businesses of three Refreshed Scenarios developed by the Working Group. The steps involved were:

- **Model refinement** – with support from farrierswier, the Working Group refined the model to analyse the analysis questions and the Refreshed 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 modelling 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.

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).

The modelling subgroup was re-established subsequently when updating the modelling to input to the *Gas Transition Analysis Paper* in 2023, with the Model updated to reflect more recent information and to include a new 'Emissions Module' that allowed for emissions impacts to be tested.

With that starting point, the modelling subgroup was re-established a third time and Concept Consulting re-engaged to undertake new analysis that looked at the Refreshed Scenarios. That new analysis involved:

[11] Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2026, Draft decision – reasons paper*, 27 November 2025.

- farrierswier updating the Model to reflect more recent information, including actual data from 2026, the Commerce Commission's draft default price-quality 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 Refreshed 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 developed previously by PwC setting out expenditure forecasts consistent with each of the Refreshed Scenarios.

Farrierswier 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 refreshed analysis undertaken by the Working Group is an Excel model that assess the potential financial impact on gas consumers and gas infrastructure owners of future scenarios for gas infrastructure in New Zealand (the Model).

The Working Group used the Model to test how alternative scenarios may affect outcomes faced by gas consumers and infrastructure owners. This took as given the Commerce Commission's draft DPP4 decision.

The Model is summarised below. A more detailed description of the model is set out in **Appendix A**. Key expenditure and demand inputs are presented in **Appendix** B. Model sensitivities are explored in **Appendix C**.

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 given their willingness to pay for delivered gas (factoring in the alternatives available to them such as electricity)
- a carbon emissions model that projects the annual emissions from gas consumption.

Outputs from these modules are 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 three 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, corporate tax rates, 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. Key simplifications

The Model incorporates several simplifications in its treatment of key economic relationships. Notably, it does not explicitly model the dynamic relationship between demand and price – that is, it assumes that demand projections are fixed for each scenario and do not respond to changes in delivered gas prices. In reality, higher gas prices would typically reduce demand, while lower prices might sustain or increase it, but these feedback effects are not captured within the current framework.

The Model also simplifies the interplay between consumers' willingness to pay, the delivered price of gas, and the resulting level of unrecoverable revenue for infrastructure owners. Specifically, it assumes that when consumers' willingness to pay is higher than the delivered gas price, most or all revenue can be recovered, thereby reducing unrecoverable revenue and lowering the risk of under-recovery of costs. Conversely, if gas prices exceed what consumers are willing to pay, unrecoverable revenue rises and the risk to cost recovery increases. These relationships are represented in a static manner, without modelling the potential adjustments in behaviour or market structure that could occur in response to changing economic incentives.

The Model further assumes that gas pipeline business expenditure decisions are static within each scenario. In practice, these decisions are likely to change in response to evolving expectations for demand and returns – businesses may, for example, opt to shut down pipelines earlier than projected if ongoing investment is unlikely to be recovered. As a result, the model does not capture the potential for businesses to dynamically adjust capital or operational expenditure in response to shifting market conditions.

3.4. Scenarios and sensitivities

A key capability of the Model is the flexibility to test alternative scenarios and sensitivities, including:

- **Market scenarios** – which are three[12] defined refreshed scenarios relating to the overall market outcomes for gas, including 1 winddown scenario and 2 alternative scenarios (demand retreat and renewable gas and/or LNG import)
- **Model scenarios** – which are five customisable scenarios used to test a range of regulatory and policy levers (and other factors).

The refreshed 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 Refreshed Analysis Paper. **Appendix C** sets out key modelled sensitivities.

The three market scenarios (i.e., the Refreshed Scenarios) are described in Table 3.1. Expenditure, gas consumption and gas connection forecasts that correspond to these scenarios are shown in Appendix B.

TABLE 3.1: MARKET SCENARIOS (REFRESHED SCENARIOS)

Market scenario	Description
1. Supply driven winddown	Gas throughput and connections reduce gradually in line with gas reserve depletion, 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 2040
2. Demand retreat to smaller network	Gas throughput and connections reduce by half by 2050 as gas consumers transition to alternative energy sources, with a reduced network footprint remaining to serve ongoing demand including gas fired generation
3. Renewable gas and/or LNG import	Gas throughput and connections reduce significantly (stabilising at ~23% of current levels) with a smaller network footprint, utilising renewable gas and/or imported LNG to offset domestic depletion. This is a financial stress-test of scenario 2, not a scenario of a transition to 100% renewable gas sustaining volumes.

3.5. 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, LPG and biomass)
- the cost of converting from gas to alternative energy, including any make good costs

[12] Note that Model has functionality to include up to six market scenarios. However, for the Refreshed Analysis Paper the Working Group has only explored three.

- an assumed markup (of 25%) to reflect non-price factors, such as consumer stickiness,[13] 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.[14] However, a precise estimate is difficult to determine. A 25% 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.

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.

3.6. Limitations

This analysis is 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.

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13 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).

14 For instance, in its recent qualitative analysis of smaller gas consumers, Pinstriped Leopard found that, for residential consumers, "*Across groups customers were generally extremely positive about gas, particularly in terms of its speed to heat/the control they had over the heat and the enjoyment they experienced from endless and instant hot water, as well as the choice it gave to not just have electricity as an energy source.*" Similar observations were made about smaller business consumers.

See: Pinstriped Leopard, What's fair? Qualitative Research, Residential Summary Report, July 2025, p.4 (link); see also: Pinstriped Leopard, What's fair? Qualitative Research, SME Summary Report, July 2025 (link).

4. REFRESHED ANALYSIS

4.1. Overview

The working group has constrained its refreshed analysis to just three questions:

1. **Cost recovery risk |** *What is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners and what are the key drivers of this risk under the various scenarios, assuming no mitigations adopted?*
2. **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)?*
3. **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)?*

These questions were previously explored in the Initial Analysis Paper, though that work was based on earlier information and assumptions. The Working Group intends to continue examining these and related questions, adapting the analysis as new information and stakeholder feedback become available. The Working Group advises caution in interpreting these findings, as both market dynamics and outlooks are subject to ongoing change, and premature or incomplete conclusions may not reflect future realities.

The rest of this chapter steps through initial analysis for each of the three questions, discussing relevant context and predictions, before exploring the outputs from the modelling. Key initial insights are identified throughout.

4.2. Question 1: Cost recovery risk

What is the extent and trajectory through time of cost recovery risk faced by gas infrastructure owners and what are the key drivers of this risk under the various scenarios, assuming no mitigations adopted?

Box 2: Cost recovery risk | Summary

- Earlier analysis by the Working Group suggested that a winddown of regulated gas pipelines exposes gas infrastructure owners 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).
- Refreshed analysis indicates that a winddown of regulated gas pipelines exposes gas infrastructure owners to material cost recovery risk of $1,012 million if there is demand retreat to a smaller network in present value terms ($2026) and *assuming* no additional regulatory or policy levers (or mitigations) are applied (beyond those adopted in the Draft DPP decision).
- Notwithstanding modelling limitations, there is little doubt that declining volumes expose gas infrastructure owners to material cost recovery risk across all scenarios, even if the pipelines remain operational with a smaller footprint.

- Accelerated depreciation helps reduce asset stranding risk but does not eliminate cost under-recovery. As volumes continue to decline, the scope to bring forward recovery is increasingly constrained by willingness-to-pay limits.
- Absent mitigation, declining cash flows and under-recovery are likely to weaken financeability and may incentivise reduced investment or earlier shutdown of uneconomic assets, potentially ahead of socially desirable outcomes
- In terms of timing, the incidence of unrecovered costs will – unsurprisingly – predominantly occur once gas infrastructure is no longer used (e.g., any unrecovered capital). Unrecovered costs before that time will be a smaller amount.
- This analysis is 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.

4.2.1. Context

Prior analysis has highlighted that a future scenario characterised by a substantial decline in gas demand is likely to present considerable cost recovery challenges for gas infrastructure owners and consumers.[15]

These challenges arise primarily from the long-lived nature of gas pipeline assets, where the initial investment is typically expected to be recovered over several decades. The regulatory framework underpinning gas pipelines has historically assumed a stable or gradually declining demand, with cost recovery spread across many years to align with the technical lifespan of the infrastructure (often 50 years or more). As gas pipeline costs are largely fixed in the medium term, sustained reductions in volumes supplied do not result in proportional reductions in cost. As volumes supplied fall, allowed revenue must be recovered from a smaller base, placing upward pressure on charges.

The extent and timing of these cost recovery risks are highly sensitive to both the pace at which demand for gas falls and the mitigations that may be implemented to address these risks. A rapid decline in demand could accelerate the crystallisation of unrecovered costs, while slower transitions may allow for more gradual adjustments. Additionally, the magnitude of cost recovery shortfalls will depend on regulatory responses and the willingness of consumers to bear increased charges as volumes decrease. Even where consumers are willing to pay, there remains a risk of sharp increases in delivered gas prices as declining volumes concentrate a largely fixed cost base over a rapidly shrinking customer pool. These pressures may be amplified if retailer margins widen over time, as networks have limited ability to influence the retail component of the delivered price.

In its recent draft decision for DPP4, the Commerce Commission has continued to support accelerated depreciation for gas pipeline assets as a key mitigation strategy. This approach is intended to bring forward the recovery of capital costs, thereby reducing the risk of stranded assets should gas infrastructure become obsolete sooner than originally anticipated. The effectiveness of accelerated depreciation, however, is ultimately constrained by consumer affordability – or willingness to pay – and the broader market context. As volumes supplied continue to decline, increasing charges to support accelerated recovery will progressively approach that constraint, limiting the extent to which accelerated depreciation can be applied without inducing further volume reductions.

[15] See: Gas Infrastructure Future Working Group, 14 March 2022, Initial Analysis Paper (link); and Gas Infrastructure Future Working Group, 29 March 2022, Further Analysis Paper (link).

The regulatory framework does not guarantee recovery of allowed revenue or the regulated asset base if charges exceed consumers' willingness to pay or if volumes supplied fall materially. Where prices cannot increase without inducing switching to alternative energy sources, infrastructure owners may be unable to recover efficient costs – including past investment incurred in accordance with regulatory settings – notwithstanding the application of accelerated depreciation.

4.2.2. Focus of analysis

Cost recovery risk arises from the interaction between declining volumes supplied, a largely fixed cost base, and limits imposed by consumers' willingness to pay.

As volumes supplied fall, average charges increase. As those charges approach willingness to pay, gas infrastructure owners face a binding constraint:

- further charge increases risk accelerating consumer switching to alternative energy sources, while
- constraining charges results in under-recovery of allowed revenue.

Either outcome weakens cash flows and financeability. This dynamic is self-reinforcing: reduced cost recovery can constrain investment, maintenance, and safe operation, increasing the likelihood of further volume reductions or earlier asset closure. This mechanism underpins the potential for a "death spiral", regardless of whether infrastructure is ultimately wound down or continues operating at reduced scale.

Question 1 therefore examines cost recovery risk across all three scenarios, recognising that the volume reductions, wholesale gas price, and GPB expenditures differ materially between them. While the supply-driven winddown scenario exhibits the sharpest decline (reaching zero by 2040), volumes supplied also fall significantly under the other two scenarios. By 2055, volumes are projected to be around 25% of 2026 levels, even where gas infrastructure remains in operation.

The analysis focuses on how these dynamics play out over time, in both magnitude and trajectory, over the period 2026 to 2055. To establish a baseline, no additional regulatory or policy mitigations are assumed beyond current settings (including those reflected in the Draft DPP decision). Potential mitigations are considered later in this chapter.

4.2.3. What to expect

Under Scenario 1, cost recovery risk is expected to increase sharply as volumes supplied decline rapidly toward full winddown. As the system approaches 2040, a small residual volume base must support a largely fixed cost structure alongside rising costs associated with disconnection and decommissioning. Allowed charges are therefore expected to rise toward, and potentially beyond, consumers' willingness to pay, resulting in substantial unrecovered revenues. This scenario represents the upper bound of cost recovery risk in both scale and speed.

Under Scenarios 2 and 3, volumes supplied decline materially but stabilise at a significantly smaller steady-state system rather than fully winding down. In these scenarios, unrecovered revenues may still arise as lower utilisation places upward pressure on charges and constrains revenue recovery. However, once volumes have largely finished tapering and the accelerated depreciation applied by the Commerce Commission also tapers off, the level of under-recovery is expected to stabilise rather than continue escalating.

The three scenarios are not intended to represent all possible futures. Rather, they span a plausible range of winddown or retreat outcomes:

- Scenario 1 reflects a relatively rapid winddown of gas infrastructure driven by a continued tightening of gas supply in New Zealand *without* any alternative gases being procured
- Scenarios 2 and 3 reflect alternative steady-state futures in which the gas system persists, albeit at materially reduced scale and higher gas prices.

Together, they broadly straddle the demand trajectory implicit in the Commerce Commission's DPP4 assumptions.

Scenarios 2 and 3 are similar in structure. The key distinction is that the availability of biomethane and LNG imports in Scenario 3 results in somewhat higher volumes supplied – particularly over the next 5 to 10 years – which affects the wholesale cost of gas. This affects how quickly allowed charges approach willingness to pay, influencing the timing and magnitude of cost recovery risk rather than eliminating it.

4.2.4. Initial quantitative analysis results

The quantitative analysis confirms that declining volumes supplied lead to material cost under-recovery across all three scenarios, under current regulatory settings and in the absence of additional mitigation. While the timing and severity differ by scenario, the results consistently reflect the interaction between a largely fixed cost base, falling utilisation, and limits imposed by consumers' willingness to pay.

The modelling results are presented below across four dimensions:

- volume forecasts, showing the assumed trajectory of reductions in gas volumes supplied under each scenario
- recoverable and unrecoverable revenue, showing how willingness-to-pay constraints limit revenue recovery as volumes supplied decline
- net cash flows, illustrating how under-recovery translates into weakening financial performance over time
- projected regulatory asset bases, indicating the extent to which accelerated depreciation reduces, but does not eliminate, the risk of unrecovered capital, and
- cost recovery, showing the overall revenue-at-risk, when combining unrecoverable revenues and any unrecovered terminal RAB (which is expected to vary across the scenarios).[16]

Together, these outputs illustrate how cost recovery risk emerges, evolves, and differs across the three scenarios.

Volume forecasts

The figures below show the assumed trajectory of gas volumes consumed under each of the three scenarios. These volume paths are a critical driver of cost recovery outcomes, as they determine the size of the consumer and throughput base over which largely fixed network costs are recovered. The forecasts are model inputs and do not endogenously reflect additional consumer switching in response to higher gas prices.

Under Scenario 1 (supply-driven winddown), volumes decline rapidly and fall to zero by RY40, reflecting a full winddown of gas supply. This sharp contraction materially accelerates cost recovery pressures as the system approaches exit.

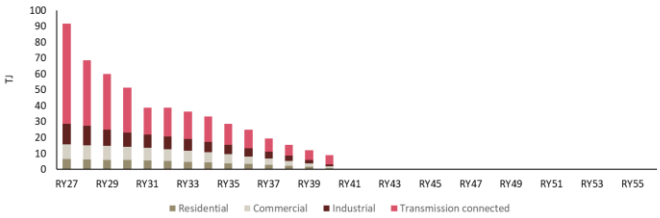
Under Scenarios 2 and 3, volumes also decline sharply in the early years, driven primarily by the assumed disconnection of several large transmission-connected consumers. Volumes fall to around 50% of RY26 levels by RY29, before stabilising at a materially smaller steady-state system of approximately 23% of RY26 levels by RY40. Volumes then remain broadly flat through the remainder of the modelling period.

While Scenarios 2 and 3 follow broadly similar long-run volume trajectories, Scenario 3 exhibits modestly higher volumes in the first five years, reflecting the availability and cost competitiveness of biomethane. This results in volumes being around 5% higher than Scenario 2 in the early period. By RY40, however, volumes under Scenarios 2 and 3 converge to very similar levels, meaning that longer-term differences in cost recovery outcomes are driven primarily by differences in wholesale gas costs (due to biomethane and imported LNG being added) rather than network utilisation.

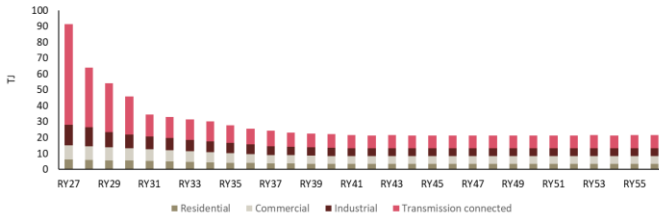
[16] The terminal RAB is assumed to be fully unrecovered under the supply-driven winddown scenario and only partially recovered in the alternative scenarios where future demand is projected to be insufficient to fully recover that value.

FIGURE 4.1: DEMAND / CONSUMPTION VOLUMES

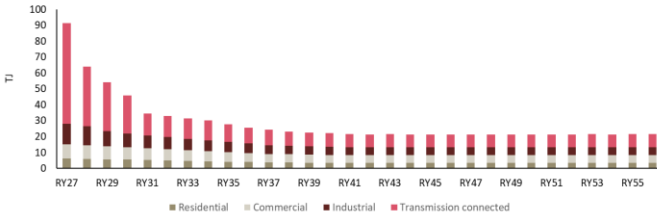
Scenario 1: Supply driven winddown



Scenario 2: Demand retreat to smaller network



Scenario 3: Renewable gas / LNG import



Recoverable and unrecoverable revenue projections

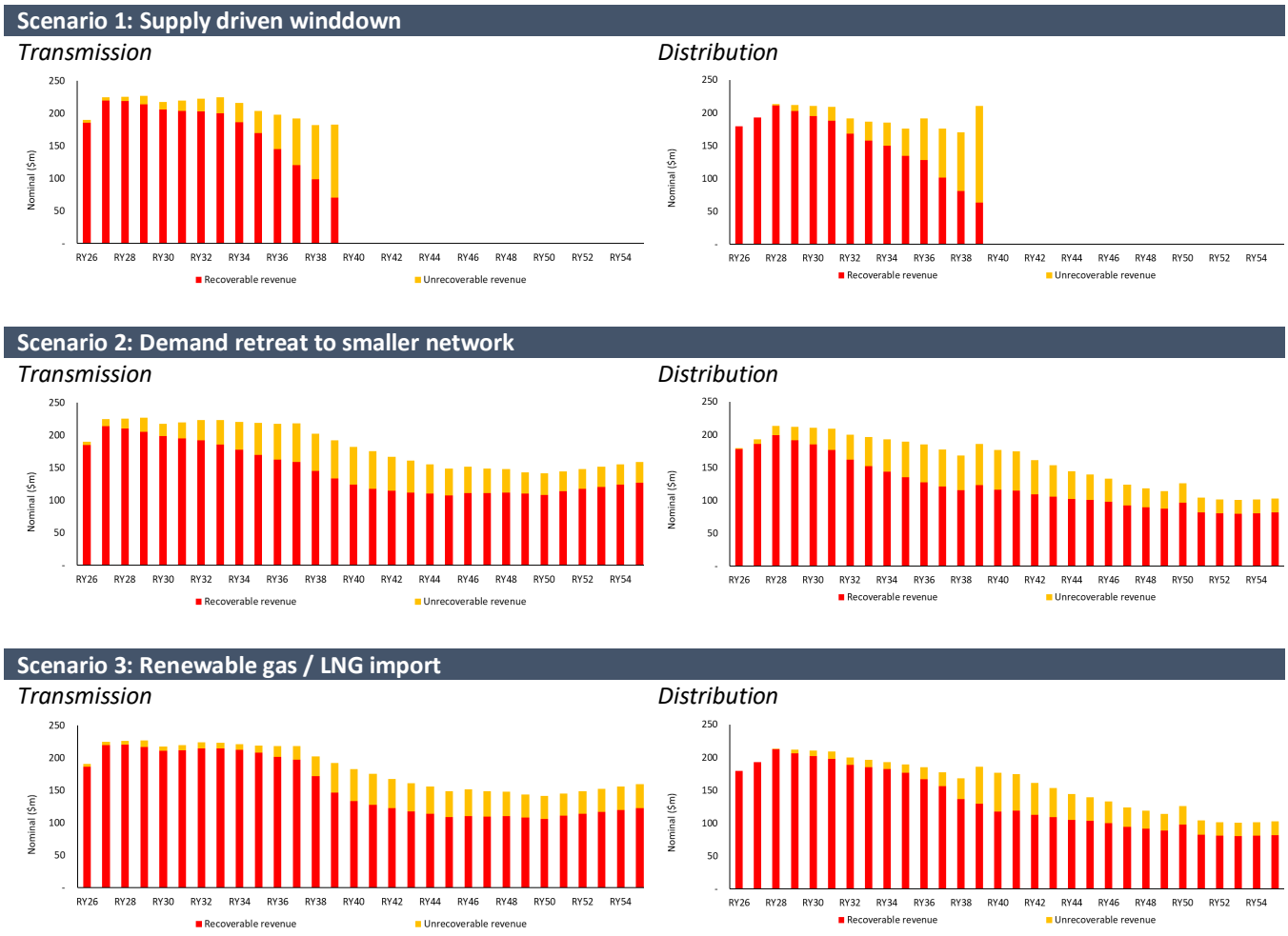
The figures below show how declining volumes supplied and willingness-to-pay constraints translate into unrecoverable revenue across the three scenarios.

- **Scenario 1 – supply-driven winddown**: recoverable revenue falls rapidly as volumes supplied decline sharply. Around 80% of allowed revenue is recoverable by RY35, falling to around 50% by RY38 and around 34% by the final year of operation. Under-recovery accelerates in the late 2030s as very low volumes, combined with disconnection and decommissioning costs, push allowed charges up against willingness to pay, particularly for residential and commercial consumers. While annual under-recovery is severe, it is concentrated over a relatively short period prior to winddown.
- **Scenario 2 – demand retreat to a smaller network**: recoverable revenue declines more gradually, from close to 100% initially to around 70% by RY38, reflecting lower network utilisation. Under-recovery then persists over a much longer period, stabilising as volumes supplied taper and accelerated depreciation moderates, with recoverability improving toward around 80% by the late 2040s. Although annual under-recovery is less severe than in Scenario 1, its persistence over a longer horizon leads to higher unrecoverable revenue in present value terms.
- **Scenario 3 – renewable gas / LNG import:** outcomes are similar to Scenario 2, with slightly higher recoverable revenue (and lower unrecoverable revenue) throughout much of the period due to higher volumes supplied in the next 5–10 years and lower wholesale gas costs delaying the point at which allowed charges approach willingness to pay. Nevertheless, unrecoverable revenue still arises and, as in Scenario 2, persists over an extended period, resulting in material under-recovery, albeit somewhat lower than in Scenario 2.

As a simplifying assumption, the analysis holds the allocation of allowed revenue across consumer types fixed over time. In addition, gas producers are assumed to retain their existing margins, rather than absorbing a share of unrecoverable revenue. Relaxing either assumption could alter the distribution – and potentially the magnitude – of under-recovery.

Unrecoverable revenue is broadly similar in magnitude across transmission and distribution in present-value terms, although the underlying drivers differ. Distribution networks are more exposed to willingness-to-pay constraints for residential and commercial consumers, while step changes in transmission reflect the assumed discrete exit of large users.

FIGURE 4.2: RECOVERABLE AND UNRECOVERABLE REVENUE



Cashflow projections

The figures below show that under-recovery of allowed revenue translates directly into declining net cash flows across all scenarios. The stacked bars present cash flows *before* interest and tax, while the net cash flow line reflects outcomes *after* interest and tax.

Key observations include:

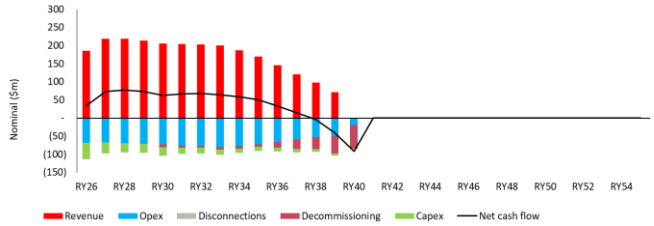
- **Scenario 1 – supply-driven winddown:** net cash flows begin to decline from around RY28, as unrecoverable revenue emerges. Cash flows fall steadily and turn negative around RY38, prior to full winddown. As these cash flows are shown before financing costs, financial stress would be expected to arise earlier, including reduced financeability and increasing difficulty in raising capital.
- **Scenarios 2 and 3 – smaller steady-state networks:** net cash flows decline more gradually as volumes supplied fall. Cash flows approach zero by around RY40 for transmission and around RY50 for distribution, before broadly stabilising at those levels (reflecting the tapering of both volume reductions and accelerated depreciation effects).

In present-value terms, net cash flows remain positive across all scenarios, but this reflects the timing of cash flows rather than the absence of material financial stress in later years (see Table 4.1). Appendix C explores how sensitive projected cash flows are to key modelling inputs, especially to those underpinning estimated willingness to pay.

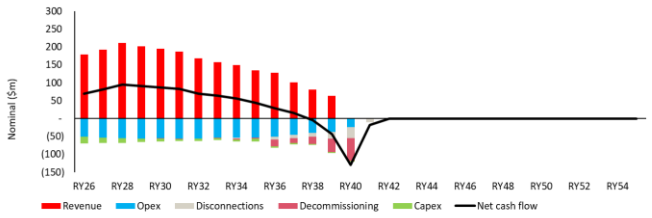
FIGURE 4.3: NET CASH FLOWS (AFTER DEBT COSTS AND TAX)

Scenario 1: Supply driven winddown

Transmission

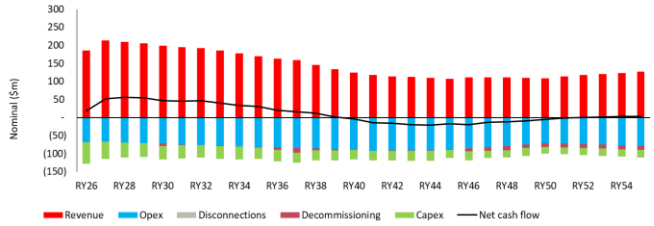


Distribution

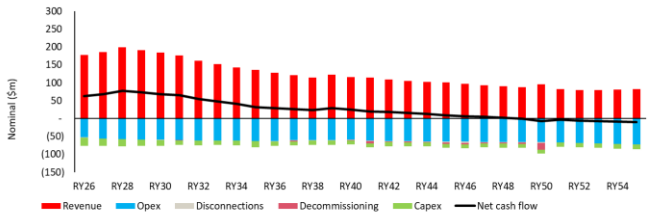


Scenario 2: Demand retreat to smaller network

Transmission

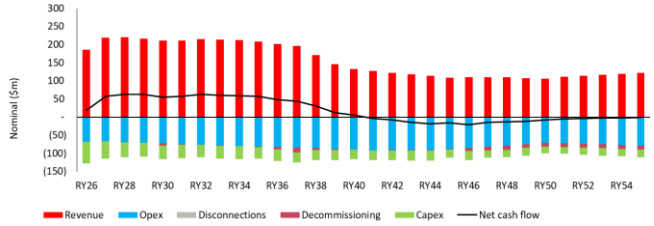


Distribution

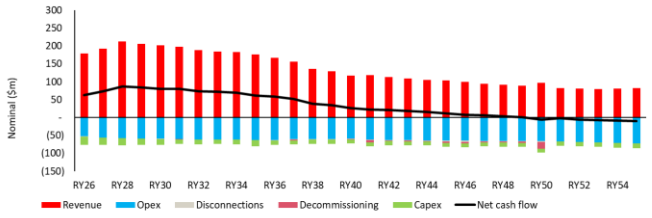


Scenario 3: Renewable gas / LNG import

Transmission



Distribution



Projected regulatory asset bases

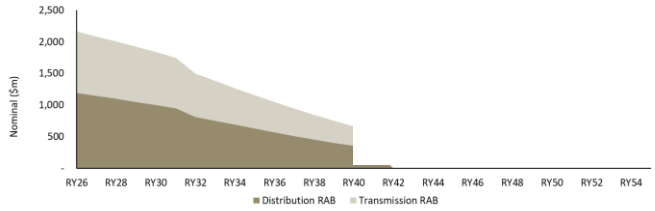
The figures below show the projected RAB trajectories under current regulatory settings, including continued accelerated depreciation:

- **Scenario 1 – supply-driven winddown:** the RAB declines rapidly for both transmission and distribution as accelerated depreciation continues. However, a positive RAB remains at around RY40, when volumes supplied have fallen to zero. With no future revenue available, the remaining RAB at that point is effectively unrecoverable, representing asset stranding.
- **Scenarios 2 and 3 – smaller steady-state networks:** the RAB declines over time due to accelerated depreciation, but plateaus from around RY45 onwards as volumes supplied stabilise and depreciation moderates. In these scenarios, the remaining RAB continues to be supported by ongoing (albeit reduced) volumes supplied, reducing – but not eliminating – asset stranding risk.

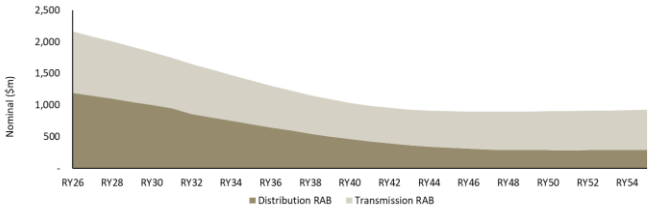
Across all scenarios, accelerated depreciation reduces terminal RAB values relative to historical profiles, but does not fully eliminate the risk of unrecovered capital, particularly where volumes supplied fall to very low levels.

FIGURE 4.4: REGULATORY ASSET BASE

Scenario 1: Supply driven winddown

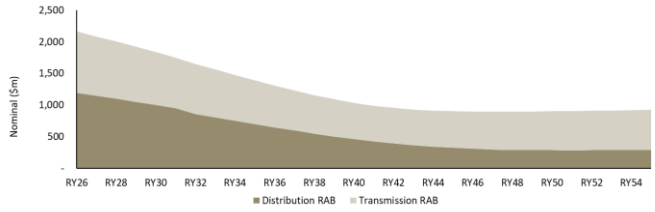


Scenario 2: Demand retreat to smaller network



*RAB is truncated at end of period when demand reaches zero. This will not be recovered by the businesses

Scenario 3: Renewable gas / LNG import



Cost recovery outcomes

Table 4.1 presents the present values of unrecoverable revenues and terminal RAB across the three scenarios, highlighting differences in potential cost recovery outcomes.

Under Scenario 1, the terminal RAB in RY40/41 is assumed to be fully unrecovered, as volumes supplied fall to zero and no future cash flows are realised beyond that point. Under Scenarios 2 and 3, a portion of the terminal RAB at the end of the modelling period (RY55) is assumed to be unrecovered. While cash flows continue beyond RY55, they may be insufficient to recover the full remaining asset value (or earn the full WACC). For the purposes of this indicative analysis, 50% of the terminal RAB is assumed to be unrecovered.

On this basis, Scenario 3 – representing a future in which the network is sustained through the introduction of alternative gases such as biomethane and imported LNG – results in the lowest potential under-recovery. By contrast, Scenario 2, which reflects a reduced network footprint without alternative gas injection, results in the highest potential under-recovery for both transmission and distribution, with a combined value at risk of $1,012 million ($2026). This primarily reflects lower volumes and higher wholesale gas costs in the early years relative to Scenario 3, and would hold even if the terminal RAB was assumed to be fully recoverable.

These results suggest that simply shrinking the network is least favourable for asset owners unless accompanied by measures that support higher utilisation or lower wholesale costs, such as the introduction of alternative gases. Absent such measures, cost recovery outcomes are more favourable where gas pipeline infrastructure winds down broadly in line with the decline in domestic natural gas supply.

Appendix C explores how sensitive estimated value at risk is to key modelling inputs, especially to those underpinning estimated willingness to pay.

TABLE 4.1: PRESENT VALUE OF VALUE AT RISK

Sector	Scenario	PV of unrecoverable revenue (RY26 $m)	PV of Terminal RAB (RY26 $m)	Year of Terminal RAB	Share of Terminal RAB at risk (assumed %)	Total value at risk (RY26 $m)
Transmission	Supply driven winddown	263	127	RY40	100%	390
	Demand retreat to smaller network	469	100	RY55	50%	519
	Renewable gas / LNG import	283	100	RY55	50%	333
Distribution	Supply driven winddown	292	118	RY41	100%	410
	Demand retreat to smaller network	470	47	RY55	50%	493
	Renewable gas / LNG import	263	47	RY55	50%	287

Impact of accelerated depreciation

A component of the draft DPP4 decision is the Commission's proposal to continue applying accelerated depreciation over the DPP4 regulatory period, building on its decision to do so over the DPP3 period.

The impact of accelerated depreciation is to bring forward the recovery (via regulated tariffs) of capital costs. The base assumption in this Refreshed Analysis Paper is that this accelerated depreciation continues over all three downside scenarios modelled. However, alternative assumptions could be made. Section C.2.3 of Appendix C explores the impact of these alternatives.

That analysis suggests that:

- either not applying accelerated depreciation over the DPP4 and subsequent periods or reverting to asset lives that would have applied if there was no accelerated depreciation over the DPP3 period, increases cost recovery risk, and
- continuing with accelerated depreciation helps reduce value at risk under the downside scenarios explored in this Refreshed Analysis Paper.

The logic is that maintaining accelerated depreciation across downside scenarios provides greater headroom to absorb future shocks and reduces the likelihood of significant under-recovery.

Limitations

This analysis is subject to the limitations noted in section 3.6.

Notwithstanding these limitations, the results indicate that cost under-recovery arises under all scenarios unless additional mitigations are adopted. The principal modelling uncertainties relate to the timing, speed, and magnitude with which under-recovery crystallises, rather than whether it occurs.

Assumptions about consumers' willingness to pay are particularly important, as they directly affect the extent to which allowed revenue can be recovered as volumes supplied decline. Further work could strengthen the analysis by developing a

more detailed understanding of willingness to pay, including the role of non-price factors influencing consumers' decisions to switch to alternative energy sources.

The analysis also abstracts from behavioural and distributional effects along the supply chain. In practice, some under-recovery could be absorbed through reduced margins for gas producers or retailers, which may alter both the incidence and dynamics of cost recovery risk.

Finally, the analysis focuses on private costs and benefits. It does not consider broader external costs or benefits that may be relevant to policy or regulatory decisions. A more comprehensive social cost-benefit analysis could therefore provide additional insight.

4.2.5. Key insights

The refreshed analysis indicates that declining volumes expose gas infrastructure owners to material cost recovery risk across all scenarios – even once accelerated depreciation in the DPP4 draft decision is factored in. While the timing and severity differ, the underlying dynamic is the same: a largely fixed cost base must be recovered from a shrinking volume base, with allowed charges increasingly constrained by consumers' willingness to pay.

Under Scenario 1, this risk crystallises rapidly as the system approaches winddown. Unrecovered revenues increase sharply in the years leading up to exit, and any remaining RAB becomes effectively unrecoverable once volumes supplied fall to zero. Under Scenarios 2 and 3, volumes supplied decline more gradually and stabilise at a materially smaller scale. Annual under-recovery is less severe but persists over a longer period, resulting in higher present-value unrecovered revenue despite the absence of full winddown.

Accelerated depreciation helps reduce asset stranding risk but does not eliminate cost under-recovery. As volumes continue to decline, the scope to bring forward recovery is increasingly constrained by willingness-to-pay limits. Absent mitigation, declining cash flows and under-recovery are likely to weaken financeability and may incentivise reduced investment or earlier shutdown of uneconomic assets, potentially ahead of socially desirable outcomes.

Finally, the results are sensitive to assumptions to willingness to pay and about how recovered revenue is allocated across the supply chain (the current modelling assumes fixed revenue shares for transmission, distribution and retailers, with gas producers fully recovering their margins). Alternative assumptions and potential mitigations warrant further examination.

4.2.6. Comparison to earlier analysis

The refreshed analysis broadly confirms earlier findings that declining demand creates material cost recovery risk under all wind-down or retreat scenarios. However, the scale and timing of that risk differ from both the Initial Analysis Paper and the Further Analysis Paper.

The Initial Analysis Paper estimated unrecovered revenue and capital of $948–$1,222 million, while the Further Analysis Paper – after incorporating draft DPP3 settings, updated RABs, WACC, inflation and expenditure – reduced this to $644 million without accelerated depreciation, and $526 million with accelerated depreciation applied (all in $2022). The refreshed modelling, in turn, estimates around $1,012 million ($2026) if there is demand retreat to a smaller network (as per scenario 2), reflecting updated DPP4 inputs, steeper volume decline assumptions, and more recent demand and expenditure data.

The refreshed analysis also shows a different timing profile to earlier work. The Initial Analysis Paper projected most under-recovery crystallising at the point of network exit. The Further Analysis Paper showed earlier and more moderate emergence of under-recovery once draft DPP3 settings were applied. The refreshed analysis shifts this further. Under-recovery now emerges earlier and more sharply, driven by faster volume loss, earlier exit of large users, and binding willingness-to-pay constraints. This results in a more front-loaded risk profile even though the overall present-value total is

lower than the Initial Analysis Paper but higher than the Further Analysis Paper's DPP3-adjusted scenarios (once regulatory settings, such as accelerated depreciation, are factored in).

Finally, the refreshed analysis spans a different mix of select winddown and retreat scenarios. While earlier work focused on slow/fast winddown and repurposing variants, the refreshed scenarios include supply-driven exit, demand retreat, and LNG/renewable-gas futures. All produce meaningful and persistent under-recovery, although the pattern differs. This reinforces the earlier insight – common to all papers – that prolonged low-utilisation pathways present challenges comparable to rapid winddown, and that some form of mitigation appears necessary under all plausible futures if full cost recovery is to be expected.

4.3. Question 2: Implications for gas 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 3: Implications for gas infrastructure owners | Summary

- As with the Working Group's earlier work, initial analysis suggests that the financial viability of GPBs is at risk under all modelled scenarios, *assuming* no change to current regulatory settings or Government intervention. This is consistent with the insight in section 4.2 above.
- Declining and increasingly uncertain cash flows are expected to weaken creditworthiness, constrain refinancing options, and limit access to new debt well before assets reach the end of their operating lives.
- Faced with that outlook it may be rational for gas infrastructure owners to shutdown 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.
- Further work could be undertaken to better understand the drivers of the cash flow projections under the three scenarios, including as to what revenue gas infrastructure owners 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.

4.3.1. Context

Cost recovery risk translates directly into financial viability risk for gas infrastructure owners. Existing debt and other financial obligations have been incurred on the expectation that efficient costs – including historical capital investment – will be recovered over time. Where allowed revenues cannot be fully recovered, future cash flows become weaker and more uncertain, undermining financeability.

As shown in Question 1, declining volumes supplied and willingness-to-pay constraints lead to persistent under-recovery under all scenarios. Question 2 considers the implications of these outcomes for the ongoing financial viability of gas pipeline businesses.

4.3.2. Focus of analysis

The analysis focuses on whether gas infrastructure owners remain financeable under the three scenarios, rather than re-examining the cash-flow drivers themselves.

Financial viability is assessed qualitatively through:

- projected net cash flows (before financing), and
- implications for creditworthiness and access to debt finance.

While return on investment and formal credit metrics (such as operating cash flow-to-debt and leverage ratios) have been considered, the central question is whether the projected cash flows are sufficient, stable, and durable enough to support continued access to finance and ongoing safe operation of the networks.

Consistent with Question 1, the analysis assumes no additional regulatory or policy mitigations.

4.3.3. What to expect

The premise is that higher cost recovery risk translates into weaker financial viability for gas infrastructure owners through its impact on cash flows and financeability.

Financial viability will primarily depend on:

- projected cash flows, which reflect the balance between future revenues and costs as volumes supplied decline,[17] and
- existing debt levels and future debt-raising needs, including the ability to refinance existing facilities and raise capital to fund ongoing expenditure.

Where projected cash flows deteriorate or become increasingly uncertain, the ability of gas infrastructure owners to service debt, refinance, or raise new capital is expected to weaken. While repurposing or alternative gas supply may support higher volumes supplied and improve cash flow outcomes relative to a rapid winddown, declining utilisation under all scenarios implies ongoing pressure on financial viability.

4.3.4. Initial quantitative analysis results

Building on the cost recovery outcomes in Question 1, the analysis indicates that declining volumes supplied and associated under-recovery place sustained pressure on the financial viability of gas pipeline businesses across all scenarios. While the timing and severity differ, financeability challenges arise both under rapid winddown and where the system continues operating at a materially reduced scale.

The implications for financial viability are illustrated below by reference to:

- net cash flows, drawing on the results in Question 1
- returns on investment, relative to the regulated cost of capital, and
- financeability, including the ability to service, refinance, and raise debt.

Net cash flows

As shown in Question 1, net cash flows (before interest and tax) weaken under all scenarios as volumes supplied decline and under-recovery emerges.

Under Scenario 1, cash flows deteriorate rapidly and become negative in the years leading up to winddown. Because these results exclude financing costs, financeability pressures – including reduced debt-servicing capacity and refinancing risk – would be expected to arise earlier.

[17] 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.

Under Scenarios 2 and 3, cash flows decline more gradually and stabilise at low levels as the system transitions to a smaller steady-state configuration. While this avoids a sharp cliff in cash flows, prolonged periods of weak or near-zero cash flows are still likely to undermine creditworthiness and constrain access to finance.

Return on Investment

The figures below show that weaker cash flows translate into declining returns on investment over time. As revenues become increasingly constrained by willingness-to-pay limits, returns fall relative to the regulated cost of capital. Sustained periods in which returns are below the cost of capital indicate that infrastructure owners are unlikely to recover the opportunity cost of invested capital, reducing incentives to continue investing or to remain in the market absent mitigation.

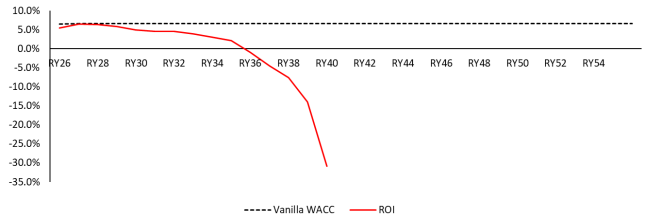
Under Scenario 1, returns deteriorate rapidly and fall well below the regulated WACC, particularly in the years of high decommissioning and disconnection costs, consistent with the sharp decline in cash flows.

Under Scenarios 2 and 3, returns improve slightly in the later years of the modelling period as most disconnection and decommissioning costs have been incurred and under-recovery moderates. However, despite this improvement, projected returns remain materially below the regulated WACC and are not sufficient to support a sustainable investment proposition absent mitigation.

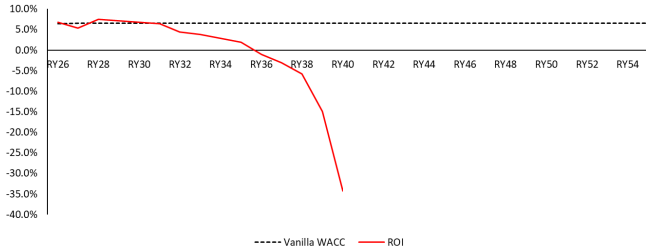
FIGURE 4.5: RETURN ON INVESTMENT

Scenario 1: Supply driven winddown

Transmission

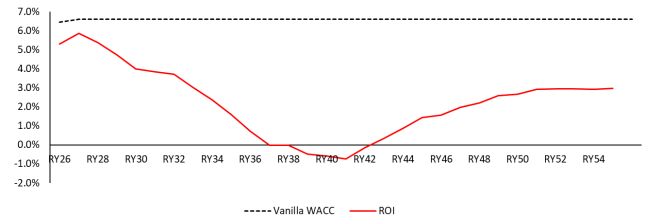


Distribution



Scenario 2: Demand retreat to smaller network

Transmission



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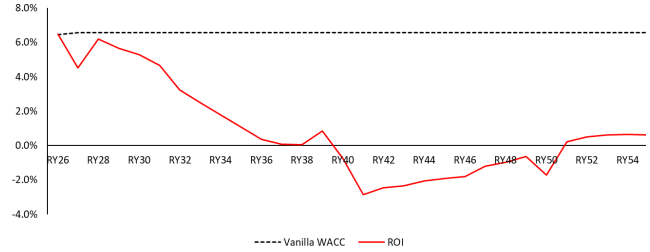
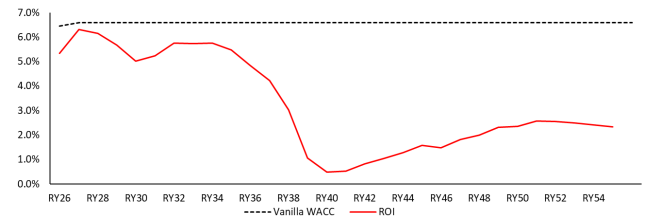
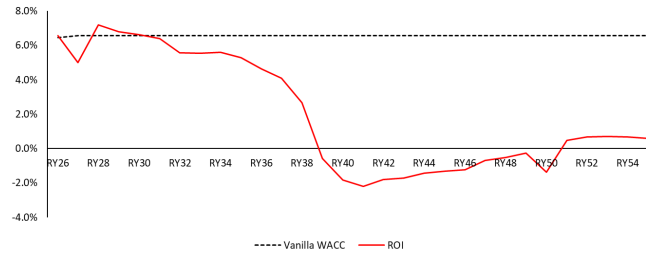


Scenario 3: Renewable gas / LNG import

Transmission



Distribution



The distribution ROI lines represent the average ROI across the 4 gas distribution networks, weighted by their respective RAB values.

Financeablility

The combination of declining cash flows and weakening returns materially affects financeability. Analysis of standard credit metrics – including operating cash flow to debt and leverage – indicates deterioration under all scenarios, consistent with the cash flow and return outcomes described above. While detailed metrics are not presented here, the results suggest increasing difficulty in refinancing existing debt and raising new capital to fund ongoing operations, maintenance, and safety-related expenditure.

Absent mitigation, these financeability pressures are likely to constrain investment decisions and may accelerate the rationalisation or closure of uneconomic parts of the gas network.

Limitations

The limitations described in Section 4.2.4 (Question 1) apply equally to this analysis and are not repeated here.

In particular, the financeability outcomes discussed above inherit the same sensitivities to assumptions about willingness to pay, the allocation of recovered revenue across the supply chain, and the treatment of under-recovery by producers and retailers as well as to financing choices made by gas infrastructure owners. To the extent that these assumptions change, the timing and severity of financeability pressures may also change.

This section focuses on the implications of projected cash flows for financial viability and access to finance, rather than on broader external costs or benefits. As noted in Question 1, a more comprehensive assessment of policy options may warrant consideration of wider social costs and benefits.

4.3.5. Key insights

The analysis indicates that cost under-recovery gives rise to financeability risks for gas infrastructure owners across all scenarios. Declining and increasingly uncertain cash flows are expected to weaken creditworthiness, constrain refinancing options, and limit access to new debt well before assets reach the end of their operating lives.

Under Scenario 1, these pressures emerge rapidly as cash flows deteriorate sharply ahead of winddown. Under Scenarios 2 and 3, financeability risks arise more gradually but persist over a longer period as the system operates at a materially reduced scale. In all cases, projected returns remain below the regulated cost of capital, indicating sustained pressure on financial viability under current assumptions.

If unmitigated, these conditions may make continued operation and investment – particularly in higher-cost or lower-utilisation parts of the network – increasingly difficult to sustain. Faced with this outlook, gas infrastructure owners may have incentives to reduce investment or rationalise assets earlier than would be socially desirable.

Further work could improve understanding of these outcomes, including the extent to which revenues can be recovered from gas consumers under different scenarios and how regulatory or policy responses might mitigate financeability risks.

4.3.6. Comparison to earlier analysis

The refreshed analysis reaches similar broad conclusions to the Initial Analysis Paper. Namely, that declining volumes and binding willingness-to-pay limits create persistent financeability pressure for gas pipeline businesses under all scenarios.

In the Initial Analysis Paper, cash flows weakened steadily as demand fell, with returns dropping below the regulated WACC and credit metrics deteriorating well in advance of any full wind-down. The refreshed analysis confirms this pattern but shows the pressures emerging earlier and more sharply, reflecting steeper assumed demand declines, earlier exit of large users, and tighter willingness-to-pay constraints. As a result, the risk of reduced investment or premature network rationalisation appears more immediate than suggested in the 2022 modelling.

The Further Analysis Paper also concluded that financial viability remained at risk despite improvements in cost recovery. Even with accelerated depreciation (as per the draft DPP3 decision at the time), returns for most years remained below the allowed WACC, and cash flows were projected to weaken materially under slow wind-down conditions. The refreshed analysis aligns closely with these findings. Although scenarios with ongoing network operation (such as demand retreat or renewable gas/LNG) moderate the speed of deterioration, they do not materially change the long-term viability challenge. All scenarios exhibit prolonged periods of low or near-zero net cash flows and declining creditworthiness.

Taken together, the three sets of modelling show a consistent story: updated regulatory settings and accelerated depreciation help but do not resolve the underlying viability issues created by structural demand decline. What differs in the refreshed analysis is the timing and profile of the risk – pressures emerge sooner, persist longer, and are more sensitive to small changes in volumes and wholesale gas prices. This reinforces the importance of developing regulatory or policy mitigations that address declining utilisation directly, as neither the Initial Analysis Paper nor the Further Analysis Paper – nor the refreshed work – include scenarios in which GPBs remain financially sustainable without some form of intervention.

4.4. Question 3: Implications for gas 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 4: Implications for gas consumers | Summary

- A rapid supply-driven winddown of gas pipelines exposes the remaining gas consumers to meaningful 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.
- Scenarios in which the gas system persists at reduced scale result in more gradual but sustained affordability pressures. While the introduction of biomethane can improve competitiveness in the near term, it does not materially change longer-term consumer outcomes once volumes supplied stabilise at lower levels and more expensive imported LNG is introduced.
- Absent mitigation, rising charges are likely to reinforce volume decline and place pressure on affordability, highlighting the importance of regulatory and policy responses in shaping consumer outcomes during the transition.

4.4.1. Context

As set out in Questions 1 and 2, declining volumes supplied through gas networks place upward pressure on charges as largely fixed cost bases are recovered from fewer consumers. These dynamics have direct implications for gas consumers through higher delivered gas prices and, ultimately, declining energy affordability.

Gas consumers effectively face a choice between continuing to use reticulated gas, switching to an alternative energy source, or shutting down (where this is an option).[18] Continuing to use gas involves paying wholesale gas costs, gas transmission and distribution charges, and retail margins. Switching involves paying the wholesale, network, and retail costs

[18] In some cases, large consumers are deciding to register as gas shippers so that they can secure gas from the wholesale market as they are otherwise unable to secure supply from gas retailers.

of the alternative energy source – most commonly electricity for residential and commercial consumers, and in some cases diesel or other liquid fuels for industrial consumers – as well as incurring upfront conversion costs such as appliance replacement or process modifications.

In the analysis, alternative energy costs are used as the benchmark for consumers' willingness to pay for gas. These costs are defined on a delivered-energy basis and include wholesale energy prices, network charges, retail margins, net conversion costs,[19] and an adjustment for non-price preferences that tend to create inertia or 'stickiness' in switching behaviour. As such, when delivered gas charges approach alternative energy costs in the modelling, consumers are assumed to be indifferent between remaining on gas and switching.

Question 3 focuses on how changes in gas charges under each scenario interact with these willingness-to-pay constraints, and how the resulting impacts differ across consumer groups and scenarios, and over time.

4.4.2. Focus of analysis

The analysis focuses on how declining volumes supplied and cost recovery pressures translate into changes in delivered gas charges relative to alternative energy costs for different consumer groups.

Consumer impacts are assessed by comparing projected gas charges with alternative energy costs, which serve as the effective willingness-to-pay benchmark. The analysis therefore examines how quickly gas charges approach this benchmark under each scenario and how outcomes differ across residential, commercial, industrial, and direct-connect consumers.

While this framework captures key drivers of consumer impacts, it abstracts from heterogeneity within consumer groups. In practice, alternative energy costs and net conversion costs are likely to vary significantly across individual consumers, which may influence switching behaviour and the pace of demand reduction. Further work could improve understanding of these differences and their implications.

4.4.3. What to expect

As volumes supplied decline, delivered gas charges are expected to rise relative to alternative energy costs across all scenarios. Where gas charges approach alternative energy costs, consumers are expected to become increasingly indifferent between remaining on gas and switching, increasing the likelihood of further volume reductions.

Under a rapid supply-driven winddown, gas charges are expected to rise quickly, accelerating consumer exit and reinforcing downward pressure on volumes. Under scenarios where the gas system persists at reduced scale, charge increases are expected to be more gradual but sustained over a longer period, placing ongoing pressure on consumer affordability.

The analysis does not model consumer switching behaviour explicitly. Instead, demand projections reflect assumed responses to changes in relative energy costs and non-price factors embedded in alternative energy cost benchmarks.

Consumer impacts are expected to differ by type. Residential and commercial consumers are generally more exposed to rising network charges and switching incentives. Some industrial and direct-connect consumers may face higher alternative energy costs or limited viable substitutes – and may therefore remain on gas for longer. In such cases, adjustment pressures may arise through higher energy costs, changes in production processes, or, in some circumstances, relocation or exit.

4.4.4. Initial quantitative analysis results

Building on the cost recovery outcomes in Questions 1 and 2, the analysis examines how declining volumes supplied and associated cost recovery pressures translate into changes in charges faced by gas consumers across the three scenarios.

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[19] Net conversion costs were used in the analysis. These were estimated by Concept Consulting and recognise both the upfront appliance, make good, and electricity network upgrade costs, and future savings such as deferred appliance replacement costs.

The consumer impacts are illustrated below by reference to:

- annual delivered gas charges per user, compared with alternative energy costs, and
- differences across consumer types and scenarios.

The analysis assume that allowed network revenues are passed through to consumers, that revenue allocation across consumer groups remains unchanged, and that no re-profiling of allowed revenues over time occurs. In practice, an increase would be expected to trigger pricing adjustments by gas networks and retailers, consumer switching, or regulatory and policy responses.

Annual natural gas charges per user

The figures below show annual delivered natural gas charges per user, compared with alternative energy costs – electricity or, for some industrial consumers, diesel, including an adjustment for non-price factors – for residential, commercial, and industrial distribution consumers. The delivered natural gas charges are broken into their network, wholesale, and retail components.

Direct-connect transmission consumers are not shown, as outcomes vary significantly by user: for some, delivered gas charges exceed alternative energy costs relatively early, while for others gas remains competitive throughout the modelling period.

The analysis suggests that:

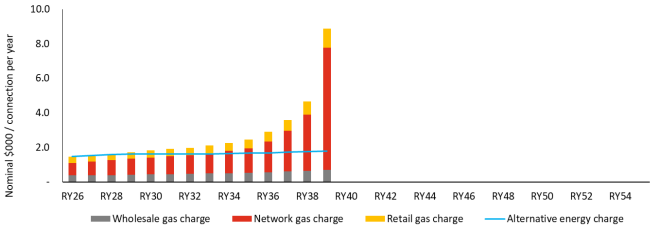
- Under **Scenario 1** – supply-driven winddown – charges for residential and commercial distribution consumers increase rapidly as network costs are recovered from a sharply shrinking consumer base. Delivered gas charges exceed alternative energy costs relatively early, creating strong incentives for consumer exit and reinforcing downward pressure on volumes.
- Under **Scenario 2** – demand retreat to a smaller network – charges increase more gradually as the system transitions to a materially smaller steady-state configuration. Gas tends to remain more competitive for residential consumers than for commercial consumers; but delivered gas charges still exceed alternative energy costs relatively early, placing sustained pressure on affordability.
- Under **Scenario 3** – renewable gas / LNG import – domestically supplied gas is supplemented with biomethane and imported LNG; together they are assumed to supply around 10% of total gas consumption by RY33, around 30% by RY38, and approximately 40% by RY44. Limited quantities of biomethane are available earlier in the period and are slightly lower cost than domestic natural gas, reducing average wholesale gas costs in the near term and improving competitiveness of gas relative to alternative energy. As domestic supply declines, LNG is introduced later and is more expensive, placing upward pressure on wholesale gas costs over time.

Overall, when gas, biomethane, and LNG are considered together, consumer charge outcomes under Scenario 3 are broadly similar to Scenario 2, with the primary difference being modestly improved competitiveness in the earlier years.

FIGURE 4.6: ANNUAL CHARGES PER CONSUMER BY TYPE

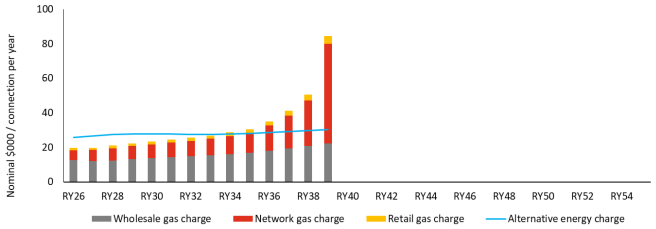
Supply driven winddown

Residential



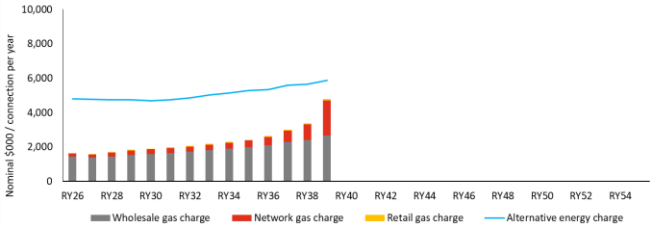
**Gas charge > alternative energy charge in RY29*

Commercial



**Gas charge > alternative energy charge in RY34*

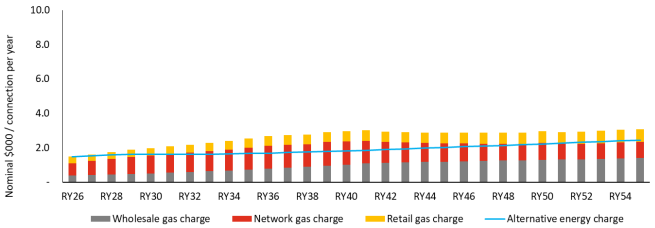
Industrial



**Gas charge does not exceed alternative energy charge*

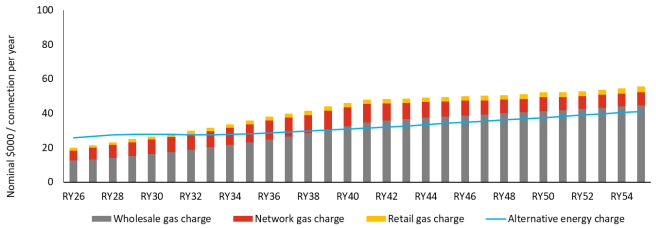
Demand retreat to smaller network

Residential



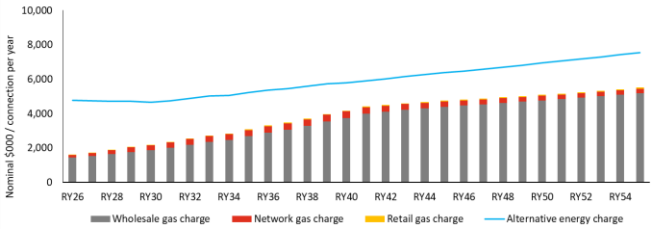
**Gas charge > alternative energy charge in RY27*

Commercial



**Gas charge > alternative energy charge in RY31*

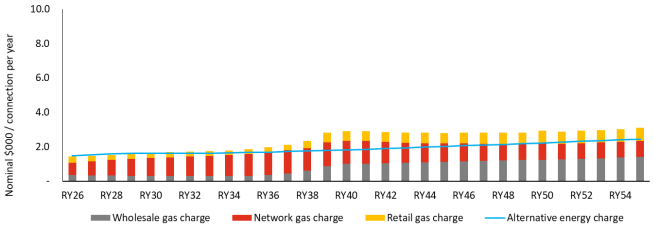
Industrial



**Gas charge does not exceed alternative energy charge*

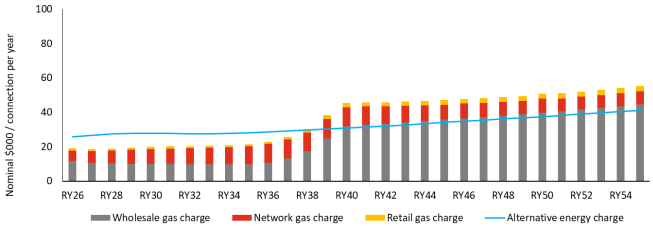
Renewable gas / LNG import

Residential



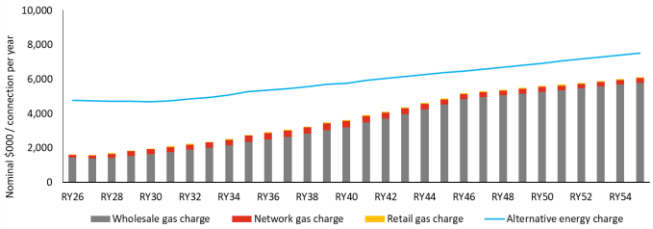
**Gas charge > alternative energy charge in RY30*
**Gas charge comprises a weighted average of domestic supply gas, biomethane, and LNG*

Commercial



**Gas charge > alternative energy charge in RY38*
**Gas charge comprises a weighted average of domestic supply gas, biomethane, and LNG*

Industrial



**Gas charge does not exceed alternative energy charge*
**Gas charge comprises a weighted average of domestic supply gas, biomethane, and LNG*

Note: scales differ across the charts.

Impact of accelerated depreciation

The removal or cessation of accelerated depreciation tends to moderate the increase in consumer charges over time. As highlighted in section C.2.3 of Appendix C, accelerated depreciation front-loads cost recovery, resulting in higher charges during early years but lower charges later on. Without this mechanism, the recovery of asset costs is spread more evenly across the asset's lifetime, which can reduce the immediate affordability pressures on consumers and smooth the trajectory of charges. This approach may help maintain consumer engagement and slow the pace of exit, particularly for residential and commercial users.

However, while removing accelerated depreciation can lessen short-term price shocks, it may also extend the period over which higher charges persist, especially as the network contracts and fixed costs are shared among fewer consumers. As a result, while the initial impact is less severe, longer-term affordability challenges may remain, particularly if gas volumes continue to decline and alternative energy costs do not fall significantly.

Limitations

The limitations described in Questions 1 and 2 apply equally to this analysis and are not repeated here.

At the same time, the consumer outcomes presented above are sensitive to assumptions about alternative energy costs, net conversion costs, and non-price factors embedded in the willingness-to-pay benchmarks. In practice, these costs are likely to vary significantly across individual consumers within each group, which may influence both the timing and extent of consumer switching.

The analysis does not model consumer behaviour, charge rebalancing, or pricing responses explicitly. Instead, these effects are reflected indirectly through scenario assumptions. As a result, actual consumer impacts may differ from those shown if networks, retailers, or regulators adjust pricing structures in response to rising charges.

Finally, the analysis focuses on private consumer costs and does not consider broader distributional or equity impacts, or potential policy interventions aimed at mitigating affordability concerns.

4.4.5. Key insights

The analysis indicates that declining volumes supplied are likely to result in rising delivered gas charges for remaining consumers across all scenarios, with residential and commercial distribution consumers most exposed. A rapid supply-driven winddown leads to earlier and sharper increases in charges, increasing incentives for consumer exit.

Scenarios in which the gas system persists at reduced scale result in more gradual but sustained affordability pressures. While the introduction of biomethane can improve competitiveness in the near term, it does not materially change longer-term consumer outcomes once volumes supplied stabilise at lower levels and more expensive imported LNG is introduced.

Consumer impacts differ materially by type. Industrial and some direct-connect consumers may face higher alternative energy costs and therefore remain on gas for longer, while residential and commercial consumers are more sensitive to rising network charges and willingness-to-pay constraints, however this will be very consumer specific and is hard to be definitive about without further analysis.

Absent mitigation, rising charges are likely to reinforce volume decline and place pressure on affordability, highlighting the importance of regulatory and policy responses in shaping consumer outcomes during the transition.

4.4.6. Comparison to earlier analysis

The Initial Analysis Paper highlighted that consumer outcomes would be shaped by how quickly network utilisation falls and how charges evolve relative to alternatives. Its modelling showed that price pressure would emerge unevenly across consumer groups, with smaller users facing affordability constraints sooner as consumption reduced and network costs were spread across a diminishing base. The refreshed analysis reinforces this general pattern but indicates a more compressed timeframe in which affordability tightens, due mainly to steeper early declines in throughput and updated assumptions on wholesale gas pricing and net conversion costs.

The Further Analysis Paper reached similar conclusions once draft DPP settings were incorporated. While accelerated depreciation helped temper the most extreme price increases in later years, the overall trend of rising delivered gas costs relative to alternatives persisted. The refreshed analysis is broadly consistent with this, but it shows greater separation between scenarios, particularly between supply-driven wind-down and the renewable-gas/LNG case, where modest near-term improvements in competitiveness do not change longer-run affordability challenges. This reflects updated demand paths and the more prominent role of willingness-to-pay limits in the refreshed modelling.

Taken together, the three rounds of analysis point to the same strategic issue: regardless of the pathway, declining system scale steadily erodes the competitiveness of reticulated gas for many users. What differs in the refreshed work is the sharper onset of pressure and the clearer differentiation in how different consumer groups are affected. This suggests that consumer-focused policy and regulatory responses will matter more if the system contracts, particularly if the aim is to manage the transition without abrupt affordability shocks or disorderly consumer exit.

Appendices

Summary

This part of the Refreshed Analysis Paper includes three appendices:

Appendix A: Model description

Appendix B: Key model inputs

Appendix C: Sensitivity analysis

Appendix D: Earlier work

Appendix E: Glossary and Abbreviations

APPENDIX A. MODEL DESCRIPTION

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

A.1. Summary

At its core, the Model is a cash flow model. It assesses the cash flows to gas infrastructure owners and gas consumers over a 31-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 infrastructure owners.

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 winddown or retreat 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 infrastructure owners and gas consumers over a 36-year forecasting period, starting with regulatory year 26 plus an additional 29 years through to regulatory year 55.[20] Although not presented in this Refreshed 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).

[20] 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.

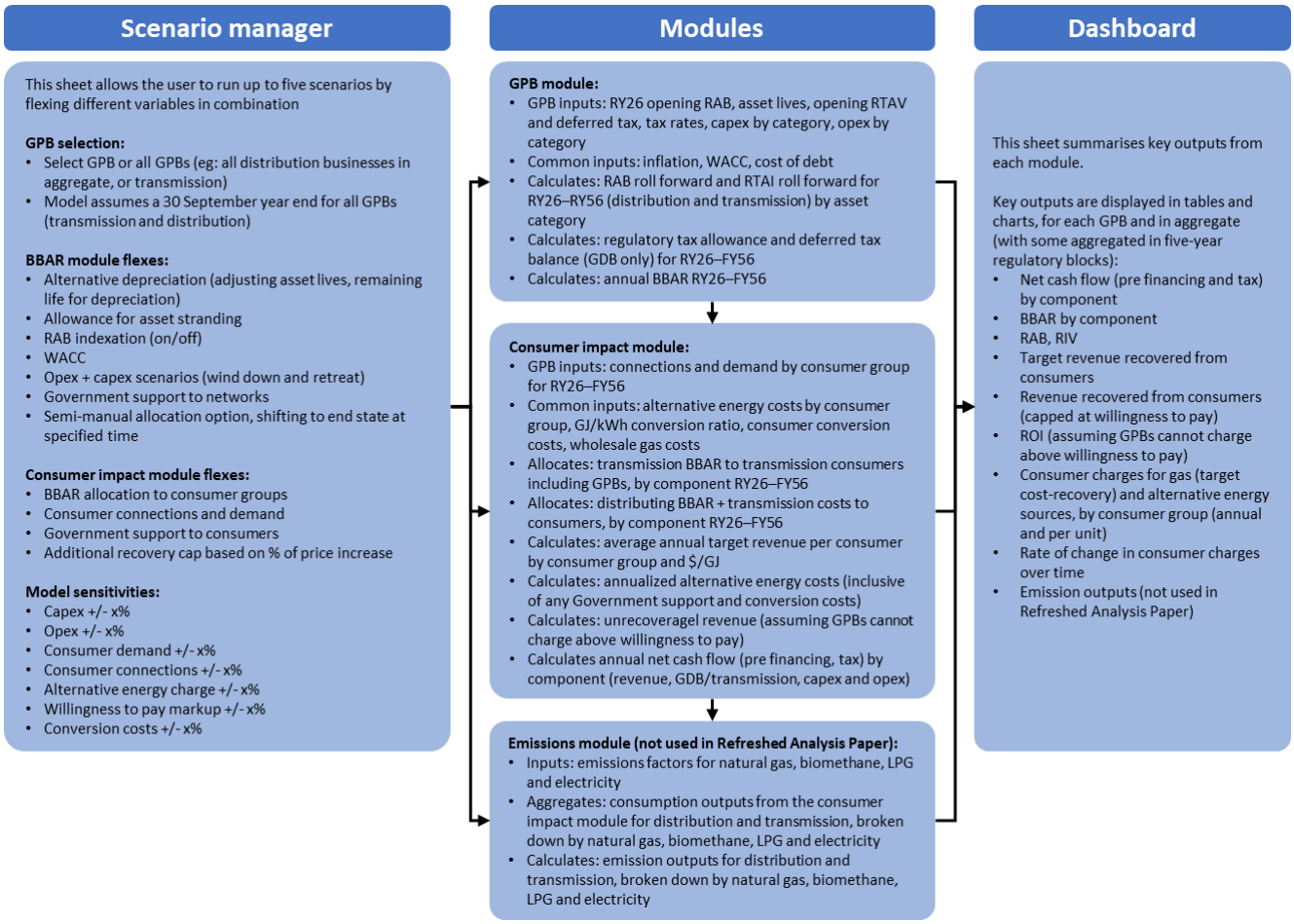
The Model also contains:

- **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 2026 to align with the most recent published GPB regulatory data. The model forecasts annual cash flows over a 30-year period, with a 30 September year-end to align with the DPP. Five-year regulatory periods are used in the Model.

Figure A-1 illustrates the high-level structure of the Model (noting that the emissions module and model sensitivities are not used in this Refreshed Analysis).

FIGURE A-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** – three 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 (not used in this Refreshed Analysis).
- **Sensitivities** – percentage-based increases or decreases applied to specific inputs (not used in this Refreshed Analysis).
- **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 three different market scenarios relating to the overall market outcome for gas (with functionality to allow for up to six scenarios). The first scenario involves a winddown of gas infrastructure while the second two assume that gas infrastructure remains in use indefinitely, albeit with a small footprint due to demand retreat. The key inputs that differ across market scenarios are gas throughput and number of connections as well as expenditure forecasts provided by GPBs.

The three market scenarios are described in Table A.5.1 below.

TABLE A.5.1: MARKET SCENARIO DESCRIPTIONS

Market scenario	Description
1. Supply driven winddown	Gas throughput and connections reduce gradually in line with gas reserve depletion, 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 2040
2. Demand retreat to smaller network	Gas throughput and connections reduce by half by 2050 as gas consumers transition to alternative energy sources, with a reduced network footprint remaining to serve ongoing demand including gas fired generation
3. Renewable gas and/or LNG import	Gas throughput and connections reduce significantly (stabilising at ~23% of current levels) with a smaller network footprint, utilising renewable gas and/or imported LNG to offset domestic depletion. This is a financial stress-test of scenario 2, not a scenario of a transition to 100% renewable gas sustaining volumes.

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 but is not used in this Refreshed Analysis.

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

Module impacted	Design variable	Description
		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 RTAV 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.
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 net 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.

Module impacted	Design variable	Description
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).
- **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.
- **Accelerated depreciation** – For the purposes of this analysis, accelerated depreciation of existing assets is implemented using a simplified approximation of the Commerce Commission's Draft DPP approach. Earlier versions of the model implemented accelerated depreciation by shortening remaining asset lives in a single year, with lives then declining by one year thereafter (e.g. 45, 31, 30, 29…). This resulted in a relatively sharp step-down in allowed revenue as assets became fully depreciated. The Commerce Commission's modelling applies accelerated depreciation by adjusting depreciation amounts rather than directly shortening asset lives, resulting in a smoother evolution of remaining lives over time (e.g. 45, 31, 30.5, 29.8…). Rather than replicating this approach in full, the analysis applies year-specific depreciation adjustment factors that approximate the Commission's year-to-year changes in remaining asset lives, with the final-year factor held constant through to the end of the modelling period. This smooths depreciation and revenue profiles while preserving the overall timing and scale of depreciation implied by the Draft DPP assumptions, and does not materially affect the conclusions of the analysis.
- **Regulatory period length** – the Model assumes regulatory (DPP) periods of 5 years. 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 conversion costs** – the Model incorporates assumed and simplified net conversion costs for residential, commercial, industrial and transmission-connected consumers based on top-down analysis provided by Concept Consulting. These are average conversion costs for each consumer group based on an assumed mix of appliances (e.g., heating and space heating), net of savings such as deferred future appliance replacement costs. Actual conversion costs incurred by consumers could be higher or lower than these assumed values.
- **Net debt approximation** – the Model calculates a proxy measure for 'net debt' whereby gearing levels are assumed to remain constant at the assumed gearing level of 42%, consistent with allowed rate of return. 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. Real world financing will undoubtably differ from this assumption.
- **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 draft DPP3 decision 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 3.5, 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 refreshed analysis, the Working Group has modelled the WTP for each consumer type, under each scenario by combing three components:

- the projected price of alternative energy provided by Concept Consulting
- the net cost of converting from gas to alternative energy, including any make good costs and net of savings such as deferred appliance replacement costs, also provided by Concept Consulting, and

- an assumed markup (of 25%) to reflect non-price factors, such as consumer stickiness,[21] amenity value, and other desirable characteristics (e.g., instantaneous hot water).

Net conversion costs are assumed to be spread evenly over a period of time – namely, 10 years for distribution consumers and 30 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, using discount rates of 5% for distribution consumers and 8% for transmission direct connect consumers.

Concept Consulting estimated net conversion costs factoring in both the immediate and ongoing costs and savings from converting to alternative energy sources. For instance, in the case of residential consumers, average net conversion costs were estimated as:

> *[net cost of space heating conversion] x [share of consumers with gas space heating (60%)] + [net cost of water heating conversion] x [share of consumers with gas water heating (85%)].*

Net space and water heating costs include the capital cost of new electric appliance, make good costs, electric appliance maintenance costs, and electricity network upgrade costs (only 5% of connections), and were reduced by avoided gas appliance maintenance costs and deferred appliance replacement (equivalent to a 30% saving on the new appliance cost).

The conversion cost assumptions are set out in the following table.

TABLE A.7.1: CONVERSION COST ASSUMPTIONS

Component	Consumer type	Assumption
Net conversion cost (RY26 $ per connection)	Residential	$5,341
	Commercial	$72,494
	Industrial	$8,366,423
	Transmission-connected	$0–$75,952,464[22]
Amortisation period	Distribution-connected	10 years
	Transmission-connected	30 years
Nominal discount rate	Distribution-connected	5%
	Transmission-connected	8%

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.

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21 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).

22 The range for transmission-connected consumers is large. At one end, those consumers might choose to shut down rather than convert. They may also be able to switch to alternative energy sources at no cost (e.g., because they have existing capacity). At the other end, converting a co-generation plant to, say, a 30 MWh boiler with 75% capacity factor is likely to be expensive.

However, a precise estimate is difficult to determine. A 25% assumption was adopted as a placeholder intended to align with the intuition mentioned above (particularly that current gas costs should not exceed willingness to pay), 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.

APPENDIX B. KEY MODEL INPUTS

B.1. Introduction

This appendix summarises the key input assumptions used in the quantitative modelling across the three scenarios. The purpose is to provide transparency over the main drivers of the results presented in Section 4, rather than to interpret outcomes.

Inputs are grouped into the following categories:

- operating expenditure (excluding disconnection and decommissioning)
- disconnection and decommissioning costs
- capital expenditure
- gas network demand, and
- consumer connections.

Operating expenditure and capital expenditure forecasts are based on information provided by gas pipeline businesses (GPBs). Demand and connection forecasts, as well as wholesale gas costs and alternative energy cost assumptions (not detailed in this Appendix), are derived from modelling undertaken by Concept Consulting. Figures are presented for each input category to illustrate the assumed trajectories under each scenario.

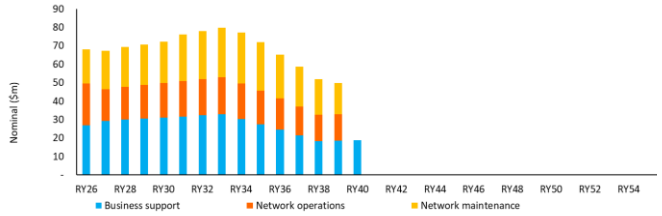
A key limitation of the modelling approach is that there is some unavoidable circularity between GPB-provided cost forecasts and the Concept Consulting demand and price modelling, combined with limited time for iterative refinement. As a result, there may be some inconsistencies between cost and demand assumptions. However, these are not expected to be of a magnitude that would materially affect the overall conclusions of the analysis.

B.2. Operating expenditure

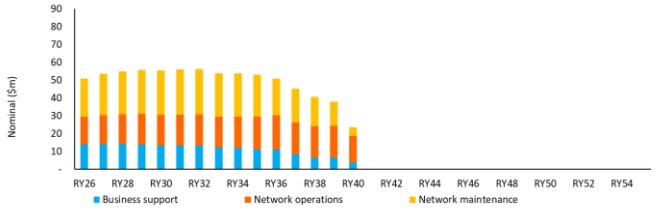
FIGURE B.1: OPERATING EXPENDITURE, EXCLUDING DECOMMISSIONING AND DISCONNECTIONS

Scenario 1: Supply driven winddown

Transmission

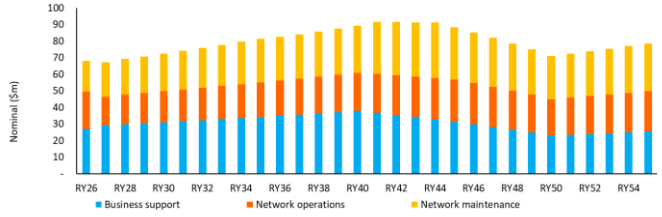


Distribution



Scenario 2: Demand retreat to smaller network

Transmission



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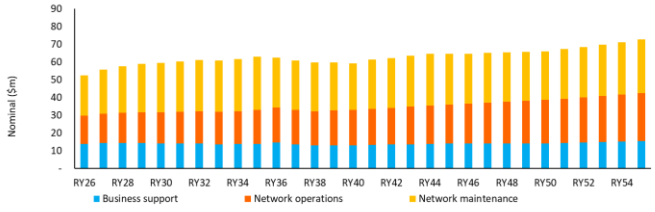
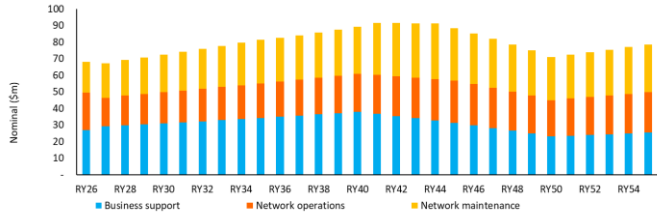


Scenario 3: Renewable gas / LNG import

Transmission



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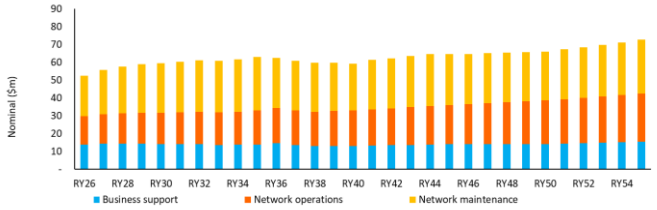
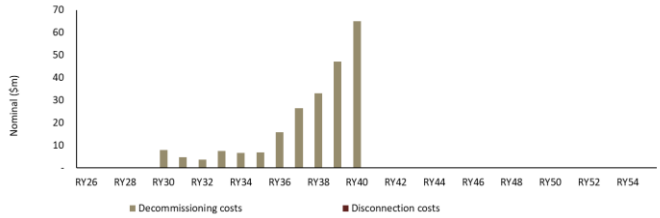


B.3. Decommissioning and disconnection costs

FIGURE B.2: DECOMMISSIONING AND DISCONNECTION COSTS

Scenario 1: Supply driven winddown

Transmission



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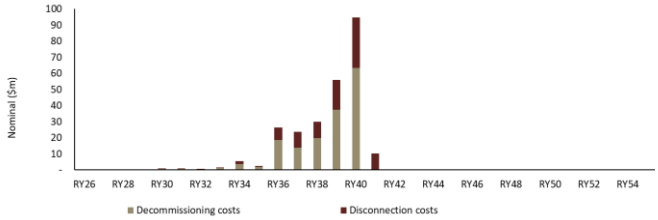
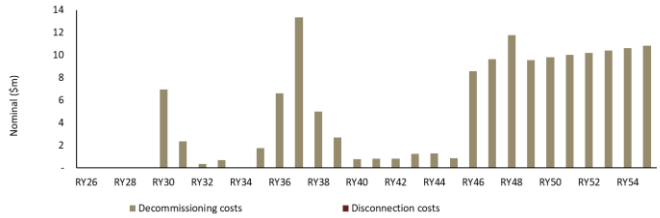


Scenario 2: Demand retreat to smaller network

Transmission



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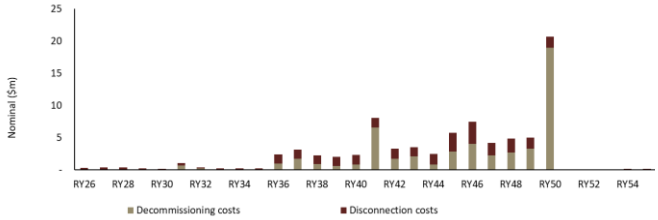
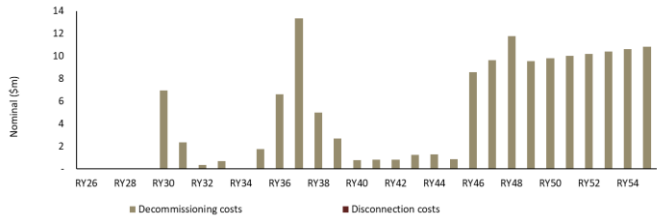


Scenario 3: Renewable gas / LNG import

Transmission



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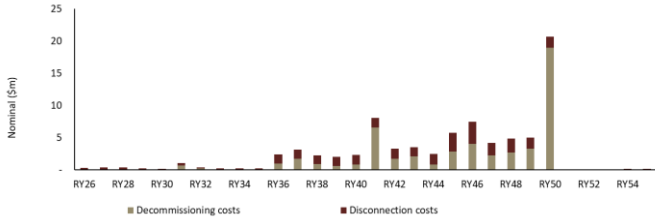
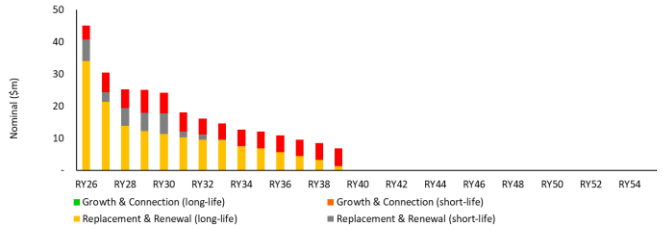


B.4. Capital expenditure

FIGURE B.3: CAPITAL EXPENDITURE

Scenario 1: Supply driven winddown

Transmission



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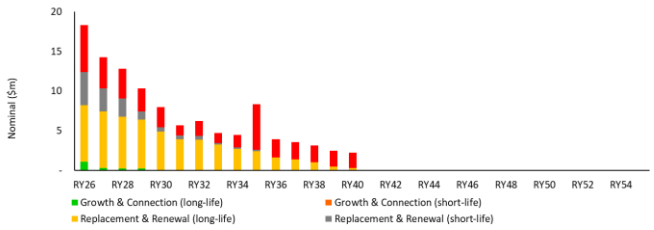
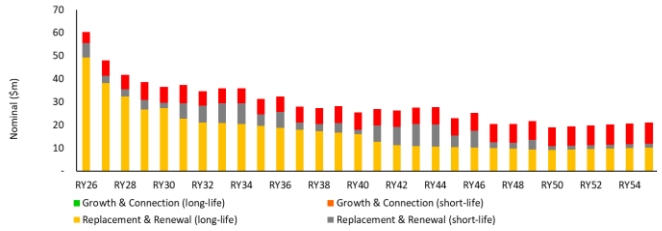


Scenario 2: Demand retreat to smaller network

Transmission



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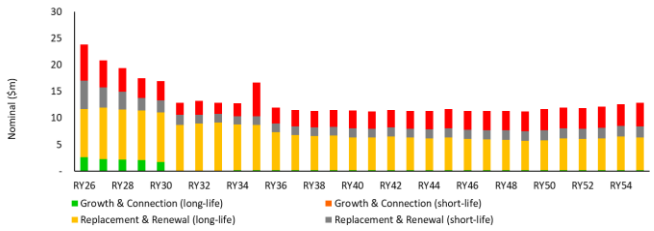
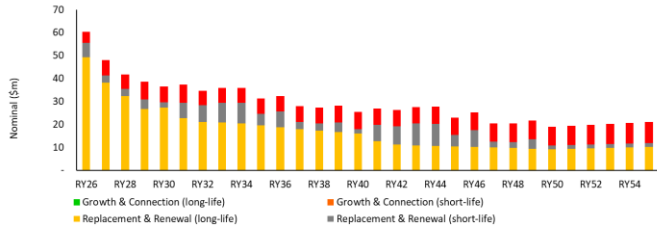


Scenario 3: Renewable gas / LNG import

Transmission



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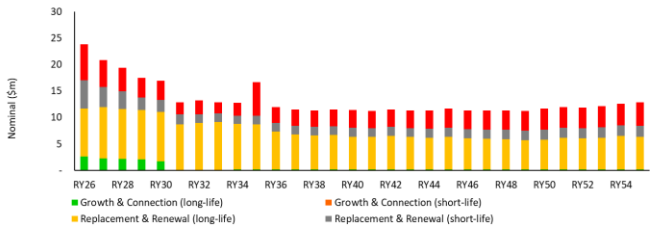
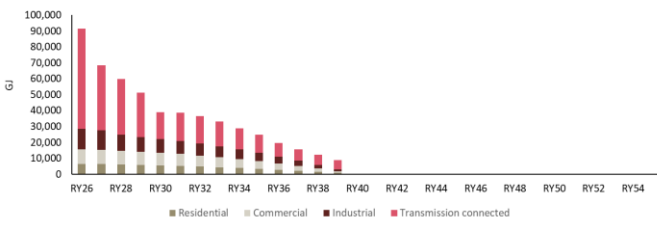


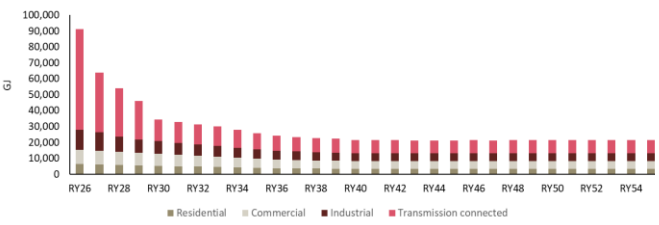
B.5. Gas network demand

FIGURE B.4: DEMAND / CONSUMPTION VOLUMES BY CONSUMER CATEGORY

Scenario 1: Supply driven winddown



Scenario 2: Demand retreat to smaller network



Scenario 3: Renewable gas / LNG import

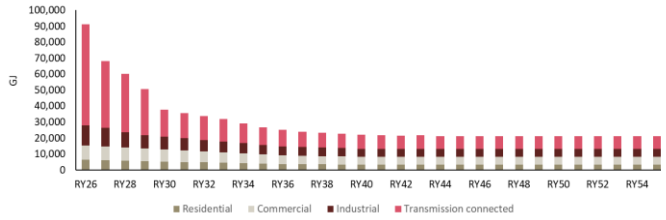
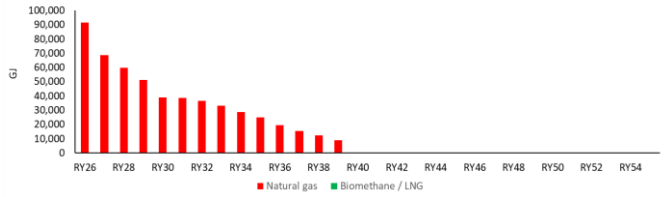
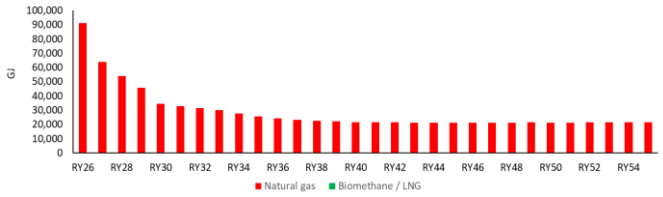


FIGURE B.5: DEMAND / CONSUMPTION VOLUMES BY GAS TYPE

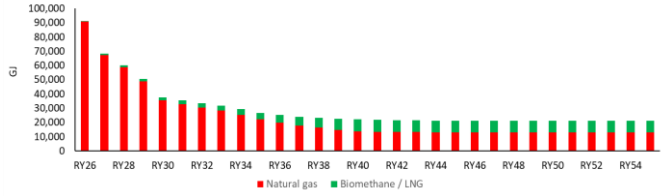
Scenario 1: Supply driven winddown



Scenario 2: Demand retreat to smaller network



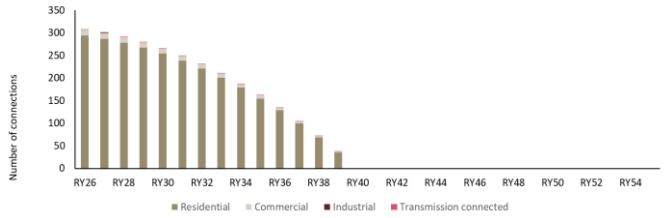
Scenario 3: Renewable gas / LNG import



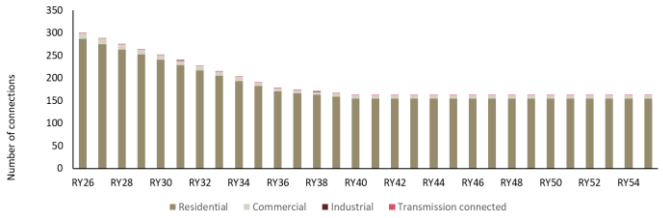
B.6. Consumer connections

FIGURE B.6: CONSUMER CONNECTIONS

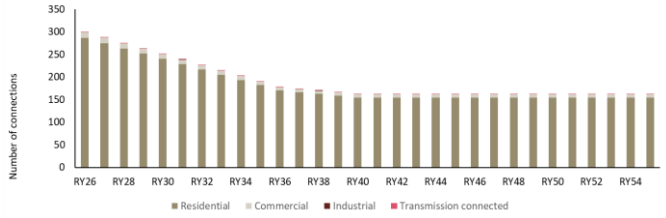
Scenario 1: Supply driven winddown



Scenario 2: Demand retreat to smaller network



Scenario 3: Renewable gas / LNG import



APPENDIX C. SENSITIVITY ANALYSIS

C.1. Introduction

This appendix assesses the sensitivity of modelled outcomes to changes in key input assumptions. Some of these are referenced within the body of the Refreshed Analysis Paper.

C.2. Sensitivity analysis

C.2.1. What happens to value at risk

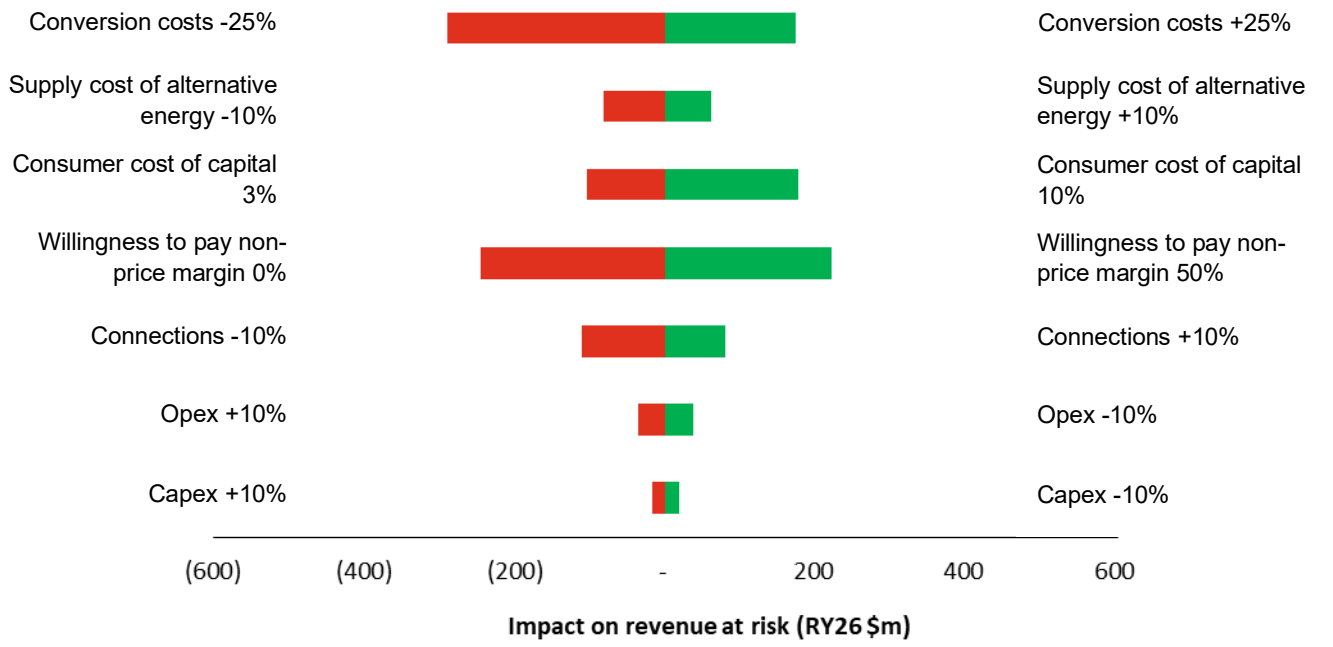
Figure C-1 shows the sensitivity of value at risk (as described in Section 4.2.4) to key modelling inputs. Results are presented as deviations from the base case assumptions reflected in the body of this paper. Positive values indicate a reduction in value at risk relative to the base case, for the combined distribution and transmission businesses, while negative values indicate an increase in value at risk.

Some key observations include:

- Cost sensitivities (opex and capex) have a relatively small impact on value at risk. This reflects the fact that cost recovery is primarily driven by declining volumes and the extent to which allowed revenues become constrained by consumers' willingness to pay, rather than by moderate changes in underlying cost levels. This effect is most pronounced in Scenario 1, where rapid volume decline causes willingness-to-pay constraints to bind earlier than the other scenarios.
- The number of connections has a material impact on value at risk, as it directly affects the extent to which largely fixed network costs can be recovered from a shrinking consumer base. Reductions in connections increase the per-connection revenue requirement and bring forward the point at which allowed charges are constrained by willingness-to-pay limits.
- Willingness-to-pay assumptions have the largest influence on value at risk. Willingness to pay is approximated by combining supply costs of alternative energy, annualised net conversion costs, and a non-price margin reflecting factors such as amenity value and consumer stickiness. These assumptions are inherently uncertain, which is reflected in the wide sensitivity ranges shown in the tornado charts – and they materially affect both the magnitude and timing of value at risk across all scenarios.
- Value impacts (which are in present value terms) tend to be larger in Scenarios 2 and 3, as under-recovery persists over a longer period relative to Scenario 1, where gas infrastructure ceases operation around RY40. Between the two steady-state scenarios, impacts are higher in Scenario 2 than in Scenario 3, reflecting higher delivered gas charges and earlier binding of willingness-to-pay constraints in the absence of lower-cost alternative gas supply.

FIGURE C-1: SENSITIVITY OF VALUE AT RISK TO KEY INPUTS (GREEN = LOWER REVENUE AT RISK, RED = HIGHER REVENUE AT RISK)

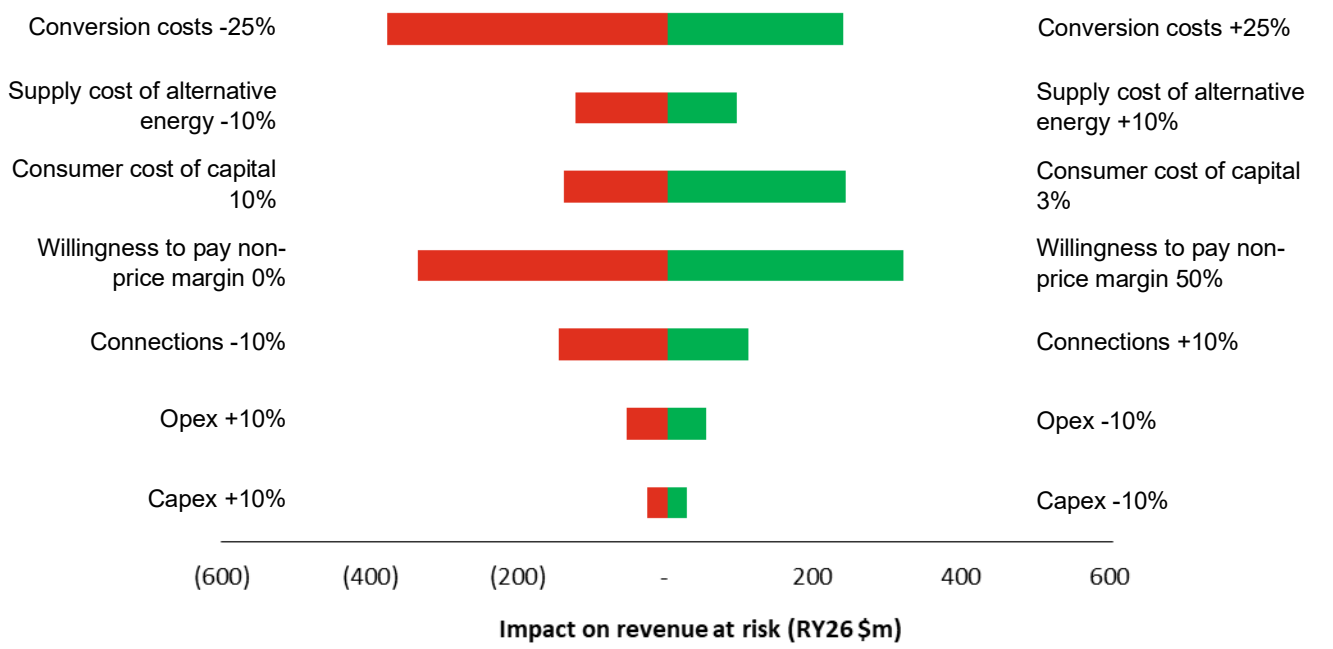
Scenario 1: Supply driven winddown



Scenario 2: Demand retreat to smaller network



Scenario 3: Renewable gas / LNG import



C.2.2. What happens to the point in time when net cash flows become negative

Building on the analysis in section C.2.1, Table A.5.1 assesses how the timing for when net cash flows (after debt costs and tax) become negative change in response to changes to the same key modelling inputs.

It shows that:

- In Scenario 1, variations in the tested inputs have little effect on the year in which the combined businesses move into negative cash flow. This reflects the sharp and rapid deterioration in cash flows under a supply-driven winddown, where outcomes are dominated by the timing of exit rather than marginal changes in assumptions.
- In Scenarios 2 and 3, sensitivities have a more pronounced effect on cash-flow outcomes. Again, assumptions related to willingness to pay materially influence results, as net cash flows in the base case only fall marginally below zero. Small changes in these inputs are therefore sufficient to delay or accelerate the point at which cash flows turn negative.

TABLE C.2.1: SENSITIVITY OF NET CASH FLOWS TO KEY INPUTS

	Year that net cash flows after interest and tax first go negative		
Sensitivity	**Scenario 1**	**Scenario 2**	**Scenario 3**
Base case (no sensitivity)	**RY38**	**RY43**	**RY44**
Capex: -10%	RY38	RY43	RY44
Capex: +10%	RY38	RY43	RY44

	Year that net cash flows after interest and tax first go negative		
Sensitivity	**Scenario 1**	**Scenario 2**	**Scenario 3**
Base case (no sensitivity)	**RY38**	**RY43**	**RY44**
Opex: -10%	RY39	RY44	RY46
Opex: +10%	RY38	RY41	RY43
Consumer connections: +10%	RY38	RY44	RY46
Consumer connections: -10%	RY38	RY41	RY43
Willingness to pay margin for non-pricing factors: 50%	RY39	None	None
Willingness to pay margin for non-pricing factors: 0%	RY38	RY40	RY41
Average consumer cost of capital: 10%	RY39	None	None
Average consumer cost of capital: 3%	RY38	RY41	RY43
Supply costs of alternative energy: +10%	RY38	RY44	RY46
Supply costs of alternative energy: -10%	RY38	RY41	RY43
Conversion cost: 25%	RY39	None	None
Conversion cost: -25%	RY38	RY40	RY41

C.2.3. Accelerated depreciation

The Model also includes functionality to test alternative depreciation options. This section explores how these options affect projected RAB, consumer charges, and value at risk. The options differ only in how accelerated depreciation is applied or unwound in time; all other assumptions are held constant.

The three options are:

- **Base case: continue DPP4 accelerated depreciation –** the accelerated depreciation approach applied in DPP4 is assumed to continue beyond DPP4.[23]
- **No DPP4 acceleration (remaining lives reset at DPP4)** – accelerated depreciation is not applied in DPP4. Remaining asset lives at the end of DPP3 are rolled forward into DPP4, removing the step-change associated with DPP4 accelerated depreciation. Depreciation allowances, revenues, and cashflows are therefore lower in DPP4 than under the base case, with longer remaining lives carried into later periods.[24]
- **Revert to pre-acceleration asset lives (DPP2 basis) – a**ccelerated depreciation applied in earlier DPP decisions is fully unwound. At the start of DPP4, remaining asset lives are reset to what they would have been had accelerated depreciation not been applied since DPP2 (i.e. original asset lives less elapsed years). This results in lower depreciation and revenues in DPP4, but relatively higher depreciation and cashflows later in the asset life.

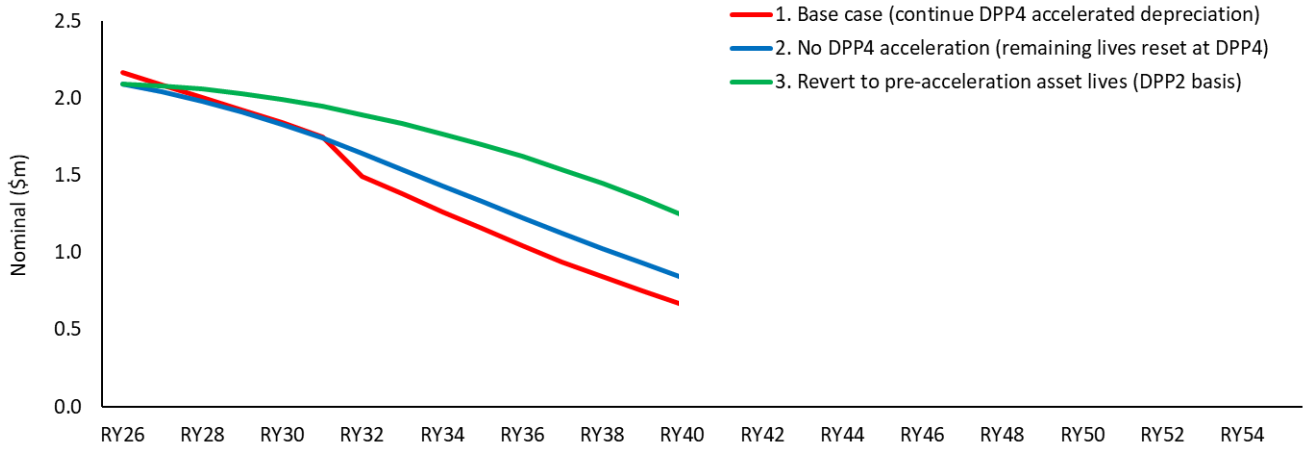
[23] Remaining asset lives are adjusted to avoid an abrupt exhaustion of the asset base, resulting in a smooth decline in depreciation, revenues, and cashflows over time. This means that, in practical terms, we assume existing assets depreciate by slightly less than one year per year going forward. This mirrors the treatment applied during DPP4 following the larger step-down in asset lives applied in the first year of DPP4

[24] A smoothed depreciation trajectory within DPP4 is still applied, consistent with the base-case treatment.

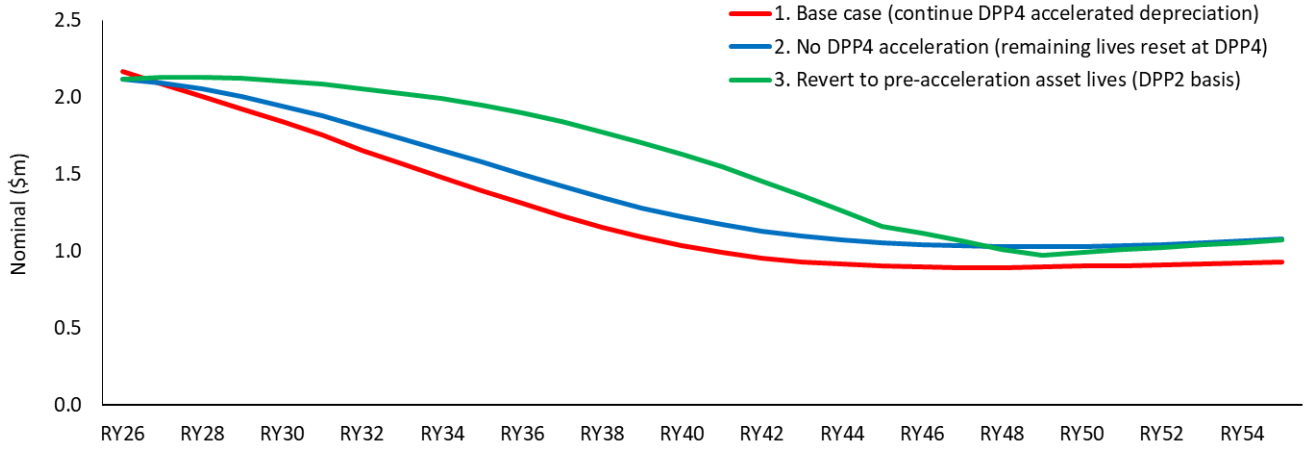
Figure C-1 illustrates how the alternative depreciation options affect the combined (distribution and transmission) RAB profile across market scenarios. Option 2 (no DPP4 acceleration) produces outcomes that broadly lie between the base case and Option 3 (reversion to pre-acceleration asset lives).

FIGURE C-1: SENSITIVITY OF RAB PROFILES TO DEPRECIATION OPTIONS

Scenario 1: Supply driven winddown



Scenario 2: Demand retreat to smaller network



Scenario 3: Renewable gas / LNG import

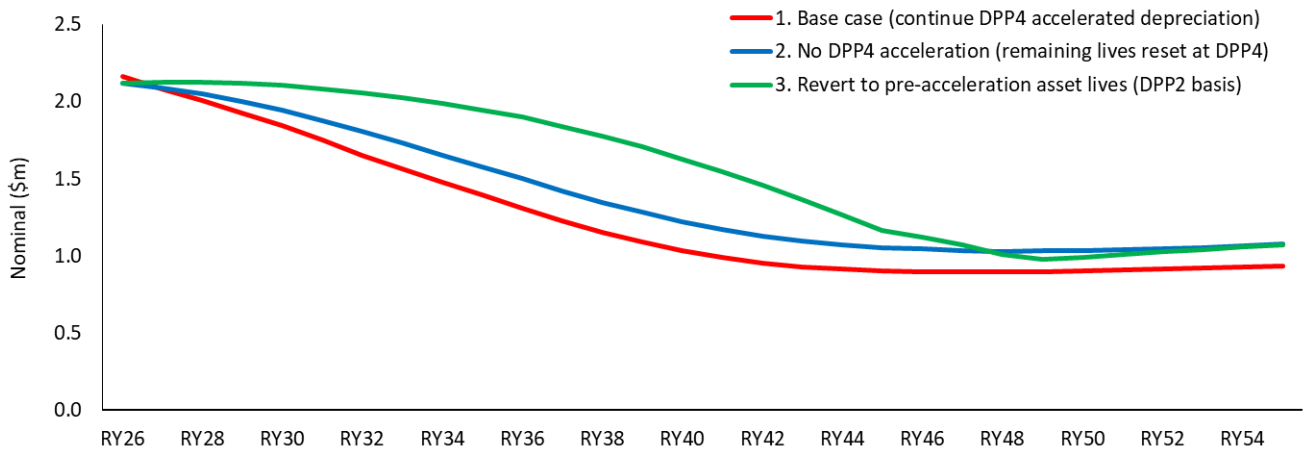


Table A.5.1 below shows the impact of the alternative depreciation options on total value at risk (across both transmission and distribution). Option 3 results in materially higher value loss, particularly in Scenario 1, where the system winds down by RY40 and there is less time to recover the existing RAB. Option 2 sits between Option 3 and the base case.

These results are as expected. As volumes decline, costs per consumer increase, and charges eventually become constrained by willingness-to-pay limits. This creates a finite window over which infrastructure owners can recover the costs of the existing asset base.

TABLE C.2.2: SENSITIVITY OF VALUE AT RISK TO DEPRECIATION OPTIONS

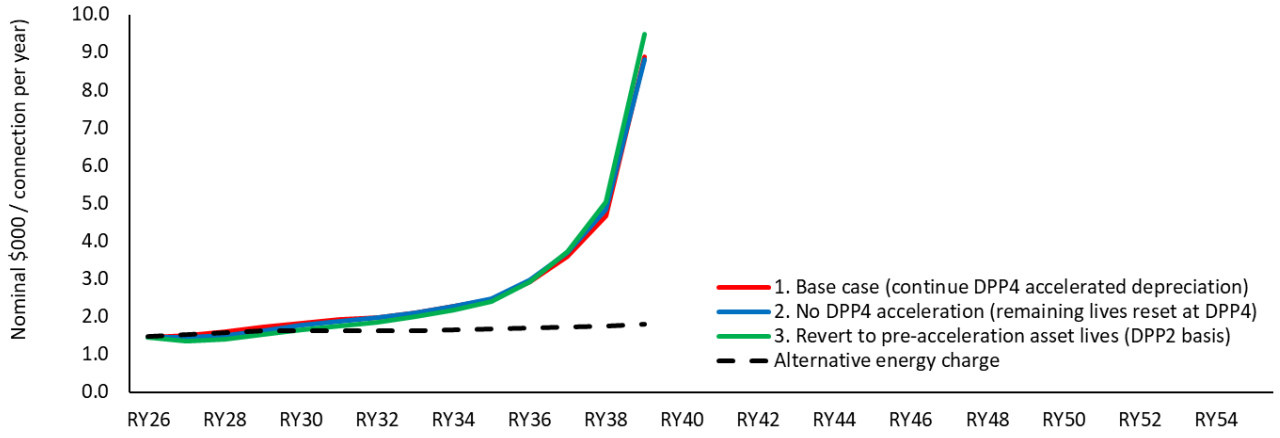
	Total value at risk (RY26 $m)		
Depreciation option	**1. Supply-driven wind-down**	**2. Demand retreat to a smaller network**	**3. Renewable gas and/or LNG import**
1. Base case: continue DPP4 accelerated depreciation	801	1,012	619
2. No DPP4 acceleration (remaining lives reset at DPP4)	856	1,022	645
3. Revert to pre-acceleration asset lives (DPP2 basis)	975	1,076	741

Figure C-1 illustrates how alternative depreciation options affect charges for delivered gas to residential customers. The results indicate that the impact to consumer charges of maintaining accelerated depreciation DPP4 over the near term is relatively small, especially relative to the differences in value at risk. This is especially so for scenario 1, where the significant reduction in volumes leads to a rapid increase in consumer charges, which largely overshadows the impact of accelerated depreciation.

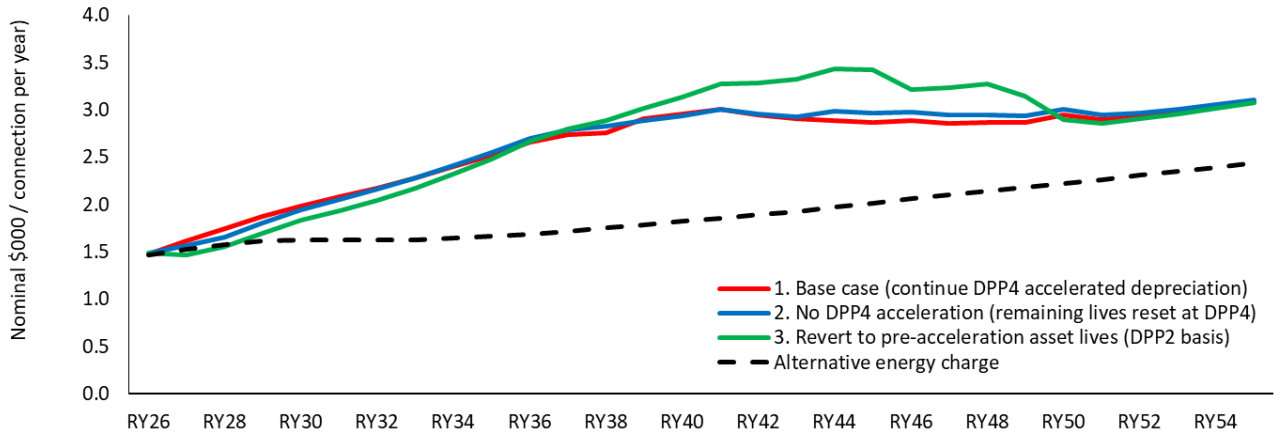
In scenarios 2 and 3, reverting to pre-acceleration asset lives (i.e., option 3) is predicted to lead to a meaningful increase in consumer charges over the RY38 to RY50 period. This suggests that adopting accelerated depreciation for DPP3 has helped mitigate potential price increases in either of those two demand retreat scenarios eventuate. The figure also shows that the impact of choosing between options 1 and 2 under those two scenarios are relatively small.

FIGURE C-1: SENSITIVITY OF RESIDENTIAL DELIVERED GAS CHARGES TO DEPRECIATION OPTIONS

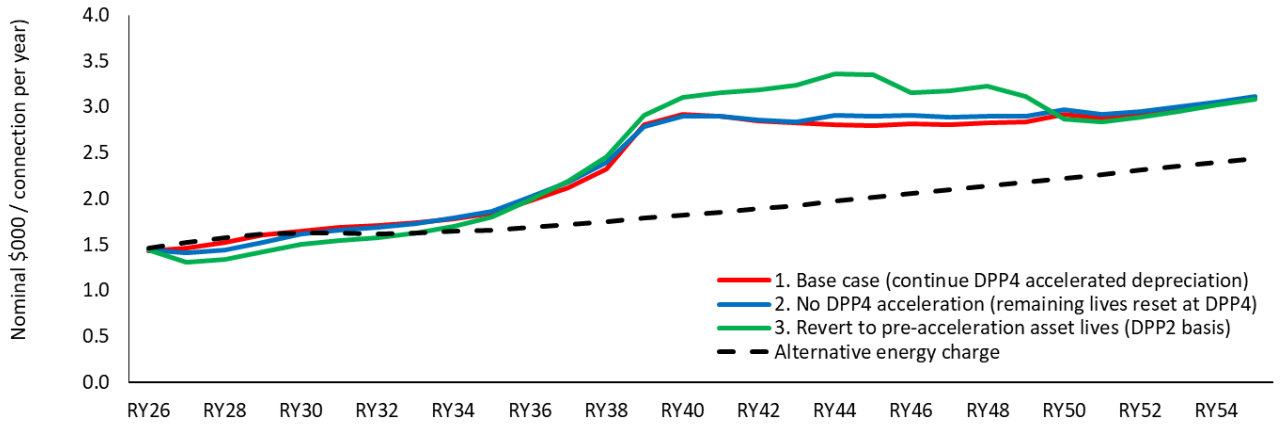
Scenario 1: Supply driven winddown



Scenario 2: Demand retreat to smaller network



Scenario 3: Renewable gas / LNG import



APPENDIX D. EARLIER WORK

D.1. Introduction

This appendix summarises earlier work undertaken by the Working Group that is relevant to the Refreshed Analysis Paper.

D.2. Findings Report

The Findings 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.

D.3. Initial and Further Analysis Papers

The Initial and Further Analysis Paper 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 made 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.

D.4. Gas Transition Analysis Paper

The Gas Transition Analysis Paper updated the earlier modelling to consider four alternative gas transition scenarios, which reflected alternative future configurations of the New Zealand's reticulated gas infrastructure.

At the time, the MBIE and the Gas Industry Company (GIC) were consulting on a proposed Gas Transition Plan. GIC asked the Working Group to update the modelling used for the Initial and Future Analysis Papers to incorporate more recent information and to test the alternative scenarios.

The analysis presented results and made preliminary findings on four interrelated questions:

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

The work reported on in the *Gas Transition Analysis Paper* was submitted to MBIE and GIC to consider as part of their consultation on the draft Gas Transition Plan.

APPENDIX E. GLOSSARY AND ABBREVIATIONS

Term	Definition
BBAR	Building Blocks Annual Revenue
CPI	Consumer Price Index
DPP	Default Price Path
GDPs	Gas Distribution Businesses
GJ	Gigajoules
GPBs	Gas Pipeline Businesses
GTP	Gas Transition Plan
GIC	Gas Industry Company
LNP	Liquified 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