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COMMERCE COMMISSION NEW ZEALAND
Te Komihana Tauhokohoko

Gas DPP4 reset 2026

Default price-quality paths for gas pipeline businesses from 1 October 2026

Draft decision - reasons paper

27 November 2025

Associated documents

Publication date	Reference	Title
27 November 2025	ISBN 978-1-991414-35-9	[DRAFT] Gas Transmission Services Default Price-Quality Path Determination 2026
27 November 2025	ISBN 978-1-991414-34-2	[DRAFT] Gas Distribution Services Default Price-Quality Path Determination 2026
27 November 2025	ISBN 978-1-991414-37-3	Gas DPP4 - Proposed amendments to input methodologies for gas transmission services - Draft decision reasons paper
27 November 2025	ISBN 978-1-991414-33-5	[DRAFT] Gas Transmission Services Input Methodologies Amendment Determination (No.1) 2026
24 November 2025	-	Gas DPP4 - Notice of Intention for potential amendments to the Input Methodologies for Gas Pipeline Services
26 June 2025	ISBN 9798-1-99-133263-9	Gas DPP4 reset 2026 - Five-year regulatory period - Draft decision paper
26 June 2025	ISBN 978-1-99-133264-6	Gas DPP4 – Issues paper
13 February 2025	-	Open letter on Gas DPP4 2026 price-quality path reset
13 December 2023	ISBN 978-1-99-108565-8	Report on the IM Review 2023 - Part 4 Input Methodologies Review 2023 - Final decision
13 December 2023	ISBN 978-1-99-108566-5	Financing and incentivising efficient expenditure during the energy transition topic paper - Part 4 Input Methodologies Review 2023 - Final decision
13 December 2023	ISSN 1178-2560	Gas Transmission Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 36
13 December 2023	ISSN 1178-2560	Gas Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 37
31 May 2022	ISBN 978-1-99-101206-7	Default price-quality paths for gas pipeline businesses from 1 October 2022 - Final reasons paper
31 May 2022	ISSN 1178-2560	Gas Transmission Services Default Price-Quality Path Determination 2022 [2022] NZCC 20
31 May 2022	ISSN 1178-2560	Gas Distribution Services Default Price-Quality Path Determination 2022 [2022] NZCC 19

Contents

Executive summary

X1 This paper presents for consultation our draft decision on the default price-quality path (**DPP4**) for gas pipeline businesses (**GPBs**) that will apply from 1 October 2026. Our decision, once finalised, will apply to Firstgas Transmission as the sole gas transmission business (**GTB**) and Firstgas Distribution, GasNet, Powerco and Vector as the gas distribution businesses (**GDBs**).

X2 We regulate the gas pipeline businesses because they are natural monopolies, with the aim under Part 4 of the Commerce Act (**the Act**) of promoting the long-term interests of consumers. We ensure GPBs have incentives to innovate, invest, improve efficiency, and provide services at a quality that reflects consumers' demands, sharing efficiency gains with consumers through lower prices, and being limited in their ability to extract excessive profits.

X3 Our draft decision for DPP4 includes revenue limits (capping the revenue of the GTB and the weighted average price for GDBs) and sets minimum quality standards for services to consumers.

X4 Our draft decision is summarised in 'Decisions at a Glance' on page 7. Chapters 1-3 of this paper present our role, the context for this reset, and discuss our decisions. The attachments contain details and analysis to support our draft decisions. Information on how to provide submissions, and our process from here, are in Chapter 1.

Overview of key decisions

Our draft decision provides a stable regulatory setting

X5 Taking into account the rapidly evolving nature of New Zealand's gas sector, we have largely continued the approach we took at the last reset (DPP3 in 2022) and seek to provide stable regulatory settings which can accommodate possible developments in the sector.

There is ongoing demand for pipeline services amid sector change

X6 The long-term outlook, similar to the outlook when we last reset the price-path in 2022, is for a significant reduction in gas consumption over the coming decades. Despite domestic gas production declining faster than the market expected, we see ongoing appetite for gas from households, businesses and power generation for at least the next 20 years. This presents an ongoing critical need for reliable gas pipeline services.

The allowances we are setting support ongoing investment to maintain safe and reliable gas transport

X7 The price-paths in our draft decision provide allowances for the pipeline businesses to maintain services currently delivered, and retain the current quality standards the businesses must meet. In line with GPBs' own forecasts of slowly declining connection numbers and gas volumes in the next five years, we have not allowed for growth costs. We expect GPBs to increasingly focus on ensuring new connections pay their way and do not impose costs on the existing consumer base.

We are have kept the same industry scenarios to set regulatory asset lives

X8 The long-term outlook of declining gas use presents a risk for GPBs – that they may not expect to fully recover the costs of their investments. We have mitigated this risk using the same industry scenarios we used in DPP3 to adjust asset lives – aligning them with economic asset lives and bringing forward some cost recovery to DPP4 as a result.

X9 This supports GPBs' incentives to continue investing in their networks to meet current and future needs of consumers. In reaching our draft decision on the extent of asset life shortening, we have weighed short-term affordability concerns against the potential for longer-term escalating prices if costs were instead deferred to be spread over a smaller future customer base. Adjusting depreciation to reflect economic asset lives achieves a fairer distribution of total costs over current and future users by flattening projected real prices.

We expect our draft decision to result in relatively modest increases on most residential bills

X10 Transmission and distribution pipeline charges together comprise about one-third of a residential gas bill. The estimated average impact of our draft decision on residential bills, excluding inflation, is a price increase of less than 2% over two years. On Vector's Auckland network, the estimated average bill increase, excluding inflation, is about 8% spread over the first two years of the period.

X11 For most GPBs, accelerated depreciation costs are offset by reductions in other expenditure allowances; Vector has already largely made these other cost reductions. This means Auckland network prices are relatively low currently and there is less scope to limit a short-term increase.

Issues raised by consumer and industry stakeholders to be addressed outside of DPP4

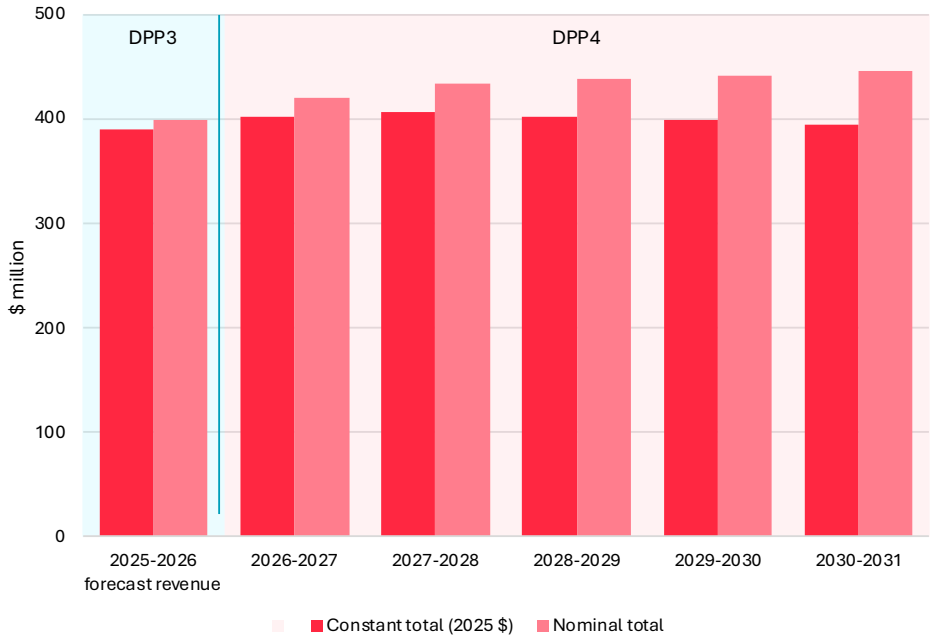
X12 Our draft decision has been informed by submissions and engagements with a range of consumer and industry stakeholders. Issues raised by them that we plan to address but fall outside the DPP process include consumer disconnections and network rightsizing.

Maximum allowed revenues in our draft decision

X13 A key overall outcome of our draft decision is the profile of maximum allowed revenue (**MAR**) for each GPB for each year in the regulatory period.

X14 Figure X1 below shows the total maximum allowable revenues, for all GPBs combined. On a real basis (ie, constant 2025$) the red bars show a small step up from our forecast for the last year of DPP3 period (2025/2026) to the first year of DPP4. The MAR profile is then almost flat. The year-on-year increase in nominal values shows the effect of forecast inflation.

Figure X1 Total maximum allowable revenue in each year of the regulatory period ($ million)



X15 Table X1 splits out the nominal MAR profiles for each GPB.

Table X1 Maximum allowable revenues in each year of the regulatory period ($ million, nominal)

GPB	2025/2026 forecast revenue	2026/2027	2027/2028	2028/2029	2029/2030	2030/2031
Firstgas Transmission	204.5	214.8	219.1	223.5	228	232.6
Firstgas Distribution	42.9	44.9	44.9	44.6	44.3	43.7
GasNet	6.5	6.6	6.7	6.8	6.9	6.9
Powerco	77.8	79.2	80.2	81.2	82.1	82.7
Vector	67.4	74.7	82.6	81.7	80.9	79.9
Total	**399.0**	**420.3**	**433.5**	**437.9**	**442.1**	**445.9**

Gas DPP4 Draft Decisions at a glance

Change relative to Gas DPP3 final decision:	Unchanged	Update or change to input	Change of policy or implementation

#	Policy measure
Price path	
P1	Set starting prices on the basis of current and projected profitability of each GPB using a building blocks allowable revenue (BBAR) model.
P2	Set a default rate of change relative to CPI (X-factor) of 0%.
P3	Set alternative X-factors where the initial price shock is greater than 10% in real terms.
P4	Adopt relevant GTB price path implementation details from the EDB DPP4 determination.
P5	Do not introduce uncertainty mechanisms to manage demand risk.
P6	Use forecasts of gas demand by consumer group that align with GDBs' forecasts of gas demand and installation control point (ICP) numbers to forecast constant price revenue growth (CPRG)
P7	Set a 'revenue smoothing limit' at 10% above the CPI-X rate of change for the GTB and specify the revenue smoothing limit with reference to the sum of forecast net allowable revenue for the current year and forecast recoverable costs for the previous year, with adjustments to preserve the revenue path for forecast net allowable revenue and for CPI.
Addressing economic network stranding risk	
A1	Maintain our focus on supporting GPBs' incentives for continued investment to satisfy long-term demand by gas pipeline consumers, through mitigating economic network stranding risk.
A2	Complete the transition to shorter regulatory asset lives that we started in DPP3 – to better reflect economic asset lives and support allowable revenues under our building blocks (BBM) framework consistent with a credible revenue recovery trajectory.
A3	Estimate the extent of asset life shortening in DPP4 for each GPB by rolling over the 2050 and 2060 industry wind-down scenarios in our stranding model from DPP3 (with their 33:67 weightings) and updating input cost variables and other technical parameters.
Operating expenditure	
O1	Assess the reasonableness of a GPB's opex forecasts by comparison to a Base-Step-Trend (BST) model, and apply the lower of either outcome for each assessment period.
O2	Set the disclosure year 2024 as the base year for all GPBs for the purpose of BST modelling, with removal of non-recurring amounts.
O3	Approve step changes which were assessed as appropriate, against a set of factors to inform our judgement as to whether the step changes are: (a) significant; (b) adequately justified with reasonable evidence in the circumstances; (c) not captured in the other components of the DPP allowance; (d) a driver outside the control of a prudent and efficient supplier; and (e) widely applicable

Change relative to Gas DPP3 final decision:	Unchanged	Update or change to input	Change of policy or implementation

#		Policy measure
O4		Escalate opex using the all-industries labour cost (60% weighting) and a producers' price (40%) indices with no adjustment to reflect GPB-specific inflation.
O5		Set a partial productivity factor of 0%.
O6		Use each GPB's own projections of ICP growth.
O7		Scale base opex for forecasts of network length and ICP growth based on historical relationship of network length to ICP growth, applying a floor of 0% in scaling network length change from ICP change.
O8		Update the elasticity factor based on the most recent available New Zealand gas supplier data.
Capital expenditure		
C1		Use the lower of each GPB's 2025 Asset Management Plan (**AMP**) forecast or the historical average (2020-2024), assessed for each year on a category-level to forecast asset replacement and renewals, non-network and reliability, safety and environment capex.
C2		Not provide for any system growth capex.
C3		Cap consumer connection capex at the lower of AMP forecast net of capital contributions or 20% of gross consumer connection capex for each year.
C4		Include an allowance for the cost of finance, scaled in proportion to the capex allowance.
C4		Apply the New Zealand Institute of Economic Research's (NZIER's) most recent Capital Goods Price Index (CGPI) inflator series to convert real $2025 capex to nominal values, with no additional adjustment.
Other inputs to the financial model		
M1		Use a weighted average cost of capital (WACC) of 6.59%.
M2		Include an allowance for disposed assets, based on historical levels.
M3		Use base year data from 2024 Information Disclosures in our draft decisions.
M5		Include an allowance for other regulated income based on historical levels.
Quality Standards		
QS1		Retain response time to emergencies (RTE) standard for GPBs.
QS2		Retain major interruptions standard for the GTB.
QS3		Do not introduce new quality standards for GPBs.
Future issues not affecting our DPP4 draft decisions		
F1	n/a	We will consider potential network rightsizing practices in a process separate to the DPP4 reset.
F2	n/a	We are not making a specific allowance for potential future large-scale network decommissioning costs (or changing any other existing regulatory setting) in DPP4.
F3	n/a	We are deferring consideration of the depreciation treatment of non-fixed life easements.
F4	n/a	The proposed conceptual solution for addressing the impact of declining demand (identified by Greymouth Gas) is out of scope for the DPP4 reset.

Chapter 1 Introduction

Purpose of this paper

1.1. This paper sets out our draft decisions for DPP4, the default price-quality path (**DPP**) for gas pipeline businesses (**GPBs**) that will apply from 1 October 2026. We seek feedback on these draft decisions before we make our final decisions by 29 May 2026.

1.2. For DPP4 we determine the prices or revenue that regulated GPBs may recover as well as the quality outcomes the GPBs must meet, for the five years from 1 October 2026.[1]

1.3. In this paper we outline our regulatory role in the gas sector, the current context of the gas industry, our consideration of key issues – including what we heard in submissions on our earlier Issues paper – and the analysis and reasons behind our draft decisions.

1.4. We welcome feedback on our draft decisions from all interested parties. Submissions are due by 5pm Thursday 22 January 2026, and cross-submissions are due by 5pm Thursday 12 February 2026.

Our role in the gas industry

1.7 The Commerce Commission's role includes the regulation of natural monopolies. Under Part 4 of the Commerce Act (**the Act**), we are responsible for price-quality (**PQ**) regulation of the gas pipeline services provided by Gas Transmission Businesses (**GTBs**) and Gas Distribution Businesses (**GDBs**), collectively known as Gas Pipeline Businesses (**GPBs**). Their customers are gas suppliers, retailers and large industrial users.

1.8 The transport of gas by pipelines are the only components of the gas industry where we have this type of regulatory role. We have no such role in gas exploration, production, or metering, nor in the sale of gas in either bilateral contracts, the wholesale 'spot' gas market or by gas retailers.[2]

1.9 The production of gas for use by customers begins with exploration, extraction, and processing. Gas producers located around Taranaki process gas for general use, then the gas is injected into high-pressure transmission pipelines (Firstgas) that stretch throughout the North Island.[3]

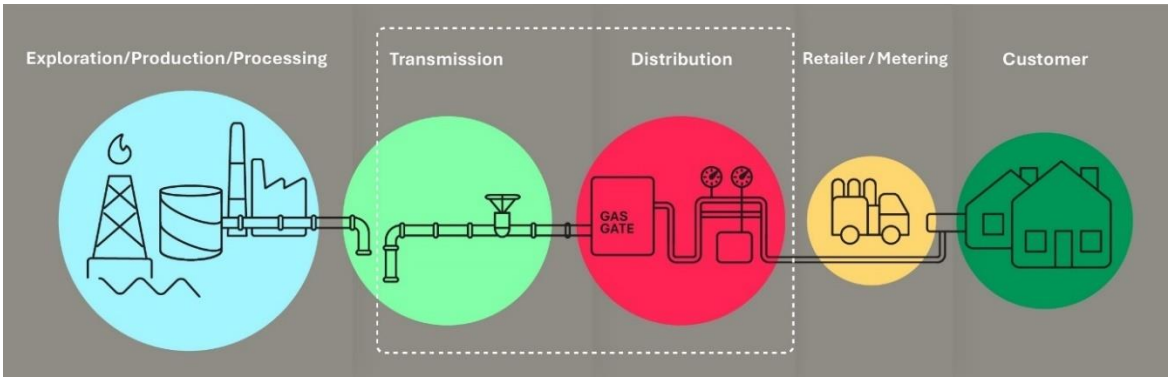
[1] Our draft decision is to implement a 5-year regulatory period. This draft decision is set out in a standalone early draft-decision reasons paper, available at Commerce Commission "Gas DPP4 – Five-year regulatory period draft decision reasons paper" (26 June 2025).
[2] Noting that the Commission's wider Fair Trading and Competition functions do apply.
[3] In this paper, 'gas' refers natural gas (i.e., primarily methane) unless otherwise stated.

1.10 Large gas customers (e.g., Methanex, Huntly power station) may connect to the transmission system directly, while local gas pipeline businesses (i.e., GasNet, Firstgas Distribution, Powerco and Vector) transport gas from the high-pressure transmission system to homes and businesses.

1.11 Gas producers sell natural gas either to retailers, or directly to large industrial users under bilateral contracts. In New Zealand, a significant share of gas is consumed by major industrial customers that have traditionally bought gas from producers under long-term contractual arrangements. Gas retailers purchase wholesale gas from producers and contract with the gas transmission operator (Firstgas Transmission) and local gas distribution businesses to transport gas from production injection points through to smaller commercial customers, businesses, and households.

1.12 Figure 1.1 below provides an illustration of the natural gas supply chain.

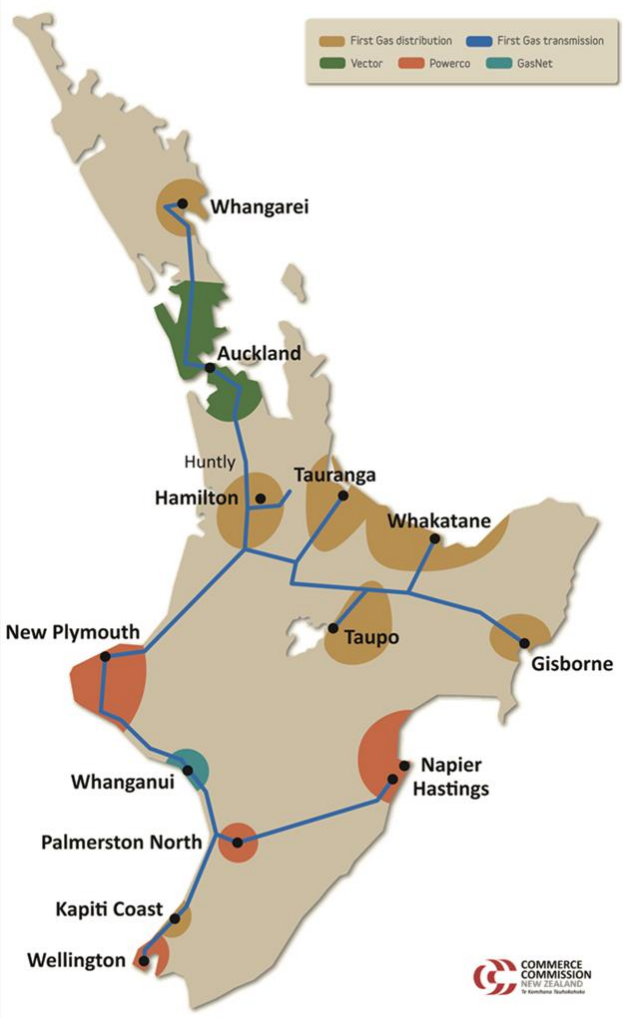
Figure 1.1 Components of the gas sector. The Commerce Commission regulates only the Gas Transmission Businesses (GTB) and Gas Distribution Businesses (GDBs).



1.13 As shown in Figure 1.2 below, Firstgas is the only GTB and owns and operates the high pressure gas transmission pipelines. Firstgas also has a distribution business, and the other GDBs are GasNet, Powerco and Vector.[4]

[4] Firstgas is regulated under DPP4 as both the GTB and as a GDB. Under an acquisition currently under review by the Overseas Investment Office, the Canada-based global investment firm Brookfield Asset Management would take ownership of Firstgas from present owners, Clarus. This acquisition in itself would not change how Firstgas is regulated under DPP4.

Figure 1.2 Map and ownership of regulated gas pipelines in New Zealand



We set DPPs as part of price-quality regulation of gas pipeline services

1.14 Our role is to provide GPBs with incentives that promote the long-term benefit of consumers. In doing so, we are guided by our responsibilities under Part 4 of the Act. Specifically, our regulation aims to provide GPBs with incentives to innovate, invest, improve efficiency, and provide services at a quality that reflects consumers' demands, sharing efficiency gains with consumers through lower prices, and being limited in their ability to extract excessive profits.

1.15 The DPP includes revenue limits (capping the revenue of GTBs and the weighted average price for GDBs) and sets minimum quality standards for services to consumers. Our setting of the DPP must comply with the Gas Input Methodologies (**IMs**), and our draft decisions reflect our application of these IMs in the current context for DPP4.[5]

1.16 That context includes a downturn in gas production, and an outlook of declining gas consumption. Volumes of gas conveyed in gas pipelines are expected to fall in the future. As we have heard in submissions on our Issues paper and in consumer engagement, this presents risks and concerns to both GPBs and consumers.

1.17 We set Gas DPP3 in 2022. In light of the uncertain outlook at that time, we decided on a shorter, 4-year regulatory period. We also shortened asset lives, which accelerated the depreciation of these assets, meaning GPBs were able to bring forward the recovery of some of their capital costs.

1.18 For Gas DPP4 our focus is setting a price-quality path which is fit-for-purpose for the next five-year period and considers the longer-term outlook. We understand the value of a predictable regulatory regime.

The GPB revenues we set are one component of consumer gas prices

1.19 In reaching our draft decision we have heard and considered consumer concerns around pricing. Our DPP4 decisions relate to gas transmission and distribution charges, which contribute about one-third of a residential user's bill. Our decision does not relate to the other underlying components of gas bills, including the wholesale gas price, metering charges and retail margin.

Structure of this paper and attachments

1.20 Chapter 1 of this paper outlines our regulatory role and the process for setting DPP4, including detail on making submissions. Chapter 2 presents the context for DPP4, and how we have approached the current outlook and uncertainty in the gas sector in making our draft decisions. Chapter 3 sets out our draft decisions, reasons, and consumer price impacts.

1.21 All technical analysis is contained within the following attachments:

Attachment A – Regulating prices and revenue

Attachment B – Forecasting capital expenditure

Attachment C – Forecasting operating expenditure

Attachment D – Addressing the risk of economic network stranding

[5] *Gas Distribution Services Input Methodologies Determination 2012* [2012] NZCC 27 and *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28.

Attachment E – Quality standards

Attachment F – Future issues not affecting our DPP4 draft decisions

Attachment G – Other inputs into the financial modelling

Attachment H – Draft Decision-making Framework

Process and timeline to our final decision

1.22 We will publish our DPP4 final decision on or before 29 May 2026. To inform that decision, we seek submissions on our draft decision. Aside from confidential information (discussed below) we will publish all submissions received.

Material published alongside this paper

1.23 Alongside this draft decisions reasons paper, we are publishing two draft determinations, two reports we commissioned from Concept Consulting on the Constant Price Revenue Growth (**CPRG**) methodology and gas demand forecasts, and the draft decision financial modelling suite.

1.24 Separately, we have published a Notice of Intention to amend the gas transmission services IMs, the draft IM amendments and a draft IM amendments reasons paper. That paper outlines the separate submissions process for the IM amendments.

Process from here and how you can make a submission

1.25 We seek feedback on our draft decision by 5pm, Thursday 22 January 2026. We are open to submissions on all parts of our draft decision, reasons and the draft determinations. A cross-submissions process will follow.

1.26 Submissions can be emailed to infrastructure.regulation@comcom.govt.nz using the subject line 'Submission on Gas DPP4 draft decision'.

1.27 Please provide both a format suitable for word processing (such as a Microsoft Word document), as well as a 'locked' format (such as a PDF) for publication on our website.

Confidential submissions

1.28 While we encourage public submissions so that all information can be tested in an open and transparent manner, we recognise that there may be cases where parties that make submissions wish to provide information in confidence. We offer the following guidance:

1.28.1 If it is necessary to include confidential material in a submission, the information should be clearly marked, with reasons why that information is confidential.

1.28.2 Where commercial sensitivity is asserted, submitters must explain why publication of the information would be likely to unreasonably prejudice their commercial position or that of another person who is the subject of the information.

1.28.3 Both confidential and public versions of the submission should be provided.

1.28.4 The responsibility for ensuring that confidential information is not included in a public version of a submission rests entirely with the party making the submission.

1.1 Please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we do not publish unless good reasons exist under the Official Information Act 1982 to withhold it. We would normally consult with the party that has provided the information before any disclosure is made.

1.2 We request that you provide multiple versions of your submission if it contains confidential information or if you wish for the published electronic copies to be 'locked'. This is because we intend to publish all submissions on our website. Where relevant, please provide both an 'unlocked' electronic copy of your submission, and a clearly labelled 'public' version.

Chapter 2 Context, challenges and priorities

Purpose of this chapter

2.7 This chapter outlines the context and challenges for DPP4, including what we have heard from stakeholders and the issues we consider to be priorities. It confirms that in setting DPP4 in light of this context, we must set a price path consistent with section 52A of the Commerce Act.[6] That is, we must promote the long-term benefit of consumers, consistent with outcomes produced in competitive markets.

2.8 It concludes with how this context has informed key elements in our approach to making our draft decisions.

Current context and challenges for the gas sector

Overview of the context for DPP4

2.9 The gas sector is in a period of change and uncertainty in the context of declining gas production and an energy transition reflecting increased electrification. Significant cost pressures are developing for consumers. In addition to safe and reliable delivery for ongoing demand, the main forward-looking issue for GPBs is how to recover capital costs in a declining market.

2.10 When we set DPP3 (2022-2026), we anticipated more clarity would emerge soon after our decision about the role of gas in New Zealand's future energy mix. In DPP3 we applied a number of new regulatory settings to help mitigate the longer-term risk of GPBs economic under-recovery to maintain their incentives for efficient investment while limiting potential for excessive profits.

2.11 Since our DPP3 decision, total production across gas fields has declined faster than anticipated.[7] Supply shocks are possible if production at major sites falls below levels required to economically support their ongoing operation.

2.12 The full effects on production and prices of Government policy changes - including reversing the ban on offshore oil and gas exploration, co-investment in new gas field development, and plans to begin a procurement process for a terminal to import liquified natural gas (**LNG**) in response to the Frontier electricity sector review - will likely take time to materialise but may bolster the longer-term supply outlook.

[6] See Commerce Act 1986 s 52A.

[7] Oil and gas reserves data released quarterly by the Ministry of Business, Innovation and Employment (MBIE) (available here) shows that natural gas reserves have been steadily declining since 2019. MBIE's July 2025 forecasts indicate that natural gas production will fall short of demand by approximately 10 petajoules annually over the next three years. This shortfall reflects both accelerated field depletion and downward revisions to reserves estimates by operators.

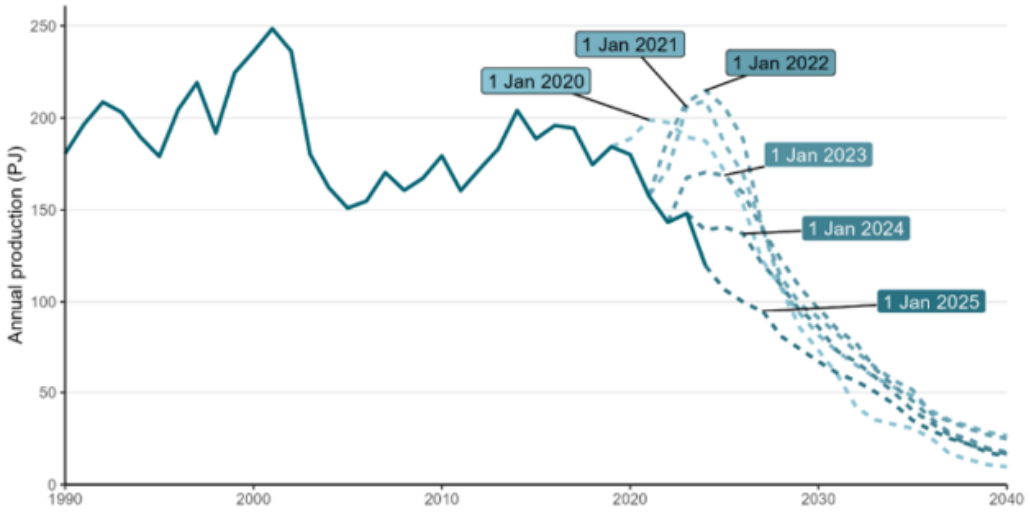
2.13 While moves to decarbonise are driving some demand reduction, gas does appear to have an ongoing role for some time in New Zealand's energy mix. Recent trends in consumption point to ongoing demand from Industrial, Commercial and Residential users. This is supported by our engagement with consumers.

Forecast supply is falling faster than expected

2.14 With no import or export facilities, New Zealand's gas production and consumption are tightly coupled. Between 1990 – 2020 total annual production - and consumption - has varied between about 150-250 petajoules (**PJ**). The average of about 180 PJ is equivalent in energy content to about 50,000 GWh, which exceeds total annual electricity demand.

2.15 As shown in Figure 2.1, forecasts for gas production have steadily fallen since 2020. In 2024 the proven plus probable (2P) natural gas reserves fell from 1,300 PJ to 948 PJ. Moreover, natural gas delivered from gas fields reduced 22% from 2023.[8]

Figure 2.1 Gas production profiles as reported from 1 January 2020 through 1 January 2025, from MBIE Energy in NZ 2025.



2.16 The recent and forecast decline in supply has increased uncertainty for gas sector participants, causing some retailers to exit the market or refuse new customers, and raising wholesale gas prices for consumers.[9]

2.17 While some onshore fields forecast ongoing reserves, the supply reduction reflects the decline of volume from New Zealand's largest producing field, the OMV-operated Maui field.

2.18 Within this context, our focus is on the future outlook for gas pipeline services. This is not a simple picture.

[8] See MBIE website.
[9] MGUG "Submission on Gas DPP4 Open Letter" (13 March 2025), para 11.

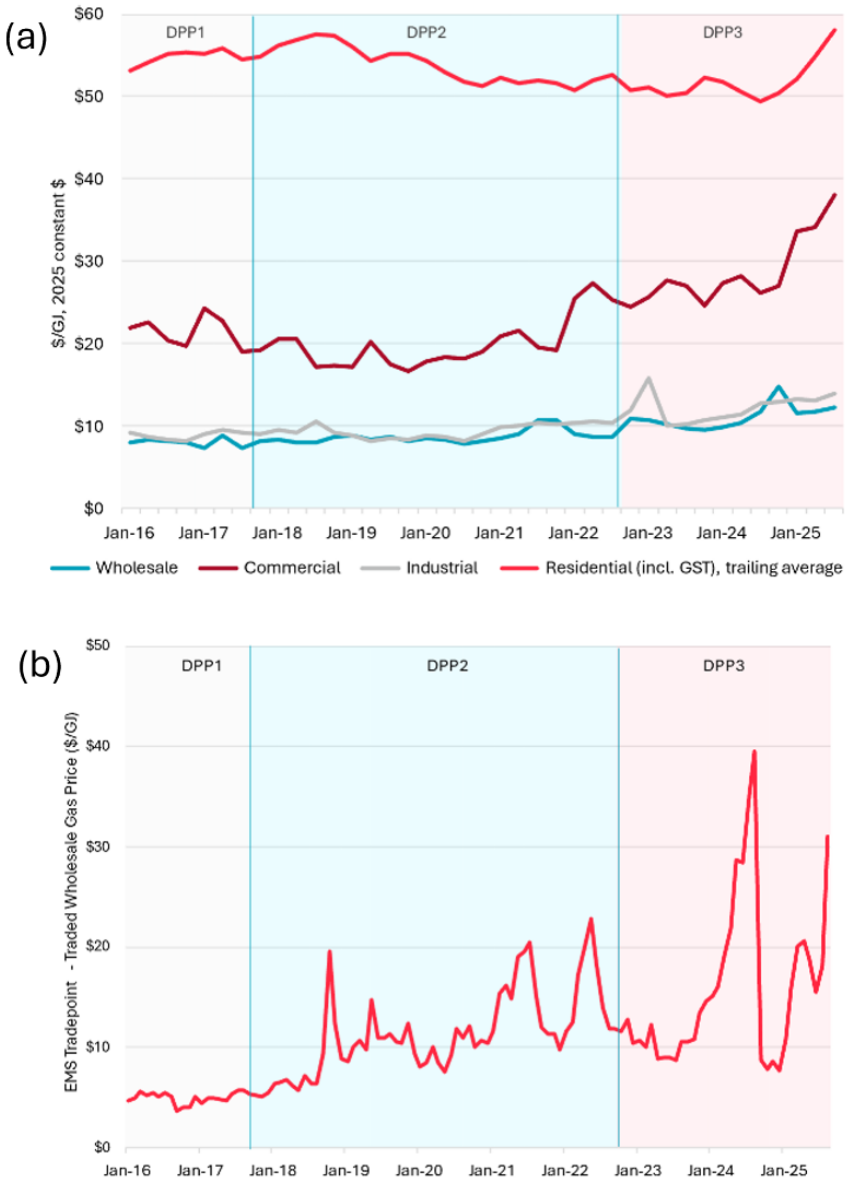
Tightening supply is impacting gas prices and use

2.19 All consumer segments are now facing gas price increases. As shown in Figure 2.2 (a), residential gas prices have generally declined in real terms since 2018 until an increase of about 20% in the first half of 2025. Further increases are signalled, with Contact Energy announcing it will raise prices by 17% from 1 December 2025. Commercial gas prices are now about double 2020 prices, in real terms.

2.20 Industrial and Wholesale prices are both up about 50% since 2020. As published by the Gas Industry Co (**GIC**), there are high price increases and volatility in the price of gas traded on the EMS platform shown in Figure 2.2(b).[10] With about 5% of wholesale gas traded on the EMS platform, this is a proxy for the marginal wholesale gas price. It shows an upward trend in recent years with high price spikes at times of increased demand for power generation.

[10] See Gas Industry Co (GIC) website.

Figure 2.2 (a) Public gas pricing from MBIE prices[11] and (b) from GIC reporting of EMS Tradepoint prices - for the 5% of wholesale market traded on the etp platform, an indication of marginal gas price for large participants.[12]



2.21 With the recent rises in the cost of living, both businesses and households are exploring ways to reduce their energy expenses. The potential for prolonged, elevated gas prices can have knock-on effects on demand, as businesses weigh up their options to reduce input costs.

[11] Residential data is a trailing 4-quarter average to smooth out seasonal variations in the MBIE data related to how fixed costs are spread over volume of gas used. The residential March 2017 residential price appears anomalous and we have replaced it with an average of March 2016 and March 2018.
[12] See Gas Industry Co (GIC) website.

2.22 Large gas users have bilateral contracts with producers. While the details of these contracts are not public, we understand that new and renewed contracts are currently priced well above previous terms and in some cases have not been available.

2.23 Several large industrial users have either scaled back or reduced/closed operations due to energy costs and energy supply issues.[13] This includes:

2.23.1 Methanex is New Zealand's largest user of gas, with two methanol production trains at Motunui and a smaller plant at Waitara Valley. The Waitara plant was mothballed in early 2021 due to insufficient gas supply, and in recent years Methanex has periodically curtailed production to release gas for electricity generation, helping to maintain security of supply during dry periods of low hydro storage.

2.23.2 Fertilizer manufacturer Ballance Agri-Nutrients' long-term gas contract with Greymouth Petroleum ended in October 2025, and after difficulty in securing an affordable replacement supply it has written down its plant value by $88 m due to uncertainty over future gas supply.[14] Greymouth is now contracted to supply Contact Energy with up to 7 PJ a year for seven years, with Contact saying it will use the gas for electricity generation and retailing.[15]

2.24 For many businesses, electrification may not be the best option due to specific industrial processes which require gas, or the costs and/or limited availability of an electric technology option.[16]

Transition to net zero and alternative uses for gas pipelines

2.25 While it is generally accepted that achieving the Government's legislated net zero 2050 target will involve a significant reduction of carbon-emitting fuels like natural gas, the pace of this reduction and the role renewable gases may play in the future of the networks is uncertain.

[13] Stuff "Taranaki methanol plant closure disappointing but not unexpected business leaders say" (24 February 2021); Oji Fibre Solutions "OjiFS Confirms Penrose Mill Closure" (18 September 2024); Oji Fibre Solutions "OjiFS Confirms Kinleith Mill Decision" (14 February 2025)

[14] Ballance Agri-Nutrients, FY25 Annual Results: Underlying earnings before tax of $38m before one-off asset write-down of $88m on the Kapuni gas-to-urea plant due to uncertain availability and affordability of future gas supply, (2025, August)

[15] Contact Energy, Media Release, Contact enters gas deal with GGNZ, 4 July 2025.

[16] Aluminium Extruders Association of New Zealand (ALENZ) "Submission on Gas DPP4 Open Letter" (12 March 2025), para 6; Fonterra "Submission on Gas DPP4 Open Letter" (14 March 2025), para 4; MGUG "Submission on Gas DPP4 Open Letter" (13 March 2025), para 13, 23; Commerce Commission "Gas DPP4 Summary of Consumer kōrero - 22 Sept 2025" (20 November 2025).

2.26 In December 2024 the Government released its second emissions reduction plan (ERP2) which signals an anticipated reduction in natural gas consumption as more current users switch to renewable energy sources.[17] However, it also indicates that gas could have a role to play in electricity generation out to 2050.[18]

2.27 ERP2 also signals a potential role for landfill gas capture, biogas and hydrogen as fuel substitutes and carbon capture, utilisation and storage (CCUS) in reducing emissions. However, the pace and scale of uptake remain uncertain, as these technologies depend on commercial viability.[19]

2.28 Recent Government policy changes have been more supportive of gas as a fuel, including removing the ban on offshore gas exploration, the $200m co-investment fund announced in the 2025 Budget for new gas fields being widened in scope to include development of existing fields,[20] and the potential development of an LNG import facility to serve our largest gas users.[21] The effects of these steps on production and gas prices will likely take time to materialise but may bolster the economic outlook for gas and gas pipelines.

Government Energy Package following the Frontier report

2.29 At the end of September 2025, the Government released a report it had commissioned by Frontier Economics on the electricity market (Frontier report) and its response (Energy Package).[22] The scope of the Frontier report and Energy Package extended to parts of the gas sector due to the use of gas in electricity generation.

2.30 Actions in the Energy Package which related to gas pipelines include:[23]

2.30.1 Improved reporting and transparency of gas reserves and production. Through publishing additional information via a public gas market dashboard, improving transparency around reserves, production, and supply-demand dynamics; and ensuring the GIC produces an annual gas supply and demand study.

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[17] Ministry for the Environment "Our journey towards net zero – New Zealand's second emissions reduction plan 2026-30" (11 December 2024)
[18] Ministry for the Environment "Our journey towards net zero – New Zealand's second emissions reduction plan 2026-30" (11 December 2024), p. 37.
[19] For examples, see Ministry for the Environment "Our journey towards net zero – New Zealand's second emissions reduction plan 2026-30" (11 December 2024) pp. 39 and 40.
[20] The $200 million Gas Security Fund, originally intended for new gas field developments, will now support a portfolio of investments, including: short-term drilling in existing fields, onshore exploration and appraisal drilling, long-term greenfield exploration beyond Taranaki and gas storage projects for energy security. 6 November 2025. See website.
[21] See Beehive website.
[22] Frontier Economics "Review of Electricity Market Performance – Final Report to Ministers & MBIE" (23 May 2025) and Ministry of Business, Innovation and Employment "At a glance: New Zealand's Energy Package" (1 October 2025).
[23] Ministry of Business, Innovation and Employment "At a glance: New Zealand's Energy Package" (1 October 2025).

2.30.2 Calling for expressions of interest in developing LNG import infrastructure. In response to medium term security of supply issues, the government will undertake a formal procurement process for an LNG import facility. Landed gas would be conveyed in existing gas pipelines, supporting and potentially extending the expected economic lives of these assets.

2.30.3 A new framework to incentivise investment in firm electricity generation is being developed. This may include gas-fired generation, and could influence future gas demand and the future use and economics of pipeline assets.

What we have heard from stakeholder engagements

2.31 Our draft decision has been informed by stakeholder submissions on our Open letter and Issues paper. We also hosted an online technical modelling workshop with GPBs and other stakeholders, on which we received submissions.[24]

2.32 We have engaged with industry experts for a wide sectoral overview, and we have actively sought consumer perspectives by attending gas user events and initiating targeted engagements to hear directly from gas consumers of different types and sizes.[25]

2.33 Through these engagements and submissions, we have heard that the number one concern for many consumers is now affordability, overtaking reliability and security (which we measure as the quality dimensions of gas pipeline services). This includes the costs of staying with gas and the costs of transition to other energy sources.[26] We have reflected on these messages, when forming our view on the 'stickiness' of residential demand, and when making decisions, particularly around the level of allowances and smoothing of revenue profiles.

2.34 Beyond pricing, we have also heard that reducing risks from exposure to the gas market is being factored into decision-making. In announcing the electrification of its previously gas-fired Whareroa factory, Fonterra noted:[27]

We've got a long-term contract, so we were OK, but we keep a watching eye on it and I think it surprised us a little bit how quickly the gas was depleting, and as you'll appreciate, we're highly reliant on gas in the North Island ... We'd always planned to move away from gas, so if anything, this just probably accelerated some of those plans.

[24] You can find submissions on our Open Letter and Issues paper on our website.
[25] You can find summaries of recent consumer engagements on our website.
[26] Commerce Commission "Gas DPP4 Summary of Consumer kōrero - 22 Sept 2025" (20 November 2025)
[27] RNZ "Fonterra announces plans to slash fossil gas use by 38%" (29 January 2025)

Gas users' forums

2.35 We attended the Gas User Forum hosted by the NZ Business Energy Council in August 2025. This forum saw the expression of an urgent supply and cost crisis for industrial gas users, with prices more than doubling in five years and many firms facing contract expiries by 2027.[28]

2.36 Businesses warned of job losses, production cuts, and a shift back to coal or diesel as electrification remains prohibitively expensive. Industry groups called for government collaboration on short-term gas supply measures and realistic transition funding, warning that without action, New Zealand risks a 'de-industrialisation crisis' within two years.

2.37 Some specific concerns raised in a survey included:[29]

2.37.1 gas prices have surged to above $25/GJ, making operations unsustainable for many manufacturers;

2.37.2 nearly half of surveyed businesses have already cut staff or reduced production due to shortages;

2.37.3 most industrial gas contracts expire by 2027, creating a narrow window for transition planning;

2.37.4 over 40% of businesses consider that alternative fuels are not commercially viable within five years;

2.37.5 some firms face prohibitive electrification costs, eg. building 50 km of transmission lines; and

2.37.6 manufacturing businesses reverting to coal or diesel, undermining decarbonization goals and increasing emissions.

Individual conversations with a range of medium to large businesses

2.38 These messages were also reflected in individual conversations we held in August 2025 with a range of medium to large businesses, across different sectors, who described facing significant cost pressures and operational challenges due to elevated energy prices.

2.39 We took a broad approach to these conversations, exploring wider energy-related challenges. The ongoing viability of large energy users directly affects the long-term utilisation and sustainability of the gas network and, by extension, the regulatory settings that support it.

[28] See BusinessNZ Energy Council website.
[29] See BusinessNZ Energy Council website.

2.40 A summary of key messaged we heard, detailed in our published summary are:[30]

2.40.1 **Energy Dependence and Cost Pressures.** Businesses reported sharp increases in contracted gas prices, some by 50–200%, which are outpacing electricity costs and straining operations. Several businesses consider themselves locked into gas for at least the next decade and face limited options for transition due to technical and economic constraints.

2.40.2 **Contracting and Market Challenges.** Participants described a lack of supplier competition, with some receiving only one or no tenders. Spot market participation is growing but presents planning risks. Long-term contracts are preferred but not widely offered, and contract features like take-or-pay hinder flexibility.

2.40.3 **Decarbonisation and Transition Barriers.** Most businesses have implemented basic decarbonisation measures and now face costly, complex upgrades. Businesses often saw electrification as uneconomic due to grid capacity limits and process-specific requirements. Alternative fuels like biomass and biogas are seen as being constrained by availability, cost, and regulation.

2.40.4 **Policy and Network Concerns.** Businesses seek clearer, consistent government policy and better coordination across agencies. They raised concerns about network cost transparency, the risk of stranded assets and ETS costs and global competitiveness. Shrinking gas user bases may drive up costs for remaining users, threatening viability.

2.40.5 **What Businesses Want.** The businesses we spoke to are asking for transparent pricing, genuine engagement from network companies, and a cohesive, long-term energy strategy supported across political lines.

Kōrero with consumer advocates

2.41 In September 2025 we hosted a kōrero with consumer advocates to better understand how communities, especially renters, seniors, and low-income households, experience piped natural gas.

2.42 These conversations have brought to our decision the lived realities of the residential users most affected by energy affordability, particularly as future network costs are considered. Advocates shared insights into current affordability as well as financial, structural, and informational barriers that limit consumer choices and their ability to transition away from gas.

2.43 A summary of key messaged we heard, detailed in our published summary are:[31]

[30] Commerce Commission "Gas DPP4 – Summary of large gas user engagements" (07 August 2025)
[31] Commerce Commission "Gas DPP4 Summary of Consumer kōrero - 22 Sept 2025" (20 November 2025)

2.43.1 **Affordability and Consumer Experience.** Low-income households, renters, and seniors face significant affordability and structural barriers to transitioning away from gas. Recently publicised high disconnection fees (in the thousands of dollars), high daily line charges, and limited control over appliances leave many consumers 'stuck' with rising costs and few options. Energy hardship is increasing, as well as under-consumption, like avoiding hot water use, to manage bills.

2.43.2 **Housing and Appliance Constraints.** Medium-density housing and landlord decisions often lock tenants into gas use. Rushed decisions to 'replace like with like' after appliance failures tend to result in missed opportunities for electrification. Better information and financing options are needed to support transitions.

2.43.3 **Information Gaps and Confusion.** Consumers struggle with inconsistent messaging, unclear pricing, and limited access to transparent information. Vulnerable groups face digital and accessibility barriers, and many are confused about future gas supply.

2.43.4 **Barriers to Switching and Electrification.** Limited retail competition, bundled contracts, and high upfront costs make switching difficult. Prepay options for gas are unavailable, excluding some consumers entirely. Innovative financing and targeted support are needed.

2.43.5 **Equity and Transition Planning.** Residential users raised fairness concerns around bearing network costs. Participants called for a managed transition, clearer policy direction, and protection for vulnerable consumers. The lack of a formal consumer challenge mechanism in regulation was also noted.

Our approach to making draft decisions for DPP4

2.44 The legal and regulatory framework under which we have made our draft decision for DPP4 is set out in Attachment H. In practical terms, setting a price path involves the specification of maximum revenues - specified by starting prices and rates of change - and quality standards.[32] We determine these aspects by the application of the gas IMs to the prevailing context, outlined above.

2.45 In doing so we aim to provide regulatory stability and maintain consumer confidence, given uncertainty around the sector outlook. In aiming for stability, we recognise the value of flexibility in being able to respond to contingencies.

[32] Noting that the GDBs are subject to a weighted average price cap, where limits on allowed revenue during the period effectively increase (or decrease) if actual demand is higher (or lower) than expected demand. See Chapter 3 for more details.

We must promote the long-term benefit of consumers

2.46 We must set a price path consistent with section 52A of Part 4 of the Act.[33] That is, we must promote the long-term benefit of consumers, consistent with outcomes produced in competitive markets.

2.47 This means suppliers should (a) have incentives to innovate and invest; (b) have incentives to improve efficiency and provide service at a quality that reflects consumer demands; (c) share with consumers the benefits of efficiency gains, including through lower prices; and (d) are limited in their ability to extract excessive profits.

Priorities and key elements in making our draft decisions

2.48 Our approach to reaching our draft decisions for DPP4 has been informed by the challenges, policy uncertainty and affordability concerns outlined above. We also recognise that our decisions relate to only a portion of gas prices (ie, the costs of delivery through the pipeline networks), and not all aspects of the consumer experience of using gas can be addressed in our DPP4 decision.

2.49 Under the overarching requirement of the Part 4 purpose above, to make our decisions in way that promotes the long-term interest of consumers, we have identified three high-level elements in our approach at this reset:

2.49.1 **Continue to incentivise businesses to invest** to operate and maintain pipelines services at a quality that consumers demand while demand for gas exists.

2.49.2 **Consider the impacts on today's consumers and tomorrow's consumers** when profiling how the cost burden of maintaining pipeline networks and services are spread over a customer base expected to decline over time.

2.49.3 **Manage price volatility within the DPP4 period** by taking an approach to provide steady and predictable pricing over DPP4 unless there is a clear and compelling case for change.

2.50 A consequence of the current uncertainty in the wider gas sector is that material changes to the DPP4 context may happen before our final decision, including in the periods between making and publishing our draft decision, and between our draft decision and final decision. Within the constraints of our regulatory framework, we aim to consider the impact of any such changes ahead of our final decision.

2.51 Through our consultation process, we have also identified issues that we do not consider relevant to setting DPP4. However, they are issues that could become more prominent in future. These issues are summarised in the final section of Chapter 3. We are considering how we take them forward, including engaging with other agencies.

[33] See Commerce Act 1986, Part 4 s 52A.

Chapter 3 Setting revenue allowances and considering price impacts

Purpose of this chapter

3.1 This chapter summarises our draft decisions for setting DPP4 revenue allowances for the GPBs and the price impacts on consumers. It briefly discusses quality standards, which are unchanged in our draft decision from the current standards, and issues deferred to future consideration.

3.2 We note which Attachments to this paper to refer to for more details.

Overall summary of our draft decision

3.3 We have assessed the current context of the gas sector and engaged extensively with stakeholders. There is significant uncertainty over the future of the gas industry in New Zealand. But our view is that the outlook for GPBs has not materially changed in a way that would cause us to significantly change our approach to DPP4 from the approach we took for DPP3.

3.4 While we do expect change to materialise in the sector within the DPP4 regulatory period, we also expect ongoing demand for gas pipelines to deliver natural gas to homes, businesses and power generation across the North Island through the next two decades at least.

3.5 Overall, the total maximum allowed revenue (MAR) for DPP4 is a moderate increase from DPP3 on a constant dollar basis. The main increase is in depreciation, with a small increase in total opex allowances and a decrease in total capex allowances.

3.6 We have decided to use the same scenarios for asset lives that we used in DPP3 – to mitigate network stranding risk for GPBs and maintain incentives for continuing investment needed to satisfy current and future demand by users of gas pipeline networks. Shortening asset lives increases DPP4 depreciation allowances, and brings forward the recovery of some costs to DPP4.

3.7 We have contained the expenditure allowances and overall maximum revenues that pipeline businesses can recover. We have profiled this so the cost of gas transmission and distribution services per connection will be roughly flat across the DPP4 period.[34]

[34] While this is how we have approached our decision, the actual bill changes consumers experience will depend on the specific pricing changes the GPBs apply, how these are passed through by retailers, and the wholesale gas price.

3.8 Transmission and distribution pipeline charges together comprise about one-third of a residential gas bill. The estimated average impact of our draft decision on residential bills, excluding inflation, is a price increase of less than 2% over the first two years. On Vector's Auckland network, the estimated average bill increase, excluding inflation, is about 8% spread over the first two years of the period.

3.9 For the other GPBs, accelerated depreciation costs are offset by reductions in other expenditure allowances, but Vector has already largely made these other cost reductions. This means prices on Vector's Auckland network prices are relatively low so there is less scope to limit this short-term increase.

3.10 For the remaining years of DPP4, increases are limited to forecast inflation.

3.11 Quality standards are unchanged from DPP3, with the expectation that networks are maintained at current levels. After investigation, our draft decision is to not introduce any new quality standards.

3.12 We expect gas disconnections to be an emerging focus over DPP4, and we intend to collect information on disconnections and monitor outcomes.

3.13 We have identified some uncertainties beyond the DPP4 period best addressed by waiting to see how the sector evolves to enable a clearer basis for decisions - and by retaining the continuity of the current path – rather than via new measures in DPP4.

Our approach to determining price-paths for the Gas Pipeline Businesses

3.14 We are required to set maximum revenues and quality standards for each GPB for the regulatory period, as set out in s 53M of the Act. The IMs specify how we limit maximum revenues in the DPP:

3.14.1 The GDBs are subject to a 'weighted average price cap', where limits on allowed revenue during the period effectively increase (or decrease) if actual demand is higher (or lower) than expected demand.

3.14.2 The GTB is subject to a 'revenue cap', where maximum revenue limits do not change in response to changes in demand, and under- or over-recovery of revenue is recovered from or returned to consumers in later years.

3.15 The two main components of the revenue limits are:

3.15.1 the 'starting price' allowed in the first year of the regulatory period; and

3.15.2 the 'rate of change' in maximum revenues allowed relative to the consumer price index (**CPI**), that is used to adjust the revenue allowed in later parts of the regulatory period.

3.16 Our 'building block' approach to setting revenue allowances is largely in line with our approach in DPP3.[35] It includes the following main steps, detailed in Attachment A to this paper:

3.16.1 We calculate 'building block' allowable revenue amounts (**BBAR**), so that forecast revenue equal forecast costs (including the cost of capital) for each year of the regulatory period.

3.16.2 To avoid volatility in prices or revenues, we smooth the recovery of the BBAR amounts so that in present value terms, expected revenues earned over the regulatory period equate to the present value of the BBAR. We use CPI and the 'X-factor' to smooth. We may set an alternative rate of change factor to smooth the 'building blocks' revenue across the regulatory period.

3.16.3 For each GDB, we also smooth against the profile of forecast demand to set the starting price such that weighted average prices are constant, in real terms, across the period and consumers are not exposed to price increases due to variations in demand.

3.17 The building block approach results in a maximum allowable revenue (**MAR**) profile for each GPB. Table 3.1 shows the five-year time series of MAR over DPP4 for each GPB. These are set as nominal values, ie, they account for forecast inflation over the regulatory period.

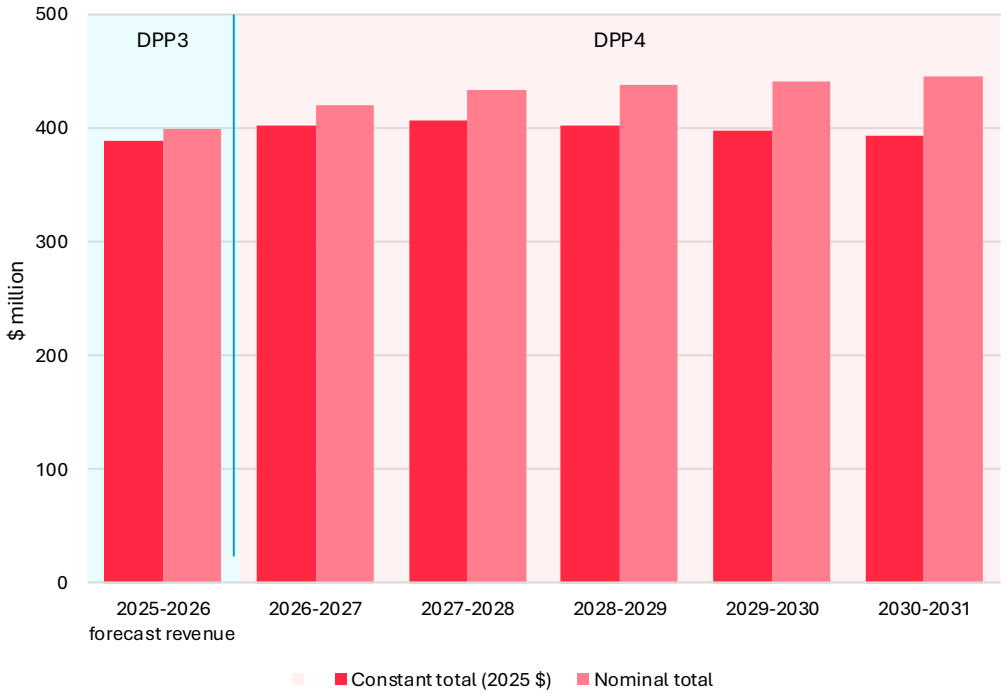
Table 3.1 Maximum allowable revenues in each year of the regulatory period ($ million, nominal)

GDB	2025/2026 forecast revenue	2026/2027	2027/2028	2028/2029	2029/2030	2030/2031
Firstgas Transmission	204.5	214.8	219.1	223.5	228.0	232.6
Firstgas Distribution	42.9	44.9	44.9	44.6	44.3	43.7
GasNet	6.5	6.6	6.7	6.8	6.9	6.9
Powerco	77.8	79.2	80.2	81.2	82.1	82.7
Vector	67.4	74.7	82.6	81.7	80.9	79.9

[35] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), Attachment A.

3.18 Figures 3.1 below shows the total MAR across all GPBs.

Figure 3.1 Total maximum allowable revenue in each year of the regulatory period ($ million)



3.19 Table 3.2 shows the starting prices and the rates of change we have determined for each GPB. Revenues are relatively flat for all GPBs apart from Vector. Table 3.2 highlights that we have used an alternative rate of change to smooth Vector's price increases over the first two years of the regulatory period. We explain how we have set Vector's alternative rate of change in the section below 'Setting rates of change for the GPBs' from paragraph 3.81.

Table 3.2 Starting prices (excluding pass-through and recoverable costs) and rate of change ($ million, nominal)

GPB	Starting price ($m)	Price increase from 2025/26	Rate of Change
Firstgas Transmission	214.8	CPI + 2.9%	CPI + 0%
Firstgas Distribution	44.9	CPI + 4.4%	CPI + 0%
GasNet	6.6	CPI - 0.1%	CPI + 0%
Powerco	79.2	CPI - 0.1%	CPI + 0%
Vector	74.7	CPI + 11.5%	CPI + 11.5% for year 2 then CPI + 0%

What is driving revenue

3.20 Parts of our revenue calculation are 'mechanical' in the sense that we are required to apply the IMs to specified inputs, for example regulatory asset base (RAB) values and forecast inflation (i.e., CPI). Other elements require decisions on implementation, for example how capex and opex allowances are set for the regulatory period.

3.21 In this section, we summarise the key factors and decisions driving revenue, including an assessment of their impacts relative to DPP3 revenues. For more details on our approach, and a discussion of the decisions we have taken in applying the BBAR method in our draft decision, please refer to Attachments A and G to this paper.

We have reduced forecast capex allowances compared with DPP3

3.22 We have considered the evolving context in determining appropriate capex allowances for the GPBs. Consistent with the relatively low-cost approach of setting a DPP,[36] we have assessed GPBs' forecast capital expenditure by category for each year against historic averages. The aggregate capex allowances we have determined are lower than what the GPBs have historically spent and what they are forecasting in their 2025 Asset Management Plans (**AMPs**) to spend over DPP4.[37]

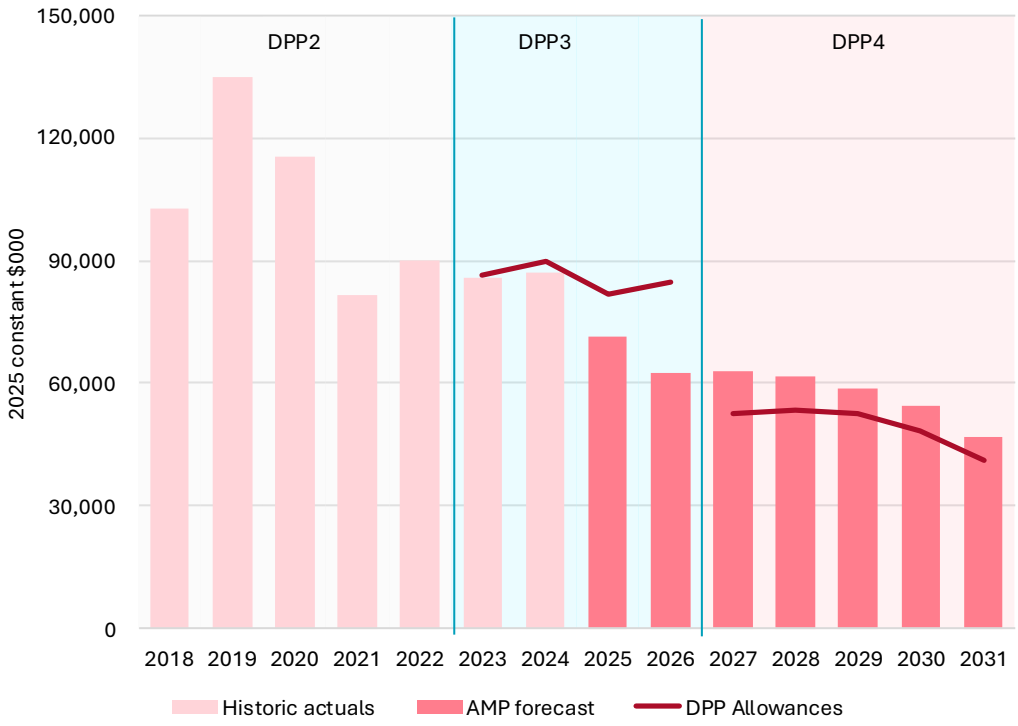
Table 3.3 Draft capital expenditure allowances (constant 2025 $'000)

GPB	GPB 2025 AMP forecast	GPB Draft allowance	Allowance as a % of 2025 AMP forecast
Firstgas Transmission	163,925	157,908	96%
Firstgas Distribution	24,274	21,410	88%
GasNet	4,905	2,483	51%
Powerco	72,032	47,207	66%
Vector	19,815	18,743	95%
Industry total	**284,951**	**247,750**	**87%**

3.23 Lower acceptance rates for some GPBs reflect AMP forecasts that are maintaining or increasing historic levels of capex, whereas higher acceptance reflect GPBs that are forecasting declining capex over DPP4. The latter is consistent with our expectations given the sector context described in Chapter 2. Figure 3.2 below shows the capex profile for GPBs.

[36] Commerce Act 1986, s 53K.
[37] GPBs' 2025 AMPs are available on their websites: Firstgas Transmission, Firstgas Distribution, GasNet, Powerco, Vector.

Figure 3.2 Comparison of industry total actual capex, AMP capex forecast and DPP allowances (constant 2025 $'000)



3.24 Given the uncertainty facing the sector, our analysis has focused on:

3.24.1 how the GPBs are considering asset replacements and renewal (ARR) investments given the GPBs are considering opex/capex substitution extending asset lives; and

3.24.2 whether connecting new customers and growing the networks is prudent in the current environment.

3.25 Expenditure within the ARR category is focused on maintaining network asset integrity to maintain current security and quality of supply. GPBs have noted their intention to move to a greater reliance on opex to defer or reduce ARR capex requirements. With different drivers on networks, forecast costs show different profiles compared to historic levels:[38]

3.25.1 Vector has clearly identified where opex solutions may reduce expected ARR spend in future years, resulting in a forecast decline in ARR for DPP4.

3.25.2 Firstgas Distribution is maintaining ARR spend at historic levels.

3.25.3 Powerco and GasNet are forecasting ARR spend above historic levels.

[38] From 2025 AMPs. GPBs' 2025 AMPs are available on their websites: Firstgas Transmission, Firstgas Distribution, GasNet, Powerco, Vector.

3.25.4 Firstgas Transmission has forecast a decline in ARR overall compared to historical periods.

3.26 We sought additional information from Firstgas Distribution, Powerco and GasNet to understand what was driving the forecasted levels of ARR capex.

3.26.1 Firstgas Distribution's 2025 AMP represents a significant increase in forecast ARR capex compared with its 2024 AMP. However, the revised level forecast is still broadly in line with historical averages. Its 2025 AMP outlines that the increase is driven by refinements to its pre-85 pipe replacement programme.

3.26.2 Powerco's significant uplift in ARR capex is in part due to resilience mitigation projects which our assessment identified were not well justified and did not clearly represent prudent and efficient expenditure.

3.26.3 GasNet did not respond to our request for information, and we have set its ARR capex forecast at its historic average.

3.27 Given the relationship between ARR capex and the opex-capex trade-off step changes within our opex framework, we have not allowed opex step-changes (sought for this reason) where we have not observed meaningful declines in forecast ARR capex.

3.28 We have decided to decline system growth capex for all GPBs. We are not satisfied that the evidence demonstrates a need to provide for system growth from any GPB. We note that all GPBs are forecasting the number of connections and gas volumes conveyed to decline over DPP4. While there may be some localised areas of growth, GPBs can seek capital contributions from the relevant parties or apply for a capacity event reopener.

3.29 We have set the forecast for consumer connection capex for Firstgas Distribution, GasNet and Powerco lower than their 2025 AMP forecasts. New customers can provide a benefit to all pipeline users as shared costs are spread across a larger customer base. However, the benefit provided by new customers can turn on the amount of upfront contribution they pay when connecting. Currently Powerco and GasNet have very low upfront capital contributions, with Firstgas Distribution showing an increasing trend. By reducing the forecast amount, we are looking to incentivise these GPBs to further consider - and evidence - that the incremental revenue exceeds incremental cost for new connections. We have not forecast any connection capex for Vector as it has moved to a full capital contributions policy where connecting parties pay all capital costs of their connection up-front.

3.30 A full discussion of our capex decisions can be found in Attachment B to this paper.

We have provided small increases in opex compared with DPP3

3.31 Opex allowances provide resources for GPBs to fund activities that are not capex, including activities essential to the network operation such as maintenance and planning.

3.32 We have used a base-step-trend (BST) approach to compare to GPBs' forecasts and have used the lower value for each year of the regulatory period to set GPBs forecast opex allowances over the DPP4 regulatory period.

3.33 The BST approach is appropriate as opex is generally related to more recurring expenditure compared with capex, which can be lumpy from year-to-year. It involves the use of opex for a recently completed year as the starting base for ongoing costs, making step adjustments for approved additional activities or to remove costs for activities no longer being undertaken, and applying trend factors to capture underlying drivers of changes in cost.

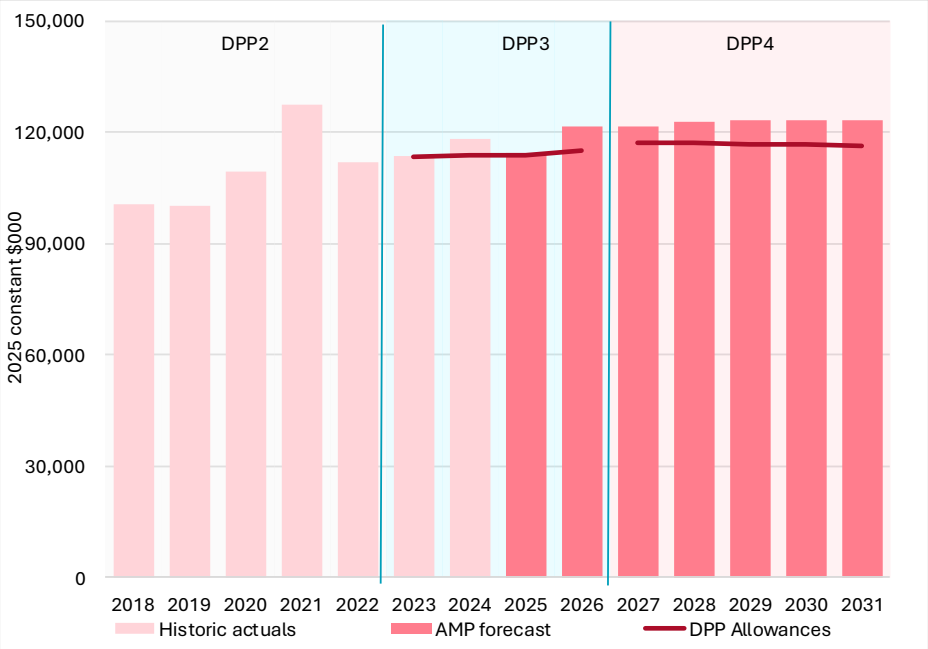
3.34 Applying this approach, we have set draft opex allowances for the GPBs over DPP4 that are between 93% and 95% of their AMP forecasts.

Table 3.4 Draft operating expenditure allowances (constant 2025 $'000)

GPB	GPB AMP forecast	GPB allowance	Allowance as a % of AMP forecast
Firstgas Transmission	326,267	311,227	95%
Firstgas Distribution	68,530	63,678	93%
GasNet	13,558	12,889	95%
Powerco	104,892	99,870	95%
Vector	101,012	96,187	95%
Industry total	**614,259**	**583,850**	**95%**

3.35 Figure 3.3 below shows the opex profile for GPBs.

Figure 3.3 Comparison of industry total actual opex, AMP opex forecast and DPP allowances (constant 2025 $'000)



3.36 Our draft decisions make a number of changes from DPP3 to better reflect the likely opex needs and cost inflation pressures affecting GPBs over the DPP4 period.

Base opex is drawn from 2024 information disclosure data

3.37 The base year sets the starting point of BST modelling used in setting opex allowances and should represent a prudent and efficient level of opex for each GPB. We have set the base year as 2024 being the latest disclosure year for which ID opex data is available. This is the best indicator of current opex costs, from which we have removed expenditure which has been identified as being non-recurring.

We have applied step changes based on our assessment against five factors

3.38 We have amended our approach from that used in DPP3 to assess step changes by using a set of factors as used in EDB DPP4.[39] The factors are:

3.38.1 significance;

3.38.2 adequately justified with reasonable evidence;

3.38.3 not captured in other components of DPP allowances;

3.38.4 a driver outside the control of a prudent and efficient supplier; and

[39] See Commerce Commission "EDB DPP4 2024 Final decision reason paper -Attachment C – Operating Expenditure" (20 November 2024).

3.38.5 widely applicable.

3.39 Assessment against these factors helps ensure only prudently incurred forecast costs are included.

3.40 We sent information requests to the GPBs seeking information on proposed opex step changes. Key adjustments that we have considered included the opex/capex trade-off and allowances for blended gas trials.

3.41 In submissions on our Issues paper, there was general agreement from stakeholders that we should focus on opex/capex trade-offs. In response to a request for information, Firstgas Distribution and Transmission, Powerco and Vector all sought a step change to provide for additional opex for opex/capex trade-offs.

3.42 We have found it difficult to establish whether there has been a corresponding specific decrease in capex related to the opex proposed in considering whether a step change was appropriate. It is challenging to directly align opex initiatives with measurable reductions in capex as the relationship between the two is complex and evolving and is not necessarily linear. Additionally, timing mismatches between when opex costs are incurred and when potential capex savings will materialise further complicates the equation.

3.43 We have decided to provide opex/capex trade-off step changes for Firstgas Transmission and Vector as we consider the step change to be in the interests of consumers. As noted in the capex section above, both GPBs have demonstrated a decrease in forecast ARR capex with an increasing reliance on opex solutions to extend asset lives.

3.44 We have not provided step changes for Powerco or Firstgas Distribution as we have not observed a decrease in forecast ARR capex when compared with historic averages.

3.45 We have also approved step changes for cyber-security (Firstgas Transmission and Distribution, Vector) and software-as-a-service (Firstgas Transmission – specified components only, Vector), although not always at the level requested by the GPB.

3.46 We have declined other step changes requested by GPBs where we considered these did not met our assessment factors and providing for them would not be in the long-term benefit of consumers. Further detail on our assessment is contained within Attachment C.

3.47 We have decided to maintain opex allowances for investigating alternative gases at the same level as DPP3 for Firstgas and Powerco. We consider that the allowances we provided in DPP3 have incentivised GPBs to undertake alternative gas investigations that may prolong the use of the pipeline networks. Maintaining this allowance for those GPBs who have clearer programmes for continued alternative gas investigation will enable them to continue trials to inject alternative gases where it is economic to do so. We have not provided for allowance for these costs for Vector and GasNet.

We have trended opex with ICP growth and forecast cost escalation

3.48 Our forecast of opex trends has three components: input prices, cost changes with scale, and productivity. We aim to forecast opex trends over the DPP4 period based on estimation of expected changes in these factors and in a way which incentivises efficiency.

3.49 The cost of maintaining and managing a network is expected to change as scale of the network changes. From analysis of historical opex data and consistent with the approach in DPP3, we have trended opex growth forward with equal weightings on forecast growth in the number of connections (ICPs) and the network length (km), as these correlate well with historical levels of opex.

3.50 GPBs forecast ICP counts but not network length, so as in our application of this approach at DPP3, we scaled network length with ICP count based on their historical relationship.

3.51 In this reset, GDBs are forecasting declining ICPs connected to their networks, particularly over later years within the DPP4 regulatory period. Our view is that unlike new ICPs which may arise from connection of new subdivisions and industrial parties and add to network length, a reduction in ICPs won't necessarily result in a reduction in network length. This is particularly so at the early stages of a transition off gas networks when disconnections may be occurring in an uncoordinated way. To address this risk, we are retaining the weightings for trending opex but implementing a floor when forecasting network length so that it does not decline with reductions in ICPs.

3.52 Cost escalator forecasts need to account for forecast cost changes relative to overall inflation – or 'real price effects'. Our draft decision is to forecast cost escalation using the all-industries labour cost (60% weighting) and producers price indices (40% weighting) with no adjustment and to apply the same cost escalator all opex costs.

3.53 We have applied an opex partial productivity factor (PPF) of 0%. This decision draws on recent trends in measured productivity, consideration of the prospect of opex-capex substitution and the wider context of a declining gas market.

We have completed the transition to shorter asset lives in DPP4

3.54 A key focus in reviewing regulatory settings at DPP4 is to ensure sufficient incentives exist for GPBs to keep investing to support safe and reliable network operations and provide gas pipeline services to meet the needs of current and future consumers.

3.55 An expectation of a long-term decline in gas use raises a concern that GPBs may recover insufficient revenues from customers over time to meet their costs and expect to make normal profits ('economic network stranding'). There is a risk this may curtail GPBs continued investment or result in other sub-optimal decisions by GPBs to the long-term detriment of consumers.

3.56 When we considered this issue in DPP3 we made decisions to shorten average gas asset lives for regulatory depreciation purposes to better align them with economic asset lives. This brought forward allowed revenues for GPBs, mitigating stranding risk and supporting ongoing investment incentives.

3.57 Our DPP3 decision assumed that the transition to shorter asset lives that mitigate stranding risk would occur over two regulatory periods, with approximately half of the transition occurring in DPP3. We said we expected to complete the transition to shorter asset lives during DPP4, subject to a fresh assessment of risk at that time.[40]

3.58 In our DPP4 consultation we heard from stakeholders about how the risks of network stranding for GPBs may have changed relative to the modelling and assessment we undertook at DPP3, with arguments for either decreasing or increasing asset lives at DPP4 to reflect this. The key factors we considered were:

3.58.1 Emergence of tighter-than-expected gas supply – recent declines in domestic gas production and lower estimated future gas reserves;

3.58.2 Continued uncertainty over government policy response to climate change and future use of natural gas; and

3.58.3 Increasing prospects for renewable 'green' gases to meet some future demand and potentially help extend the economic life of networks.

3.59 Considerable uncertainty remains about the pace at which gas usage will decline. After reviewing the available information, we concluded that although some factors contributing to network stranding risk have evolved since the DPP3 reset, the modelled scenarios we used for DPP3 remain central in the distribution of risk and are plausible and reasonable scenarios for the DPP4 context.

3.60 We have therefore decided to re-apply the network stranding model we used for DPP3, retaining its 2050 and 2060 long-term industry wind-down scenarios (and their relative weightings). We have updated the model's long-term cost variables and assumptions to reflect the latest data available (eg, regulated asset values, cost of capital, forecasts of near-term demand, and trends in long-term opex and capex).

3.61 Our draft decision for DPP4 is to apply the asset life adjustment factors in Table 3.5. The effect of this is to complete the transition to shorter asset lives that we started in DPP3.

[40] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para 6.30.2.

Table 3.5 DPP4 network stranding mitigation – draft decision ($m, nominal BBAR, all depreciable assets)

GPB	Asset life adjustment factor (2 dp)	Forecast DPP4 depreciation allowance before adjustment	Forecast DPP4 depreciation allowance after adjustment	Additional forecast depreciation in DPP4
Firstgas Transmission	0.71	303.8	425.9	122.2
Firstgas Distribution	0.68	63.1	92.8	29.7
GasNet	0.62	7.1	11.4	4.3
Powerco	0.69	122.7	177.4	54.7
Vector	0.77	126.8	164.0	37.2
Industry total		**623.5**	**871.5**	**248.1**

The long-term benefit to consumers of accelerating depreciation

3.62 Applying these asset life adjustment factors in DPP4 promotes the long-term benefit of consumers of gas pipeline services as it:

3.62.1 Promotes incentives for GPBs to continue investing, making it more likely that gas networks will remain available to satisfy consumer demand while needed (at the level of quality demanded by consumers);

3.62.2 Is NPV-neutral with respect to GPBs' cost of capital, so does not commit gas consumers to paying more in total costs over the economic lifetime of the networks, and limits the possibility of GPBs making excessive profits; and

3.62.3 Creates better pricing signals now and in the future so consumers have better information on which to base decisions (eg, continuing to use gas, repairing/replacing aging gas appliances, switching to alternative energies).

3.63 Given that gas pipeline usage has likely plateaued ahead of DPP4 (and may now be falling in some GPB networks) we consider it important to make these adjustments while the customer base is at its broadest. This reduces the risk of escalating prices for future gas consumers as New Zealand moves further towards decarbonisation.

3.64 Lastly, we consider acting now to complete the transition maintains optionality that likely has value for gas consumers and is the best approach to take in the circumstances. Decisions on regulatory asset lives and levels of risk mitigation can be reviewed at future resets, and adjusted in line with the latest information available.

3.65 For further discussion, see Attachment D to this paper.

The return on capital has increased

3.66 Our building block model includes a return on capital, being the weighted average cost of capital (WACC) multiplied by the value of the regulated assets base (RAB). The value of the WACC can have a large impact on the revenue allowances we set, as it determines the return a GPB is allowed on both its existing RAB and its forecast capex over the regulatory period.

3.67 We estimate the WACC separately to the DPP process following a methodology specified in the WACC IMs.[41]

3.68 For our draft decision, we use the 50th percentile vanilla WACC estimate of 6.59%. This is a 0.45% increase from the WAAC estimate we used in DPP3 which was 6.14%.

3.69 The WACC figure we have used in our draft decision is based on the WACC we determined for ID purposes for Firstgas and Powerco and was determined:[42]

3.69.1 as-at 1 October 2025;

3.69.2 using input data as outlined in our recent WACC determination for disclosure year 2026 for information disclosure regulation, adjusted for a five-year regulatory period; and

3.69.3 applying the IMs, which were amended in 2023, including using a mid-point percentile rather than the 67th percentile.

3.70 We will determine the final WACC for DPP4 before 31 March 2026, incorporating data up to 1 March 2026.

We have shaped GDBs' revenue paths for an expected decline in consumption over DPP4

3.71 Demand forecasts play an important role in setting the price path for GDBs as they determine the timing of revenue recovery across the regulatory period.

3.72 We use demand forecasts for gas quantities delivered and the number of connected consumers to calculate a constant price revenue growth (CPRG) forecast for each GDB. This forecast shows how the revenue path will change with delivered quantities and number of connected consumers, if prices were constant in real terms over the regulatory period.

[41] *Gas Distribution Services Input Methodologies Determination 2012* [2012] NZCC 27, Part 4, subpart 4, and *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, Part 4, subpart 4.

[42] Commerce Commission "Cost of Capital determination for disclosure year 2026 for information disclosure regulation [2025] NZCC 21" (30 October 2025).

3.73 The revenue impact of the CPRG forecast is NPV neutral – it affects the timing of revenue recovery rather than the amount of revenue the GDBs can recover. We also use CPRG forecasts to set maximum revenue in the first year of the regulatory period, with GDBs bearing the in-period demand risk. If quantities delivered fall below forecast quantities, GDBs earn less revenue until prices are reset at the next regulatory period. GDBs also receive the upside of this risk. If they outperform the forecast of quantities delivered, they retain the additional revenue during the DPP.

3.74 We have used the GDBs' demand forecasts to determine the CPRG forecasts, which is consistent with our DPP3 approach. We engaged Concept Consulting to provide us with an independent forecast and are satisfied that the GDB forecasts are reasonable.

3.75 With demand forecast to decline over DPP4, the CPRG factors that we have calculated are negative for all GDBs. This means that revenue in year one is higher than if demand was forecast to increase. Based on this constant price, total (real) revenue is forecast to decline over the regulatory period as demand falls.

We consider that the GDBs are able to manage demand risk through DPP4

3.76 GPBs have raised concerns about the potential impacts of demand variations within the regulatory period and proposed uncertainty mechanisms to manage these risks.[43] [44] [45] Our draft decision is to not implement a demand variation mechanism to allocate some of this risk to consumers.

3.77 We are not satisfied that a hybrid price-path mechanism would best promote the long-term benefit of consumers under s 52A of the Act We understand suppliers' submissions on the option to implement hybrid price-path mechanism similar to what the Australian Energy Regulator (AER) approved for Jemena Gas Networks' 2025-30 price path reset. However, we did not receive any submissions quantifying the potential risk for consumers resulting from a large demand shock.

3.78 We have independently tested and accepted the businesses' demand forecasts. We expect that these would be a central estimate of forecast demand and include prospects of both potential for upside improvement as well as downside risk.

3.79 In addition, under our existing WAPC as specified in the IMs and the DPP, the GDBs are able to manage their businesses to take account of variations in demand through:

3.79.1 management of expenditure;

3.79.2 restructuring pricing;

3.79.3 application for a CPP; and

[43] Firstgas "Submission on the Gas DPP4 Open Letter" (13 March 2025), pp.5 and 6.
[44] Powerco "Submission on Gas DPP4 Open Letter" (13 March 2025), p.1, 2 and 5.
[45] Vector "Submission on Gas DPP4 Open Letter" (13 March 2025), pp.1 and 2.

3.79.4 application for a capacity event reopener.

3.80 We considered introducing a new reopener to manage significant changes in demand. However, we are not convinced there is new evidence showing that the level of risk to consumers justifies changing our position from the IM Review 2023, where we decided not to include a demand reopener. Instead, we believe the customised price-quality path (CPP) process is a better tool for this purpose, as it allows for a detailed, bottom-up forecast and assessment of what is needed to continue delivering services efficiently at the level consumers require.

Setting rates of change for the GPBs

The default rate of change is zero

3.81 Under the Act, we must set a rate of change for the GPBs. This rate of change must be based on the long-run rate of productivity improvement achieved by suppliers of the relevant goods or services in New Zealand or other comparable countries. We refer to this rate of change in productivity as the 'X-factor'. We have decided not to apply a productivity adjustment and the default rate of change for the GPBs is zero.

We have considered alternative X-factors to smooth price impacts

3.82 We may set an alternative rate of change for a particular GPB, as an alternative in whole or in part, to the starting prices (under s 53P(3)(b) of the Act), if this is necessary or desirable to:

3.82.1 minimise any undue financial hardship to the GPB;

3.82.2 minimise price shocks to consumers; or

3.82.3 create an incentive (under s 53M(2)) for a GPB to improve its quality of supply.

3.83 Having completed our assessment of the GPBs' current and projected profitability, we have considered whether an alternative rate of change for each GPB is necessary. To do so we have assessed whether the starting price adjustment implied by our assessment of the GPBs' current and projected profitability might result in price shocks for consumers.

3.84 Table 3.6 below shows the implied starting prices for each GPB if we were to apply a one-off starting price adjustment and a 0% X-factor, ie no annual real price increase for the remaining years of DPP4.

Table 3.6 Implied real price increases due to a one-off starting price adjustment ($ million nominal)

GDB	Implied starting price ($ million)	Implied real price increase for year 1 of DPP4
Firstgas Transmission	214.8	2.9%
Firstgas Distribution	44.9	4.4%
GasNet	6.6	-0.1%
Powerco	79.2	-0.1%
Vector	81.3	21.3%

3.85 Our draft decision is to set a default rate of change of 0% for all GPBs except Vector, which will have an alternative rate of change. Our approach mitigates initial price shocks to Vector's consumers.

We have smoothed Vector's price path over the first two years

3.86 We have considered the consumer impacts of the price shock posed to Vector's consumers from a 21.3% starting price increase. While we limited Vector's real price increases to 0% for the last three years of DPP3, wholesale gas prices and inflation are resulting in increasing retail bills for consumers.

3.87 In reaching our decision to smooth Vector's price path we considered the following options:

3.87.1 No smoothing – allowing the full price shock in between DPP3 and DPP4;

3.87.2 Uniform smoothing – entirely smooth the revenue path so that the initial price shock matches the average year-on-year growth rate;

3.87.3 Medium smoothing – a combination of 11.5% steps in both of first two years, followed by 0% real price growth rate for the remaining three years.

3.88 Table 3.7 below shows the increase in the first year of DPP and increase in subsequent years for these options.

Table 3.7 Revenue smoothing options we considered for Vector

	Initial year price change	Subsequent year price change
No smoothing	CPI + 21.3%	CPI + 0%
Uniform smoothing	CPI + 6.9%	CPI + 6.9%
Medium smoothing	CPI + 11.5%	CPI +11.5% for year 2, then CPI + 0%

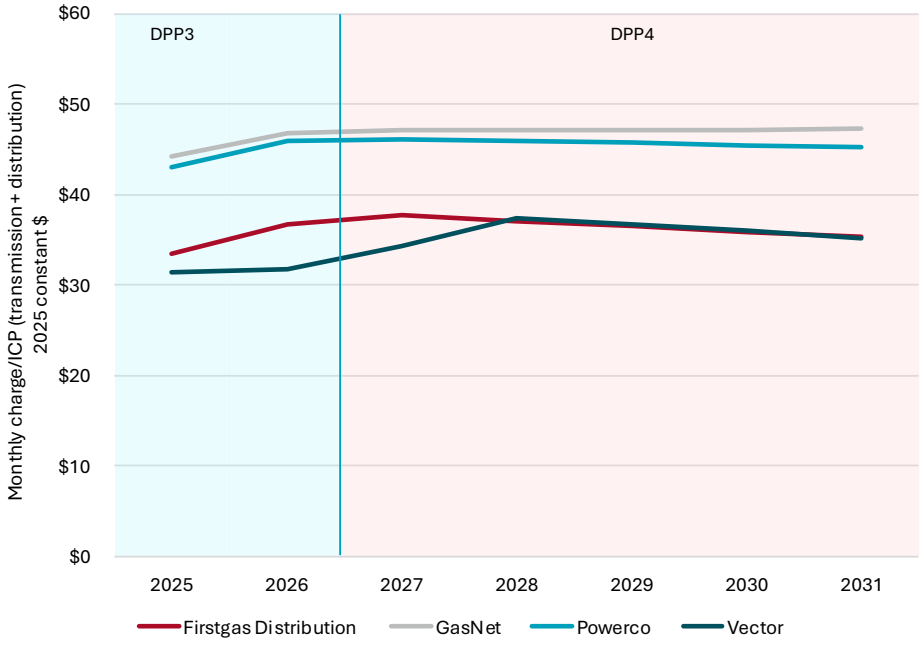
3.89 We have decided that the medium smoothing approach is in the best interest of consumers. Our view is that this is the best approach to minimise price shocks to consumers—many of whom we have heard are struggling with the rising costs of energy—while ensuring prices reflect the costs of providing the service and reducing the potential for volatility between regulatory periods.

The GDB revenue paths equate to generally flat residential bill impacts

3.90 Pipeline charges comprise about one-third of residential gas bills. We have estimated the impact on residential bills of our draft decision revenue paths on this basis, noting that the impact on individual consumers, as well as commercial and major industrial users, will depend on their particular circumstances and pricing from pipeline businesses and retailers.

3.91 As shown in Figure 3.4, the estimated average monthly charges for residential users over DPP4 are largely flat in real terms, other than the smoothed two year step-up for Vector consumers. The indicative charges in this figure reflect both the local GDB pipeline charge and an allocation of the transmission charge from the GTB. We have allocated revenues to residential users based on GDBs' current allocations, with the allocation then divided equally between residential users.

Figure 3.4 Estimated average monthly residential charges over DPP4, including distribution and transmission charges (constant 2025 $ per ICP).



We are retaining the DPP3 quality standards

3.92 Our draft decision is to retain the current quality standards that apply to the GPBs. These are:

3.92.1 for the GTB and GDBs, the time taken to respond to any emergency must be less than 180 minutes;

3.92.2 for the GTB and GDBs, the percentage of emergency responses taking longer than 60 minutes must not be greater than 20%;

3.92.3 the number of major interruptions for the GTB must not exceed zero; and

3.92.4 if there is a major interruption, that the GTB must provide a detailed publicly available report.

3.93 We investigated introducing additional quality standards but were not convinced that these were necessary at this time. In reaching our draft decision, our reasons for not making a change to the current gas quality settings include:

3.93.1 gas sector quality outcomes have been relatively stable;

3.93.2 there are other regulatory measures and commercial incentives driving gas sector quality outcomes;

3.93.3 stakeholder feedback to our Issues paper did not identify that a change was supported; and

3.93.4 our analysis indicates that the current quality standards are fit for purpose.

3.94 Over the DPP4 period we will also continue to monitor key quality metrics disclosed through ID, such as GDB CAIDI performance, as it may provide insight into potential unreliability in uneconomic parts of networks, and GTB gas leaks. This ongoing monitoring will inform whether additional quality standards are necessary in DPP5.

3.95 See Attachment E to this paper for more discussion of quality standards.

We are considering next steps around disconnections as an emerging issue

3.96 Some stakeholders have identified disconnections as an emerging issue, with some suggesting we introduce new standards to provide for affordable and timely disconnections from the gas networks.

3.97 Given the expected increase in customers disconnecting from the gas networks, we expect disconnections to become an emerging focus over DPP4. We have not specifically considered disconnection issues in the past. As the gas networks have been growing, we have not seen large numbers of disconnections and there has been limited focus on the costs and activities related to disconnections.

3.98 We consider that the first step is to collect information on disconnections and monitor outcomes. We will consult on any information disclosure requirements in due course. This will increase transparency on how disconnections are being carried out and help inform us and stakeholders on whether quality standards should be set in future.

Future issues not affecting our DPP4 draft decisions

3.99 We have also considered several issues raised by submitters during our DPP4 consultation process which have not affected our draft decisions for DPP4. We recognise, however, that they could play a role in the development of regulatory policy for future price-quality paths or other Part 4 regulation.

3.100 Table 3.8 below sets out these issues and our views. See Attachment F to this paper for further discussion.

Table 3.8 Future issues not affecting our DPP4 draft decisions

Issue	Our view
Regulatory treatment of network rightsizing	We understand that plans for network rightsizing by GPBs are still in their formative stages, and are unlikely to materially affect DPP4. Any regulatory response could be co-ordinated as part of the next Part 4 IM review (due to be completed by the end of 2030 at the latest). A key future potential concern is the withdrawal of service from consumers who still demand piped gas. While this may be economic for suppliers, withdrawing service may result in significant consumer costs to switch to alternative energy source. We will engage with policy agencies to highlight emerging issues from network rightsizing and consider whether appropriate protections are needed for consumers (eg, a withdrawal code).
Potential large-scale future network decommissioning costs	We are not making a specific allowance for future decommissioning costs (or changing any existing regulatory setting) in DPP4. We do not have sufficient information about the basis for future decommissioning liabilities, or the likely type or scale of the costs, and it is therefore not in consumers' interests to progress a specific solution for DPP4. We may consider the treatment as part of the next Part 4 IM or as part of DPP5, when further information and greater clarity for the gas sector may have emerged.
Non-depreciable easements	We are deferring consideration of this issue in the absence of information establishing that it is material for DPP4, or any other urgent or compelling reason to initiate an out-of-cycle review of the GDB and GTB IMs for the treatment of easements ahead of the DPP4 reset.
Cross-sector solution for addressing the impact of declining demand	In submissions, Greymouth Gas proposed a conceptual solution for dealing with the impact of declining supply and demand for GPBs and gas consumers.[46] Broadly, it involves shifting the recovery of costs for a revalued portion of GPB RABs to consumers of electricity lines services. This proposal is out of scope of our regulatory regime (and therefore the DPP4 reset). It would be a significant policy decision to impose costs of one regulated service on consumers of another, and, as noted by Vector in cross-submissions, it is best considered as part of wider government policy processes.

[46] Greymouth Gas "Submission on Gas DPP4 Issues paper" (27 July 2025); Greymouth Gas "Cross-submission on Gas DPP4 Issues paper" (13 August 2025).