COMMERCE COMMISSION NEW ZEALAND
Te Komihana Tauhokohoko

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Gas DPP4 reset

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

Final decision reasons paper - Attachments A - H

27 May 2026

Contents

Attachment A Regulating prices and revenues

Purpose of this attachment

A1 This attachment sets out details on the core components for how we have set price paths for the default price-quality path for the fourth regulatory period (DPP4) which commences on 1 October 2026. It covers:

A1.1 our approach to setting starting prices and the rate of change in subsequent years of the price path for the gas pipeline businesses (GPBs); and

A1.2 specific price path settings for the gas distribution businesses (GDBs) and the gas transmission business (GTB).

Structure of this attachment

A2 In Table A1 we describe the structure of this attachment.

Table A1 Structure of this attachment

Title	Description of content
Practical application of default price-quality regulation	Sets out our decision for a five-year DPP4 regulatory period.
Setting starting prices based on an assessment of current and projected profitability	Describes the price paths which will apply to the GPBs in DPP4. Note that different forms of control will apply to the GDBs and the GTB.
Setting revenue for the GDBs	Describes the operation of the weighted average price cap (WAPC) for the GDBs and we note the decisions we made in the 2023 input methodologies (IM) Review and other subsequent IM amendments with respect to the IMs which will apply to the GDB price paths for DPP4.
Implementing GDB IM amendments by introducing features of the demand variation revenue adjustment mechanism	Describes how we made our GDB DPP implementation decisions on the demand variation revenue adjustment hybrid price-quality path.
Setting revenue for the GTB	Describes the operation of the revenue cap and noting the decisions we made in the 2023 IM review and other subsequent IM amendments with respect to the IMs which will apply to the GTB price path for DPP4.
DPPs are not used to regulate GPB pricing methodologies	Explains why we do not regulate the GPB pricing methodologies in the DPP.

Practical application of default price-quality path regulation in DPP4

Final decision on five-year regulatory period (Decision T1)

A3 Our final decision for GDB and GTB DPP4 is to set a five-year regulatory period commencing on 1 October 2026.

A4 Our final decision is unchanged from our draft decision.

What we heard from stakeholders

A5 We published our draft decision on the length of the regulatory period alongside our issues paper in June 2025 to provide stakeholders with an early indication of our thinking on this matter, as we understood this information was useful to the GPBs we regulate and to customers and suppliers of those regulated businesses.[1]

A6 In response to our open letter, Firstgas submitted that forecasting risk grows with time and it considers that a five-year regulatory period would exacerbate risk factors for suppliers. It argued that a four-year period similar to the third default price-quality path (DPP3) would continue to offer better flexibility and risk management in an environment characterised by policy volatility and supply-side uncertainty. It also submitted that if we decided to proceed with a five-year period, it encouraged further consideration of mechanisms that could enhance responsiveness and safeguard against emerging risks, including the hybrid price cap mechanism described in the Gas Infrastructure Futures Working Group (GIFWG) submission.[2]

A7 Powerco supported a five-year period, however it noted that forecasting accuracy is difficult over a five-year period, particularly in the current market. While it supported our draft decision, it expressed concern that forecasting becomes more difficult the longer the period, with subsequently greater risk to both consumers and the GPBs if forecasts are materially different from reality. It suggested this uncertainty could be mitigated by ensuring sufficient regulatory mechanisms are available to deal with situations that evolve in-period.[3]

A8 Vector also, on balance, supported the five-year regulatory period. This is on the basis it may reduce workload (and therefore regulatory costs) for both us and the pipeline businesses associated with more frequent price-quality path resets. However, it considered it critical a longer regulatory period is accompanied by appropriate uncertainty mechanisms to address the significant forecast risk and other unforeseen circumstances that could arise during the period.[4]

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[1] Commerce Commission "Gas DPP4 reset 2026: Five-year regulatory period - Draft decision reasons paper" (26 June 2025)
[2] Firstgas "Gas DPP4 2026: Firstgas views in response to Issues Paper" (124 July 2025), p.22-23.
[3] Powerco "Powerco response to the Gas DPP4 issues paper" (13 March 2025), p.7-9.
[4] Vector "Reset of the gas default price-quality path 2026: Issues paper" (24 July 2025), p.11.

A9 Entrust, Vector's major shareholder, also supported the five-year period if it is accompanied by appropriate mechanisms to address uncertainty/forecasting errors and suggested we should consider a volume reopener and/or a 'hybrid mechanism' which shares volume risk with consumers.[5]

A10 Fonterra supported the move to extend the regulatory period to five years. It argued that a five-year horizon would provide stability for consumers and would support future certainty on pricing for its internal business planning. It considered this particularly important as energy prices are escalating more generally.[6]

A11 We did not receive any further submissions on the length of the regulatory period following the publication of our draft decisions in November 2025.

Our assessment taking into account stakeholder views

A12 Under s 53M(4) of the Commerce Act 1986 (the Act), the default length of a regulatory period for a default price-quality path is five years. However, the Act states that we may shorten the regulatory period to four years if we consider that doing so would better meet the Part 4 purpose.

A13 When we considered whether to apply the default five-year period in our DPP3 decisions in 2022, a number of matters had resulted in significant uncertainty about the future direction of climate change policy, and its impact on the sector. To give ourselves the earliest possible opportunity to revisit the DPP3 settings based on our appreciation of this significant uncertainty at that time, we decided to apply a four-year regulatory period to DPP3.[7]

A14 Our expectation then was by setting the shorter regulatory period, we would be able to consider new developments and expected significant government energy policy initiatives affecting the gas sector sooner, when making our price-quality path decisions for DPP4. We said: "Our draft decision to shorten the length of the regulatory period was a means of mitigating the impact of uncertainty".

A15 The gas sector remains in a state of relatively high uncertainty. However, at this time there is no reason to believe we should shorten the DPP4 regulatory period to better meet the Part 4 purpose:

A15.1 We do not consider that a five-year regulatory period will diminish the incentives on GPBs to invest efficiently in replacement or upgraded assets (consistent with s 52A(1)(a) of the Act); and

A15.2 We do not consider that a five-year regulatory period will adversely impact the limiting of the ability of GPBs to earn excessive profits (consistent with s 52A(1)(d) of the Act).

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[5] Entrust "Gas price reset needs to ensure investment cost-recovery in face of decreasing demand" (24 July 2025), p.7-8

[6] Fonterra "Fonterra submission on Gas DPP4 reset 2026" (24 July 2025), p.1.

[7] Commerce Commission, "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final reasons paper" (31 May 2022), para E88 to E89.

A16 We consider that a default five-year regulatory period for DPP4 is appropriate and we are not satisfied that the shorter four-year alternative will better meet the Part 4 purpose, based on the current circumstances. We address the submission points raised by the GPBs and Entrust on in-period adjustment mechanisms later in this attachment.

Setting starting prices based on an assessment of current and projected profitability

A17 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:

A17.1 The GDBs are subject to a 'WAPC', where limits on allowed revenue during the period effectively increase (or decrease) if actual demand is higher (or lower) than expected demand.

A17.2 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.

A18 The two main components of the price or revenue limits which are specified in s 53O of the Act are:

A18.1 the 'starting price' allowed in the first year of the regulatory period; and

A18.2 the 'rate of change in price', or X-factor(s), relative to the consumer price index (CPI), that is allowed in later parts of the regulatory period.

Final decision on setting starting prices (Decision P1)

A19 Our final decision is to set starting prices for DPP4 based on current and projected profitability under the building blocks model (BBM).

A20 Our final decision is unchanged from our draft decision.

What we heard from stakeholders

A21 The Act allows us to set starting prices based on our assessment of current and projected profitability or by rolling over the prices which apply at the end of DPP3.[8]

A22 We sought feedback on this option of rolling over prices from DPP3 in our issues paper and stakeholders submitted against rolling over prices. In particular, Vector in its submission on our issues paper submitted:[9]

[8] Commerce Act 1986, s 53P(3)(a).

[9] Vector "Reset of the gas default price quality path 2026: Issues paper - Vector Submission" (24 July 2025), paras 154 to 157.

> We strongly recommend the Commission continue its approach setting starting prices based on its assessment of current and projected profitability under the building blocks model rather than the alternative approach of rolling over DPP3 prices.
>
> In line with the Commission's reasoning in DPP3, using the building blocks model will better reflect the evolving circumstances of gas pipeline businesses and better create financial incentives to improve efficiency thereby aligning incentives between GPBs and consumers.

A23 In its submission on our draft decision, Vector again agreed with our draft decision to set starting prices based on current and projected profitability under BBM.[10]

A24 Major Gas Users' Group (MGUG) criticised our decision to apply the BBM in a situation of falling demand. However, it made no recommendation on an alternative approach.[11]

A25 We did not receive any other submissions on the setting of the starting prices for DPP4 following the publication of our draft decisions in November 2025.

Our assessment taking into account stakeholder views

A26 We consider that using current and projected profitability better reflects the evolving operating environment of the gas sector than the alternative of rolling over prices. We are seeing declining gas production and lower volumes of gas being transported over the networks.

A27 The point that MGUG has highlighted through its criticism of the BBM is the challenge of regulating infrastructure with largely fixed costs, ie, that demand for gas will fall and as the infrastructure costs are mainly fixed, prices will continue to rise over the regulatory period.

A28 In this context, we consider it is appropriate to undertake an assessment of the GPBs' most up-to-date forecasts, asset management and operations plans to ensure that forecast costs are prudent and to then use these cost forecasts as the basis of calculating revenue forecasts to provide appropriate incentives to the GPBs to invest while limiting excessive profitability.

A29 In line with our approach in DPP3,[12] we have set the revenue allowances and resulting starting prices using our BBM approach. The starting prices are an amount that does not include pass-through costs and recoverable costs. We have calculated the starting price amounts through two key processes:

A29.1 Process 1: Determining a building blocks allowable revenue (BBAR) for each year of the regulatory period. At the simplest level, the BBAR is calculated using separate cost building blocks as follows:

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[10] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision "(22 January 2026), p.8 and 28.

[11] MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026), p.37, para 68.

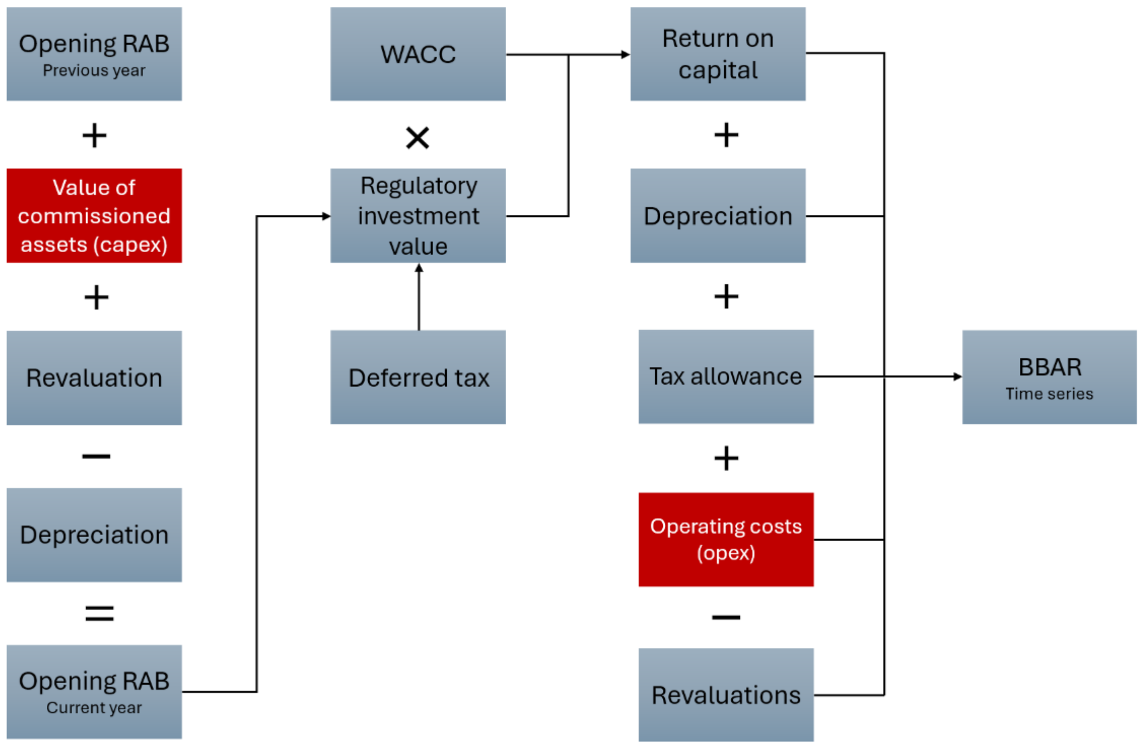
[12] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022) ,p.7.

A29.1.1 Return on capital - Revaluations + Depreciation + Operating costs (opex) + Tax allowance. A high-level schematic is provided in Figure A1; and

A29.2 Process 2: The annual BBAR amounts can vary markedly year by year. 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 as well as the forecast constant price revenue growth (CPRG) in the case of a GDB as the mechanism to smooth forecast revenues over the regulatory period. A diagram on this step is provided below in Figure A2.

A30 Using the fixed prices or revenue path (calculated using the BBM) creates financial incentives which align the GPBs' interests with those of consumers in reducing costs and becoming more efficient. This alignment of incentives is achieved over regulatory control periods, where the maximum revenue (or prices) for delivering the regulated services over the regulatory control period are specified up-front.

Figure A1 Building blocks model used to calculate building blocks allowable revenue



A31 We have highlighted in red in Figure A1 two key inputs to the building blocks that are not determined by the IMs and which we must forecast through the price-setting process. These two inputs are discussed in Attachments B and C:

A31.1 Capex, which represents the value of assets expected to be commissioned during the regulatory period; and

A31.2 Opex, or operating costs.

A32 In our capex decisions in Attachment B we note in particular:

A32.1 The capex allowance is an input to determining the revenues GPBs may earn affecting their profitability, incentives to invest, and ability to deliver gas pipeline services. The capex values do not represent allowances to be received during the period, but are included within our 'BBM' approach, which determines GPBs receiving a return of capital (depreciation) and a return on capital (weighted average cost of capital (WACC) applied to the regulatory asset base (RAB)) applied from when assets are commissioned during the regulatory period;

A32.2 Although a capex allowance is not the biggest contributor to the regulated revenue path, it is important because of the long-term implications for consumers. Once an asset is built, the cost recovery for this asset is spread over many years being both the return of capital and requirements for ongoing maintenance;

A32.3 The DPP4 capex allowance is a significant decrease from that provided at the DPP3 reset, which reflects the significant reduction in growth-based capex (consumer connection and system growth) and an increasing trend by GPBs to an opex based approach, which will result in material reductions in some capex;

A32.4 We have not set the capex allowances as high as the values forecasted within the GPB 2025 asset management plan (AMP) forecasts; and

A32.5 We considered the prudency and efficiency of expenditure across capex and opex categories. We have declined step changes in opex for capex-opex trade-offs where we considered these do not clearly correspond to reductions in capex forecasts.

A33 In our opex decisions in Attachment C we note in particular:

A33.1 the opex allowance is an input to determining the revenues GPBs may earn affecting their profitability, incentives to invest, and ability to deliver gas pipeline services. Unlike capex, the costs will be recovered during DPP4, as opex is recovered in the year it is incurred under our building blocks approach (ie, before revenue smoothing);

A33.2 we have used a modelling approach that tests GPBs' AMP forecasts and as a means of setting the DPP4 allowances. We forecast what a prudent and efficient GPB would be expected to spend over the regulatory period. Our modelling approach reflects the fact that opex is generally more predictable, as it largely comprises expenditure related to recurring activities as well as those costs that have a predictable trend, and the approach allowed us to model specific adjustments that affect each GPB; and

A33.3 our DPP4 opex allowances are lower than the GPBs' forecasted levels of expenditure and are generally consistent with recent levels of expenditure, except for Vector. Vector's DPP4 allowances are higher than recent levels of expenditure, reflecting its well-evidenced proposed implementation of capex-opex trade-offs.

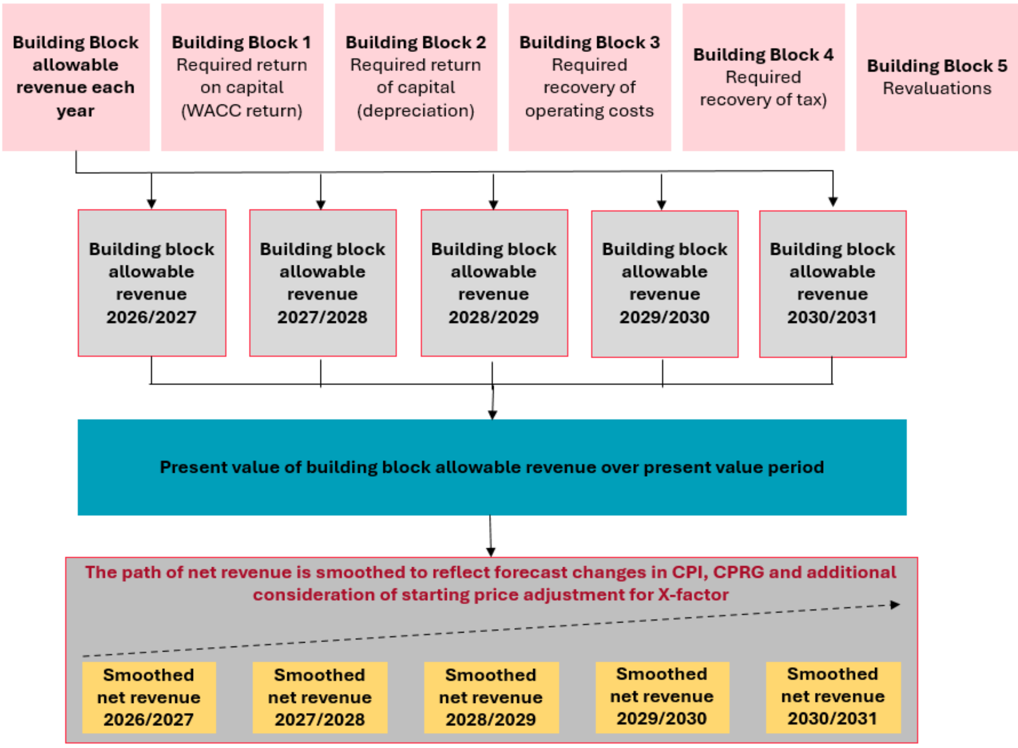
A34 Some inputs into the elements of the BBAR come from information disclosures. For example, we take the opening RAB value as disclosed by the businesses as the starting point for calculating total regulatory investment value.

A35 Other inputs into the elements of the BBAR are wholly or largely set in the IMs. For example, the Cost of Capital IM sets out:[13]

A35.1 how we must estimate the WACC, including specifying values for most of the parameters eg; asset beta, leverage, tax-adjusted market risk premium (TAMRP); and

A35.2 the methodology for estimating the risk-free rate and the debt premium.

Figure A2 Setting forecast revenues equal to forecast costs



A36 Costs that are considered outside of the GPBs' control are recovered through separate allowances for 'pass-through costs'. Other costs that GPBs have little control over are recovered through allowances for 'recoverable costs'. The items that qualify under these categories, and the criteria for inclusion that must be satisfied, are set out in the respective GDB and GTB IMs.[14]

Setting revenue for the gas distribution businesses

The gas distribution businesses are subject to weighted average price caps

A37 Under the GDB IMs, the GDBs are subject to a WAPC, which limits their maximum average prices during each year of the regulatory period.

[13] See for example Gas Distribution Services Input Methodologies Determination 2012 [2012] NZCC 27, Part 4 Subpart 4.

[14] Gas Distribution Services Input Methodologies Determination 2012 [2012] NZCC 27, clauses 3.1.2 and 3.1.3, and Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28, clauses 3.1.2 and 3.1.3.

A38 For the GDBs we aim to set constant real prices over the regulatory period to deliver the present value of the BBAR. We determine starting prices that can be held constant over the regulatory period in real terms, taking into account forecasts of CPI and gas volumes (represented by our CPRG forecasts).

Final decision on applying constant price revenue growth (Decision P6)

A39 Our final decision is to use the latest GDB forecasts of demand and customer growth as the key input into our CPRG forecasts for DPP4. We issued a request for information (RFI) to the GDBs to provide us with their most up-to-date demand and customer growth forecasts. Where there was no response to the RFI, we used demand and growth forecasts included in their disclosed AMPs.[15]

A40 Our CPRG forecasts are set out in Table A2.

Table A2 CPRG factors for DPP4 for each GDB

GDB	2026/27	2027/28	2028/29	2029/30	2030/31
Firstgas Distribution	-2.16%	-2.27%	-2.51%	-2.70%	-3.14%
GasNet	-0.86%	-0.88%	-0.91%	-0.92%	-1.01%
Powerco	-0.71%	-0.86%	-0.69%	-0.96%	-1.16%
Vector	-2.66%	-2.44%	-2.48%	-2.52%	-2.59%

A41 Declining CPRG factors means that revenue (before applying any X-factor) will be highest at the start of the period before declining in line with forecast demand.

A42 We have made the following changes to the forecast CPRG in our final decision:

A42.1 The forecast CPRG for each of Firstgas Distribution, GasNet and Powerco have been updated from our draft decision to reflect actual 2025 information disclosure (ID) data.

A42.2 The forecast CPRG for Vector has been updated from our draft decision to reflect actual 2025 ID data and to align the modelled customer categories with Vector's tariff categories.

What we heard from stakeholders

A43 Submissions on our draft decision largely focused on Concept Consulting's demand forecast, which we used as a reasonableness check on the GDBs' forecasts:

A43.1 MGUG noted that it did not consider Concept Consulting's modelling (which we did not use but adopted as an independent test of the forecasts), could be relied

[15] We took this approach for GasNet which did not respond to our RFI.

on. It noted that it considers our analysis to be appropriate and noted scepticism with directly using the GDB forecasts;[16]

A43.2 Castalia (for MGUG) noted it did not consider Concept Consulting's modelling takes account of changes in government policy or technological developments which will likely sustain gas demand;[17]

A43.3 Firstgas noted that it did not agree with all of Concept Consulting's analysis and underlying assumptions, but it did agree with our decision approach to base forecasts on GDB forecasts;[18] and

A43.4 Rewiring Aotearoa proposed we use a then soon-to-be-released national Regional Energy Transition Accelerator analysis by EECA to revisit industrial and large commercial gas demand.[19]

A44 Vector supported our approach and recommended updates to our CPRG model that would provide "a more accurate and up-to-date picture of Vector's volume and connection forecast" including updated installation control point (ICP) and gigajoule (GJ) forecasts as well as an updated consumer group categorisation.[20]

A45 Vector asked that we adopt its more negative ICP and GJ forecasts as well as updated customer segment information which would result in a lower demand and CPRG profile, having the effect of front-loading the smoothed price path profile and resulting in greater revenue recovery in the earlier years of DPP4.

Our assessment taking into account stakeholder views

A46 The selection of volume forecasts informing our CPRG forecasts is an important input in seeking to ensure that the resulting WAPC delivers an unbiased estimate of the prices required to deliver expected ex-ante financial capital maintenance (FCM).

A47 For DPP3 we used the GDB's AMP forecasts of volumes to determine the CPRG forecast.[21] In our DPP3 Final reasons paper we said that the GDBs' AMP forecasts of gas demand were appropriate because we believed that those forecasts were credible and the best option available given the current gas demand uncertainty.[22]

A48 Our starting point for DPP4 was the to use the GDB's AMP forecasts to determine the CPRG forecast. We tested whether these were appropriate and credible similar to DPP3.

[16] MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026), para 25-28.
[17] Castalia "Evidence-based assessment of accelerated depreciation of gas transmission and distribution networks" (January 2026), p.6.
[18] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p.37-38.
[19] Rewiring Aotearoa "Rewiring Aotearoa submission on the Gas DPP4 reset 2026 – Draft Decision" (22 January 2026), p.2.
[20] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision" (22 January 2026), p.44.
[21] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 - Final Reasons Paper" (31 May 2022), decision P6.
[22] Ibid, para E63.

A49 There are incentives on the GDBs to adopt unduly conservative forecasts of future volumes, as this may translate to higher prices. In coming to our decision to rely on GDB forecasts, we tested the GDB forecasts using independent forecasts to validate the reasonableness of the GDB forecasts.

A50 We engaged Concept Consulting to produce independent forecasts of demand and ICP growth. We used the Concept Consulting forecasts and compared these against the GDB forecasts.[23] We found that Concept Consulting's forecasts were consistent with the GDB forecasts and as such, we are satisfied that the GDB forecasts reasonably reflect anticipated demand.[24]

A51 We have considered the submissions received from MGUG and Firstgas regarding specifics of Concept Consulting's modelling assumptions. We note that because Concept Consulting's model is only used to check on the reasonableness of GDB forecasts it does not need to reflect the level of accuracy that submitters suggest.

A52 We consider that using the GDB forecasts as the input into our CPRG to be appropriate for the following reasons:

A52.1 we consider GDBs have the best information on their existing consumers, enquiries from potential consumers, and their willingness to pay and trends in customer behaviour. They are forecasting their demand with the best possible information;

A52.2 the most recent forecasts reflect the most up-to-date expectations of demand; and

A52.3 independent testing of demand forecasts showed GDB forecasts are reasonable.

A53 However, we decided to reject Vector's updated ICP and GJ forecasts (submitted January 2026). Our view is there was insufficient reasoning provided to justify us adopting Vector's updated ICP and GJ forecasts, given the possible impact on the price path shape and CPRG factors. It did not explain the drivers or other rationale for the updated ICP and GJ forecasts. The forecasts were not yet in its AMP or otherwise publicly available and thus the forecasts had not had the opportunity for independent public scrutiny. We did agree to accept Vector's proposed grouping of customer segments as this is consistent with what it had specified in an RFI at the draft decision stage.

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[23] Concept Consulting "Gas DPP4 draft demand forecasts report -Prepared for the Commerce Commission (22 August 2025).

[24] For a comparison of difference between GDB forecasts and Concept forecasts, we have published Concept's report which demonstrates the difference between GDB forecasts and Concept forecasts of demand and ICP growth.

Incorporating asset management plan forecasts in the forecast of gas demand

A54 In calculating the CPRG forecasts using the GDB's forecasts, there are calculation methodologies and assumptions which we must undertake.

A55 For the period of 2025 to 2031, we took the GDB's aggregate demand and ICP projections in their RFI responses and AMPs, and estimated the split between residential, commercial, and industrial consumer groups, followed by estimating the split between fixed price and variable price for each of the customer segments.

A56 Revenue by customer segments (residential, commercial, and industrial) from 2025 ID was used to derive a notional proportion between these three consumer segments for each GDB.

A57 For each consumer segment for each GDB, we also calculated the weighting of fixed and variable charges based on its 2025 ID actual data related to GDBs fixed revenues.

A58 We calculate the expected growth rate applicable to each consumer segment using the following methods:

A58.1 the growth for the fixed revenue component for each GDB is a linear growth rate based on the number for forecast ICPs for 2026-2032; and

A58.2 growth rates for the variable revenue component for each GDB consumer segment are based on forecast gigajoule (GJ) growth relative to the previous year.

A59 We then apply the fixed and variable revenue weighting to the respective growth rates, for a total fixed component and annual variable components, for each GDB's consumer segments.

A60 Each GDB's consumer segments' CPRG is the total fixed component plus annual variable components. The total CPRG for each GDB is calculated as the weighted sum of the CPRG values across its three customer segments. We then make time adjustments for different year ends for the price path CPRG.

Our constant price revenue growth conclusions

A61 Our conclusions for the CPRG forecasts for DPP4 are to:

A61.1 use the GDBs' AMP forecasts, and RFI responses, of gas demand and ICP numbers to forecast CPRG, consistent with our draft decision;

A61.2 update our CPRG model for 2025 ID actual numbers of ICPs and GJs;

A61.3 not update the CPRG model for Vector's updated forecast GJ and ICP values; and

A61.4 update the CPRG model to align customer categories with Vector's tariff categories.

Implementing gas distribution business input methodologies amendments by introducing features of the demand variation revenue adjustment mechanism

Final decision on implementing the hybrid mechanism (Decision P5)

A62 Our decision and our reasons for amending the GDB IMs to give effect to the demand variation revenue adjustment (hybrid mechanism) are described in the GDB IM amendments reasons paper.[25] In our gas DPP4 draft decision we proposed not to introduce uncertainty mechanisms to manage demand risk.[26] After consideration of submissions and cross-submissions on our draft decision, we proposed a revised draft decision to introduce the hybrid mechanism. Our final decision is unchanged from our revised draft decision.[27] In this paper we set out our decisions on the implementation of the required features of the hybrid mechanism in the GDB DPP determination for DPP4. Our decisions are:

A62.1 GDBs will continue to bear all demand risk for variations in actual revenue within a threshold of +/-15% of CPI-adjusted forecast revenue, assessed on an annual basis; and

A62.2 the revenue impact of revenue shocks exceeding this threshold, in either a positive or negative sense, will be shared equally between GDBs and consumers.

What we heard from stakeholders

Submissions received on our updated draft decision to implement the hybrid mechanism

A63 After consideration of the stakeholder submissions on our draft decision and the risks and benefits, in April 2026 we published for consultation a revised draft GDB DPP4 determination setting out our updated draft decision on the implementation of the hybrid price path mechanism.[28] [29]

[25] Commerce Commission "Amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 Gas default price-quality path – Final Decision reasons paper" (26 May 2026)

[26] Commerce Commission "Gas DPP4 reset 2026 – Default price-quality paths for gas pipeline businesses from 1 October 2026 – Draft decision – reasons paper" (27 November 2025), p.6 "Gas DPP4 Draft Decisions at a glance".

[27] Commerce Commission "Revised Draft GDB Default Price-Quality Path Determination – Changes related to proposed amendments to input methodologies for gas distribution services – Draft decision reasons paper" (2 April 2026).

[28] Ibid.

[29] Commerce Commission "[DRAFT – option 1] Gas Distribution Services Default Price-Quality Path Determination 2026" (2 April 2026).

Firstgas, Powerco and Vector joint submission

A64 Firstgas, Powerco and Vector included the following joint submission points on the +/-15% threshold for the hybrid mechanism:[30]

> A key design feature of the proposed hybrid mechanism is the tolerance (or 'deadband') around forecast revenue before any 50/50 sharing applies. The Commission proposes setting this threshold at +/-15% of CPI-adjusted forecast revenue, which it considers would represent a significant demand shock. This compares to the +/-5% threshold adopted by the AER for JGN.
>
> In our view, the key concern over DPP4 is not simply the risk of a one-off 'significant demand shock', but the cumulative impact on consumers and GDBs if actual demand is consistently higher or lower than the forecast underpinning the DPP4 decision.
>
> Against that context, we consider the proposed +/-15% threshold is too high.
>
> - A +/-15% variation from forecast revenue in any one year is significant for both consumers and GDBs, particularly given amounts outside the tolerance are only shared 50/50.
> - When considered cumulatively across the DPP4 period, a high annual tolerance can materially weaken the mechanism's ability to share sustained forecast error and to protect consumers from windfall gains or GDBs from large under-recoveries.
> - A threshold of +/-5% (as adopted by the AER for JGN) would better align with the purpose of promoting the long-term benefit of consumers by reducing the risk of large price corrections and financeability pressures heading into DPP5.
>
> By way of illustration, if actual revenue is 10% lower than that allowed in each year over the DPP4 period, then with a +/-15% tolerance the hybrid mechanism would not be triggered in any year. Consumers would face no within-period adjustment while GDBs would bear the full under-recovery each year. Cumulatively over the regulatory period GDB under-recoveries would be in the order of 50% of average annual revenues – a significant amount that could adversely affect the incentives of suppliers to invest.

Firstgas submission

A65 Firstgas included the following in its submission on the +/-15% threshold on the hybrid mechanism:[31]

> We support the decision to introduce a hybrid mechanism and recommend that the threshold for applying the mechanism is lowered from ±15% to ±5% to better achieve the Commission's regulatory intent...
>
> The Commission proposes to use a threshold of ±15% of revenue for the hybrid mechanism, with revenue variances outside this threshold shared equally between suppliers and consumers. This is a significantly wider threshold than applied in Australia and suggested in submissions, and is intended to capture only "large, abrupt and unforeseeable supply or demand shocks" (see paragraph 2.4 of the draft decision reasons paper).

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[30] Firstgas, Powerco and Vector "Gas DPP4 2026 – Submission on hybrid mechanism and IM amendments" (21 April 2026), p.1.

[31] Firstgas "Firstgas submission on proposed hybrid mechanism for DPP4" (21 April 2026), p.1 and p.2.

Powerco submission

A66 Powerco included the following in its submission on the +/-15% threshold on the hybrid mechanism:[32]

> Powerco endorses the hybrid mechanism as a proportionate tool to manage the unique forecasting uncertainties of the DPP4 period. However, to effectively mitigate the risk of consumer price shocks and to preserve the incentives for gas distribution businesses (GDBs) to provide safe and reliable networks, the threshold must be set at a more realistic level.
>
> To appropriately share risk amongst customers and GDBs, we recommend the Commission lower the threshold that triggers a hybrid mechanism to 5% a level more consistent with international precedents and existing reopener frameworks.
>
> A 15% threshold is disproportionate. This would only achieve the Commission's intent if, the sharing formula is altered to include the full amount of the revenue variation.
>
> Both of these options would ensure the mechanism remains a safeguard for material shocks while remaining accessible enough to actually provide the stability the Commission intends.

Greymouth Gas submission and cross-submission

A67 In its submission on the implementation of the hybrid mechanism, Greymouth Gas submitted:

> The Commission should consider the risk of GDBs gaming locations where they (and their related parties) can maximise gas revenue while not discouraging demand reduction (by way of narrative) with the effect of maximising electricity revenue. Parties who are indifferent to demand reductions should not be protected from demand shocks.[33]

A68 Greymouth Gas raised the risk that GDBs could set their pricing in such a way that the +/-15% threshold would be met to qualify for the sharing with consumers. It suggested a solution to this problem: [34]

A68.1 An asymmetric +5% positive threshold and a greater negative threshold, which could accelerate the point at which the effects of positive demand shocks would be shared between consumers and the GDB. It considers that this would have consumer benefits in the way GDBs set their fixed and variable prices;

A68.2 A variable negative threshold for each GDB based on the size of each pipeline business, ranging from -15% for GasNet to -25% for Vector;

A68.3 A requirement for a GDB to apply to us for approval of equal sharing between consumers and the GDB once the adjustment exceeds -30%, with us being satisfied that the GDB needs increased revenue in the regulatory period to pay for opex (and minimal capex), so the GDB can continue providing pipeline services.

[32] Powerco "Powerco supports the introduction of a hybrid mechanism" (21 April 2026), p.1.
[33] Greymouth Gas "Re: Gas DPP4 2026 – Hybrid mechanism and IM amendments" (21 April 2026), p.1-2.
[34] Ibid, p.2.

A69 In its cross-submission, Greymouth Gas submitted:[35]

> GDB requests for a lower 5% threshold (when demand reduces) are inappropriate given-
>
> (a) CPPs weren't applied for when previous demand reductions have been more than that,
>
> (b) the closer GDB cost-sharing goes to zero the more this solution is a poor band-aid and the potential for gaming is increased, and
>
> (c) citing investment in the context of reducing demand seems a proxy for maximising revenue rather than supporting gas conveyancing services at risk.

Firstgas, Powerco, and Vector joint cross-submission

A70 In relation to the decisions on the parameters of the hybrid mechanism, the joint cross-submission from Firstgas, Powerco and Vector disagreed with suggestions by other submitters that a threshold of 15% annual demand reduction could be considered business as usual. They also submitted that where there is sustained decline in demand that is faster than forecast, under-recoveries can accumulate over multiple years, with consequential sharper price rests at the next DPP. In particular, the joint cross-submission noted the following cross-submission points with respect to the setting of the threshold:[36]

> Other submitters have suggested that a 15% demand reduction could be 'business as usual' however, this appears to conflate the direction of demand with forecast error (i.e., differences between actual and forecast demand). The hybrid mechanism addresses forecast error, even where demand is forecast to decline. The suggestion also implies that a 15% decline is immaterial, which we disagree with. By way of illustration, a 15% revenue under-recovery could reduce the realised return on equity by around half based on the draft DPP4 decision – this is significant and will undermine efficient investment in the gas networks, especially if compounded over the DPP period...
>
> We support submissions that emphasise the importance of clear, objective safeguards around the operation of a hybrid mechanism, including avoidance of gaming and clarity over trigger conditions.
>
> These concerns are legitimate and should be addressed through design discipline, not abandonment of the mechanism. In a price cap framework (i.e., without a revenue cap), a simple sharing mechanism is needed so smoothing does not leave either consumers or GPBs carrying the full impact of forecast error.
>
> In our view, effective guardrails include:
>
> - objective, transparent trigger definitions tied to forecast revenue or demand
> - symmetric sharing of over- and under-recovery beyond the tolerance, and
> - avoidance of discretionary reopening tests that re-introduce CPP-like complexity by another name.

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[35] Greymouth Gas "Re: Gas DPP4 2026 – Hybrid mechanism and IM amendments (cross-submission)" (28 April 2026), p.1.
[36] Firstgas, Powerco and Vector "Gas DPP4 2026 – Cross-submission on hybrid mechanism and IM amendments" (29 April 2026), p.2.

> We do not support network-specific thresholds or bespoke tests that materially weaken simplicity, predictability or consistency across GDBs. Over-engineering the mechanism would undermine its core purpose: to provide a low-cost, durable way of addressing material forecast error within the regulatory period.
>
> Absent a revenue cap, a simple hybrid mechanism with well-defined parameters is preferable to either:
>
> - reliance on CPPs as a default and asymmetric response to demand shocks, or
> - retention of a pure WAPC that leaves both consumers and GPBs exposed to sharper, less predictable price outcomes over time.

Vector cross-submission

A71 Vector supported the hybrid mechanism and included the following points on the setting of the threshold for the hybrid mechanism:[37]

> However, we continue to recommend changes to the threshold: the proposed ±15% tolerance is too high to achieve the mechanism's stated objectives in DPP4, where the principal risk is sustained forecast error and cumulative impacts over a five-year period, rather than only a single-year "shock".
>
> We recommend that the Commission adopt a tolerance of ±5% (or lower).

Arete Consulting submission

A72 Arete Consulting submitted on the hybrid mechanism.[38] It acknowledged that the submission addresses deeper concerns with our DPP4 draft decision and the Part 4 regulatory framework. It does not address the implementation details of the hybrid mechanism.

Our assessment on implementation of the hybrid mechanism taking into account stakeholder views

A73 To make our decisions on the implementation of the demand variation revenue adjustment mechanism in a way that promotes the long-term interest of consumers, we identified two high-level elements in our approach:

A73.1 continue to incentivise GDBs to invest to operate and maintain pipelines services at a quality that consumers demand while demand for gas exists; and

A73.2 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.

[37] Vector "Cross-submission on Gas DPP4 – Hybrid mechanism and IM amendments" (29 April 2026), p.1.
[38] Arete Consulting "Re: Revised Draft Default Price-Quality Path Determination" (21 April 2026).

A74 We consider the GDBs are best placed to manage risk under a WAPC. Currently GDBs have some ability to manage demand-related risks through expenditure reprioritisation, pricing and commercial arrangements with customers and the option to apply for a customised price-quality path (CPP). However, as several submitters noted, these tools have limits particularly where demand changes are large, sudden, or driven by factors outside the control of the GDB.

A75 Where an unforeseen demand variation is sufficiently large to be considered to have a shock effect on consumers and GDBs where they can no longer manage the risk, the threshold in the hybrid price path mechanism will incentivise GDBs to continue to operate normally and provide services at a quality demanded by consumers, consistent with s 52A(1)(b), as it will provide certainty as to recovery of additional revenue to partially mitigate the demand/revenue shock.

A76 The risk-sharing proportions and the threshold help to mitigate excessive profitability to some degree by sharing the additional demand risk between the business and consumers (consistent with s 52A(1)(d)). This is because the risk-sharing will maintain an incentive for the business to manage expenditure, restructure tariffs or otherwise grow demand, and would also share some of the benefit in the event of a significant one-off positive demand or supply event.

A77 The mechanism will also promote s 52A(1)(d) by limiting the potential for excessive profitability in the event of large positive demand shocks. The combination of the +/- 15% threshold and the 50/50 sharing ratio will ensure that consumers share in the benefit of materially higher than forecast volumes, while GDBs retain incentives to manage expenditure and respond efficiently to changes in demand.

A78 The +/- 15% threshold is relatively high and is set with the intention that the mechanism is only triggered by large shocks of the type that neither GDBs nor consumers would be well placed to manage. A lower threshold would risk triggering the mechanism during normal, manageable demand fluctuations, while a higher threshold would reduce its effectiveness as a safeguard against consumer harm, provide a strong incentive on the GDBs to ensure pricing designs and commercial arrangements maintain existing customers, and incentivise them to explore and promote renewable gases in order to maintain connections.

A79 We consider a 50/50 sharing ratio:

A79.1 balances risks between both parties when extreme events occur;

A79.2 prevents excessive profitability in positive-shock scenarios;

A79.3 maintains incentives for GDBs to manage demand changes efficiently; and

A79.4 avoids full risk transfer to either party, consistent with our key economic principle of risk allocation.

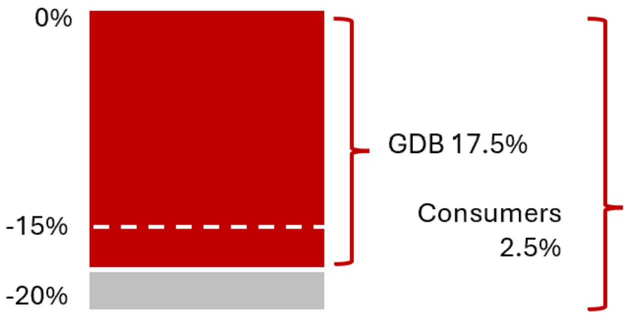
A80 The +/-15% threshold and the 50/50 risk-sharing ratio as a combined mechanism are intended to provide only partial in-period revenue mitigation of significant demand shock events until the next price-quality path reset or until such a time when the pipeline business can apply for a CPP, where in each case we can fully scrutinise and reset any demand forecasts and consider how the business is or should be operating in response to the demand shock.

A81 These parameters mean that the hybrid mechanism will apply only in circumstances involving significant in-period shocks, and GDBs will continue to bear the risk associated with normal variations in demand. For the purposes of the threshold, we consider the revenue should be measured as the variation of actual revenue compared to the forecast revenue for each assessment period which we model at the time of determining the DPP4 price path.

A82 Figure A3 illustrates in a simple way an example of a 20% revenue shock, and the shared impact of 15%, 20% and 25% alternative shocks. The GDB will bear all of the risk up until the 15% threshold, and the GDB and consumers will equally share the incremental impact above the 15% threshold. The consumer impact of a negative revenue shock of 20% in year ‘t’ would result in a recoverable cost leading to a 2.5% increase in revenue in year ‘t+2’. If year ‘t+2’ fell outside the DPP4 period, the recoverable cost would be incorporated into the price-quality path that applied at that point.

Figure A3 Key implementation features of the hybrid mechanism, with 15% threshold and 50/50 sharing ratio beyond of the threshold (negative and positive)

Revenue shock = departure of actual revenue from CPI-adjusted revenue forecast



Revenue Shock	GDB Share (t)	Consumer share (t+2)
-15%	-15%	-
-20%	-17.5%	-2.5%
-25%	-20%	-5%

A83 Weighing up the pros and cons of the arguments for setting the threshold, we have decided to set the threshold as +/-15% of CPI-adjusted forecast revenue, assessed on an annual basis. This will preserve the core features and incentives of the WAPC for normal and moderate demand variations, while providing limited, predefined in-period risk-sharing between GDBs and consumers for large, unforeseen shocks.

A84 While we understand that the higher +/-15% annual threshold will mean that there would be less sharing of any upside revenue shocks, we consider a possible benefit to consumers from a lower percentage threshold rate does not outweigh the disbenefit caused by having a lower threshold that is too easy to satisfy, which we consider would increase the potential for gaming.

A85 We considered the GDBs' submissions advocating for a lower threshold to mitigate the "cumulative effect" of sustained under-recovery that could expose the businesses to financeability risk. We discuss below our view that a CPP is the most appropriate mechanism to address sustained demand shocks. The hybrid mechanism is intended to provide limited automated intervention that may assist in deferring or avoiding the need for a CPP, the application costs of which are treated as a recoverable cost. We consider that, in the specific case of large, abrupt demand shocks, a pre-specified and automatic mechanism provides greater certainty than a CPP about how such events will be treated. This certainty supports timely decision-making by suppliers and helps maintain incentives to continue investing in, operating, and maintaining gas distribution networks during periods of stress.

A86 We have considered the financeability arguments submitted by the GDBs. As noted in their analysis including impact on credit rating, the analysis noted that "even with a higher tolerance [of 15%], the mechanism reduces the risk of financeability pressure compared to leaving all with in-period demand risk with GDBs." We consider a 5% threshold is more likely to reflect normal demand variations rather than a shock effect and consider there could be a risk that a threshold that is too low increases gaming risk by the GDBs or lessens the incentive to take other actions to mitigate the impact of the demand reduction.

A87 We have also considered MGUG's submission that Vector's advocacy for a revenue cap or hybrid reflects its own strategic incentives. We interpret MGUG's submission as being relevant to the threshold and sharing parameters. We have considered the potential gaming risk in deciding the appropriate threshold and the sharing parameter such that an incentive to maintain demand on the network is retained. While there is the potential for gaming risk, we have factored this gaming risk into setting a higher annual threshold. This maintains most of the demand risk and only offers partial risk-sharing in demand shock scenarios.

A88 We also appreciate and acknowledge the positive features in the "Potential solution" of a "hybrid" between the hybrid mechanism and a price-quality path reopener as submitted by Greymouth Gas.[39] However, we do not consider the four tests it proposed for each demand shock are proportionate to the perceived gaming risk. We consider the potential disadvantage Greymouth Gas has identified is addressed through the level of the threshold. Implementing its submitted approach could increase regulatory burden with marginal benefit for consumers. We do not consider the tests to be practical or beneficial for the following reasons:

A88.1 a positive threshold that is too low and with a high asymmetric downside threshold may create a disincentive on the businesses to manage demand if they must bear a greater portion of the loss but also return a significantly greater portion of any upside;

A88.2 the level of scrutiny recommended for revenue shocks of 30% and above is more likely to be appropriate for a CPP; and

[39] Greymouth Gas, "Submission on hybrid mechanism and IM amendments", (21 April 2026), p.2.

A88.3 in a DPP context, we do not consider the different levels of thresholds to be appropriate.

A89 As noted in the IM amendment reasons paper, we consider the CPP is the most appropriate tool to be used to recalibrate the price path when there is a wider and sustained in-period change in the demand for gas rather than setting the threshold at a lower percentage rate as suggested by the GDBs (even if it is potentially administratively burdensome).

Setting revenue for the gas transmission business

The gas transmission business is subject to a revenue cap with wash-up

A90 Under the GTB IMs, the GTB specification of 'price' is set out as an ex-ante revenue cap, where:[40]

A90.1 the forecast revenue from prices in each pricing year must not exceed the forecast allowable revenue for that pricing year; and

A90.2 the forecast revenue from prices less forecast pass-through costs must not exceed the revenue smoothing limit specified in the GTB DPP determination for each pricing year other than the first pricing year in the regulatory period.

A91 The revenue cap will be subject to an ex-post wash-up mechanism, where:[41]

A91.1 a 'wash-up accrual amount' will be calculated for each pricing year, being actual allowable revenue less actual revenue for the pricing year;

A91.2 the wash-up accrual amounts will be accumulated in the 'wash-up account balance' with a time value of money adjustment at the mid-point estimate of WACC as the balance is rolled forward from year to year, with a slight variation in methodology for the balance rolled forward from DPP3 to DPP4; and

A91.3 a 'wash-up drawdown amount' will be calculated for each pricing year and specified in the GTB DPP determination to allow the wash-up account balance to be recovered as a recoverable cost, with the objective of ultimately drawing down the balance to zero over time.

A92 Under the revenue cap, consumers bear the in-period demand risk. The purpose of the annual wash-up mechanism is to ensure that revenue is not over or under recovered during the regulatory period, given the forecast revenue for each year is based on prices multiplied by forecast quantities.

A93 The GTB can set prices in a manner consistent with the relevant transmission and operating codes, but it cannot exceed the revenue cap.

[40] Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28, cl 3.1.1(1).
[41] Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28, cl 3.1.4.

Implementing gas transmission business input methodologies amendments by introducing price path smoothing features (Decision P4)

A94 Our final decision is to implement GTB IM amendments by introducing price path smoothing features, where unrecovered wash-up amounts will be deferred for future recovery.

A95 We did not receive any submissions or cross-submissions on our draft decision. Our final decision is unchanged from our draft decision.

Our reasons

A96 The GTB revenue cap is being carried forward from DPP3 with price path wash-up amendments from the 2023 IM review.[42]

A97 The GTB IM changes to the specification of price provisions made as part of the 2023 IM review and those we are proposing for this reset largely replicate the changes which were made to the electricity distribution businesses (EDB) IMs with respect to the specification of price that applies to EDBs in EDB DPP4 and for this reason, subject to any specific context applying to the GTB, we are adopting many of the price path implementation details from the EDB DPP4 determination.[43]

A98 In the IM review 2023, we made a suite of changes to the revenue wash-up provisions in the GTB IMs including a shift from individual building block wash-ups to a 'one big bucket' approach to wash-ups to aggregate the wash-up calculation and changes to reduce volatility in pricing.[44] For the purposes of the DPP4 reset, the following IM changes are particularly relevant:

A98.1 replace the "annual maximum percentage increase in forecast allowable revenue as a function of demand" with a "revenue smoothing limit";

A98.2 include the voluntary "undercharging limit" on the revenue path for GTBs; and

A98.3 the ability for us to specify the pace of drawdown over subsequent regulatory periods, for the purpose of returning the wash-up account balance towards zero over time.

A99 These IM changes require us to specify the method and amounts for these limits and drawdown pace in the DPP and as such, we have made our decision as part of this DPP reset.

[42] Commerce Commission "Report on the IM Review 2023 - Part 4 Input Methodologies Review 2023 - Final decision" (13 December 2023), Current specification of price IM decision SP02, p.81, para 7.12
[43] Electricity Distribution Services Default Price-Quality Path Determination 2025 [2024] NZCC 28
[44] Commerce Commission "Report on the IM Review 2023 - Part 4 Input Methodologies Review 2023 - Final decision" (13 December 2023), Current specification of price IM decision SP01, pp. 78 – 81.

Gas transmission business revenue smoothing limit (Decision P7)

Limiting inter-period revenue increases under the gas transmission business revenue cap

A100 Our decision is to 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 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.

A101 The 'revenue smoothing limit' is defined in the GTB IMs as:

> means a maximum limit on revenue (excluding recovery of pass-through costs) specified by the Commission in a DPP determination or CPP determination;

A102 This effectively means the limit is to be calculated in the GTB DPP determination as a combination of 'forecast net allowable revenue' and 'recoverable costs'.

A103 We have included the forecast recoverable costs from the prior year in the limit formula in the GTB DPP determination rather than the forecast recoverable costs for the current year because the 'wash-up drawdown amount' for a pricing year is one of the recoverable costs for the current year under the GTB IM determination, and our approach has the effect of limiting any large variation in that drawdown amount that the GTB can recover in any particular year.

A104 Our decision is also to implement the undercharging limit as required by the wash-up provisions in the GTB IMs (similar to EDB DPP4) into the GTB DPP4 determination,[45] but our decision is not to specify a threshold factor for the purposes of calculating the undercharging limit.[46]

A105 We have set a 10% cap as we currently consider a 10% cap reflects a balance between ensuring prices reflect the costs of providing the service and minimising price shocks to consumers, therefore promoting the s 52A purpose.

A106 Our final decision is unchanged from our draft decision.

What we heard from stakeholders

A107 Firstgas submitted on our draft decision.[47] It recommended that we include the current year's forecast recoverable costs in the smoothing limit calculation. It argued that this approach would help to avoid the recovery of balancing costs and fuel gas costs being deferred and placed on future consumers.

[45] Electricity Distribution Services Default Price-Quality Path Determination 2024 [2024] NZCC 28, Schedule 1.5.
[46] Ibid, Schedule 1.7.
[47] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p.36.

A108 Firstgas' concern is with the potential for deferral of some revenue due to the use of variable (*FRC_{t-1}*) in the revenue smoothing limit in the GTB DPP determination. This variable reflects the sum of all forecast recoverable costs for the prior year. It said:

> Firstgas acknowledges the Commission's and MGUG's concerns regarding large in-period increases in transmission prices during DPP3. As highlighted in our submission on the issues paper, revenue wash-ups have been caused by a variety of factors in recent years. We agree that gas consumers can benefit from a pricing regime that limits volatility and promotes predictable outcomes to the extent practicable.
>
> However, we have concerns with the way in which the Commission proposes to implement revenue smoothing, particularly in the treatment of recoverable costs. Under the Commission's draft decision, the amount of revenue that a gas transmission business can earn in a year is a function of the previous year's estimate of recoverable costs.
>
> In our case, recoverable costs are overwhelmingly made up of balancing and fuel gas costs. These costs are very difficult to predict, as the quantity of gas required to balance the transmission system and the price of gas are both difficult to predict. Ideally, the costs of balancing and fuel gas will be borne by the shippers benefitting from that expenditure; that is, from the parties using the transmission system in that year.

Our assessment taking into account stakeholder views

A109 The GTB IMs now include a high-level description of the revenue smoothing limit and the undercharging limit, implemented as part of the suite of changes in the IM review 2023 to better manage inter-period volatility.

A110 The revenue smoothing limit was introduced into the GTB IMs in the 2023 IM review as a secondary revenue smoothing limit that can require the GTB to defer revenue recovery in a present value neutral way. Its purpose is to smooth out any large variations in the GTB revenue cap (and hence consumer pricing), including those resulting from the annual price path wash-up process. This will mean that as far as the carry-forward of any large wash-up accrual amount in the GTB wash-up account balance goes, there will be an effective cap on the amount that can be recovered in prices (ie, revenues).

A111 The IMs do not set the level of the revenue smoothing limit. They require this to be done in a DPP or CPP determination, and for DPP4 this will be described by way of a formula in the GTB DPP4 determination.

A112 This is a new feature that we are porting across from the EDB IMs and we are copying the relevant implementation details into the DPP determination from the EDB DPP4 determination.

A113 The revenue smoothing limit will limit the maximum amount a supplier can charge in any given year with the result that it limits volatility and price shocks by creating an effective 'cap' on the price increases passed to consumers in each year. In setting a DPP, we can set the details (including the amount and form of increases) of the revenue smoothing limit. This means that we may set an amount such that price increases in each year that would not result in a 'price shock'.

A114 The cap limits the amount of the 'forecast revenue from prices' at the sum of the forecast net allowable revenue plus the forecast recoverable costs for the prior pricing year, multiplied by the 'revenue smoothing limit'. In the case of the EDBs we set the formula as the forecast CPI for revenue smoothing plus 10% (ie, effectively a real 10% increase in the recoverable costs each pricing year compared to the prior pricing year).

A115 The revenue smoothing limit we proposed in our gas DPP4 draft decision was based on the same feature that applies to the EDBs under the EDB DPP4 determination,[48] and it limits the extent to which recoverable costs (principally the wash-up drawdown amount) can have the effect of increasing allowable revenues to 10% over and above the CPI-X rate of change.

A116 The revenue smoothing limit does not apply to the initial ex-ante setting of the price path for DPP4. However, it will smooth out how ex-post wash-up amounts calculated during the regulatory period in accordance with the IMs are recovered during the regulatory period.

A117 If the sum of net allowable revenue and recoverable costs exceed the 10% limitation level in any particular year, it will mean any recoverable cost which is not able to be recovered in that year (including an amount in the 'wash-up account balance') will be carried forward in the wash-up account balance in accordance with the GTB IMs to the next year and so on, as applicable. Any carry-forward of the balance will be inclusive of a time value of money adjustment.

A118 We have included the forecast recoverable costs from the prior year in the limit formula rather than the forecast recoverable costs for the current year because the 'wash-up drawdown amount' for a pricing year is one of the recoverable costs for the current year under the GTB IM determination, and this approach has the effect of limiting any large variation in that drawdown amount that the GTB can recover in any particular year.

A119 Under the IMs, the wash-up drawdown amount in any year except the first year of the regulatory period is the wash-up account balance for the pricing year two years prior.[49]

A120 If the formula was based on all forecast current year recoverable costs as submitted by Firstgas, the formula could allow large wash-up drawdown amounts from prior years to be included in the forecast revenues of the later year without any limitations or smoothing deferrals. This could have potential for shock effects in consumer bills if there had been a large buildup in the wash-up account balance two years or more prior to that later year.

[48] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Final decision – Reasons paper" (20 November 2024), paras 4.24.4, 4.28.2, 4.44, and 4.70 to 4.76.
[49] Gas Transmission Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 36, clause 3.1.4(5(a)(ii).

A121 We have applied the formula equally to all recoverable costs in accordance with the definition of 'revenue smoothing limit' in the GTB IM determination. Our reason for including the forecast recoverable costs in this calculation is primarily because the wash-up drawdown amount for a pricing year is a recoverable cost under the GTB IM determination,[50] and this has the effect of limiting the level of the drawdown amount that the GTB can recover in a year.

A122 We have not distinguished the Firstgas compressor fuel gas recoverable costs from the wash-up drawdown amounts or other categories of recoverable costs defined in the GTB IM determination.[51] As a result, if the variations between forecast and actual compressor fuel gas costs end up forming part of an amount of forecast revenue that is limited by this mechanism, the unrecovered amount will be accumulated in the wash-up account balance and rolled forward for future recovery.

A123 Firstgas did not provide quantitative information in its submission to demonstrate the extent of the issues related to balancing gas costs and fuel gas costs, or to show how material these amounts are relative to its total recoverable costs and to its total forecast allowable revenue under DPP3.

A124 Based on the low materiality of the actual Firstgas compressor fuel gas costs in earlier years relative to the total annual Firstgas allowable revenues, we do not consider these costs justify a different treatment than other recoverable costs under the revenue smoothing limit. We consider the pattern of variability of the balancing costs demonstrated in the Firstgas published annual compliance statements is a normal expected revenue smoothing and revenue deferral pattern based on the wash-up process as set out in the IMs is not unusual and does not require any adjustment to the formula we proposed in our draft decision.

A125 We have set the limitation formula and the 10% level of the cap in a way that reflects a balance between ensuring prices reflect the costs of providing the service and minimising price shocks to consumers, both of which will promote the s 52A purpose.

A126 If this 10% limitation binds for a pricing year, the GTB must recover a wash-up drawdown amount that is lower than the wash-up account balance. Under the GTB IM determination the GTB is allowed to set a drawdown amount of between zero and the wash-up account balance two years prior.[52] The GTB would therefore need to set a value that sits within that range that meets the revenue cap requirement to meet the revenue smoothing limit.[53]

[50] Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28, clause 3.1.3(1)(k).
[51] Gas Transmission Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 36, clause 3.1.3(1).
[52] Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28, clause 3.1.4(5)(a).
[53] Ibid, clause 3.1.1(1)(b).

A127 The wash-up account balance set out in the GTB IM determination is reduced in a pricing year by the actual drawn down amount. The rest of the wash-up account balance after application of the revenue smoothing limit will then roll forward until the GTB elects in a future pricing year to recover the remaining balance. Recovery of the wash-up account balance will not be foregone because of this revenue smoothing limitation.[54]

How the revenue smoothing limit can limit the effect of in-period demand shocks for consumers

A128 Under the GTB revenue wash-up any sudden large decline in revenue could result in a large 'wash-up accrual amount' which would enter the wash-up account balance and be able to be recovered by the GTB in future pricing years.

A129 In its submission on our open letter, MGUG comments on large in-period increases in transmission prices in DPP3.[55] Based on our initial review of Firstgas' DPP3 disclosures,[56, 57] a significant part of the changes each year in Firstgas' DPP3 transmission revenue appears to be attributable to larger than expected revenue wash-ups caused by large one-off in-period reductions in demand.

A130 We consider the revenue smoothing limit and the effective cap it creates will address some of the concerns about large in-period increases raised by MGUG.

Default price-quality paths are not used to regulate gas pipeline businesses' pricing methodologies

A131 DPPs set the maximum forecast revenue GPBs can recover and for the GDBs, the resulting maximum aggregate prices it may charge over the regulatory period. We do not set individual prices/tariffs for services provided by the GPBs and we do not regulate the pricing methodology of GPBs through the GDB DPP or GTB DPP. However, the GDB and GTB IMs require GPBs to publicly disclose their pricing methodologies and how they calculate their prices and, for the GDBs, how this complies with the WAPC.[58]

A132 The purpose of ID is to ensure that sufficient information is readily available to interested persons to assess whether the purpose of Part 4 in section 52A of the Commerce Act is being met.[59]

[54] Ibid, clause 3.1.4(1)(d).
[55] MGUG "Submission on Gas DPP4 Open Letter" (13 March 2025), para 24.
[56] Firstgas Transmission "Gas transmission services: Compliance with the wash-up amount calculation and quality standards" (February 2024), Assessment Period 1 October 2022 – 30 September 2023.
[57] Firstgas Transmission "Gas transmission services: Compliance with the wash-up amount calculation and quality standards" (February 2025), Assessment Period 1 October 2023 - 30 September 2024.
[58] Commerce Act 1986, s 53A.
[59] Ibid, s 53A.

A133 Under the GPB ID determinations, the GTB and GDBs are required to make annual disclosures about their pricing methodologies.[60,61] These include demonstrating the extent to which their pricing methodology is consistent with the pricing principles set out in the GTB and GDB IMs.[62] [63] They are required to explain any inconsistencies between their pricing methodology and those pricing principles.

A134 The most recent published GPB pricing methodologies for the 2025 pricing year from 1 October 2024 to 30 September 2025 are published on the GPB websites. [64,65,66,67,68]

A135 Some submitters on our open letter highlighted that some GDBs were recovering a greater proportion of their revenue through fixed charges each year.[69] [70] MGUG suggested that we look at whether GDBs are shifting their demand risk onto consumers by proportionally increasing their fixed revenue recovery from consumers by transferring more revenue to fixed connection charges.[71]

A136 While we have general pricing principles specified in our IMs, our suite of regulation does not prescribe specific limits on how GDBs must set individual tariff levels and we do not assess the balance of pricing.

A137 Under a WAPC form of regulation, the businesses are incentivised to determine a reasonable balance between fixed and variable charges. Excessive fixed charges that cause consumers to disconnect from the network would result in lower revenues to the GDBs that cannot be recouped, whereas under revenue cap regulation, that risk would be removed from the GDB.

A138 The WAPC places intra-period demand risk on the GDBs and gives them an incentive to respond to changes in demand. Under the constraint of the WAPC we expect the GDBs to optimise pricing to maximise revenues, including rebalancing between fixed and variable charges. GDBs that set excessive levels of fixed charges will risk low volume users prematurely exiting the network, leading to worse revenue outcomes for the GDB relative to alternative fixed/variable balances.

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[60] Gas Transmission Information Disclosure Determination [2012] NZCC 24, clause 2.4
[61] Ibid, clause 2.4.
[62] Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28, clauses 2.5.1 and 2.5.2.
[63] Gas Distribution Services Input Methodologies Determination 2012 [2012] NZCC 27, clauses 2.5.1 and 2.5.2.
[64] First Gas "Pricing Methodology for Gas Distribution Services - From 1 October 2024 (Pricing Year 2025)" (30 September 2024).
[65] GasNet "2024/25 Pricing Methodology - Gas Distribution Network Services - Valid from 1 October 2024 to 30 September 2025" (30 August 2024).
[66] Powerco "Gas Distribution Pricing Methodology - October 2024 - September 2025" (September 2024).
[67] Vector "Vector Gas Distribution Services 2025 Pricing Methodology - From 1 October 2024".
[68] Firstgas "Pricing Methodology for Gas Transmission Services - From 1 October 2024" (1 September 2024).
[69] Aluminium Extruders Association of New Zealand (ALENZ) "ALENZ views in response to the Commerce Commission's open letter on Gas DPP4 2026" (12 March 2025), p.1.
[70] MGUG "Re: Open letter on gas DPP4 2026 price-quality path reset" (13 March 2025), para 15.
[71] Ibid, para 21.

A139 Based on the evidence presently available to us, it is not evident that tariff restructuring is inconsistent with s 52A of the Act and we consider they are permitted to do so under the current WAPC.

Attachment B Forecasting capital expenditure

Purpose of this attachment

B1 The attachment explains how we have set capital expenditure (capex) allowances for gas default price-quality path (DPP4).

B2 This attachment sets out:

B2.1 a summary of our decisions for capex allowances (see Table B1);

B2.2 a description of our approach to setting DPP4 capex allowances;

B2.3 how we set capex allowances for gas pipeline businesses (GPBs) related to capex categories including submissions on our draft decision;

B2.4 how we convert constant 2025 $ (2025 $) capex to nominal values; and

B2.5 how we set a revised cost of finance value.

B3 We have performed all capex analysis using historical and forecast expenditure in 2025 $ prices. All expenditure in this attachment is expressed in 2025 $ prices and assessed net of capital contributions[72] unless stated otherwise.

B4 In our draft decision we set out our analysis and draft decisions by capex category for the gas distribution business (GDB) capex categories. The analysis and draft decision by capex category for the gas transmission business (GTB) was set out in a separate section. Here we bring all the analysis together and present our conclusions by capex category across all GPBs (i.e., GDBs and GTB).

Summary of our capital expenditure allowance decisions

B5 Table B1 sets out our capex allowance for GPBs and compares this to our draft decision and GPBs 2025 Asset Management Plan (AMP) forecasts. Figure B1 sets out the actuals AMP forecasts and allowances.

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[72] Capital contributions are money or the monetary value of other consideration that is charged to or received from consumers or other parties for the purposes of asset construction, acquisition or enhancement. Where a GPB receives capital contributions, these reduce the amount it needs to spend on asset construction. Accordingly, we remove capital contributions in establishing capex allowances, these are referred to as “net of capital contributions”. Where we say “gross” forecasts, we are referring to forecasted expenditure before capital contributions have been removed.

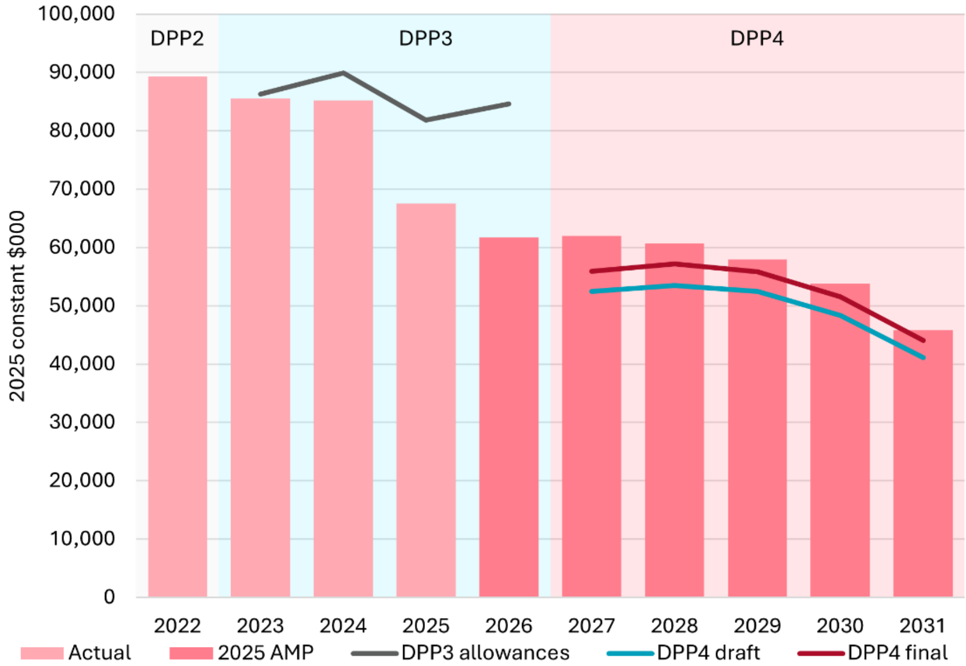
Table B1 Capital expenditure allowances for DPP4 (2025 $000's)

GPB	GPB AMP forecast	Draft decision	Capex allowance[73]	Capex allowance Variance to AMP	Capex allowance Variance to draft decision
Firstgas Transmission	163,922	157,908	158,967	-4,955 (-3%)	1,059 (1%)
Firstgas Distribution	24,067	21,410	21,177	-2,891 (-12%)	-233 (-1%)
GasNet	4,905	2,483	3,735	-1,170 (-24%)	1,251 (50%)
Powerco	71,939	47,207	61,638	-10,301 (-14%)	14,431 (31%)
Vector	19,786	18,743	19,043	-743 (-4%)	300 (2%)
Total	**284,619**	**247,750**	**264,559**	**-20,060 (-7%)**	**16,808 (7%)**

B6 The larger variances for GasNet and Powerco from the draft decision to final are due to increased allowances for system growth and consumer connections due to a change in approach allowing for greater levels of forecasted costs. In addition, asset replacement and renewal values increased for GasNet due to the impact of reference period value changes and for Powerco a decision to provide an additional $1million per annum uplift for resilience related expenditure.

[73] An adjustment is required within our model to account for the misalignment of the disclosure year for Vector and GasNet which applies from 1 July to 30 June, compared to the DPP regulatory year which runs from 1 October to 30 September. No adjustment is required for Powerco and Firstgas as their disclosure year and the regulatory years are aligned.
For Vector and GasNet the Financial model calculates a "BBAR" and the "BBAR&Tax" for each of the six Disclosure years which are within, at least in part, the regulatory period. Then it scales the first year by ~75% (which represents the period 1 October 2026 to 30 June 2027) and the last year by ~25% (to reflect the period 1 July 2032 to 30 September 2032). Following this the present value of those six values are smoothed to determine five years of MAR value.
This adjustment occurs after calculations have been undertaken within other models, including but not limited to the expenditure model. The values within those models are displayed on a disclosure year basis and includes 2032. The 2032 outputs are used in the Financial model and only affect the results for GasNet and Vector.
Within this paper (including both the decision paper and supporting attachments) we have used disclosure years 2027 – 2031 when we refer to "final allowance" for capex for clarity of comparison to AMPs and reconciliation with the values within the expenditure model.
Vector capex allowance when the disclosure years are weighted to reflect the regulatory period would equate to $18,727 (constant 2025 $000s) (not 19,043) with GasNet's allowance equating to 3,696 (not 3,735). The reduction in value arises due to the lower forecasted capex in the 2032 disclosure year compared to 2027.

Figure B1 GPBs historical capex, 2025 AMP forecasts, DPP3 allowances and DPP4 allowances, draft and final (2025 $000's)



B7 The capex allowance is an input to determining the revenues GPBs may earn affecting their profitability, incentives to invest, and ability to deliver gas pipeline services. The values represented here are used within our building blocks model (BBM) approach, which calculates for each GPB a return of capital (depreciation) and return on capital (weighted average cost of capital (WACC) applied to regulatory asset base (RAB) when the assets are forecast to be commissioned during the regulatory period.

B8 Although the capex allowance is not at the outset the biggest contributor to the regulated revenue path, it is important because of the long-term implications for consumers. Once an asset is built, the cost recovery for this asset is spread over many years being both the return on and of capital and requirements for ongoing maintenance.

B9 The capex allowances are a significant decrease from that provided at the DPP3 reset, which reflects the significant reduction in growth-based capex (consumer connection and system growth) and an increasing trend by GPBs towards greater use of opex to maintain existing assets in service, which in some cases results in material reductions in asset replacement and renewal capex.

B10 While we have increased GPBs overall capex allowances from our draft decision, we have not set these as high as the values forecasted within their 2025 AMP forecasts.

B11 We note that the forecasted capex required varies across GPBs, reflecting different views on the ability to reduce capex with increased opex, different commercial outlooks, different regional dynamics and different approaches to capital contributions. We have applied a consistent assessment framework across all GPBs per capex category. Our assessment to establish what framework to apply has considered the reasonableness of underlying drivers across GPBs individually and as a sector.

B12 We have also considered the reasonableness of expenditure across capex and opex categories and have declined step changes in opex for capex-opex trade-offs where we consider these do not clearly correspond to reductions in asset replacement and renewal (ARR) capex forecast.

Capital expenditure allowance decisions applied compared to draft decisions

B13 Table B2 lists our decisions and compare these to our draft decision for each capex policy decision as applied to each capex category.

Table B2 Comparison of draft decisions and our final decisions

Capex policy decision	Draft decision	Final decision
C1: Setting capex allowances	Use the lower of each GPBs' 2025 AMP forecast or the historical average (2020-2024), assessed for each year on a category level for asset replacement and renewals, non-network, reliability, safety and environment, and asset relocation capex amounts.	As per the draft decision except, where applied, the historical average is for a reference period of 2021-2025. Except for: Firstgas transmission (FGT) non-network capex where the reference period is 2020 – 2025. Powerco, an additional $1 million per year is added to ARR historical average capex amount.
C2: System growth capex allowance	Not provide any allowance for system growth.	Cap the system growth capex at the lower of 2025 AMP forecast net of capital contribution or 50% of gross system growth capex in year one (2027) declining linearly to 40% by year five (2031).
C3: Consumer connection	Cap consumer connection capex at the lower of 2025 AMP forecast net of capital contribution or 20% of gross consumer connection capex for each year.	Cap consumer connection capex at the lower of 2025 AMP forecast net of capital contribution or 50% of gross consumer connection capex in year one declining linearly to 40% by year five.
C4: Nominal capex value	Apply the New Zealand Institute of Economic Research's (NZIER's) most recent Capital Goods Price Index (CGPI) inflator series to convert real 2025$ capex to nominal values with no additional adjustment.	As per draft decision.
C5: Cost of finance	Include an allowance for the cost of finance, scaled in proportion to the capex allowance.	As per draft decision.

Approach to setting capital expenditure allowances

B14 Our approach to setting capex allowances for the DPP4 period draws on the approaches we have used in the past, with adjustments to reflect updated GPB forecasts of declining gas production and new gas connections.

B15 We did not receive any stakeholder submission on our overarching approach to setting capex allowances for GPBs as set out in our draft decision and accordingly have maintained our approach by:

B15.1 using GPBs' 2025 AMP forecast as the source for GPB forecast expenditure information, supported by further information provided under requests for information (RFIs) or in submissions;

B15.2 applying a five-year reference period where historical averages were insightful for future capex requirements (not applied for consumer connection or system growth); and

B15.3 setting the capex allowance for each GPB based on the capex category analysis rather than setting an aggregated allowance given the underlining drivers across the categories are sufficiently different.

B16 Our approach applies the lower of the GPBs' 2025 AMP forecasts or our derived values calculated on a category basis for each year of the DPP4 regulatory period.

Using the asset management plans and additional information to assess gas pipeline businesses' forecast expenditure

B17 For each GPB we have used its 2025 AMP as the most appropriate and consistent source of information for GPB forecast information. This approach was supported at the issues paper stage and we did not receive any submissions on our draft decision for an alternative source for expenditure information.

B18 However, for DPP4 capex allowances, we did not consider it appropriate to fully adopt all GPBs' 2025 AMP forecasts.

B19 We have reviewed supporting information contained within the AMPs and those provided in submissions to our draft decision. Where further supporting information was required to understand investment drivers, we issued targeted RFIs.

Establishing the reference period for comparison

B20 We have assessed GPBs' 2025 AMP forecasts compared to their most recent historical average expenditures as disclosed by the GPBs under information disclosure (ID). The exceptions to this general application are system growth and consumer connections capex categories and these are explained in more detail under each of these capex categories.

B21 Where we have used historical averages, we have used a five-year reference period except in the case of Firstgas Transmission (FGT) non-network capex category where we have used a six-year period.

B22 The use of a six-year period for FGT is to minimise the distortion of a 2021 negative outlier since this outlier is related to the reversal of increased spend in 2020.

B23 Our approach reflects a targeted use of the reference period as a starting point for our analysis where expenditure is more likely to be consistent with historical periods. We recognise that future capex requirements are likely to be lower in a declining demand environment, which is consistent with submissions received on the issues paper that historical expenditure may not necessarily be a good predictor of future capex requirements.[74]

B24 Using past expenditure for comparison against future expenditure requirements provides an understanding of relative scale of change and accounts for network characteristics in a relatively low-cost way.

B25 We have retained the five-year duration as the reference period and rolled it forward to include the 2025 year-end information for all GPBs. We consider this best reflects the current operating environment and GPBs' revised expenditure profiles. By averaging over the reference period, we are better able to account for the variability of when assets are commissioned.

How we have set capital expenditure allowances by category

B26 In our analysis we have investigated each capex category individually to gain insight into what was driving expenditure forecasts. The expenditure categories in most instances reflect distinct underlying drivers of cost and accordingly are appropriate to assess individually. However, we have grouped aspects of our assessment of system growth and consumer connection as submissions by GPBs on our draft decision pointed to similar drivers for these capex categories.

B27 The capex categories that we have analysed are:

B27.1 system growth (SG);

B27.2 consumer connections (CC);

B27.3 asset replacement and renewal (ARR);

B27.4 non-network (NN);

B27.5 reliability, safety and environment (RSE); and

B27.6 asset relocation (AR).

[74] Commerce Commission "Gas DPP4 Draft decision reasons paper - Attachments A-H" (27 November 2025), para B9.

B28 While we have assessed capex forecasts at a category level, we determine each GPB’s capex allowance by aggregating the categories. This allowance sets the value of commissioned assets input into our building blocks allowable revenue (BBAR) model for each disclosure year.

B29 Our category level analysis does not represent limits for expenditure categories which GPBs must operate within and GPBs may spend more or less on individual capex categories. We would expect variation to occur during the regulatory period compared to the forecasted levels as GPBs continue to appropriately prioritise expenditure, including balancing with opex alternatives.

Breakdown of gas pipeline businesses’ 2025 asset management plan capex forecasts by category

B30 For each GPB we provide a breakdown of capex forecasts by capex category based on the 2025 AMPs. Figure B2 represents the percentage for each category and Figure B3 the amounts.

B31 Differences in GPBs’ outlooks and approaches drive different expenditure profiles. There are material differences in capex category allocation reflecting differences in views on consumer connection activity, the application of capital contributions and the ability for capex-opex trade-offs to meaningfully defer capex.

Figure B2 Percentage breakdown of capital expenditure by category for all gas pipeline businesses’ 2025 asset management plan forecasts

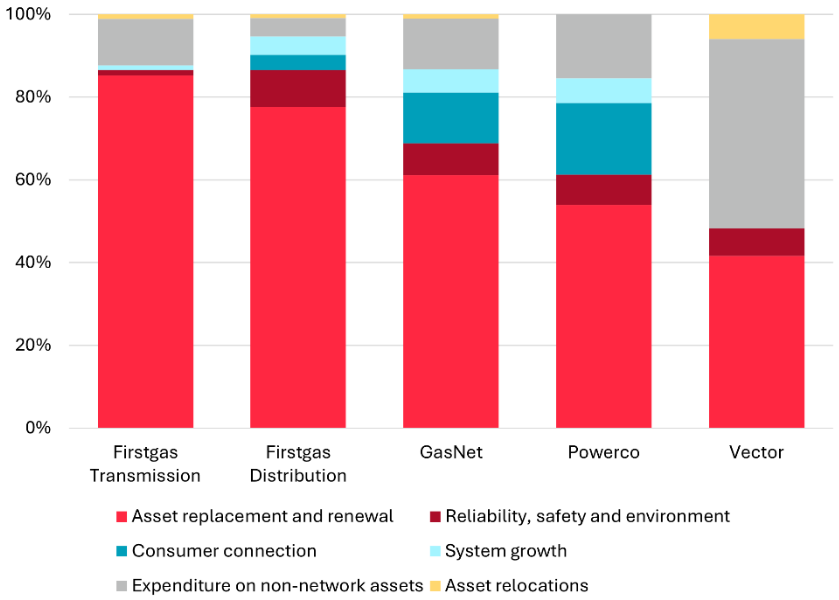
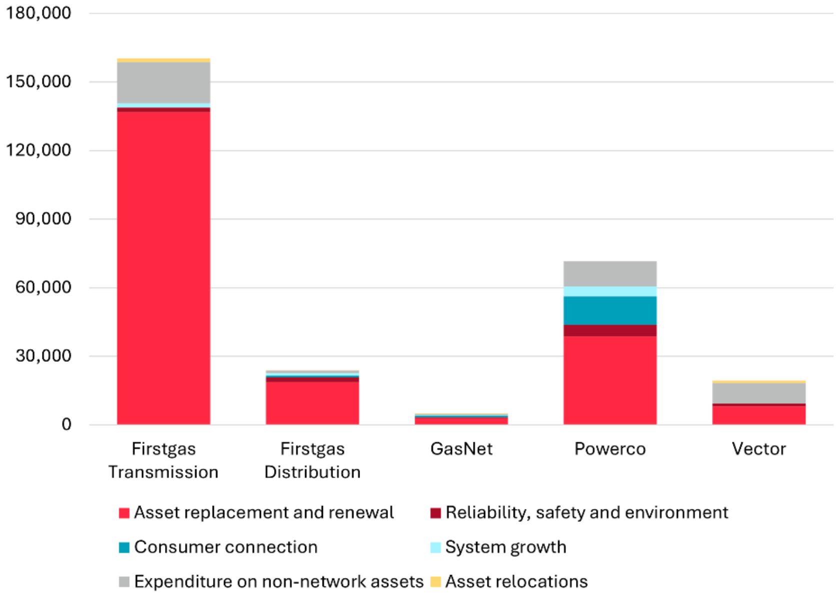


Figure B3 Capital expenditure breakdown by category for all gas pipeline businesses' 2025 asset management plan forecasts (2025 $000's)



Common assessment of system growth and consumer connections

B32 While we have set out our analysis of system growth and consumer connections separately below, we have considered the significant overlap in underlying drivers for these categories.

B33 This is reflected in submissions by Firstgas and Powerco who combined aspects of the rationale for expenditure for system growth and consumer connection capex together given forecasted levels of reticulation of subdivisions are key drivers of both capex categories.[75,76]

B34 Our approach to analysing these growth-based categories has included the following considerations:

B34.1 providing GPBs commercial flexibility to respond, including by increasing network length and connections where this is beneficial to existing customers;

B34.2 minimising additional asset stranding risk;

B34.3 avoiding price shocks which may materially change developer or consumer gas sentiment by considering the impact of step change in capital contribution requirements compared to a graduated decline; and

B34.4 the potential role of renewable gas in providing long-term value to the gas networks (system growth only).

[75] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), Pg.33.
[76] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026),Pg.11.

B35 Given the significant decline compared to historic levels of both consumer connections and system growth expenditure across all entities we have not applied an approach based on historical averages as we do not think it is a reliable predictor of efficient and prudent future expenditure for these categories.

Setting system growth capital expenditure (Decision C2)[77]

B36 Our decision is to allow for system growth capex for each year in DPP4 at the lower of:

B36.1 2025 AMP system growth forecast net of capital contributions; and

B36.2 2025 AMP gross system growth forecasts, scaled down by a factor declining linearly from 50% in year one (2027) to 40% by 2031.

B37 The total amounts from applying this approach are set out in Table B3 and Figure B4. Other than Vector, which had no system growth capex in its 2025 AMP forecast, these are increases from the zero amounts in our draft decision.

B37.1 Firstgas Distribution (FGD) is allowed all its net AMP forecast. Due to high forecast capital contributions, their net AMP values were less than the capped gross values;

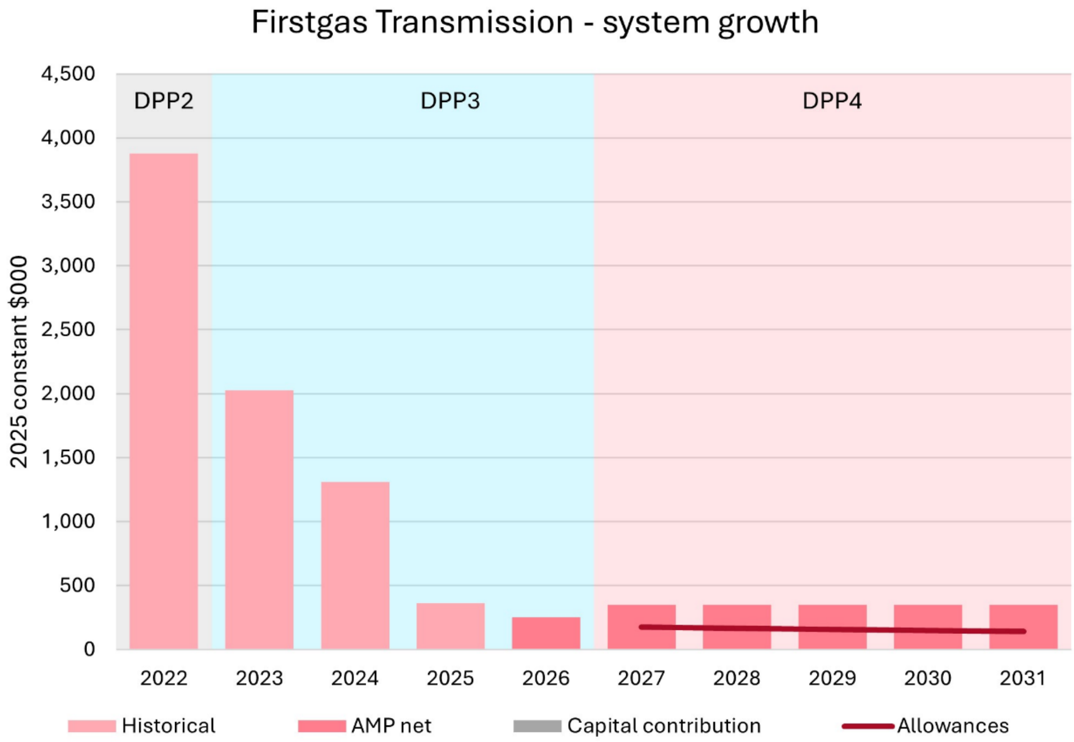
B37.2 FGT, GasNet and Powerco all have their net AMP values capped by the fractional gross forecasts.

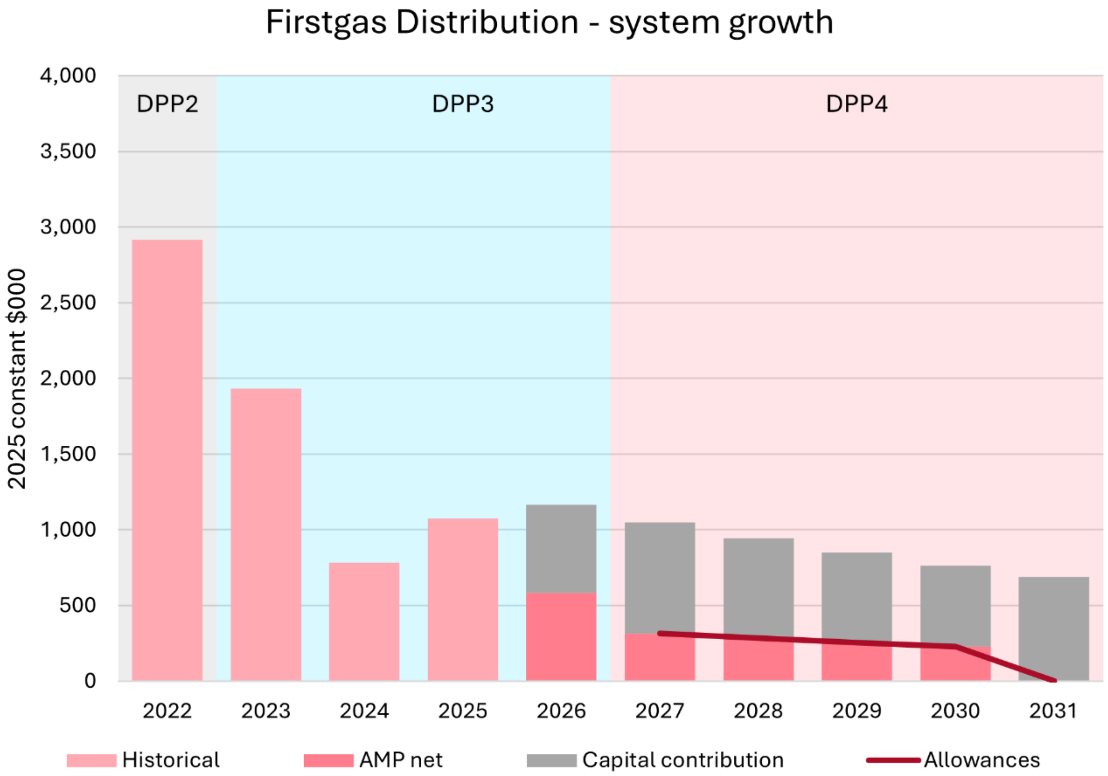
Table B3 System growth capital expenditure asset management plan forecast, amount and variance (2025 $000's)

GPB	AMP forecast	Draft decision	DPP4 amount	DPP4 amount – Variance to AMP	DPP4 amount – Variance to draft
Firstgas Transmission	1,750	0	788	-963 (-55%)	788
Firstgas Distribution	1,082	0	1,082	0 (0%)	1,082
GasNet	275	0	127	-148 (-54%)	127
Powerco	4,322	0	2,665	-1,657 (-38%)	2,665
Vector	0	0	0	0 (0%)	0

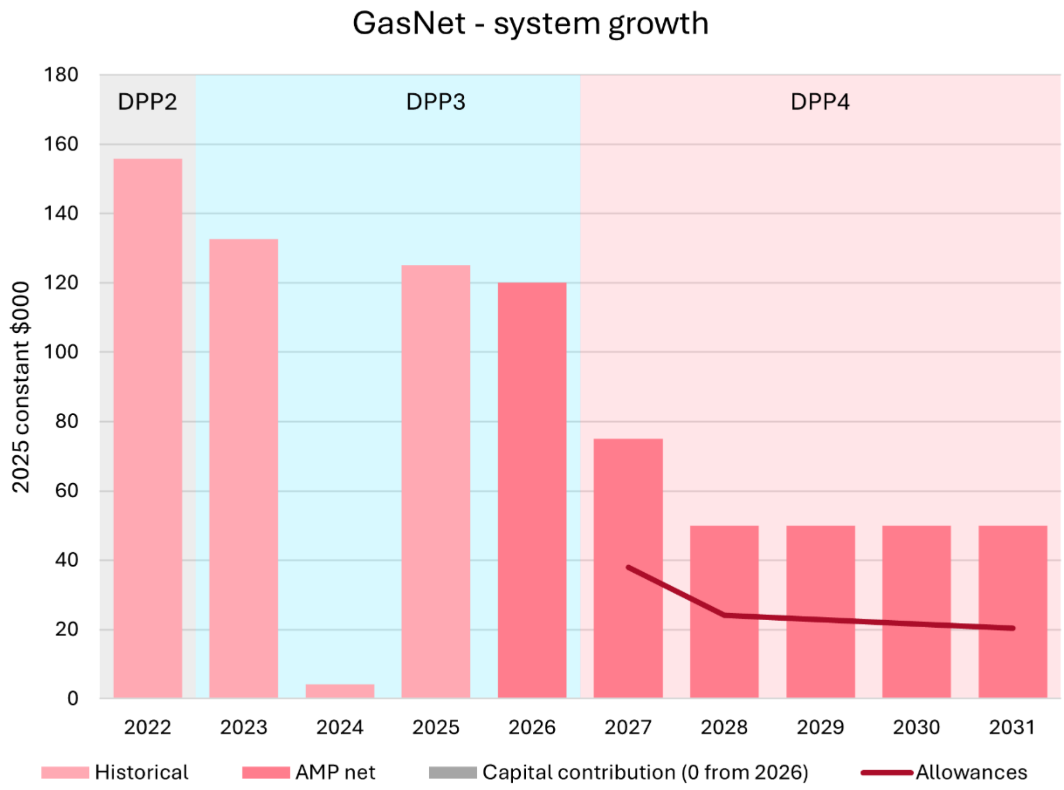
[77] System growth capex covers expenditure on assets where the primary driver is a change in demand on the part of the network which results in a requirement for either an additional capacity to meet this demand; or additional investment to maintain the current security and/or quality of supply standards due to the increased load.

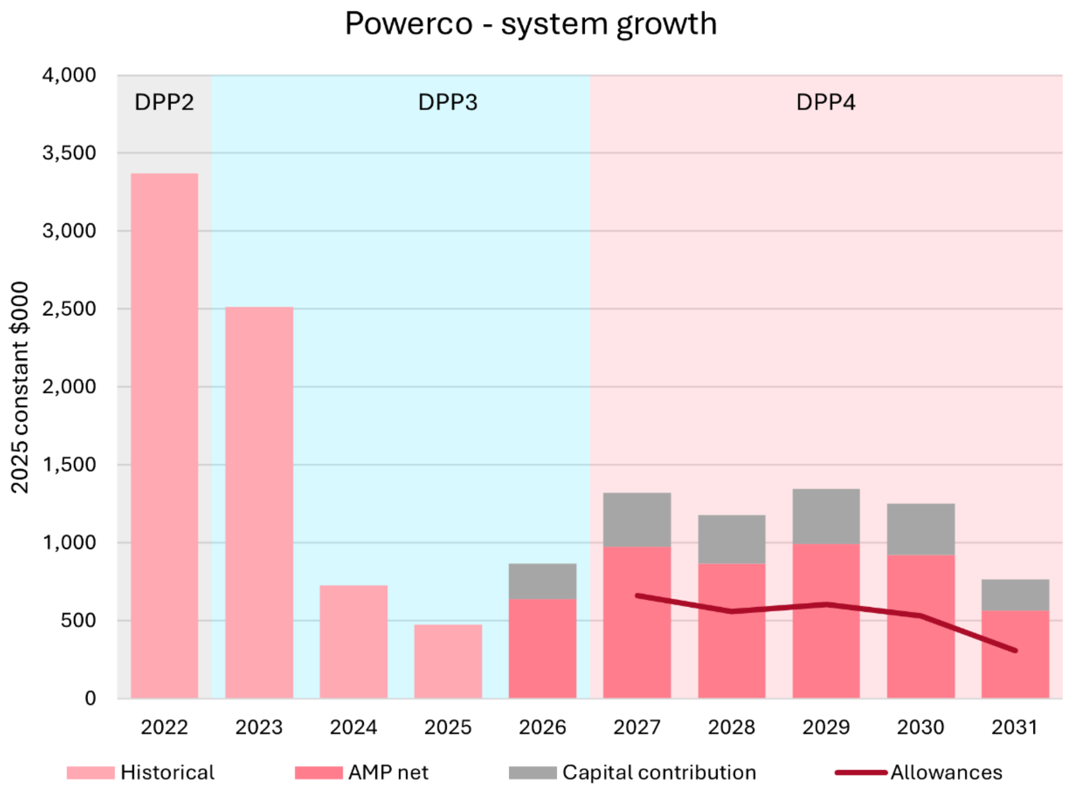
Figure B4 System growth capital expenditure actuals, asset management plan forecast, and historic averages (2025 $000's)[78]





[78] Historical values are expressed net of capital contributions. Negative values arise where the level of capital contributions received for that category exceeds the level of gross capex.


GasNet - system growth
180
160
140
120
100
80
60
40
20
0
2025 constant $000
DPP2
DPP3
DPP4
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Capital contribution (0 from 2026)
Allowances


Powerco - system growth
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2025 constant $000
DPP2
DPP3
DPP4
2022
2023
2024
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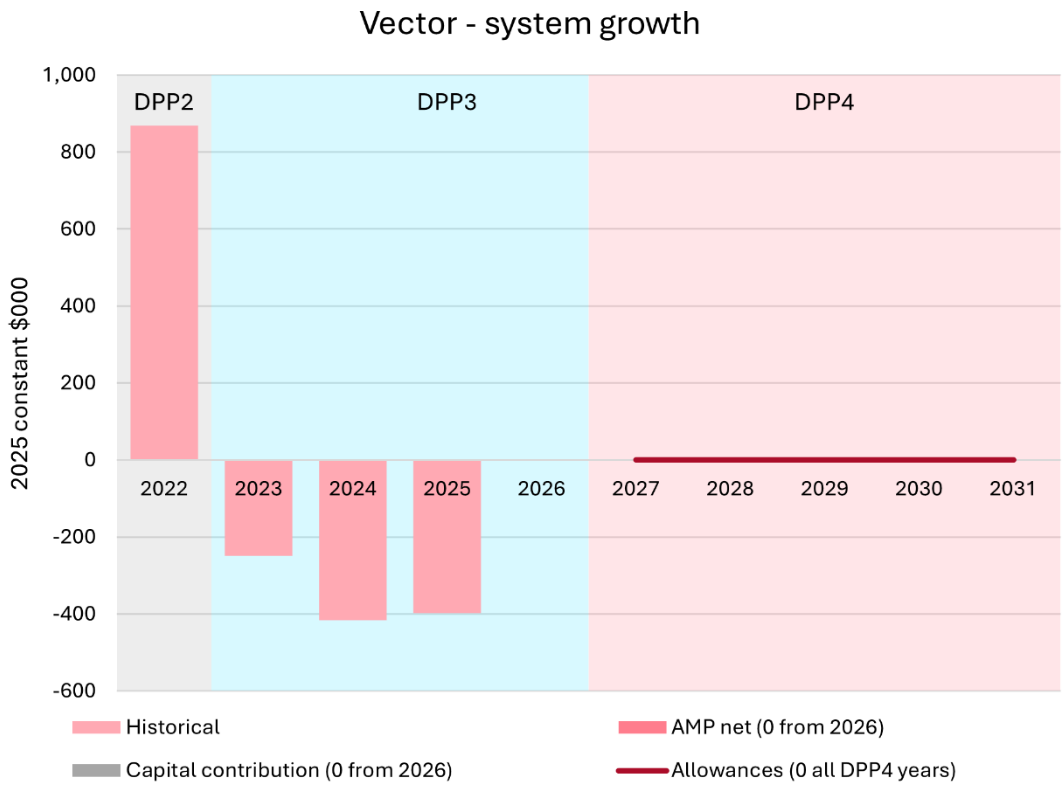
Historical
AMP net
Capital contribution
Allowances



Submissions on our draft decision on system growth

B38 Our draft decision rejected all system growth expenditure on the basis that GPBs' demand forecasts and sector growth trend did not sufficiently support the investment need.[79]

B39 The draft decision also noted that to mitigate the risk that rejected system growth expenditure is needed over the DPP4 period, GDBs may apply for a capacity event reopener with a system growth driver, should better information become available.

Mercury and Rewiring Aotearoa

B40 Mercury supported our draft decision and submitted that it is not appropriate to provide for any system growth capex for any GPB in the context of an outlook of declining gas use.[80]

B41 Rewiring Aotearoa supported our draft decision to not allow for system growth capex and stated that GPBs should ensure new connections pay their way and do not impose costs on the existing consumer base.[81]

B42 Rewiring Aotearoa also stated:[82]

[79] Commerce Commission "Gas DPP4 Draft decision reasons paper - Attachments A-H" (27 November 2025), para B72, p.35.
[80] Mercury "Submission on Gas DPP4 Draft Decision" (16 January 2026) Pg.1.
[81] Rewiring Aotearoa "Rewiring Aotearoa submission on the Gas DPP4 reset 2026 Draft Decision" (22 January 2026), Pg.2.
[82] Rewiring Aotearoa "Rewiring Aotearoa submission on the Gas DPP4 reset 2026 Draft Decision" (22 January 2026), Pg.2.

> Whilst we acknowledge that there will be benefits from more customers connecting to the gas distribution network as ongoing costs can be shared over a large pool of customers, we think on balance it is in the best interest of gas customers to require new connections to cover the full capital cost of their connection up-front.

Energy Resources Aotearoa

B43 Energy Resources Aotearoa requested a flexible framework, which includes allowances for system growth. It stated:[83]

> If capex allowances are removed too steeply, the signal to developers and medium-large businesses looking to connect is not subtle. It effectively says that the gas network may not be there when you need it. Even if that is not the Commission's intent, that is how the signal is likely to be read.
>
> Developers and new customers need confidence that connections will be available and that service quality will be maintained over the lifetime of their investment. With tightly constrained allowances (i.e., the developer pays nearly all of the capex, which is not status quo), developers may face higher up-front connection charges or require bespoke funding arrangements. This introduces unquantifiable risk, which is often enough to rule gas out.
>
> We recommend a balanced and flexible framework that enables distributors to invest growth capex and connections capex to suit forecast development and types of customer connections in their network area. Flexibility of this kind will help retain consumer options where this is shown to be justified, which should be most of the network in the medium-term at least.

Firstgas

B44 Firstgas focused on settings for the GDB stating:[84]

> The Commission's direction for capex spend across new connections and system growth aligns with Firstgas' intended strategy over the course of DPP4 period. The first stage of this strategy will be to implement a new capital contribution policy from 1 April 2026 allowing a maximum cap of 40% Firstgas spend across all customer-initiated capital expenditure. This is higher than the 20% contribution assumed in the draft decision.

B45 We note that the representation here reflects our draft decision on consumer connection when referring to contribution percentages rather than our draft decision of not providing any system growth capex.

B46 Firstgas also mention that "selected growth can still provide consumer value and support energy choice but costs should be weighted towards direct beneficiaries to avoid adding to the risk of future price shocks".[85]

[83] Energy Resources Aotearoa "Cross-submission on the Default Price-Quality Path 4 (DPP4)" (12 February 2026) Para.12-14,Pg.3.
[84] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), Pg.35.
[85] Ibid, Pg.2.

Powerco

B47 Powerco stated that excluding growth capex and reducing connection capex would limit the tools available for GDBs to manage demand risk under a weighted average price cap (WAPC) and over the long-term could result in:[86]

B47.1 Underserving customers as decision-making shifts to short-term cost minimisation where demand is lower than assumed for the WAPC;

B47.2 Rate shocks due to DPP5 WAPC calculations with lower forecast volumes;

B47.3 Reduced incentives to invest efficiently given limitations in tools to manage demand compared to DPP3; and, ultimately

B47.4 Accelerating network stranding by making it harder to offset demand reduction through new connections.

B48 Powerco provided the most extensive submission to support increased system growth capex. It requested we increase the draft decision allowance by $3.056 million to account for forecasted network growth focussing on:[87]

B48.1 system expansion for residential subdivision reticulation; and

B48.2 connecting renewable gas opportunities.

B49 Powerco also submitted commercially sensitive confidential information substantiating the assertions in its public submission of a pipeline of forward connections:[88]

> Our growth capex forecast is supported by clear evidence of sustained (while regionally diverse) demand for new connections from subdivisions currently progressing on our network. We track confirmed subdivision gas enquiries expected to proceed, alongside a reasonable (but reducing) uptake in the remainder of the new housing construction market.

B50 Powerco focused on its strong relationships with residential subdivision developers to outline expected future subdivision activity where gas connections will be part of the development.

B51 Powerco's submission outlined that recent levels of system growth capex may have been lowered by depressed developments and that it expected this to change, with an improvement in general economic conditions. This was supported by a declining trend in new electricity connections which was comparable to the decline in gas connections.

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[86] Powerco "Gas DPP4 draft decision - stability as the transition becomes clearer" (22 January 2026), Para 6, Pg.5.
[87] Ibid, S.2, Pg.11, 13.
[88] Ibid, Para 16, Pg. 11.

B52 Powerco also outlined why it considered a capacity event reopener is not an option in these circumstances to support inclusion in the up-front allowance "the cost for each subdivision, or a staged subdivision within the 5-year period is well under the threshold of $2 million, generally less than $250,000." [89]

B53 It also represented that it is in the long-term interest of tomorrow's consumers to provide incentives to support a wider future consumer base over which to spread the future cost burden:[90]

> Requiring 75 – 100% customer contributions is removing customer choice and likely to quickly reduce customer numbers causing a greater impact for consumers of tomorrow

Major Gas Users Group (MGUG)

B54 MGUG in its cross-submission provided some overall support for Powerco's submission. Of relevance to system growth capex, MGUG agreed that "GDBs need incentives to invest in repurposing and growth opportunities" and was opposed to the introduction of new costs.[91]

Vector

B55 Vector submitted in support of not allowing for system growth capex in DPP4, consistent with its asset management plans, which assume no growth investment in the context of declining gas demand, and it submitted that allowing system growth capex would increase stranded asset risk and transfer growth-related costs to existing consumers.[92]

B56 Vector instead focused on connection policy, submitting that new connections should be largely or fully funded by connecting customers to avoid cross-subsidisation, and did not seek or support any system growth capex allowance in its submission or cross-submission.[93,94]

Analysis

B57 GPB system growth forecasts for the DPP4 regulatory period are driven by two primary components, subdivision reticulation and renewable generation connection, these are discussed respectively in the following sections.

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[89] Powerco "Gas DPP4 draft decision - stability as the transition becomes clearer" (22 January 2026), Para 22, Pg. 13.
[90] Ibid Para 31, Pg.16.
[91] MGUG "Re: cross-submission on Gas DPP4 draft decision" (12 February 2026) Para. 3, Pg.3.
[92] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026) Pg.7.
[93] Vector "2025-2035 gas distribution asset management plan", section 7.3, System growth
[94] Vector "Cross-submission on the default price-quality path for gas pipeline businesses beginning 2026" (12 February 2026) Para. 52, Pg.11.

Subdivision reticulation

B58 GPBs differ in their future outlooks for system growth which includes uncertainty around the demand for gas reticulation, regional development potential as well as the wider economic environment.

B59 Powerco note that it is seeing evidence of sustained demand for new connections, although regionally diverse, and expect the market to rebound from the slower housing construction over the past three years. The downward trend over the last three years was evident for both gas and electricity.[95]

B60 Powerco provided direct, albeit confidential, evidence of a pipeline of subdivision work where proposed reticulation is likely to occur as well as the rate of uptake on existing new subdivisions.

B61 The analysis provided by Powerco outlined a compelling case regarding a reasonable pipeline of system growth capex supported by historical knowledge of subdivision reticulation and engagement with developers. Powerco provided detail outlining its:[96]

B61.1 knowledge of confirmed subdivisions proceeding in the DPP4 period where Powerco have strong confidence in gas connections based on previous stages of these subdivisions, the specific developer sentiment on gas, or recent information from that developer, which was supported by a confidential detailed listing of subdivisions;

B61.2 assumed connections, how Powerco applies regional uptake rates, with an additional 10% reduction to reflect some lowering of consumer gas sentiment for new connections; and

B61.3 potential in other subdivisions, where some uptake could occur but Powerco have not assumed connections at this stage.

B62 While Powerco has reduced the number of connections forecast within subdivisions compared to historical levels, this is an important factor in determining the economics of investment to expand its network. If consumer and developer sentiment towards gas declines, the risk these extensions are non-economic increases.

B63 Powerco's 2025 AMP reflects a relatively constant level of gross system growth capex increasing from the most recent years but significantly decreased from longer-term historical levels. The moderate increase from recent years (2024 and 2025) was supported by evidence of the decline being attributable to the economic downturn, rather than a clear reflection of a change in sentiment on gas.

B64 We are aware that GPBs are actively considering the level of capital contributions they may require during the period and note that Powerco is forecasting a constant level of capital contributions for system growth (26%) across the DPP4 regulatory period.

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[95] Powerco "Gas DPP4 draft decision - stability as the transition becomes clearer" (22 January 2026), Para.16, Pg.11.

[96] Ibid S2.1, Pg.11-13.

B65 FGD did not provide similar level of substantive evidence on subdivision activity. It's 2025 AMP however forecasts declining system growth capex across the DPP4 period (10% reduction year-on-year) with a higher, but constant level of capital contributions at 70% of gross system growth capex, until 2031 when it has forecasted moving to a 100% capital contribution policy.

B66 FGD's submission aligns with its position in its 2025 AMP which outlines that system growth investment, including upgrading capacity, to develop its distribution network are primarily driven by demand growth and changing behaviours and needs of its customers.

B67 We note the FGD 2025 AMP provides a reasonable representation regarding the difficulties in forecasting system growth capex:[97]

> This decrease in system growth activity mirrors broader uncertainties regarding future demand for gas distribution and the risks associated with stranded infrastructure. Declining uptake could result in underutilised assets and unrecovered capital investment. Our approach to system growth and subdivision reticulation is currently under review, and we expect to implement significant changes prior to and throughout DPP4. These changes will ensure that investment into new developments, particularly residential subdivisions are de-risked and contribute more equitably to the expansion and extension of the distribution network, thereby safeguarding existing customers and the business from increased exposure to stranded asset risk.

Connection of renewable gas projects

B68 Only Powerco and FGT have included connection of renewable gas projects within their system growth AMP forecasts with these representing $0.98 million for Powerco and $1.75 million for FGT.

B69 Powerco's submission highlighted its confidence that biomethane will be injected into its network during the DPP4 period.[98] Powerco's submission outlined the three key projects that it considers will likely advance in DPP4, and that there may also be other projects commenced later in the period or projects advanced by other parties that will inject into the network.

B70 Powerco outlined that providing funding for system growth capex for renewable gas maintains incentives for investment and provides a key customer benefit of maintaining optionality and choice.

B71 Information submitted in confidence by Powerco provides clear representations of projects which are likely to progress and reflect cost estimates. We consider there is an element of risk with accepting the full forecasts as some of the Powerco projects are early stage and that Powerco also has related financial interests outside of the regulated gas pipeline service.

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[97] Firstgas Distribution "Asset Management Plan - Distribution" (30 September 2025), Summary Pg.18
[98] Powerco "Gas DPP4 draft decision - stability as the transition becomes clearer" (22 January 2026), Para. 55, Pg.22.

B72 While Powerco has represented a reasonable rationale for supporting renewable growth expenditure the justification has not necessarily been well supported on a basis of incremental revenue exceeding incremental cost, given the more speculative nature of the forecasts but on a wider more generic basis.

B73 We consider that while some allowance would be appropriate to facilitate investment in renewable gas infrastructure, a greater expectation of capital contribution may be appropriate to ensure the projects are less likely to result in stranded assets whose value have not been recovered from the connecting party, and therefore the expenditure is more likely to be for the long-term benefit of consumers.

Firstgas Transmission

B74 The FGT AMP states the system growth capex forecast is to "accommodate potential blended gas opportunities should they emerge". It did not provide a submission with detail to support any related expenditure and is forecasting no capital contributions for system growth.[99]

B75 Similar to Powerco, we consider an approach which requires a higher level of capital contributions to ensure the projects connected are financially viable and do not result in new connecting customer imposing additional costs on existing consumers is appropriate.

Potential application of reopener

B76 Submissions noted concerns raised about the threshold for the capacity event reopener ($2m after capital contributions for Vector, Firstgas and Powerco, $100k for GasNet).[100,101]

B77 While GPBs can apply for the capacity event reopener in respect of a programme rather than individual project basis we acknowledge there will be concerns on the level of certainty which may be available to include projects forecasted to occur later in the regulatory period.

B78 We consider it is not appropriate to reconsider the reopener threshold for this or other capex categories as:

B78.1 the thresholds were considered in the 2023 IM review. This is beyond the scope of the DPP4 reset and is not sufficiently material in terms of promoting the s 52A purpose that we consider it is necessary to consider an IM amendment for it outside of our statutory IM review cycle;

B78.2 there are other levers which GPBs can use to manage capex allowances including the level of capital contributions required;

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[99] Firstgas Transmission "Asset Management Plan - Transmission" (30 September 2025), Figure 4.2, Pg.18.

[100] Powerco "Gas DPP4 draft decision - stability as the transition becomes clearer" (22 January 2026), Pg.1.

[101] Gas Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 37, Clause 4.4.11(3), Pg.97.

B78.3 GPBs are incentivised to invest to grow the network under a WAPC, and accordingly we consider there is less likely to be investment holdout, where capex investments required which are not explicitly provided for within allowance levels do not occur.

Conclusion

B79 Our decision is to cap system growth capex at the lower of 2025 AMP forecast net of capital contributions and 2025 AMP gross system growth forecasts, scaled down by a factor declining linearly from 50% in year one (2027) to 40% by year five (2031).

B80 While the wider contextual information on demand forecasts and sector growth trends are for declining consumption (and therefore limited growth) there are pockets of investment based on information submitted, which to the extent they are net beneficial to the network through increasing the number of consumers that contribute to shared and common costs are appropriate.

B81 GPBs are closer to the network demands, regional growth opportunities and their pricing structures to assess whether extending sections of the network will be in the long-term interests of their consumers.

B82 We consider our approach balances providing GPBs flexibility to respond, including increasing network length where this is net benefit to existing customers while managing the risk of potential asset stranding.

B83 In addition, the connection of renewable gas should improve the availability of gas supply to consumers, while providing long-term optionality for the networks and consumers.

B84 Our final decision is to introduce a reducing cap (linear decline from 50% to 40% across the regulatory period), which better reflects our expectation of GPBs increasing the level of capital contributions to progressively limit further exposure to network stranding risk over the period. We consider an implied 50% capital contribution reducing over the period better reflects the increased expectation of the continued greater role of capital contributions which aligns with signals from GPBs of ongoing consideration of this factor.

B85 A progressively increasing reliance on capital contributions provides greater time for GPBs to respond flexibly and provides a more extended time frame for the pricing signal to connecting parties of an increased capital contribution requirement. We expect the GPBs to continue to assess the effectiveness of their capital contribution policies and commercial arrangements with new consumers in enhancing the overall economics of their networks throughout the regulatory period.

Setting consumer connection capital expenditure (Decision C3)[102]

B86 Our decision is to allow for consumer connection capex for each year in DPP4 at the lower of:

B86.1 2025 AMP consumer connection forecast net of capital contributions; and

B86.2 2025 AMP gross consumer connection forecasts scaled down by a factor that declines linearly from 50% in year one of the regulatory period to 40% by year five.

Impact of decision and comparison to historical expenditure levels

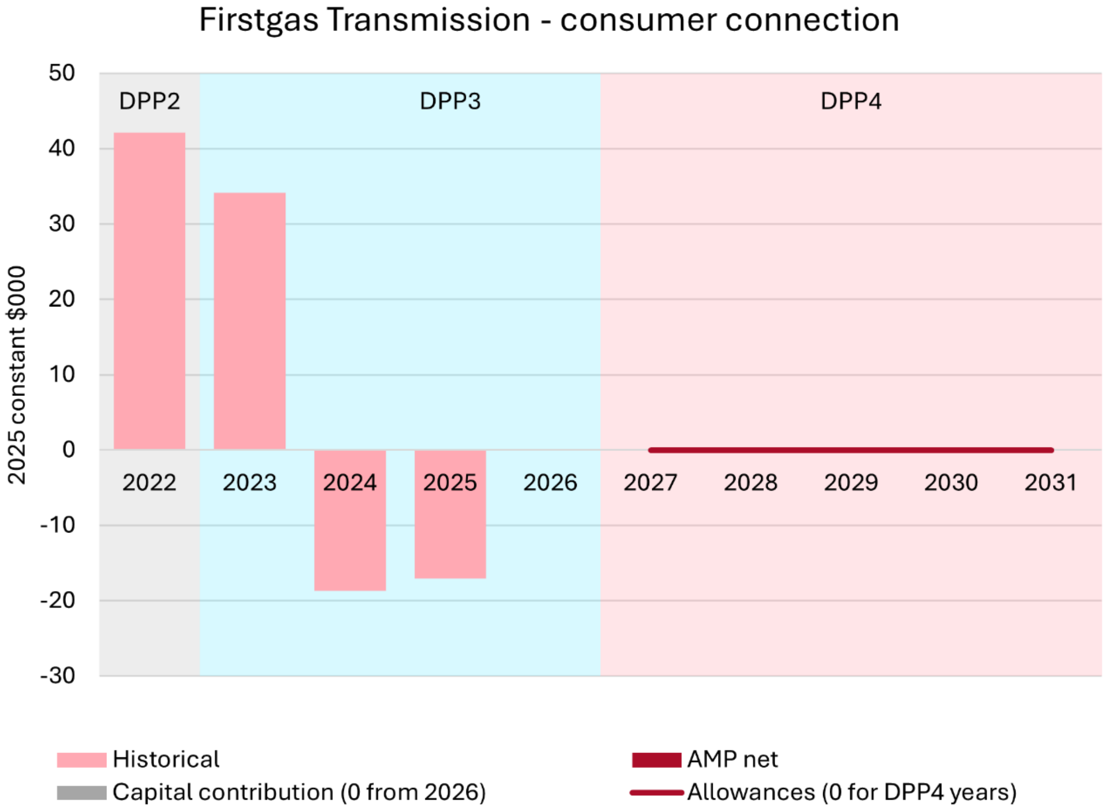
B87 The outcomes of this decision and comparisons with recent actuals are set out in Table B4 and Figure B5.

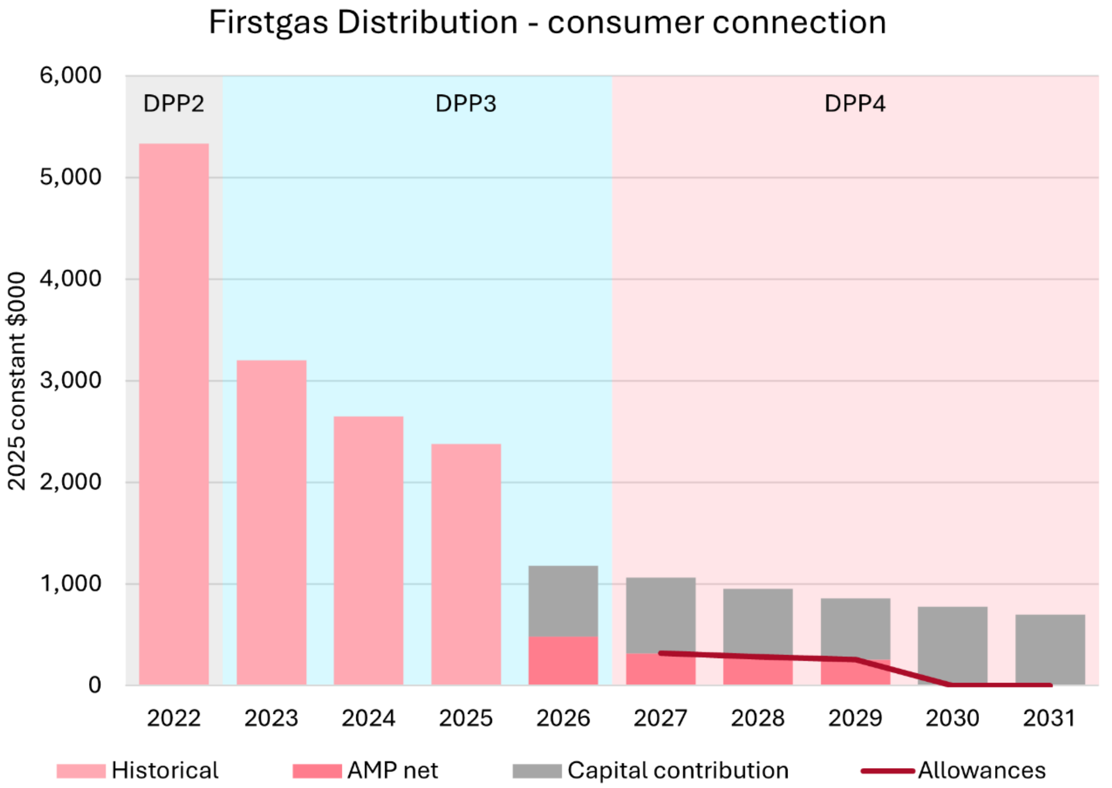
Table B4 Consumer connection capital expenditure asset management plan forecast, draft decision, DPP4 amount and variances (2025 $000's)

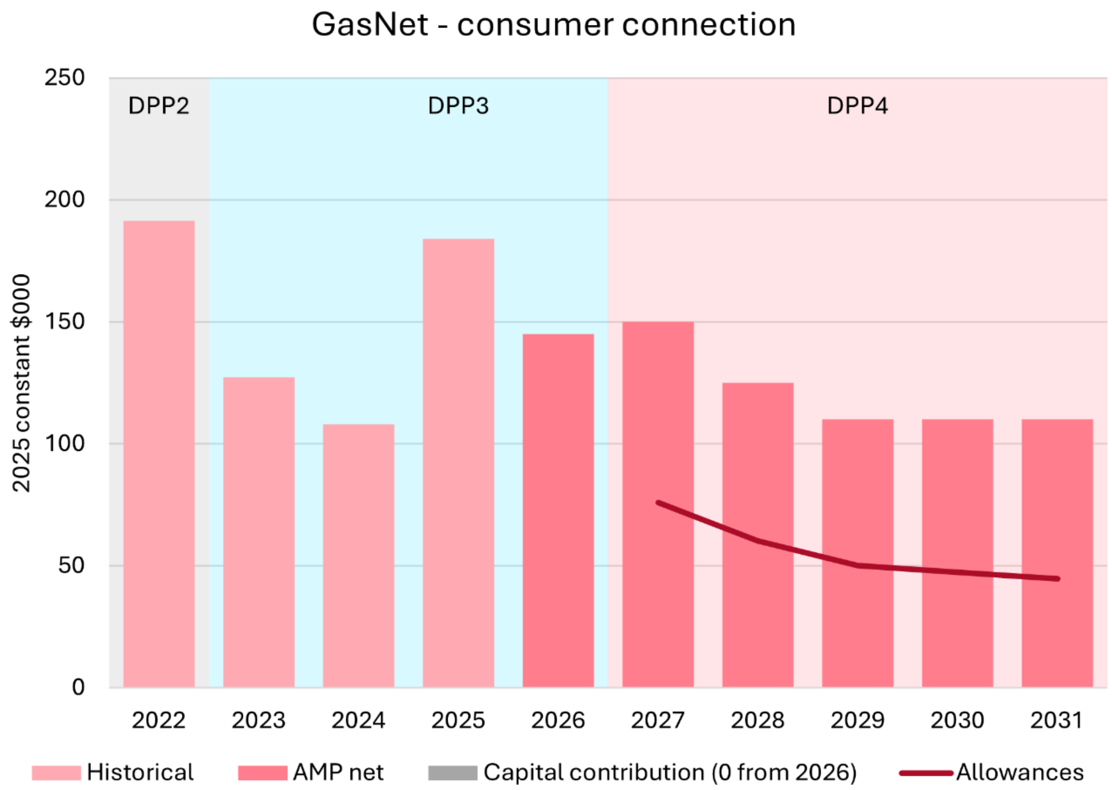
GPB	AMP Forecast	Draft decision	DPP4 amount	DPP4 amount – Variance to AMP	DPP4 amount – Variance to Draft
Firstgas Transmission	0	0	0	0 (0%)	0 (0%)
Firstgas Distribution	862	574	862	0 (0%)	288 (50%)
GasNet	605	121	278	-327 (-54%)	157 (130%)
Powerco	12,319	3,062	6,887	-5,433 (-44%)	3,825 (125%)
Vector	0	0	0	0 (0%)	0 (0%)

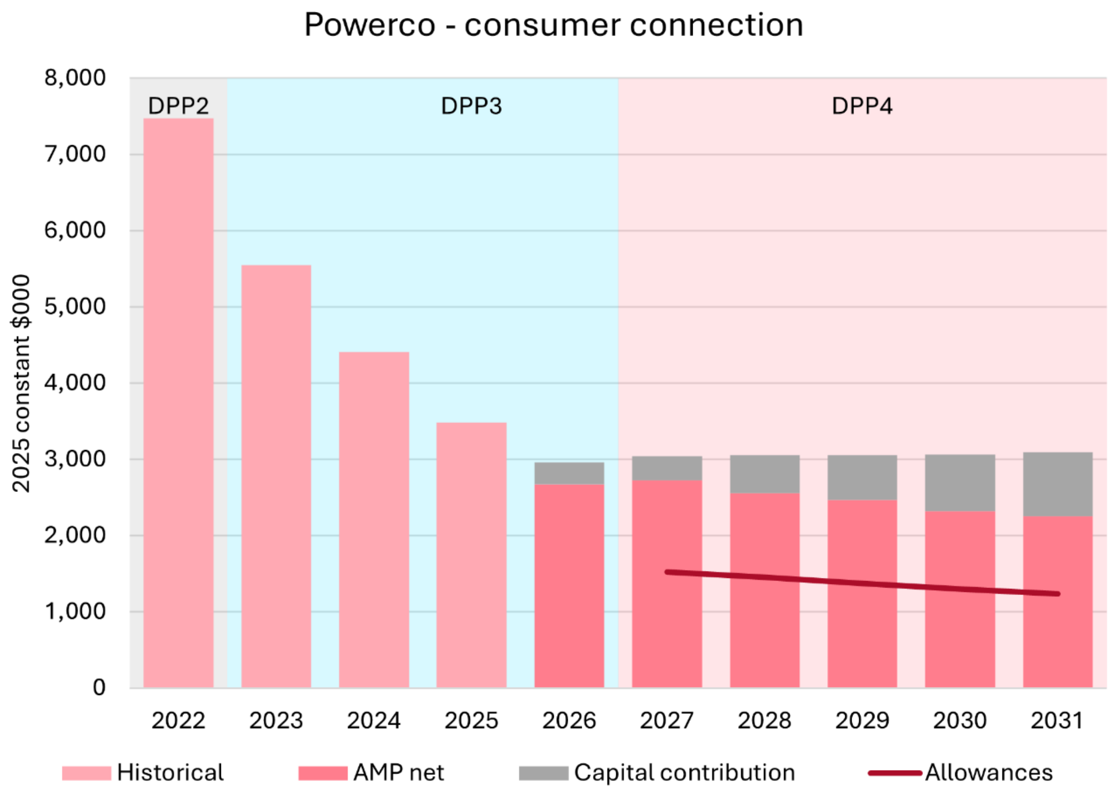
[102] Consumer connection means, in relation to expenditure, it is expenditure where the primary driver is the establishment of a new customer connection point or alteration to an existing customer connection point. This capex category includes expenditure on assets relating to: connection assets and/or parts on the network for which the expenditure is recoverable in total, or in part, by a contribution from the customer requesting the new or altered connection point; and both gas injection and offtake points of connection.

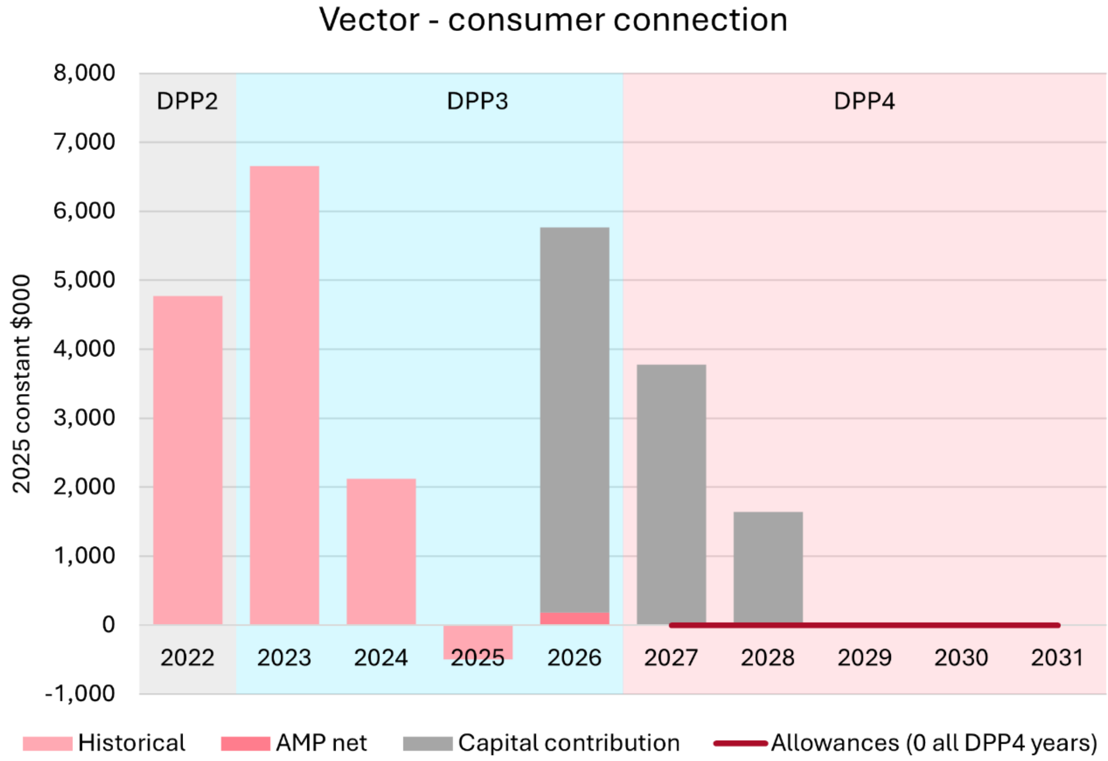
Figure B5 Consumer connection capital expenditure actuals, asset management plan forecast and historic averages (2025 $000's)






GasNet - consumer connection
2025 constant $000
250
200
150
100
50
0
DPP2
DPP3
DPP4
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Capital contribution (0 from 2026)
Allowances


Powerco - consumer connection
2025 constant $000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
DPP2
DPP3
DPP4
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Capital contribution
Allowances



Draft decision and rationale

B88 Our draft decision was to cap consumer connection capex at the lower of the 2025 AMP forecast net of capital contribution or 20% of gross consumer connection capex, assessed individually for each year of the regulatory period.[103]

B89 We noted with the approach we were seeking to incentivise GPBs to assess whether, and at what level of capital contributions will ensure that the incremental revenue from new connections will exceed the incremental cost, recognising that consumer connection expenditure which meets this standard will be in the long-term interests of network consumers.

Submissions to our draft decision on consumer connection capital expenditure

B90 Submissions generally accepted that, in a declining-demand environment, new connections should not impose costs on existing consumers. Differences focused on the appropriate level of customer contributions and the extent to which contribution requirements should be applied rigidly or with flexibility over time. Those in support of high or full customer funding of new connections, noted that new customers should largely or fully pay their own connection costs to avoid cross-subsidisation and protect remaining consumers.

[103] Commerce Commission "Gas DPP4 Draft decision reasons paper - Attachments A-H" (27 November 2025) B52-B71.

B91 Mercury “agrees that existing customers should not bear any costs associated with new gas connections and that all new connections be self-funded”[104]

B92 Powerco submitted we should:[105]

> Retain flexibility in customer contributions through higher consumer connections capex. Mandating significant change in customer contributions is not prudent. Flexibility to enable a range of customer contribution options will provide efficiency and benefit for all customers. Consumer choice through balanced connection contributions supports energy affordability for all customers.

B93 Powerco’s submission outlined its forecast subdivision growth as a key driver of consumer connection capex. In addition, it noted: [106]

> There are also approximately 1,000 lots in subdivisions already reticulated in the last three to four years that have been slow to sell due to the economic conditions but as conditions improve, these lots represent a near-term source of additional connections.

B94 Powerco provided detail to support that its approach “exceeds the incremental cost, accounts for impact/benefit on the connecting customer and all customers, while ensuring changes to contributions are managed at a reasonable rate of change.”[107] This included representations of how customer contribution calculations are derived.[108] As well as actual examples of its workings for customer contribution calculations which showed a range of capital contribution requirements and an assessment of incremental revenue vs incremental cost as well as different factors that it has considered.

B95 Powerco’s view is its flexibility allows it to consider health of a particular network, size of investment and return timing and notes “With considerable uncertainty across all elements of the market (policy, demand, supply) ... bold changes in contributions approach may have unintended consequences....”[109]

B96 Powerco in its cross-submission state:[110]

> Powerco’s experience is that flexible capital contributions are a critical tool to manage demand risk. Mandating 100% up-front costs would remove consumer choice and accelerate network stranding by making it impossible to offset demand reduction through new connections.
>
> Managing customer contributions now, and through a managed changed programme supports a prudent and balanced approach to affordability and efficient cost recovery.

B97 Firstgas submitted that the level of cap should be increased from the 20% cap proposed at draft to 40%:[111]

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[104] Mercury "Submission on Gas DPP4 Draft Decision" (16 January 2026) Para. 4, Pg.1.
[105] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), Summary of positions, Pg.11.
[106] Ibid, Para.17, Pg.12.
[107] Ibid, Para.24, Pg.14.
[108] Ibid, Table 2, Pg.14.
[109] Ibid, Para.29, Pg.15.
[110] Powerco “A stable regulatory environment is the best response to issues raised in submissions” (12 February 2026), S.2, Pg.4.
[111] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), Para.2,4, Pg.35.

> We believe that this initial 40% cap is an appropriate position entering DPP4. This policy will significantly increase capital contributions while continuing to recognise the benefits that new customers bring across the fixed costs of the network. This more gradual approach to increasing customer contributions will also support consumers partway through projects who have made specification commitments based on existing policy. While a significant drop off in new connection activity is forecast because of higher contributions, a 40% capex spend will continue to support energy choice in the market and meet consumers desire for gas which continues to be demonstrated across market research and consumer feedback.
>
> Ongoing contractual agreements based on existing and historical contribution policy may result in instances where actual capital spend in DPP4 goes beyond the 40% cap. The impact of this spend is considered minimal in context to the wider capital expenditure forecasts but should be acknowledged in the context of this response.

B98 Rewiring Aotearoa submitted in opposition to any consumer connection capex.[112]

Analysis

B99 GPB submissions, consistent with their 2025 AMPs, reflect that the level of capital contributions for consumer connection capex is an evolving area which GPBs intend to further consider during DPP4, with GPBs taking materially different approaches:

B99.1 FGT and Vector are forecasting no net consumer connection capex.

B99.2 FGD are forecasting a 10% decline year-on-year for gross capex within the regulatory period, with a 70% capital contribution requirement for 2027 – 2029, increasing to 100% in 2030.

B99.3 GasNet are forecasting a moderate decline in consumer connection capex over the period with no capital contributions forecasted.

B99.4 Powerco are forecasting a relatively consistent level of gross consumer connection spend of ~$3 million, with capital contributions following a consistent upward trend from 10% in 2027 to 24% of gross spend in 2030.

B100 Powerco's submission addressed our position in the draft decision reasons paper that GPBs would need to evidence that capital contributions had been set at a level consistent with incremental revenue exceeding incremental cost.

B101 Confidential information provided by Powerco showed how its approach to capital contributions actively considered the return period to ensure that incremental revenue exceeded incremental cost for new connections.

B102 Powerco states:[113]

> We are satisfied that our approach to assessing the contributions for individual connections is prudent and robust, ensuring the incremental revenue exceeds the incremental cost, accounts for impact/benefit on the connecting customer and all

[112] Rewiring Aotearoa "Rewiring Aotearoa submission on the Gas DPP4 reset 2026 – Draft decision" (22 January 2026), Pg.2.
[113] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), Para.24, Pg.14.

customers, while ensuring changes to contributions are managed at a reasonable rate of change

B103 We consider that the amount of gross consumer connection capex required will be driven by a number of external factors, consumer interest in gas and economic trends which will be impacted by consumer expectations on longevity and fuel-source preference, but also decisions from developers which may reflect comparative installation costs and is accordingly challenging to forecast.

B104 Firstgas did not provide any information to support its (FGD) capital contributions policy had been well considered to ensure incremental revenue exceeds incremental cost. However, we note that FGD has a much higher level of capital contributions than Powerco.

B105 GasNet did not submit on the effect of our draft decision on consumer connection capex. As GasNet has not forecast capital contributions, a cap on gross capex applies directly to its forecast consumer connection expenditure.

Consistency with the Electricity Authority work programme on capital contributions

B106 Some submissions queried the consistency of our approach with the Electricity Authority's (Authority) work programme on capital contributions for electricity distribution businesses (EDBs).

B106.1 Entrust submitted "that the fully funded approach to capital contributions protects consumers, is in clear conflict with the Electricity Authority which considers the fully funded approach to be a problem."[114]

B106.2 Vector states "We encourage the Commission to highlight any read across from its position on GPB capital contributions to the electricity sector in its discussions with the Electricity Authority."[115]

B107 Both regulators are aligned that connection pricing should have regard to the incremental revenue vs incremental cost of a connection and that consumer connection expenditure which meets this standard will be in the long-term interests of consumers.

B108 Our DPP process is seeking to incentivise GPBs to assess whether or at what level of capital contributions will ensure that the incremental revenue from new connections will exceed the incremental cost, taking into account the longer-term outlook for the gas sector. This is consistent with the Authority's framing of the "neutral point" as the floor of the subsidy-free range.

[114] Entrust "Gas price reset needs to ensure investment cost-recovery in face of decreasing demand" (21 January 2026), Pg.2.

[115] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision" (22 January 2026), Para.86, Pg.26.

B109 We have not expressly looked to cap at the “balance point” (new connections contribute to sunk and shared costs at a level that is commensurate with similar existing connection). The evolving gas context means the expected lifetime for some types of assets installed may not be consistent over time. The Authority is also still consulting on this concept and how in practice it is determined, so there is not currently a definitive answer or comparison point for how we could apply this approach for capital contributions in the gas DPP.

B110 We acknowledge the risk of inefficiently deterring connections with high up-front capital contributions requirements exists for both EDBs and GDBs. However, we note that GDBs, unlike EDBs, are under a WAPC and accordingly bear the in-period demand risk. If a GDB is inefficiently deterring demand and accordingly quantities delivered fall below forecast quantities, it will earn less revenue.

B111 For this reset we are not requiring specific aspects of a methodology be applied or capital contribution requirements be established within certain limits which means GPB’s have discretion to apply different expectations around capital contributions which provides greater levels of business flexibility. We consider that the risk of asset stranding on gas pipelines creates a significant operational distinction to that which may apply for EDBs and justifies retaining flexibility for GPBs to respond.

B112 We will continue to engage with the Authority in its development of capital contributions requirements and will consider how these could inform future DPP resets, but we also expect the GPBs to actively monitor the effectiveness of their capital contribution policies and commercial arrangements in contracting with new consumers throughout the regulatory period to ensure they are delivering efficient outcomes.

Conclusion

B113 Our decision is to cap consumer connection capex at the lower of the 2025 AMP forecast net of capital contributions; or 2025 AMP gross forecast, multiplied by a factor that declines linearly from 50% in year one of the regulatory period to 40% by year five.

B114 While overall demand forecasts indicate declining ICP numbers, new connections may be efficient where the incremental revenue exceeds the incremental cost and are therefore provides net benefit to existing consumers. Our approach allows for such efficient growth while managing the risk of asset stranding and preserving appropriate incentives for GPBs.

B115 Although the supporting evidence provided by GPBs varied in scope and detail, we have applied a consistent approach across all GPBs. We consider this provides a clear and consistent signal. It reflects our view that the underlying drivers of demand, costs, and investment incentives are likely to be broadly similar across businesses, while allowing for regional variation within that framework.

B116 Our decision, of an increasing requirement for capital contributions minimises the impact of price shock for consumers already committed to gas connections at the start of the regulatory period. It aligns with GPB's expectations on an increased reliance on capital contributions and balances risks around asset stranding ensuring connecting parties are providing a net benefit.

Setting asset replacement and renewals capital expenditure amounts (Decision C1)

Summary of decisions

B117 Our decision is to:

B117.1 cap the ARR capex amount at the lower of each GPB's 2025 AMP forecast or the historical average assessed for each year;

B117.2 update the reference period from 2020-2024 to 2021-2025 for the historical average to reflect 2025 ID data; and

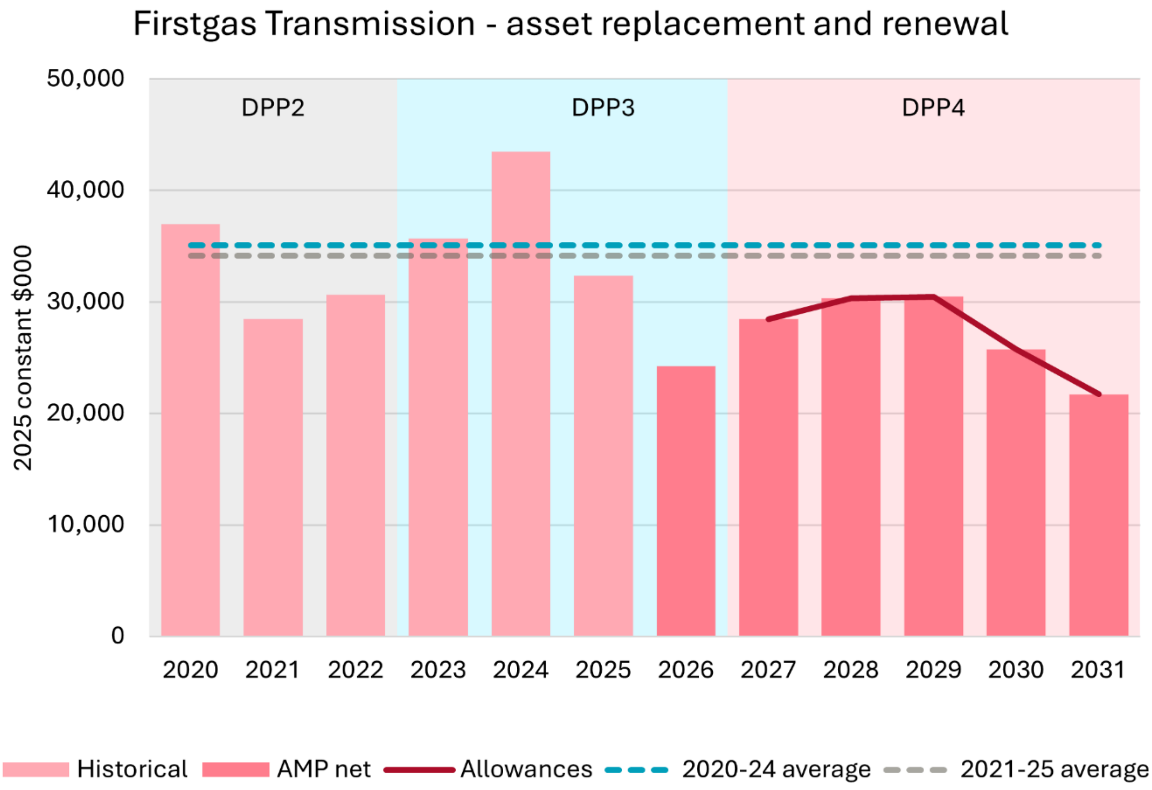
B117.3 allow additional resilience capex for Powerco of $1 million per annum beyond that which is provided by the historic average approach to address the priority resilience risks it has identified.

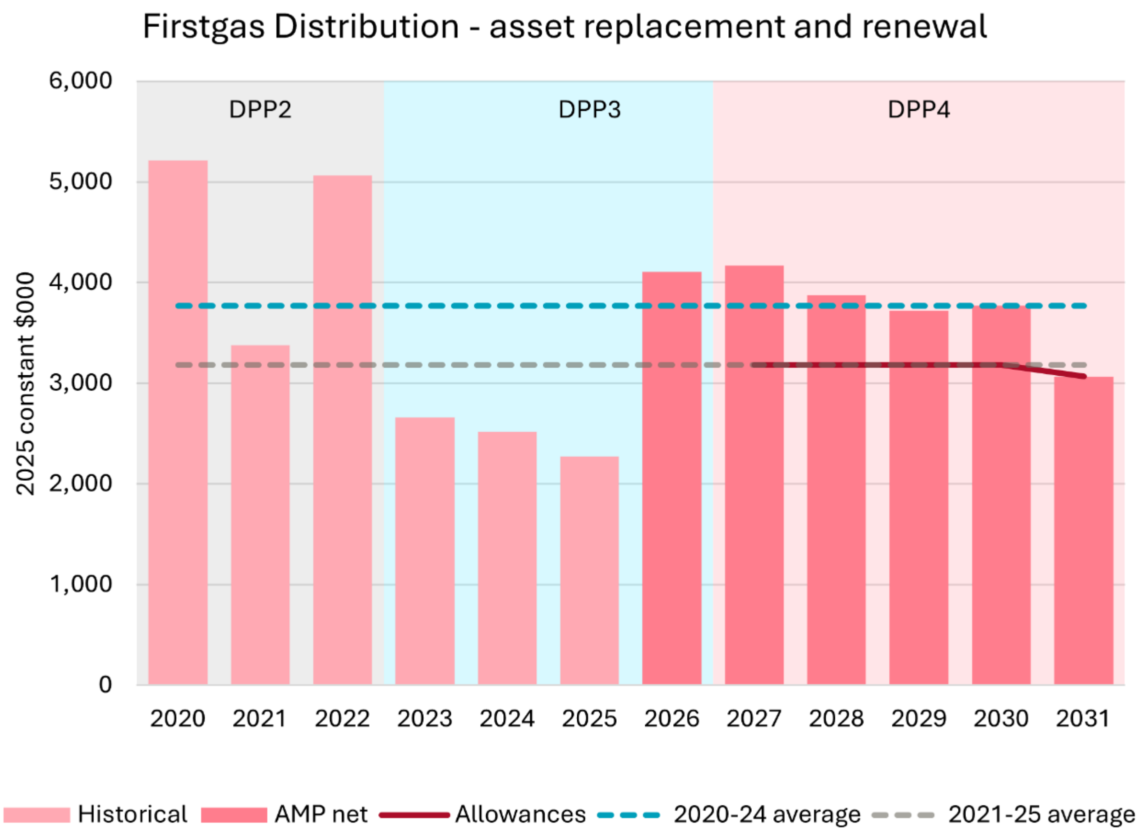
B118 Other than the inclusion of Powerco's resilience capex, this retains the approach in our draft decision, with an updated reference period. The outcomes of this decision are set out in Table B5 and Figure B6.

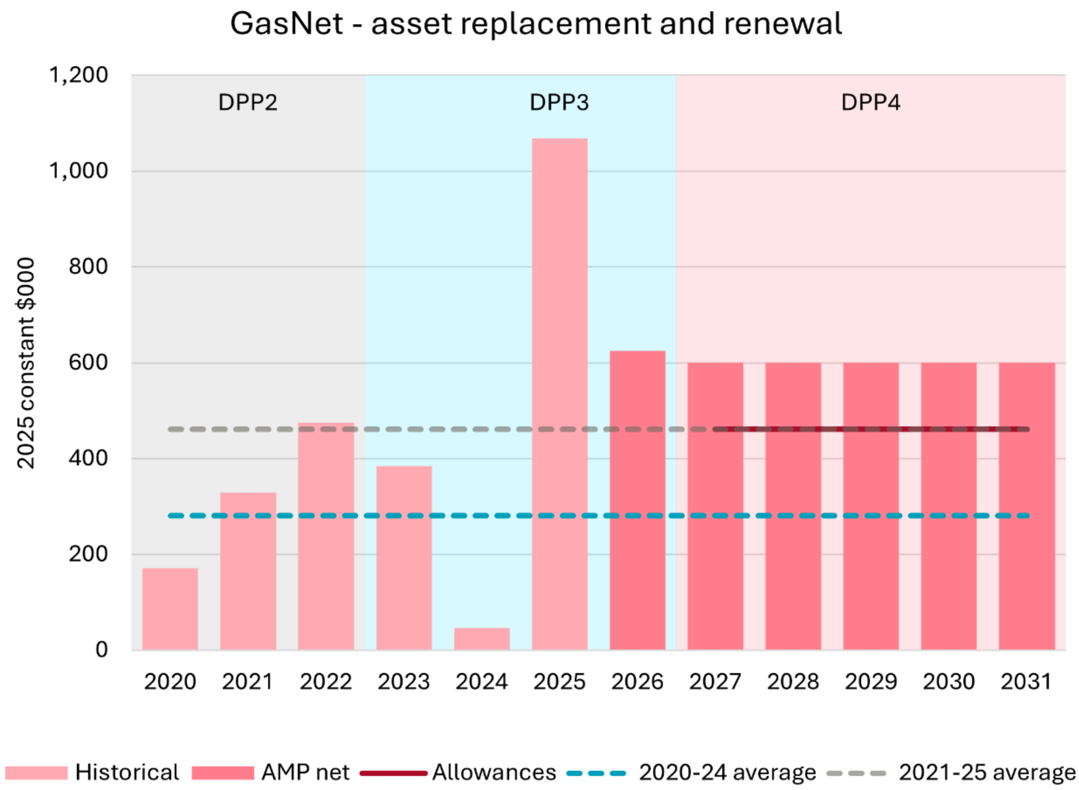
Table B5 Asset replacement and renewals capital expenditure asset management plan forecast, draft decision, DPP4 amount and variances (2025 $000's)

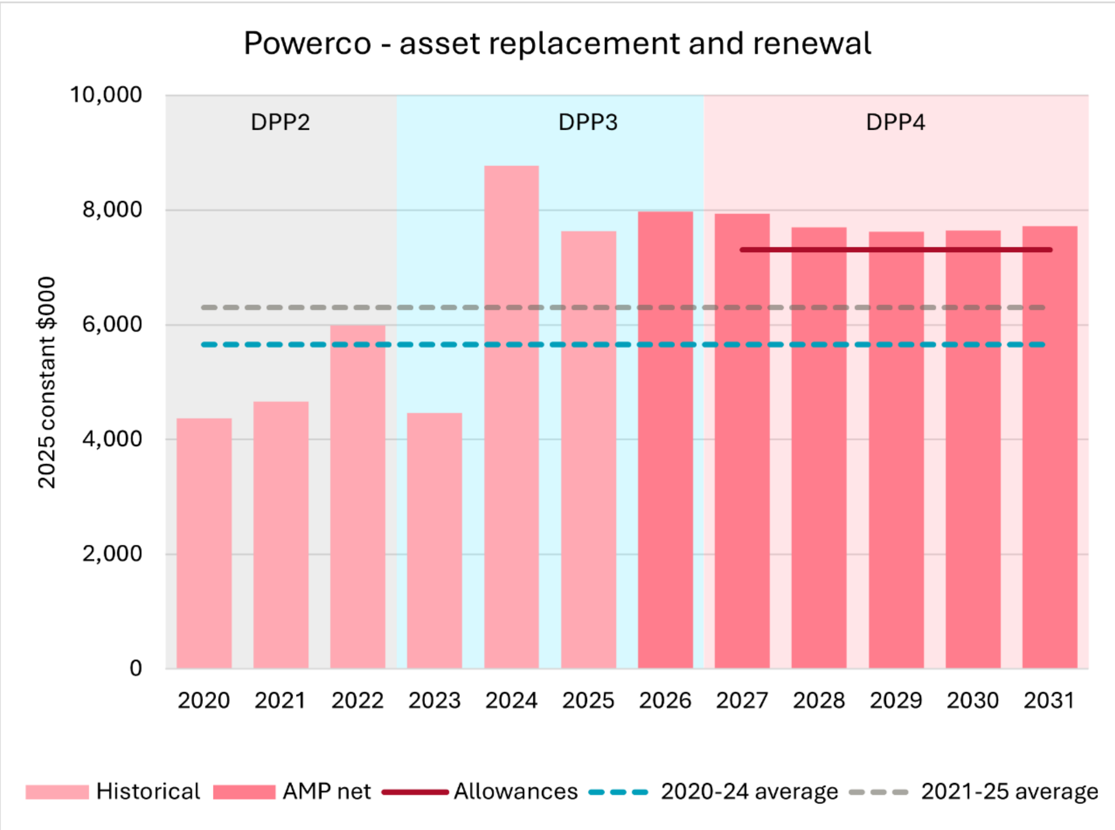
GPB	AMP forecast	Draft decision	DPP4 amount	DPP4 amount – Variance to AMP	DPP4 amount – Variance to Draft decision
Firstgas Transmission	136,736	136,736	136,736	0	0
Firstgas Distribution	18,605	18,091	15,788	-2,817 (-15%)	-2,304 (-13%)
GasNet	3,000	1,406	2,304	-696 (-23%)	898 (64%)
Powerco	38,622	28,249	36,518	-2,104 (-5%)	8,269 (29%)
Vector	8,064	8,064	8,064	0	0

Figure B6 **Asset replacement and renewals capital expenditure actuals, forecasts and historic averages (2025 $000's)**






GasNet - asset replacement and renewal
2025 constant $000
0
200
400
600
800
1,000
1,200
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average


Powerco - asset replacement and renewal
2025 constant $000
0
2,000
4,000
6,000
8,000
10,000
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
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2027
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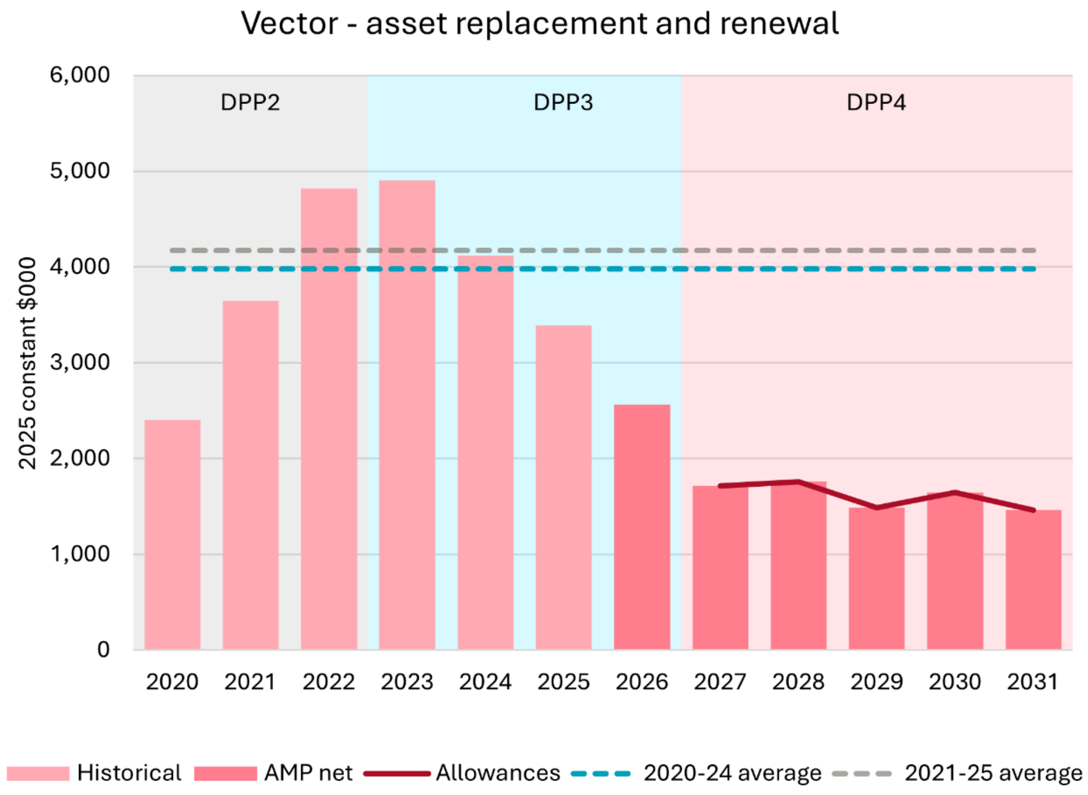
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average



Draft decision and rationale

B119 In the draft decision we recognised that replacement and renewals work (whether this is capex or opex) will still be necessary to maintain a safe and reliable supply and maintain the standards expected by consumers.

B120 To mitigate the risk that the capped DPP expenditure allowances will be insufficient to address network risk issues, GDBs have access to the 'resilience or AR event' and 'risk event' reopener mechanisms introduced in DPP3. These reopeners apply to individual projects or programmes relating to work required to address deterioration on the network or to prepare to mitigate or respond to high-impact low-probability events.

Submissions to our draft decision on asset replacement and renewals capital expenditure

B121 Submissions generally supported our draft decision approach to ARR capex. Powerco provided additional detailed information, including on its resilience programme.

B122 Submissions generally accepted the need for ongoing ARR capex to maintain safety, integrity, and service reliability during the transition away from gas.

B123 Powerco submitted that ARR capex remains necessary to safely operate the network and cannot decline in proportion to customer numbers. Its activities within this expenditure category are consistent with historical investment patterns and are required to maintain the safety and integrity of the network. Powerco submitted that: [116]

[116] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), Para.24, Pg.14., Para.52, Pg.20.

> Maintaining the ARR forecast enables timely remediation of high-risk assets before failure occurs. This supports ongoing service quality, safety, and reliability, rather than deferring investment and increasing the likelihood of disruptive, emergency-led responses.

B124 Firstgas cross-submitted in response to Castalia outlining that a minimum level of ARR capex is largely non-discretionary and required to meet safety, asset integrity, and legal obligations regardless of demand trends.[117]

B125 In response to the Powerco submission, MGUG supported considering ARR levels for resilience projects supported by robust business cases.[118]

Analysis

B126 As part of our draft decision, we assessed the reasonableness of proposed ARR expenditure with a particular focus on those with elevated levels of ARR compared to historical periods to test the justification for possible increases in this capex category and did not consider further uplifts were justified.[119]

Impact of revised reference period

B127 For our final decision we have rolled forward the five-year reference period to cover the period 2021 – 2025, instead of 2020 – 2024.

B128 As shown in Figure B6, the difference between ARR capex levels in 2025 compared with 2020 has had an impact on ARR capex amounts for FGD, GasNet and Powerco.

B129 FGD is adversely impacted by the revised reference period. We note the revised reference period value is more reflective of recent work programme delivery by FGD. According to its 2025 AMP, FGD's ARR capex is largely driven by its pre-85 pipe replacement programme and the need to address emergent leaks.[120] While FGD point to changes in its ARR strategy and using opex solutions where appropriate, it does not explain the scale of increase from historical levels and previous forecasts (2024 AMP). We note the somewhat offsetting effect of increased RSE spend in 2025 which allows a higher recovery of forecast RSE capex.

B130 Given FGD's negative trend on ARR in recent years and its intention to move to an increased opex focus for ARR, we consider that capping its capex amount to historical levels is appropriate.

B131 GasNet have received an increased capex amount with a rolled forward reference period given the higher level of spend in 2025 reflecting delayed capitalisation in 2024 which artificially deflated the previous historical average. Despite this, GasNet's ARR capex is still capped by the historic average compared to forecast spend.

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[117] Firstgas "Gas DPP4 2026: Firstgas views in response to Issues Paper submissions" (14 August 2025), Pg.14.
[118] MGUG "Re" cross-submission on Gas DPP4 draft decision" (12 February 2026), Pg.3.
[119] Commerce Commission "Gas DPP4 Draft decision reasons paper - Attachments A-H" (27 November 2025), B36 – B44.
[120] Firstgas Distribution "Asset Management Plan - Distribution" (30 September 2025), Pg.18-19.

B132 As in our draft decision, our view is that GasNet's AMP reflects the focus of ARR on the continuing replacement of metallic pre-natural gas low pressure assets consistent with its traditional focus of ARR. We have not identified a clear driver to support an increase in expenditure beyond existing levels.

Powerco

B133 Powerco's submission outlined that, excluding resilience, its forecast ARR capex has not increased but is steady over the DPP4 duration.[121] However, it requested additional funding beyond that provided by our historical reference period approach to address identified resilience risks.

B134 In our draft decision we acknowledged that Powerco did have resilience risk exposures but that it had yet to provide sufficiently quantified evidence whether its forecast expenditure for resilience was justified. We explained that to justify resilience expenditure, Powerco needed to estimate the cost of resilience risk manifesting on an annualised basis to test whether mitigations were cost effective.

B135 Our view at the draft, was that Powerco had only provided a qualitative analysis and that to judge that risk mitigations are cost effective, it needed to quantify risks, monetised consequence of those risks, and how investments mitigate the risks to provide a benefit to consumers.

B136 In its submission to our draft decision, Powerco provided further information about its proposed resilience investment programme. Powerco note that:[122]

B136.1 its "approach to climate risk assessment and response is based on recognised business standards" and that it has developed this approach "in line with our electricity business and to inform prudent investment justified by robust assessment";

B136.2 the general need for resilience investment has been endorsed by the Minister of Energy to EDBs;

B136.3 resilience expenditure levels will be confirmed once individual project business cases are developed;

B136.4 the proposed resilience expenditure will have a minimal impact on consumer pricing; and

B136.5 the resilience allowance should allow for "resilience of $2 million per year, or a lower allowance with an alternative reopener-type process as we verify specific project resilience investment within the period".

[121] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), Para.49, Pg.20.
[122] Ibid Summary, Pg.17.

B137 Powerco argued that its resilience programme is based on a robust assessment and is in the long-term consumer interest, stating that “resilience ARR capex delivers value to customers by reducing the likelihood, scale, and duration of supply disruptions, while avoiding significant restoration costs and safety risks that would otherwise be borne by customers and communities”.[123]

B138 Powerco presented further analysis of some of the major resilience exposures, with a focus on the major priority risks. Powerco note that it has identified four priority projects, such as the bridge special crossings which can affect a large number of consumers. It noted that should we determine that the full forecast is not justified then a reduced allowance of $1 million per annum may be appropriate, which would allow it to “cover our identified priority projects plus an assumption or process for the outcome of the feasibility studies to be completed in RY26 for two bridges and the 46 District Regulator Stations (DRS)”.[124]

B139 Powerco also noted that the current risk event reopener mechanism settings, which would include resilience risk events, may not be appropriate because “the reopener threshold does not align with the scale of our resilience projects which are well under the $2m threshold”.[125]

B140 Powerco suggested that if our final decision is that the reopener process is still appropriate for the scrutiny of individual resilience projects, rather than approving capex allowance, then two changes to the reopener are required, namely:

B140.1 lower the resilience event reopener threshold (maximum of $1 million); and

B140.2 provide a streamlined reopener-type process for approval of the works programme based on business case assessment.

B141 We have considered Powerco’s submission material. We agree that it is likely that the mitigation expenditure for the four priority projects, which will address risks that will affect a significant number of consumers, and may involve extended outage durations if events occur, are likely to be in consumers best interests. We also consider that Powerco’s suggestion that it advances feasibility studies on the other investments so that investments also provide a benefit, is a reasonable approach.

B142 The Commission is currently undertaking work to develop an infrastructure-wide resilience principles framework that provides guidance on investment decision-making. The principles that we are developing are those that we view would need to be considered when developing businesses cases. We expect future development of business cases from Powerco will align with this framework.

[123] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), Para.34, Pg.17.
[124] Ibid, Para.43, Pg.19.
[125] Ibid, Para.44, Pg.19.

B143 We understand that Powerco has identified a number of small resilience investments that will not meet the current risk event threshold of $2 million. We note that the resilience or AR event reopener can be applied for on a project or programme basis, which allows aggregation of related projects which may not individually meet the limit. Our view is that the reopener thresholds are still appropriate based on our assessment outlined earlier in this paper and accordingly we have not reconsulted on these IMs as part of this DPP reset.

Conclusion

B144 We have maintained our approach to set ARR capex based on the lower of GPBs' forecasts or the five-year average of historical levels (2021-2025). For Powerco we have increased the ARR cap by adding $1 million to the historical average. This reflects the likely consumer benefit of addressing priority resilience risks. Doing so increases the lower bound of ARR capex by $1million. Even with this adjustment, Powerco's ARR capex remains below the level forecast in its 2025 AMP.

B145 While in the current context historical ARR capex may not be as strong a predictor of future need as it has in previous periods, it is still a reasonable base to apply in the context of a relatively low-cost DPP regime.

B146 We expect GPBs to be undertaking more detailed assessment on asset age and cost information to determine replacement strategies, particularly regarding identified capex-opex trade-offs.

B147 We note some GPBs are forecasting consistent (and increasing) levels of ARR capex in addition to opex step change increases related to capex-opex trade-offs. For GPBs with ARR forecasts which exceed historical levels we have not accepted proposed opex step changes for capex-opex trade-offs, further detail on this is contained in Attachment C.

Setting non-network capital expenditure amount (Decision C1)

B148 Our decision for non-network capex is to:

B148.1 set non-network capex amount based on the lower of 2025 AMP forecasts and the historical averages, assessed annually; and

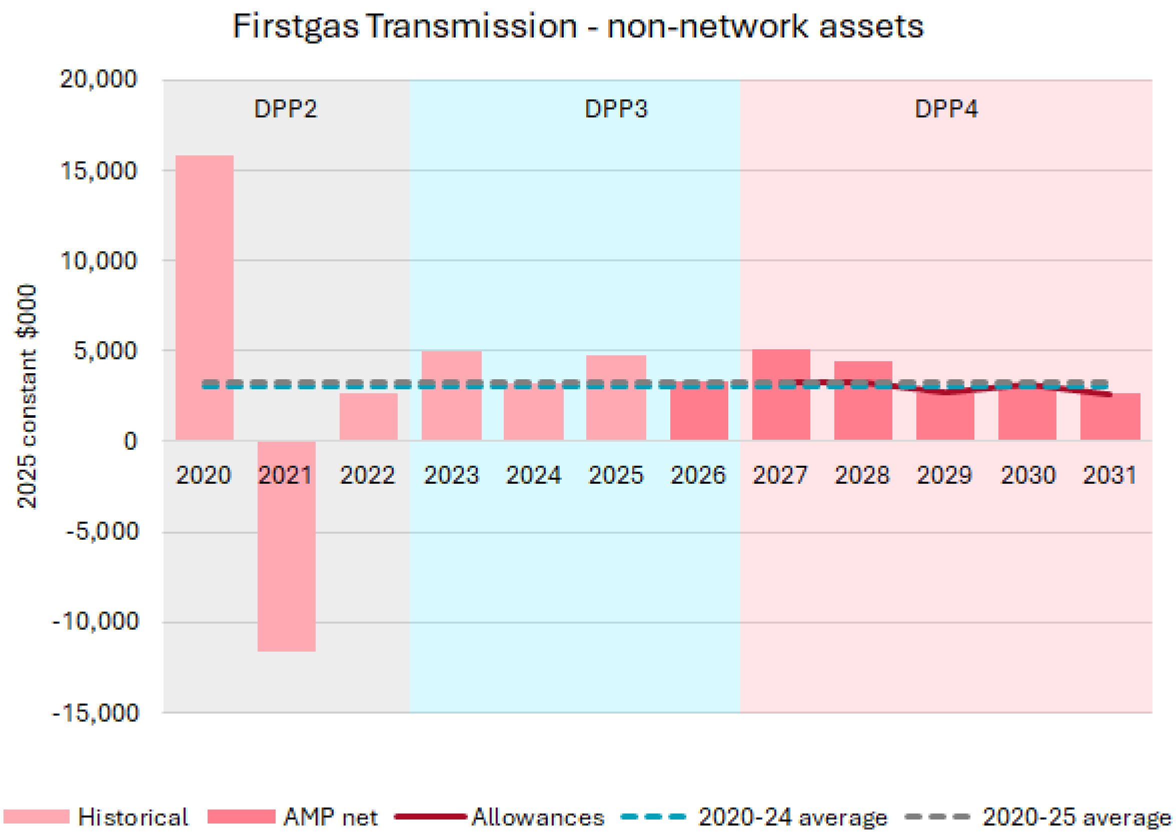
B148.2 apply a reference period for historical averages of 2021 – 2025 for GDBs and 2020 – 2025 for FGT.

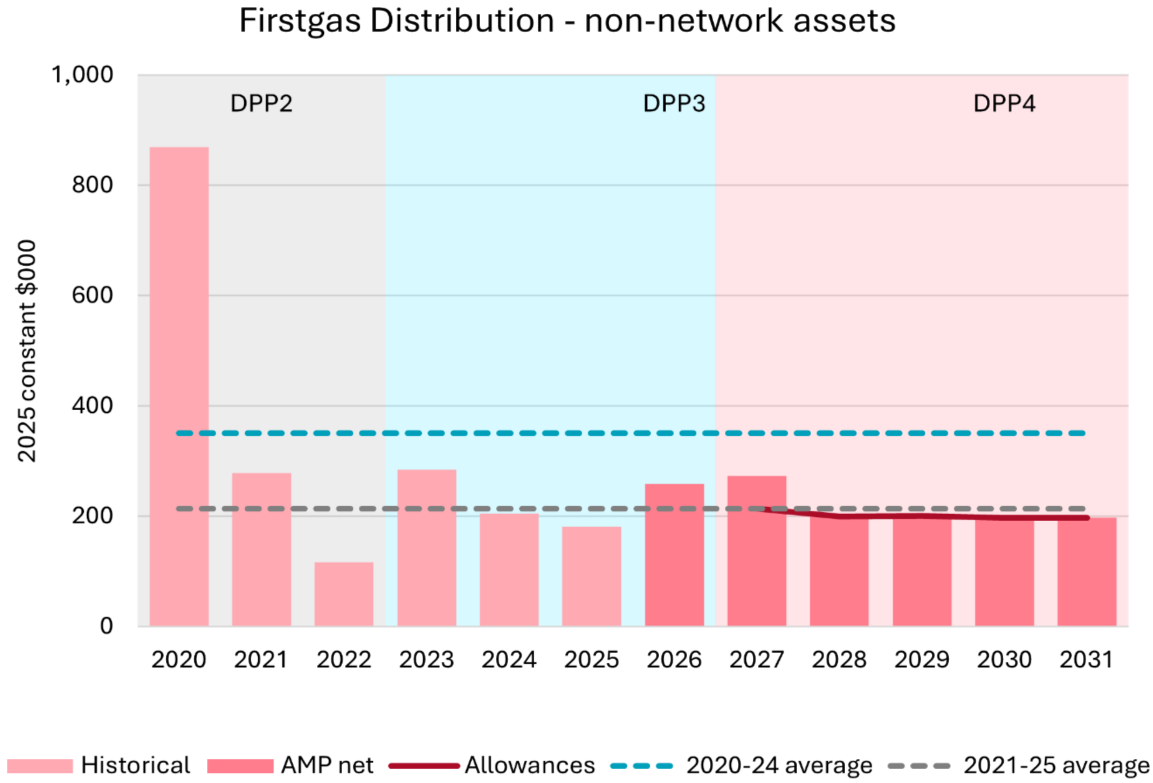
B149 This retains the approach in our draft decision, with updated reference periods. The outcomes of this decision are set out in Table B6 and Figure B7.

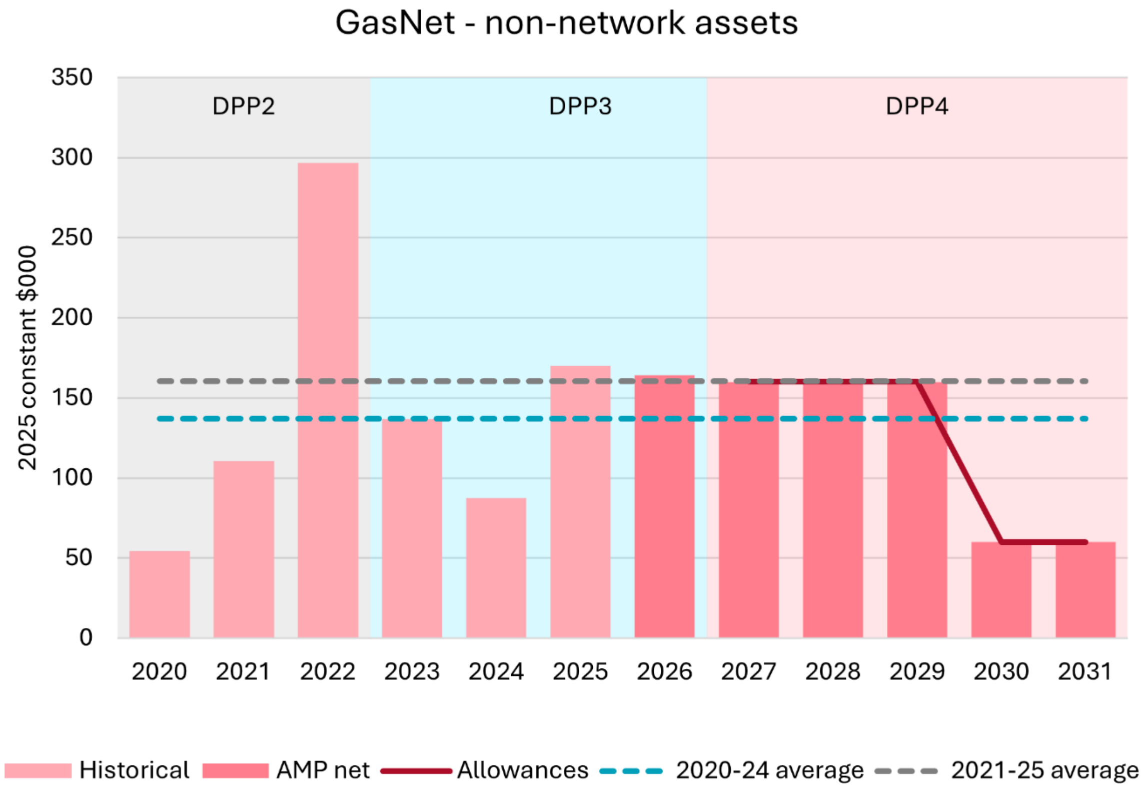
Table B6 Gas pipeline businesses' non-network capital expenditure in asset management plan forecasts, draft decision, final decision and variances (2025 $000's)

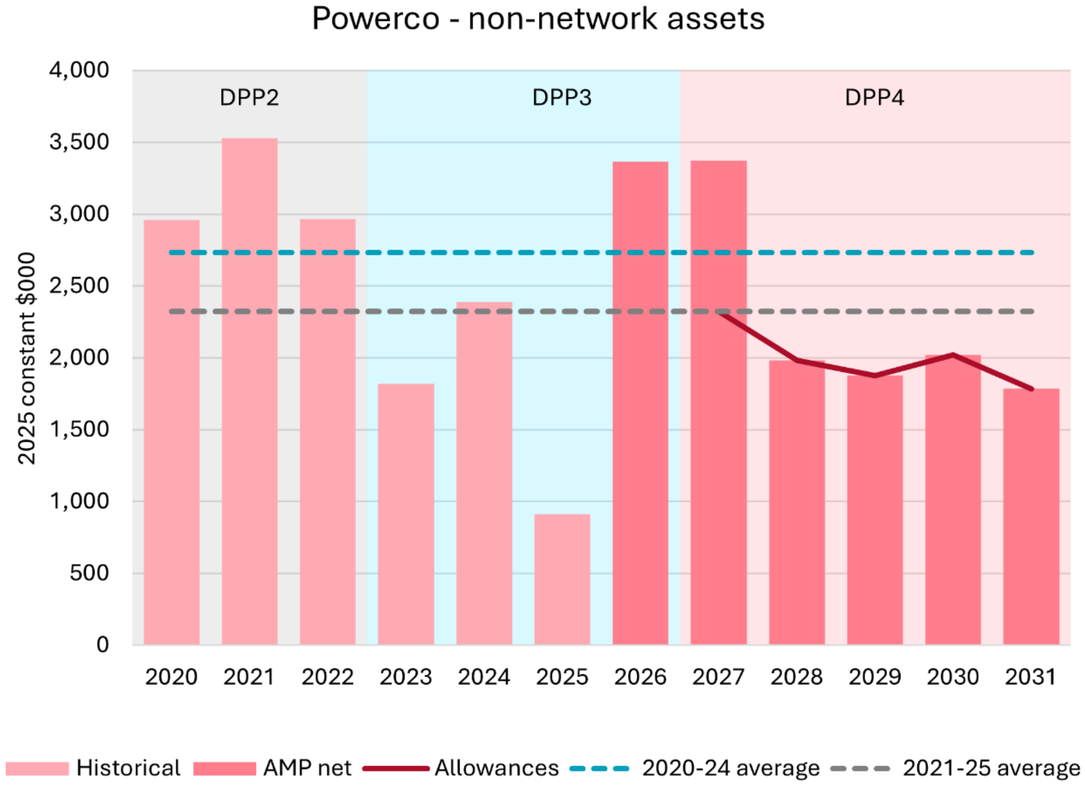
GPB	AMP forecast	Draft decision	DPP4 amount	DPP4 amount - Variance to AMP	DPP4 amount – Variance to draft decision
Firstgas Transmission	18,102	14,306	15,099	-3,002 (-17%)	793 (6%)
Firstgas Distribution	1,068	1,068	1,008	-60 (-6%)	-60 (-6%)
Gasnet	600	531	600	0	69 (13%)
Powerco	11,036	10,393	9,985	-1,051 (-10%)	-409 (-4%)
Vector	8,850	8,850	8,850	0	0

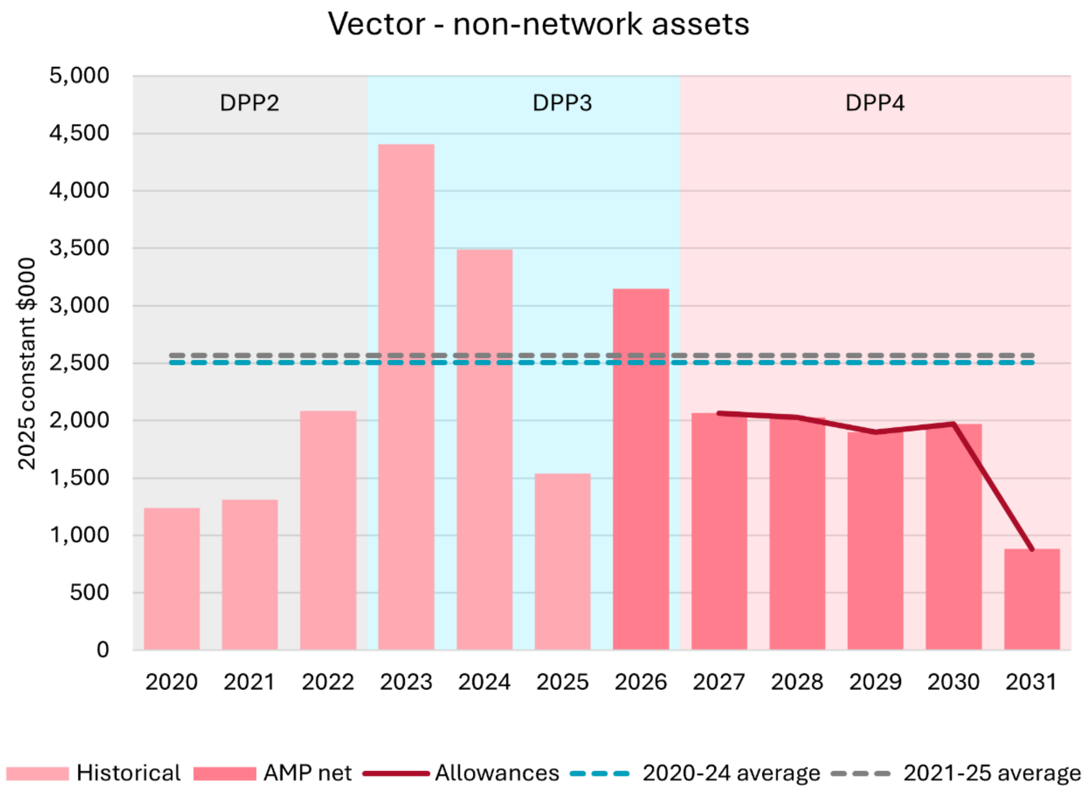
Figure B7 Gas pipeline businesses' asset management plan non-network assets forecast, capital expenditure actuals, historic averages (2025 $000's)




Firstgas Distribution - non-network assets
2025 constant $000
1,000
800
600
400
200
0
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average


GasNet - non-network assets
2025 constant $000
350
300
250
200
150
100
50
0
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average


Powerco - non-network assets
2025 constant $000
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average


Vector - non-network assets
2025 constant $000
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average

Draft decision and rationale

B150 Our draft decision on non-network capex was based on our review of information provided in the RFIs and AMPs. This did not identify any expenditure that warranted further scrutiny and that we were generally satisfied that the information and explanations for expenditure supported it was prudent and efficient and in the long-term interest of consumers.

Submissions to our draft decision on non-network capital expenditure

B151 Firstgas was the only stakeholder to submit on our draft decision on non-network capex. It submitted that while it agreed with our approach to set non-network capex amounts, additional works may arise which increase category expenditure above recent historical averages.[126]

B152 FGT is upgrading its Open Access Transmission Information System (OATIS) to replace the end-of-life system and bespoke integration items to be able to port and operate OATIS securely on cloud infrastructure. These costs are partly opex and partly non-network capex.

B153 FGT sought additional capex allowance in regard to this work, submitting that "Failing to fund this work risks unplanned outages, reactive emergency spend, or price shocks if a failure forces an accelerated replacement".[127] The amount sought was provided on a confidential basis.

Conclusions and reasons

B154 Our final decision for non-network capex is to: set non-network capex amount based on the lower of 2025 AMP forecasts and the historical averages, assessed annually; and apply a reference period for historic averages of 2021 – 2025 for GDBs and 2020 – 2025 for FGT.

B155 We have declined FGT's submission for additional OATIS costs, this decision is explained below.

Impact of accounting anomaly on FGT

B156 FGT non-network capex recent historical average is dominated by two large expenditure items (see Figure B7 above) namely:

B156.1 the first, in DY20, relates to costs incurred in relation to the Gas Transmission Access Code (GTAC) project IT systems; and

B156.2 the second, in DY21, relates to the GTAC project being abandoned and capex costs in that year being written off and expensed as business support opex.

[126] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), Para.1, Pg. 34.

[127] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), Para. 4, Pg.34.

B157 As a result, for FGT non-network capex, our final decision is to use a 2020–2025 reference period. Including 2020 here avoids the distortion that would otherwise result by offsetting the large negative GTAC capex in 2021 with the large positive value in 2020. Using 2020-2025 here results in a more meaningful measure of historical recent non-network capex than if we used the 2021-2025 period used for other capex categories.

OATIS costs

B158 We have considered, and declined, FGT's submission to seek an adjustment to provide expenditure beyond its historical average to reflect its proposed OATIS expenditure.

B159 We accept that new works may not be included in historical expenditure, just as some works included in historical expenditure may not be required in the future. In this case, we are not convinced that imposing on consumers the additional costs of a departure from our approach applied to all GPBs for non-network capex is supported.

B160 FGT's non-network capex amount in our final decision is $15.009 million, which represent 9.4% of its total capex allowance of $158.967 million for the regulatory period. This total capex allowance is 3% ($4.955 million) less than its AMP forecast.

B161 Given that capex for the regulatory period is fungible and the declined amount is a small proportion compared to AMP forecasts, we consider that part of the capex allowance for lower priority capex could be redirected to the OATIS work programme.

B162 We note that FGT are forecasting relatively significant levels of opex uplift in software as a service (SaaS) expenditure via step changes. While we acknowledge there may be both capex and opex costs associated with the OATIS initiative, there are likely components of historical non-network capex related to IT which are included within the historical average but are now not required given the move to SaaS.

Setting reliability, safety and environment capital expenditure (Decision C1)

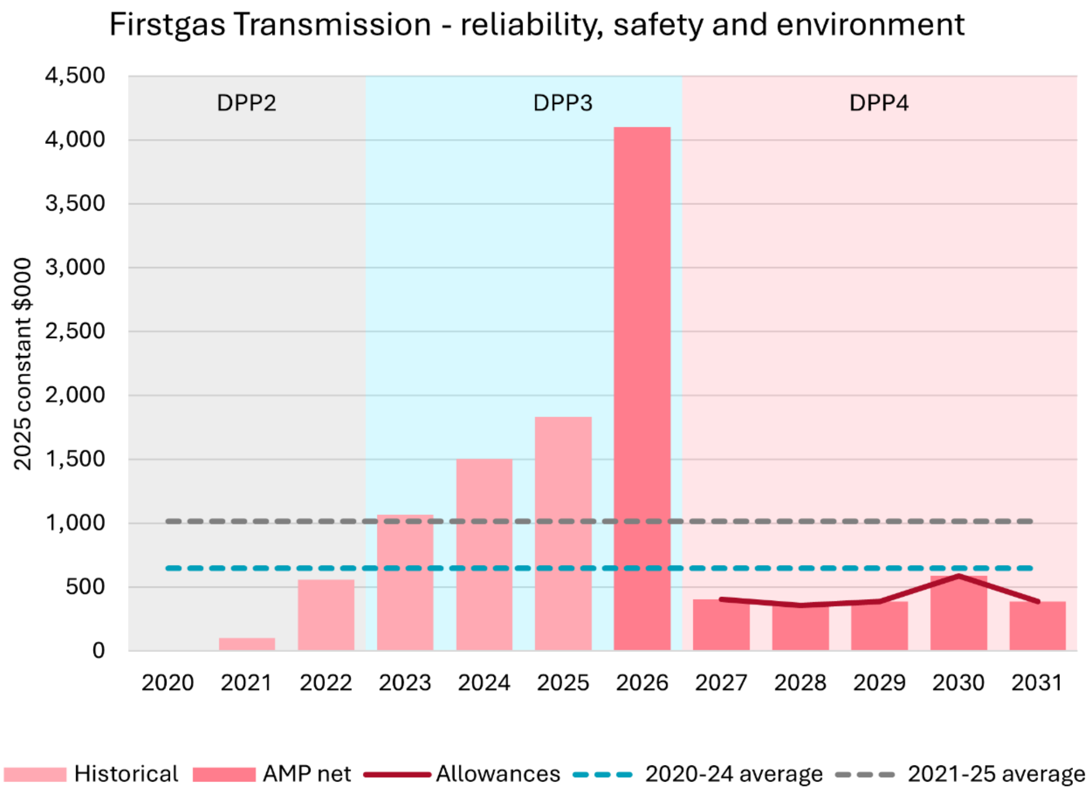
B163 Our decision is to set RSE capex amount based on the lower of the GPB AMP 2025 forecast and the 5-year historical average, updated to 2021-2025.

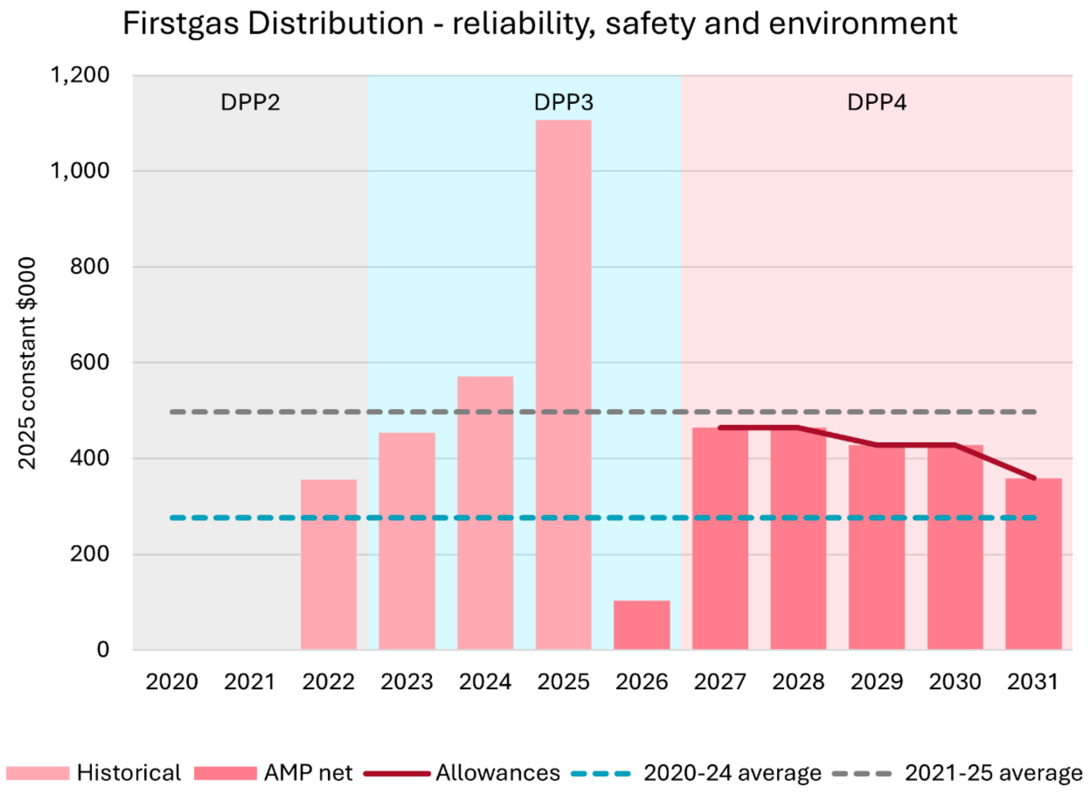
B164 This retains the approach in our draft decision, with updated reference periods. The outcomes of this decision are set out in Table B7 and Figure B8.

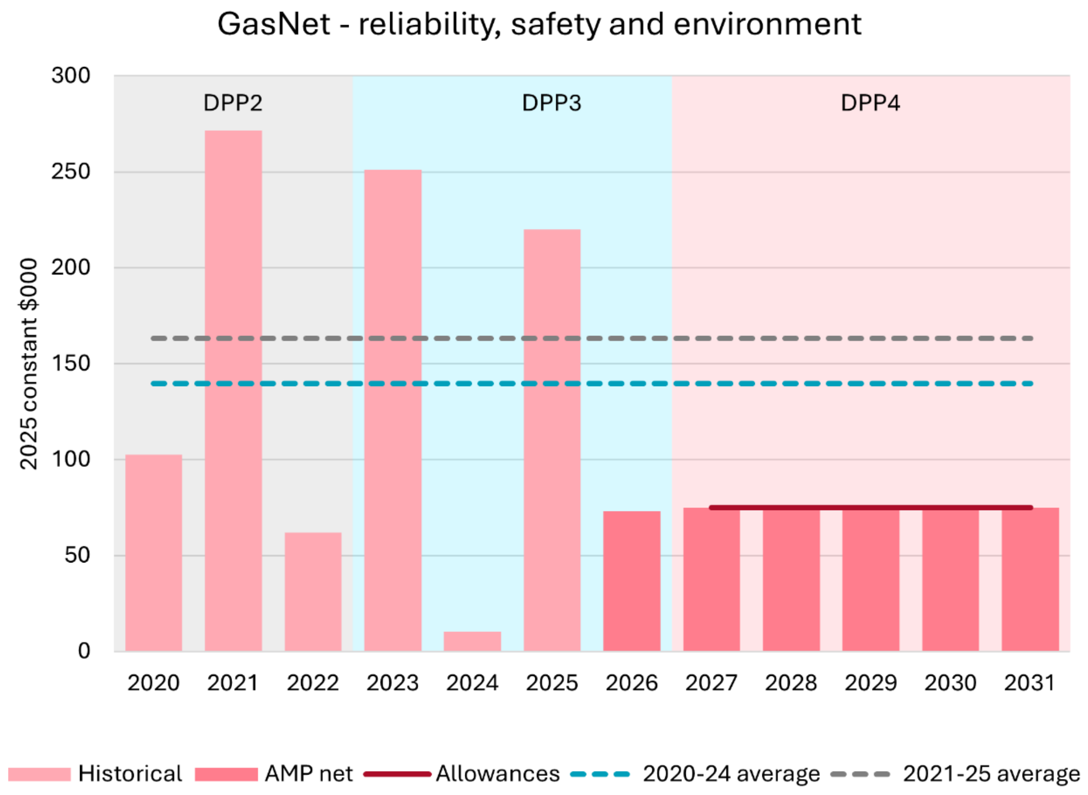
Table B7 Gas pipeline businesses' reliability, safety and environment capital expenditure forecast, draft decision, DPP4 amount and variance (2025 $000's)

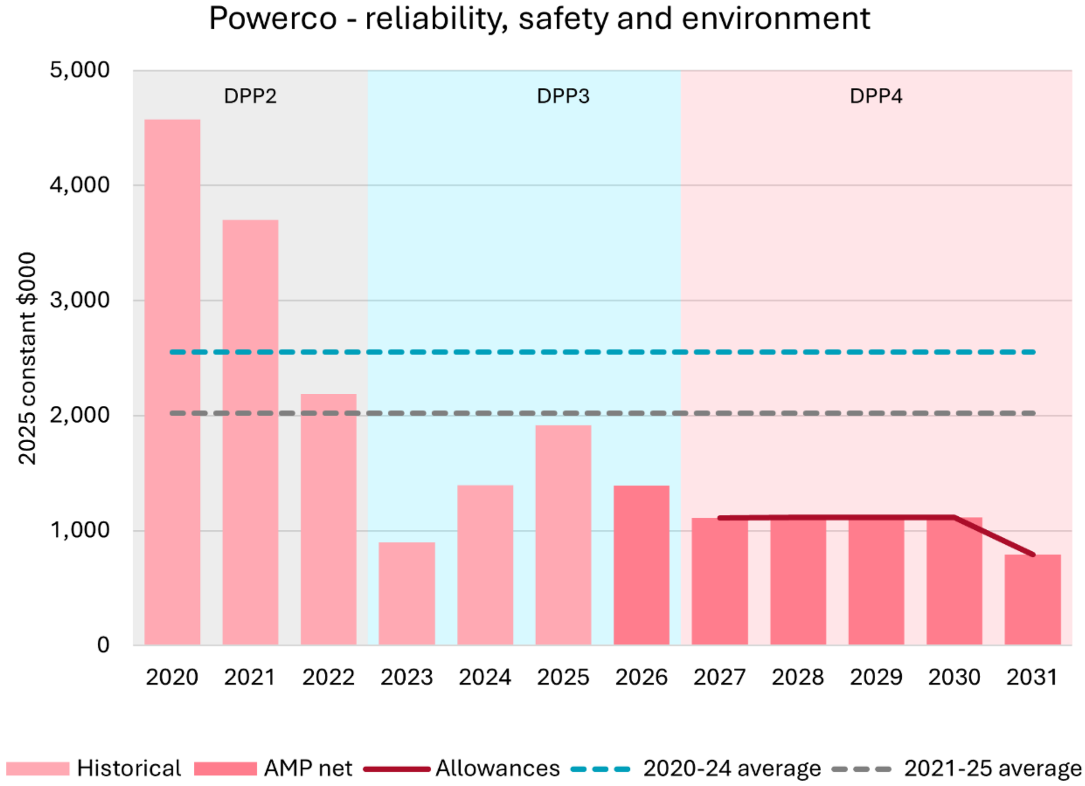
GPB	AMP forecast	Draft decision	DPP4 amount	DPP4 amount - Variance to AMP forecast	DPP4 amount - Variance to Draft decision
Firstgas Transmission	2,131	2,131	2,131	0	0
Firstgas Distribution	2,146	1,384	2,146	0	762 (55%)
GasNet	375	375	375	0	0
Powerco	5,238	5,238	5,238	0	0
Vector	1,287	1,287	1,287	0	0

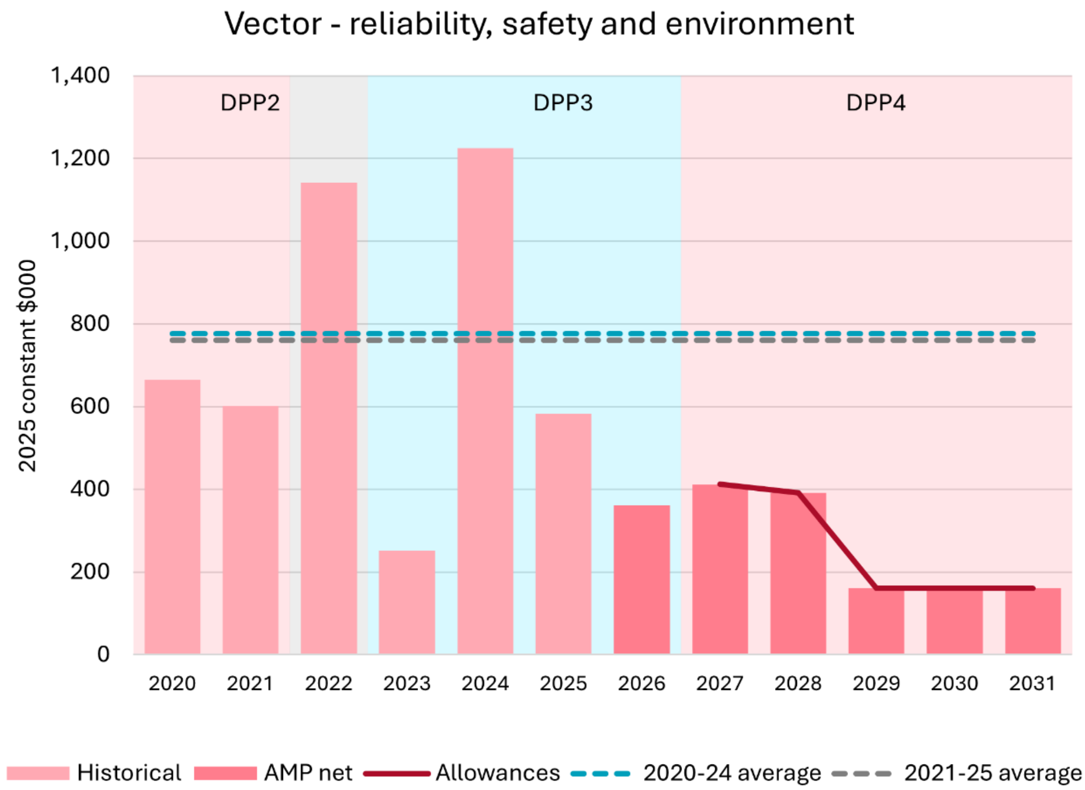
Figure B8 Reliability, safety and environment capital expenditure actuals, forecasts and historic averages (2025 $000's)




Firstgas Distribution - reliability, safety and environment
1,200
1,000
800
600
400
200
0
2025 constant $000
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average


GasNet - reliability, safety and environment
300
250
200
150
100
50
0
2025 constant $000
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average


Powerco - reliability, safety and environment
5,000
4,000
3,000
2,000
1,000
0
2025 constant $000
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average


Vector - reliability, safety and environment
1,400
1,200
1,000
800
600
400
200
0
2025 constant $000
DPP2
DPP3
DPP4
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Historical
AMP net
Allowances
2020-24 average
2021-25 average

Draft decision

B165 For the draft decision we reviewed AMP and RFI material and did not identify any specific expenditure we assessed as unlikely to be required from a prudent and efficient operator.

Submissions on our draft decision on reliability, safety and environmental capex

B166 No stakeholder explicitly mentioned RSE capex in its submission to our draft decision.

Analysis

B167 We note FGD and FGT have incurred an increased trend of expenditure related to the need to meet the latest standards for fire values on district regulator stations for FGD and reinforcing the network after optimising the sizing of compressor stations along the southern network and installing vehicle impact protection for FGT.[128]

B168 However, all GPBs are now forecasting lower than their historical average RSE expenditure over the DPP4 period, when the reference period is updated to reflect the period 2021-2025. This is particularly relevant for FGD who were previously capped under the draft decision, but with application of the revised reference period to include actual values for 2025 the forecast values for the DPP4 regulatory period are now lower than the historical average.

Conclusion

B169 We are satisfied that the approach to RSE capex set out in our draft decision remains appropriate. We note that the update of the reference period for recent historical expenditure to 2021-2025 as opposed to that applied at the draft 2020 – 2024, results in FGD now also receiving its AMP forecasted values.

Gas pipeline businesses' asset relocations capital expenditure (Decision C1)

B170 Our decision is to set AR capex amounts based on the lower of the GPB 2025 AMP forecast and the 5-year historical average, updated to 2021-2025.

B171 This retains the approach in our draft decision, with updated reference periods. The outcomes of this decision are set out in Table B8 and Figure B9.

[128] Firstgas Transmission "Asset Management Plan - Transmission" (30 September 2025) S.4.2.5, Pg.27.

Table B8 Asset relocation capital expenditure forecasts, draft decision, DPP4 amount and variances (2025 $000's)

GPB	2025 AMP forecast	Draft decision	DPP4 final decision	Variance to AMP	Variance to Draft
Firstgas Transmission	1,678	1,405	864	-815 (-49%)	-541 (-39%)
Firstgas Distribution	199	199	199	0 (0%)	0 (0%)
GasNet	50	50	50	0 (0%)	0 (0%)
Powerco	0	0	0	0 (0%)	0 (0%)
Vector	1,155	118	411	-743 (-64%)	293 (248%)

B172 Given the relatively low materiality of values for this category, we have not included the graphs comparing historical values with allowances.

Draft decision and rationale

B173 Our draft decision was to set the set the AR capex based on the lower of the historical average (2020-2024) or GPBs AMP forecast, assessed individually for each year of DPP4 period.

B174 Since the forecast is based on third-party initiation and varied across the past periods, we considered it was appropriate to compare past expenditure and GPBs forecast and set the capex accordingly.

Stakeholder submissions on our draft decision

B175 Stakeholders did not submit on our draft decision for AR capex category.

Analysis

B176 The level of AR expenditure is inherently quite variable across periods. It is relatively small compared to other capex categories, is driven by third-party requests and impacted by GPBs capital contribution policies.

B177 Rolling forward the historical reference period has resulted in changes from the draft for AR capex for FGT and Vector:

B177.1 The value for FGT is $864 k, down $541k from the draft. This change is significant as a percentage at a category level, but not overall, with AR representing only 1% of total forecast capex. We note that for a longer time series including 2017 - 2019, the value is relatively aligned with historical averages.

B177.2 For Vector, the value is $411 k, up $293 k from the draft. This is again a small variance against its total capex allowance. We note the volatility in Vector's data series and its intention to move to a full contribution approach for other capex categories likely results in a low value of net AR expenditure arising.

B178 We note the "resilience or AR event" reopener is available, where significant increases in expenditure are required.

Converting constant 2025 $ capital expenditure to nominal values (Decision C4)

B179 Our decision is to convert the capex allowances into nominal values using forecasts for the CGPI with no adjustments.

B180 This is the same as our draft decision, with values updated to latest available forecasts.

B181 The capex allowances above have been calculated in constant 2025$ terms. We are required to convert them to the nominal values required for price path specification.

B182 Consistent with our position and reasons set out at the draft decision, we recognise that there may be higher inflation in electricity, gas, water and wastewater sector (EGWW) which resulted in an applied uplift for the EDB DPP4 reset. However, we do not consider it is likely that the GPBs have the same inflationary pressures on capital expenditure as the EDBs.

B183 In the context of growth in the electricity sector there may be upward pressure due to global demand for equipment. We do not have evidence of the same inflationary pressures applying to gas as for electricity.

B184 We did not receive any submissions on our draft decision.

B185 Accordingly, we are not proposing to apply an additional adjustment beyond CGPI for inflating capex allowances set in 2025$ terms to nominal terms.

Setting a value for cost of finance (Decision C5)

B186 Our decision is to include an allowance for the cost of finance, scaled in proportion to the capex allowance. This is the same as our draft decision.

B187 AMP forecasts include the cost of financing expected to be accumulated during the construction of the works programme, i.e., ‘works under construction’ or ‘works in progress’ (WIP).

B188 We did not receive any submissions on our draft decision.

B189 We have retained the approach taken in our draft decision, and consistent with past resets, of including a value for cost of finance scaled proportionate to the amount of declined capex.

Attachment C Forecasting operating expenditure

Purpose of this attachment

C1 This attachment outlines the rationale for our final decision on setting operating expenditure (opex) allowances for this gas default price-quality path (DPP4).

C2 This attachment sets out:

C2.1 a description of our approach to setting opex allowances for each GPB for each year of DPP4; and

C2.2 our final decisions for:

C2.2.1 use of base-step-trend (BST) approach to set opex, including setting the yearly opex allowances for each GPB as the lessor of its 2025 Asset Management Plan (AMP) forecast and BST modelling outcome;

C2.2.2 choice of base year, including adjustments required to reflect non-recurring amounts;

C2.2.3 analysis of step changes requested by GPBs;

C2.2.4 trend factors applied; and

C2.2.5 escalators used in converting opex to nominal values.

C3 We have performed all opex analysis using historical and forecast expenditure in constant 2025 $. All expenditure in this attachment is expressed in constant 2025 $ prices unless stated otherwise.

Summary of our operating expenditure allowance decisions

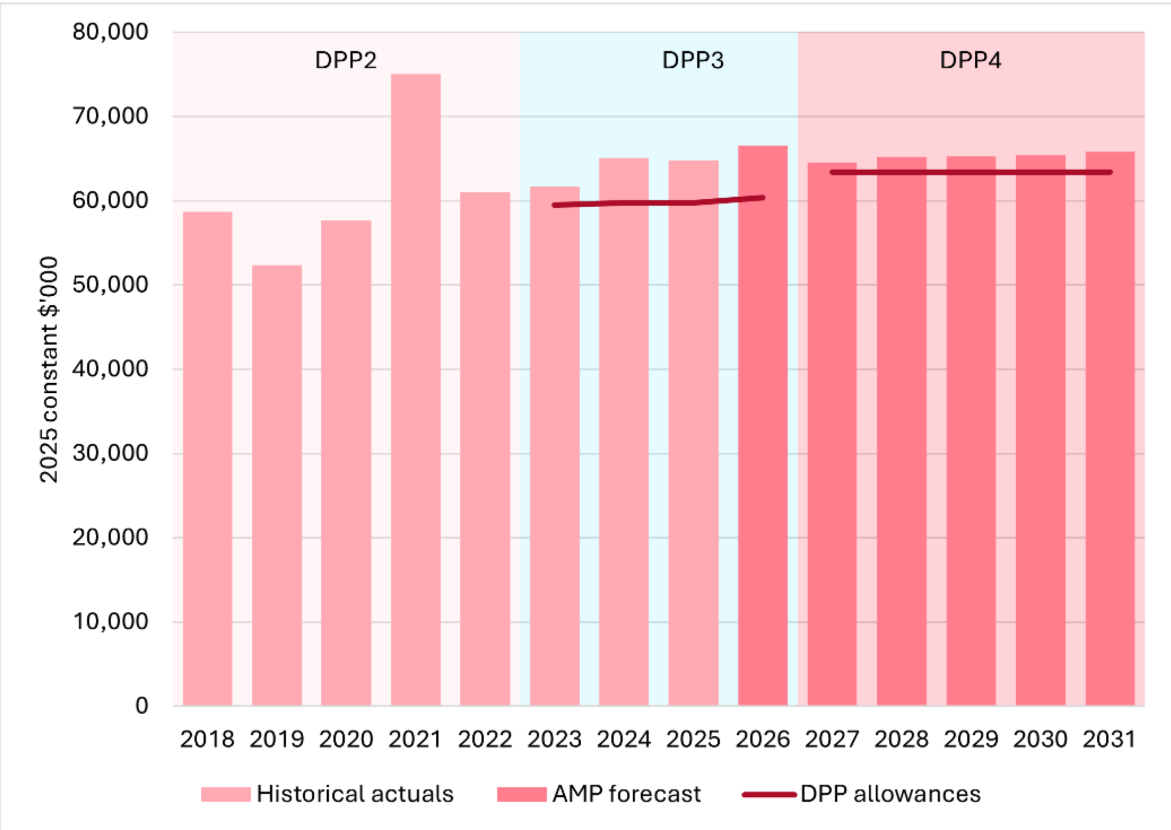
C4 Table C1 below sets out our opex allowance for the GPBs and compares this to our draft decision and GPBs 2025 AMP forecast.

Table C1 Comparison of total operating expenditure in asset management plan forecasts to DPP4 allowances (constant 2025 $'000)

GPB	AMP opex forecast	Draft decision	DPP4 opex allowance[129]	Opex allowance Variance to AMP	Opex Variance to draft decision
Firstgas Transmission	326,267	311,227	316,860	-9,407(-3%)	5,633 (2%)
Firstgas Distribution	68,530	63,678	59,826	-8,704(-13%)	-3,852 (-6%)
GasNet	13,558	12,889	12,460	-1,098(-8%)	-429 (-3%)
Powerco	104,892	99,870	99,372	-5,520(-5%)	-497 (0%)
Vector	101,012	96,187	94,026	-6,986(-7%)	-2,161 (-2%)
Total	**614,259**	**583,850**	**582,543**	**-31,716(-5%)**	**-1,306 (0%)**

C5 Figures C1 to C5 below shows total opex graphically for each GPB, including historical actuals, AMP forecast and DPP allowances in the three regulatory periods.

Figure C1 Firstgas Transmission total opex



[129] Consistent within our capex approach outlined in Attachment B, within this paper we have used disclosure years 2027 – 2031 when we refer to "final allowance" for opex, for clarity of comparison to AMPs and reconciliation with the values within the expenditure model. Vector's opex allowance when the disclosure years are weighted to reflect the regulatory period would equate to $93,997 (constant 2025 $000s) (not 94,026) with GasNet allowance equating to $12,457 (constant 2025 $000s) (not 12,460).

Figure C2 Firstgas Distribution total opex

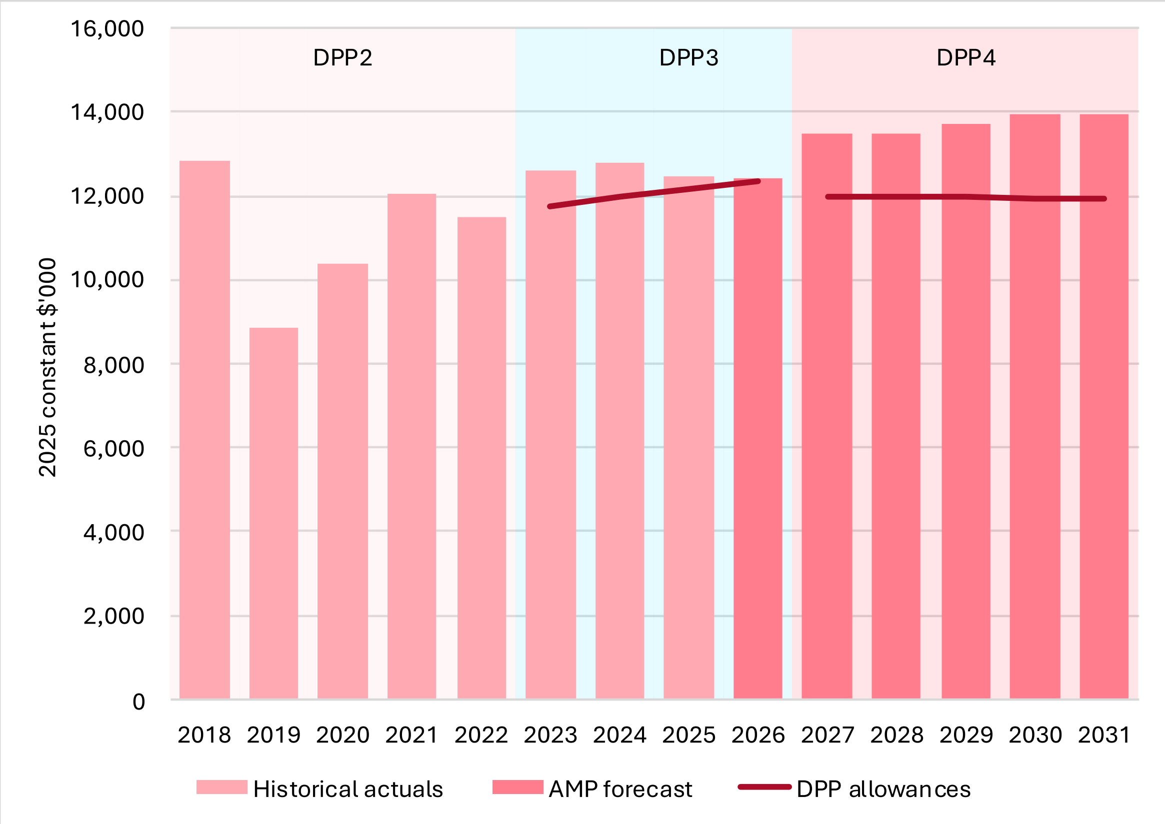


Figure C3 GasNet total opex

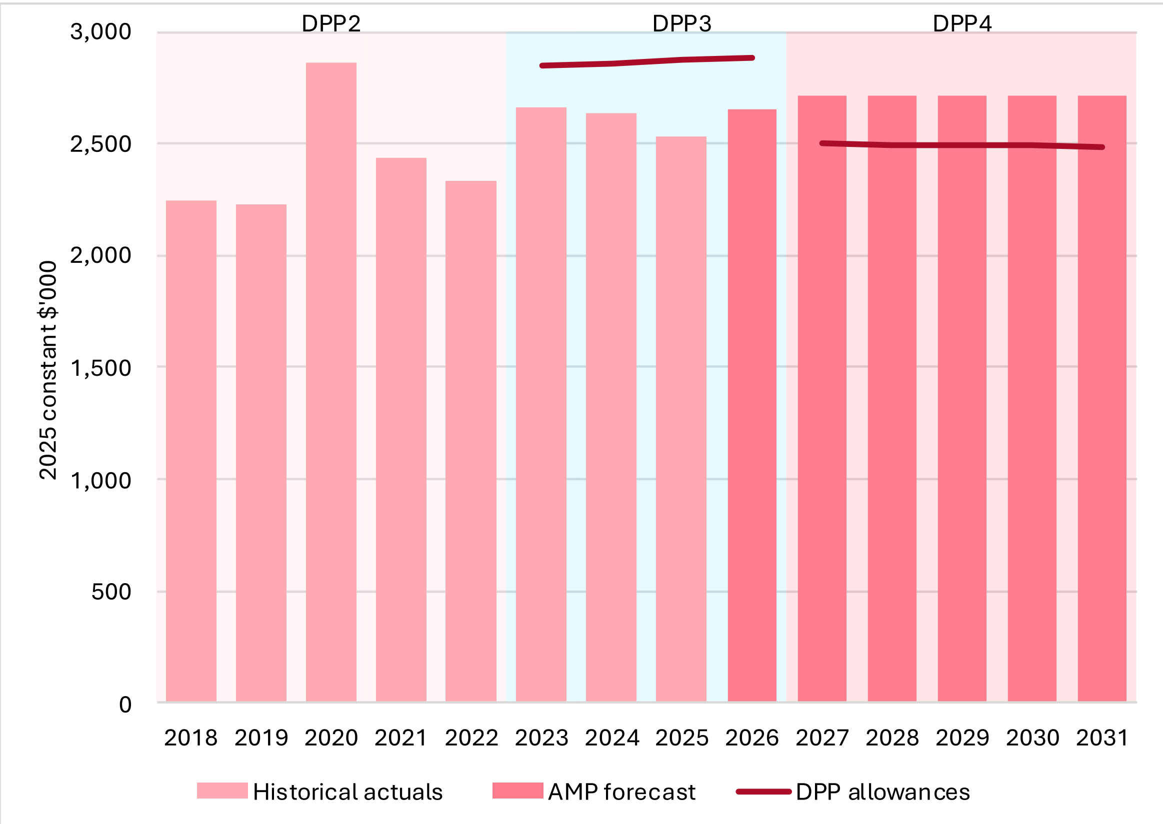


Figure C4 Powerco total opex

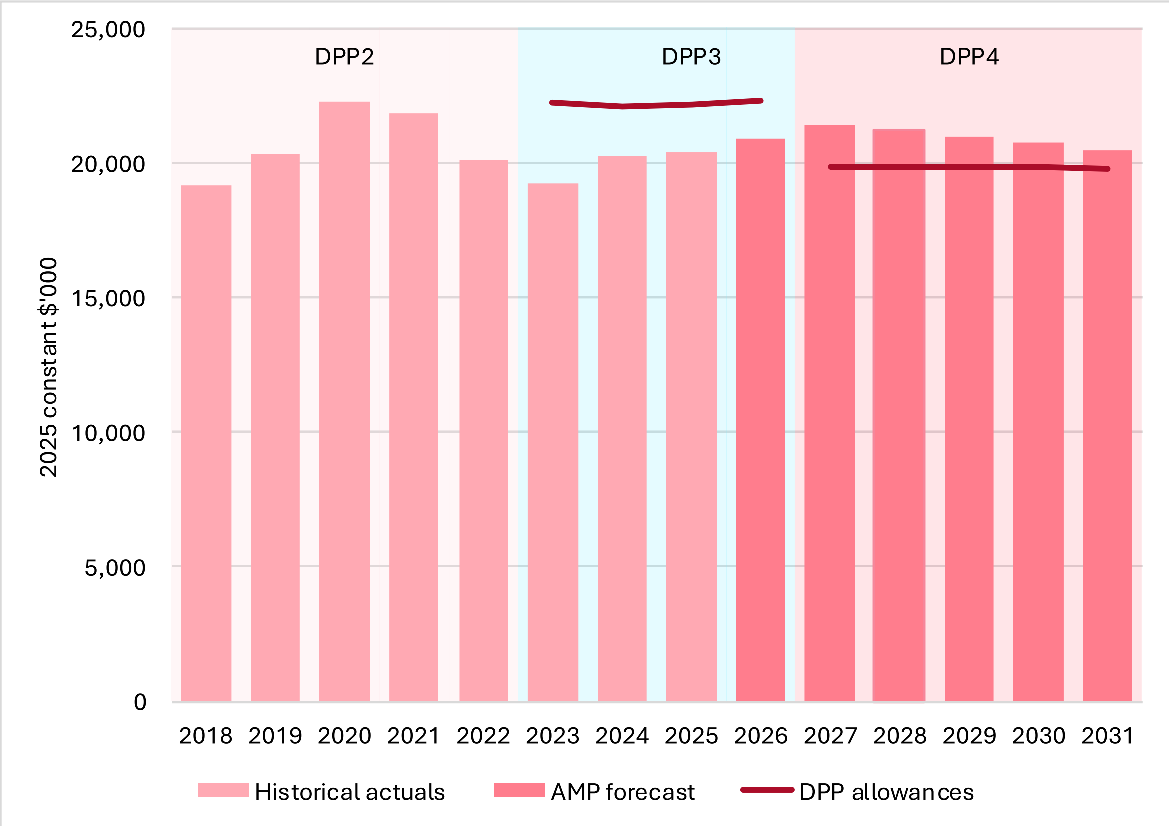
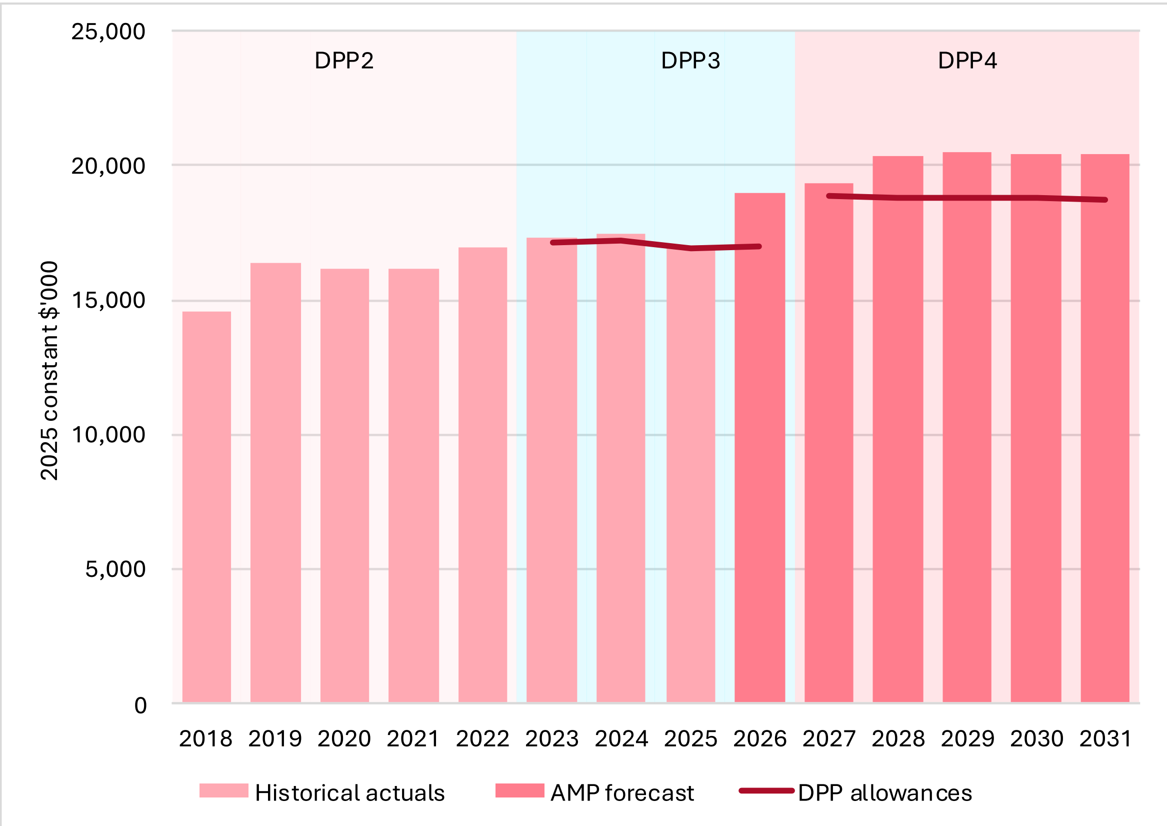


Figure C5 Vector total opex



Impact of our opex decisions

C6 The opex allowance is an input to determining the revenues GPBs may earn. Unlike capex, the values represented here are recovered during DPP4, as opex is recovered in the year it is incurred under our building blocks approach (ie, before smoothing).

C7 As can be seen from the graphs above, our DPP4 opex allowances are lower than the GPBs' forecasted levels of expenditure and are generally consistent with recent levels of expenditure, with the exception of Vector. Vector's DPP4 allowances are higher than recent levels of expenditure, reflecting its well-evidenced proposed capex-opex trade-off implementation.

C8 Although parts of the analysis that forms part of our BST modelling are built on specific cost assessments (such as non-recurring adjustments and step changes), we consider the appropriateness and reasonableness of the aggregate opex building block forecast amount in the wider context, including consideration of the proposed capex allowance and the context for the GPB.

C9 While our approach assesses the reasonableness of specific costs we do not approve or constrain expenditure for specific expenditure categories during the regulatory period. We expect GPBs to appropriately prioritise expenditure within opex categories, and across capex and opex to the highest priority expenditure needs to respond to the changing environment.

C10 Our final decisions on opex largely retains our draft decisions other than updates to base year opex and associated non-recurrent amount adjustments, additional step changes to reflect additional evidence provided in submissions to our draft decision and an adjustment to the application of trends to reflect that operating expenditure may not decrease in a linear fashion aligned with ICP decline.

How we are setting operating expenditure allowances for DPP4 (Decision O1)

C11 For this reset, we have used the BST modelling approach to test GPBs' AMP forecasts and as a means of setting the DPP4 allowances. We used BST to forecast what a prudent and efficient GPB would be expected to spend over the regulatory period. We consider this modelling approach reflects the fact that opex is generally more predictable, as it largely comprises expenditure related to recurring activities as well as those costs that have a predictable trend.

C12 To better understand the drivers of opex forecasts we sought information through requests for information (RFIs) to the GPBs, on non-recurring costs, rationale for significant changes in levels of historic opex between years, capex/opex substitution and forecasted step changes in costs for the DPP4 regulatory periods. We also considered information submitted by stakeholders relevant to setting the opex allowances.

C13 In applying the information we have:

C13.1 used opex data from the most recently received disclosure year for all GPBs (being disclosure year 2025) to set an opex base value and made adjustments for non-recurring amounts;

C13.2 factored certain opex activities as step changes and made supplier-specific step changes where they were supported by evidence showing its prudency and efficiency; and

C13.3 modelled opex trends using the following three main cost drivers:

C13.3.1 network scale – the scale of the network may affect operating expenditure as the number of connections changes;

C13.3.2 partial productivity – changes in operating efficiency will affect the amount of operating expenditure needed to provide a given level of service; and

C13.3.3 input prices – changes in input prices will affect the cost of providing a given level of service over time.

C14 Upon completing our analysis and review, we set opex allowances at the lesser of the BST model outcome and the supplier's AMP forecast for each year of DPP4.

C15 The results of our BST model were lower than the AMP forecast for all years and as a result, the aggregate total allowance for all individual GPBs over the five-year DPP4 period is lower than their 2025 AMP forecasts.

Our approach to setting operating expenditure allowances for DPP4

C16 Submitters to our open letter noted that there may already be a shift towards opex solutions in aggregate and we should consider how this can be facilitated through this reset.[130]

C17 In our issues paper, we sought stakeholder views on what alternatives to the BST methodology could be used to test and scrutinise GPBs' forecasts.

Stakeholder submissions

Issues paper submissions

C18 In the issues paper consultation phase, we had engagement on our approach to setting opex allowances.[131, 132]

[130] Firstgas "Gas DPP4 2026: Firstgas views in response to open letter" (13 March 2025), p.4; Vector "Open letter on gas DPP4 2026 price-quality reset" (13 March 2025), p.2 and para. 32-34; and Powerco "Gas DPP4 2026 – A customer driven period supported by adaptive regulation" (13 March 2025), p.9.
[131] These are set out at paragraphs C17 – C23 of our draft decisions reasons paper.
[132] Commerce Commission "Gas DPP4 Draft decision reasons paper - Attachments A-H" (27 November 2025), paras C17 – C23.

C19 Firstgas, Powerco, and Frontier Economics on behalf of Vector supported continued use of a base-step-trend (BST) approach, noting its consistency with previous DPPs, but noted the importance of flexibility, the role of scrutiny of GPBs' AMPs and the need for refinements in a more uncertain operating environment. Suggesting the use of AMP scrutiny as a complementary tool to assess reasonableness.

C20 Vector considered that ensuring efficient opex is central to the reset and preferred an AMP-based forecasting approach, subject to appropriate scrutiny, submitting that BST alone would not be sufficient without material step changes.

C21 We also heard from Fonterra and MGUG suggesting that we should further scrutinise the GPBs' AMPs in setting opex allowances.

Draft decision submissions

C22 We received limited submissions related to our draft decision on the methodology to use the BST to scrutinise GPB opex forecasts and set the allowances as the lower of the BST or AMP forecasts.

C23 We heard general submissions from Mercury who supported our decision to only allow well justified opex and from Optima Energy who noted that "there should be maximum downward pressure on all operators [...] to reduce costs and improve efficiencies. Without this downward pressure, there will be little confidence efficiency gains and cost reductions are being achieved."[133, 134]

C24 No submitter proposed an alternative methodology for determining opex allowances or argued that AMP forecasts should prevail over our proposed approach.

Ability to assess AMPs to set opex allowances

C25 Our view is that the GPBs' AMPs do not of themselves provide sufficient information for us to scrutinise opex forecasts, having not been designed to provide detailed drivers of changes in expenditure. If we were to scrutinise the GPBs' AMPs, we would still need to establish a top-down assessment method that may rely on historical averages for consistency, given a bottom-up re-establishment of reasonable opex values would be complex and may not be consistent with a relatively low-cost regime per s 53K of the Commerce Act.

C26 Based on submissions, we understand that Firstgas is using a BST approach to forecast opex.[135] Powerco and Vector have also noted that they consider BST could still be used with appropriate adjustments to the components.[136] Considering this, and limitations in the suggested alternative of relying solely on suppliers' AMPs, we consider that using the BST model is an appropriate approach for assessment of GPBs' opex forecasts.

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[133] Mercury "Submission on Gas DPP4 Draft Decision" (16 January 2026), p. 1.
[134] Optima Energy Management Solutions "Submission to the Commerce Commission re Gas Pipeline Pricing (DPP4 Reasoning Paper)" (22 January 2026), p. 2.
[135] Firstgas "Submission on Gas DPP4 Issues paper" (24 July 2025), p.10.
[136] Powerco "Submission on Gas DPP4 Issues paper" (24 July 2025), Vector "Submission on Gas DPP4 Issues paper" (24 July 2025).

C27 While we expect to see some reduction in the volumes of gas that will be carried over the pipelines in DPP4, opex tends to be more predictable as it relates to recurring activities.

C28 Overall, we consider a BST approach with step changes or trend factors applied to account for prudent new activities in a less certain operating environment is appropriate.

Additional scrutiny of GPBs' forecast expenditure

C29 We have undertaken discretionary targeted scrutiny of the GPBs' AMPs and issued RFIs where there are other factors we considered required further discretionary targeted scrutiny. Particular areas of focus for the expenditure incurred in DPP3 and forecast for DPP4 related to innovation allowances for blended gases, treatment of disconnection costs and capex/opex substitution.

C30 In addition to the targeted areas above, the BST approach has allowed us to apply scrutiny to items of opex that GPBs are forecasting to increase. This has enabled us to determine whether it is appropriate to approve additional opex beyond a GPB's historical level.

C31 As part of our analysis for the final decision, we focused on incremental changes to expenditure amounts from the draft decision. This involved assessing the reasonableness of DY2025 actual expenditure as the base year, assessing non-recurrent amounts incurred by GPBs in 2025 as well as changes to step changes and additional non-recurrent items submitted by stakeholders.

Our final decision for the opex base year (Decision O2)

C32 Our decision is to set the opex base year as disclosure year 2025 for all GPBs for the purposes of BST modelling with adjustments to remove non-recurring amounts.

C33 The choice of an opex base value is important because it sets the starting point for the BST modelling that we use for setting the opex allowances over the DPP4 period.

Stakeholder submissions

C34 In our draft decision, we proposed using a single year base value set as the most recent actual levels of opex available.[137] This is our established approach applied in recent price-quality path resets for EDBs and Transpower.

C35 In our draft decision, we considered observations raised by Frontier Economics on behalf of Vector that there was no workable alternative to using the base year with most recent data.[138]

[137] Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), paras. B77 and B78.

[138] Commerce Commission "Gas DPP4 Draft decision reasons paper - Attachments A-H" (27 November 2025), paras C31 – C33.

C36 We received limited submissions directly on our draft decision on how we should establish the base year.

C37 Firstgas submitted that when considering non-recurrent amounts, we should consider adjusting base year expenditure for non-recurrent savings as well as non-recurrent costs.[139]

We are using disclosure year 2025 opex for the base year

C38 Since the opex base value sets the starting point for the BST modelling, we are trying to set this at a level which reflects a prudent and efficient level of opex for each GPB.

C39 We consider that in the current environment where there is an expected increase in opex to accommodate a more opex-centric asset management approach and significant changes in the operating environment and expectations, it would be preferrable to use a dataset that represents the most recent expenditure values.

C40 In our draft decision, we noted our intention to use 2025 data for the base year for our final decision as audited information for that year will be available. We considered this would be applied unless we were not satisfied that DY2025 opex appropriately reflects an efficient level, once non-recurring amounts have been taken into account.[140]

C41 We undertook a cross-check of reasonableness of the actual expenditure incurred in DY2025 compared to the base year values we had set in the draft decision and what we predicted 2025 base expenditure amounts would be in rolling forward that base year value. We consider that the DY2025 expenditure appears reasonable when compared with the expenditure values used in the draft decision. For most GPBs, this amount is either in line or lower than the amounts used in the draft decision when compared on a constant $ basis (ie, real).

We have adjusted base year opex for non-recurring amounts

C42 When setting a base year, it is important to remove non-recurring amounts as those amounts would create an artificially higher or lower opex profile, impacting our opex forecast. We considered what adjustments would need to be made to the DY2025 base year for non-recurring amounts including consideration of information available from;

C42.1 AMPs;

C42.2 wider operational context for GPBs, and entity specific issues;

C42.3 information submitted to us in the draft decision phase on non-recurring amounts; and

C42.4 responses to RFIs from GPBs.

[139] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 20-21.
[140] Commerce Commission "Gas DPP4 Draft decision reasons paper - Attachments A-H" (27 November 2025), para C40.

C43 We set out below the adjustments we have made to opex base year values. These reflect both adjustments made for non-recurring amounts identified by the GPBs in response to our RFI, and targeted adjustments we have made for individual GPBs for treatment of costs associated with disconnections, blended gas investigations and compressor fuel costs, discussed below.

Adjustments related to non-recurring changes identified by GPBs and regulatory recognition changes

Summary of all base year adjustments

C44 For Firstgas Transmission (FGT), we adjusted the base year to account for non-recurring costs and savings by:

C44.1 removing compressor fuel gas costs;

C44.2 removing costs related to Clarus' proposed sale of Firstgas;

C44.3 providing an additional amount for blended gas investigation given this was below the level of the proposed allowance; and

C44.4 including an additional amount accounting for savings resulting from a senior management vacancy which Firstgas is not expecting to recur in DPP4.

C45 For Firstgas Distribution, we adjusted the base year to account for non-recurring costs and savings by:

C45.1 removing costs related to Clarus' proposed sale of Firstgas;

C45.2 removing blended gas investigation spend over and above the level of the proposed allowance; and

C45.3 including an additional amount accounting for savings resulting from a senior management vacancy which Firstgas is not expecting to recur in DPP4.

C46 For Powerco, we adjusted the base year down by adjusting its actual spend on blended gas investigations down to our proposed allowance.

C47 For GasNet, we adjusted the base year down by removing expenditure related to blended gas investigations given this is not forecasted to recur.

C48 For Vector, we adjusted the base year by removing:

C48.1 blended gas investigation spend incurred in 2025; and

C48.2 opex for disconnection costs.

Reasons for adjustments

C49 We have removed compressor fuel gas costs for FGT as this will be recognised as a pass-through cost for DPP4 and needs to be removed from base opex to avoid double-counting.

C50 We have removed the costs related to Clarus' proposed sale of Firstgas for FGT and Firstgas Distribution as it was an amount identified by Firstgas as an amount that is unlikely to be recurring for DPP4 in response to an RFI.

C51 We have adjusted the base year opex upwards to account for savings resulting from a senior management vacancy which Firstgas is not expecting to recur in DPP4. We consider it is reasonable to expect that Firstgas will operate with and fill the Chief Financial Officer role for DPP4. We have taken the amount and allocations provided to us in the RFI.

C52 The following sections discuss our rationale for:

C52.1 declining some base year adjustments sought by Firstgas;

C52.2 removing disconnection costs from Vector's DY2025 opex; and

C52.3 adjustments related to blended gas investigations for all GPBs.

We have declined some base year adjustments sought by Firstgas

C53 In its submission on the draft decision, Firstgas submitted two additional non-recurrent savings for us to consider for its transmission business, related to software as a service (SaaS) savings and lost efficiencies on corporate services.[141]

C54 Firstgas' justification for artificially low SaaS costs was that this was driven by a legacy system project, where a significant portion of the technical effort was capitalised and the capex treatment temporarily suppressed the expected opex profile.[142]

C55 While Firstgas have represented this may have temporarily suppressed expenditure on SaaS in this period we note the investment which was capitalised was for a legacy system project related to bespoke development and integration and Firstgas have stated that "these legacy capitalisable development efforts will no longer exist".[143] While we understand that further SaaS related project work would likely be treated as opex, we are not certain the underlying driver of this expenditure will be recurring unless it reflected only internal employee time.

C56 We have also considered whether the value of step changes and non-recurring amounts provided by Firstgas under our BST model reconciles in aggregate with the Firstgas AMP and are concerned that providing for this value may result in an aggregate value from a BST approach which materially exceeds the AMP forecast.

C57 We also note that the impact of the increased capitalisation will be provided for in part through the capex allowance as it will be included as part of the 2025 value we have used to calculate the historical average for capex. On balance, we have declined this requested adjustment.

[141] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 66.
[142] Ibid, p. 66.
[143] Ibid, p. 67.

C58 Firstgas also noted that it would lose efficiency savings as corporate services costs are currently allocated amongst group businesses including Firstlight. Firstgas submitted no information to support this. We consider it would be inappropriate for consumers to pay for lost efficiency due to the change in ownership.

Adjustments related to disconnection costs

C59 The wider context around disconnection costs has been set out within Chapter 3 of this paper.

C60 Consistent with the position outlined in our draft decisions reasons paper, GPBs record disconnection costs as opex under the category "routine and corrective maintenance opex". Accordingly, we have considered whether there is likely to be a significant change in scale such that these need to be accounted for under our BST model.

C61 Recognition of recovery of costs associated with disconnections is inconsistent across regulated parties with Vector netting revenue off against the expense, and Powerco and Firstgas recognising the revenue separately as "other regulated income". The treatment will depend on the nature of the contract between the GPB and the retailer and how this should be recorded according to generally accepted accounting practice (GAAP).

C62 Based on information submitted in response to our RFI for Firstgas distribution and Powerco, we do not consider an adjustment is required as the existing practices and expected forecast recovery of costs for the DPP4 regulatory period are not materially different.

C63 We did not receive a response from GasNet and as such, we have not made an adjustment for GasNet as we are not aware of proposed material adjustment to its proposed practice for cost recovery of disconnection costs.

C64 Exposure to a potential increase in scale of disconnections can be managed by changes to the level of costs recovered, given that is at the discretion of GPBs. We have not implemented a mechanism to address the risk of under-recovery, given design would be complicated and may take away flexibility which is useful in the transition.

C65 For Vector we adjusted the base year by removing disconnection opex. Vector stated that it intended to move to fully recovering the cost of disconnections from consumers in DPP4 and as such, will no longer be a net expense incurred in DPP4.[144]

We have considered the levels of blended gas investigation expenditure within GPBs' base year opex

C66 In DPP3 we provided some opex for the investigation of gas blends in gas networks, that met our interpretation of natural gas, for the purposes of the regulated service.[145] We considered this was appropriate because:

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[144] Vector's response to RFI2.

[145] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final reasons Paper" (31 May 2022), p.84.

it provided incentives to GPBs to innovate to extend the economic lives of networks, which would be a benefit to consumers of natural gas; and

it may reduce carbon emissions while using natural gas and still promote the outcomes of s 52A.[146]

C67 Compared to the context of the DPP3 reset, there has been evidence from GPBs that the development of blended gases injection is progressing beyond the theoretical desktop investigations we had envisaged in the DPP3 reset to trialling injecting blended gases into their networks. In light of this, we are providing some ongoing funds where the GDBs have provided evidence of activities continuing or advancing during DPP4.

C68 We assessed the GPBs' 2025 opex for levels of expenditure on blended gas investigations (set out in its RFI responses) separately as it has implications for both the base year and potential step changes.

C69 In considering the amount of blended gas investigations opex to set in its base opex, we reviewed information on GPBs plans for blended gas investigations submitted in response to our RFI. While we are satisfied that FGT, Firstgas Distribution and Powerco are likely to incur recurring blended gas investigations expenditure, we are not satisfied there is a case to provide additional amounts for the base allowance above our DPP3 amount for FGT and Firstgas Distribution. In particular, the GPBs did not provide an explanation to sufficiently justify additional values above DPP3 level allowances adjusted for inflation and as such, we were not satisfied that the additional amounts were prudent and efficient.

C70 In the case of Vector and GasNet, the AMPs for both GDBs and responses to RFIs did not mention specific blended gas investigations planned for DPP4 and accordingly we have not proposed an allowance for blended gas investigation.

C71 We have maintained the DPP3 allowance amounts for blended gas investigations for Powerco, in addition we have provided a partial step change to Powerco for justified additional renewable gas programmes which we have reflected in the table below. We discuss our rationale for the partial step change in the section on step changes.

C72 Table C2 outlines the allowance to be provided for in the DPP4 period.

[146] In line with s 5ZN of the Climate Change Response Act 2002, it is open to us to consider matters relevant to the Emissions Reduction Plan, provided this does not detract from the s 52A purpose of Part 4 of the Commerce Act.

Table C2 Opex allowance for blended gas investigation[147]

GPBs	DPP3 Opex Allowance (2021 $'000s) per annum [148]	DPP4 Period allowance (2025 $'000s) per annum
Firstgas Transmission	200	248
Firstgas Distribution	135	168
GasNet	45	0
Powerco	45	121[149]
Vector	45	0

More broadly we have decided not to introduce an innovation allowance

C73 Submitters on our open letter noted that we should assess the potential role that innovation by GPBs plays to support the energy transition and future use of gas pipelines, such as developing and testing low carbon gas alternatives. The joint GPB submission also suggested we consider options to address a lack of funding such as an "innovation allowance" as allowed for EDBs.[150]

C74 Submitters on our issues paper advocated for an innovation allowance mechanism similar to the Innovation and Non-traditional Solutions Allowance (INTSA) mechanism as implemented for the EDBs to support transition and increase economic efficiency of GPBs during a wind-down.[151]

C75 We recognise that trialling low carbon gas alternatives could be an important measure to extend the useful life of the pipelines, providing a benefit to consumers. This is why we have continued to provide an allowance to GPBs that have more clearly evidenced their intention to continue investigations and we are satisfied that continuing to do so is in the long-term benefit of consumers.

C76 The design and introduction of the INTSA mechanism within the EDB DPP4 decision was intended to provide non-exempt EDBs, who lacked strong enough incentives to innovate an additional incentive to innovate. [152]

[147] Table C2 is derived from DPP3 allowances with DPP4 period allowance representing the total opex allowance allowed for blended gas investigation for DPP4.
[148] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final reasons Paper" (31 May 2022), para. 5.80.
[149] Powerco total allowance includes DPP3 allowance levels rolled over for DPP4 plus a step change which is discussed later.
[150] Firstgas, Powerco & Vector "Gas DPP4 2026 – Views in response to open letter" (13 March 2025).
[151] These submissions are set out in Commerce Commission "Gas DPP4 Draft decision reasons paper - Attachments A-H" (27 November 2025), paras C59 – C62.
[152] The EDB DPP4 paper noted that the INTSA would not be the sole source of funding for innovative or NTS projects that an EDB may wish to undertake; these can still be funded through approved expenditure allowances.

C77 While we received limited submissions directly related to our draft decision to not create an innovation allowance mechanism, Vector noted that it considers the innovation allowance would support the long-term benefit of consumers by providing greater incentives to invest in innovative solutions to re-purpose the network.[153] It also noted that while it agrees that GPBs have a natural incentive to extend the useful life of their networks, it noted that current levels of in-period demand risk create a disincentive to invest in innovation as they may need to reduce the amount of "discretionary" investment such as those on less certain innovations.[154]

C78 Consistent with our draft decision position, we have not created an innovation allowance for GPBs, because:

C78.1 GPBs have a natural incentive to extend the useful life of their networks in order to continue to operate and remain in business and invest where it is economic to do so;

C78.2 GDBs operating under a weighted average price cap (WAPC) have an incentive to deliver innovation which consumers value given this may result in increased quantities and accordingly revenue, and have an inherent incentive to deliver innovative activities which reduce costs;

C78.3 the step change for blended gas investigations provided in DPP3 has allowed GPBs to undertake the trials and investigations, with Firstgas beginning its blended gas pilot and we have provided allowances for the GPBs above DPP3 allowances where these have been justified and we consider it likely to be prudent and efficient;

C78.4 we have provided step changes for capex-opex trade-offs which would provide funding for some aspects of innovation where we are satisfied that GPB's have identified opex innovations as alternatives to defer capex; and

C78.5 we have not been provided clear evidence of potential innovation opportunities where this would represent consumer benefit aside from blended gas and capex-opex trade-offs. The EDB INTSA aims to incentivise innovation in a context where there may be a greater number of technical and market innovation opportunities available. We do not currently consider the scope of innovation solutions to be as wide ranging in the gas context. In the EDB context there were multiple innovations specifically identified which may be available, the same opportunities have not been identified for gas.

C79 Accordingly, we have not included an INTSA type mechanism for gas because we consider there is not a compelling case for its need.

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[153] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), p. 8.
[154] Ibid, p. 9.

C80 In general, the regime continues to provide incentives for GPBs to innovate to find efficiencies, and to support ongoing usage. In addition, we are satisfied that our allowances in DPP4 for blended gas investigation support, in a scrutinised and targeted way, the main area of innovation identified by GPBs.

C81 As noted earlier in the chapter, the opex allowance is fungible and we expect GPBs can prioritise within their expenditure envelopes to prioritise innovation which they think is likely to be commercially viable.

Our decisions on step changes (Decision O3)

C82 Our final decision is to apply step change factors to help inform our judgement of prudency and efficiency of proposed opex step changes. This helps to ensure only prudently incurred forecast costs are included at an efficient level, which we consider promotes the s 52A purpose.

C83 These factors include whether the step change is:

C83.1 significant;

C83.2 adequately justified with reasonable evidence in the circumstances;

C83.3 not captured in the other components of the DPP allowances;

C83.4 a driver outside the control of a prudent and efficient supplier; and

C83.5 widely applicable.

Stakeholder submissions

C84 Firstgas, Vector and Powerco generally supported our draft decision to apply these step change assessment factors and pointed towards the approach applied in the recent EDB DPP4 reset.

C85 In its issues paper submission, Firstgas submitted that the step change criteria of widely applicable should be reconsidered as each GPB will have different drivers of step changes and may not be widely applicable. [155]

C86 We did not receive any submissions on our draft decision to implement these factors to guide our judgement in assessing proposed step changes.

We have applied the factors above in assessing opex step changes

C87 Potential step changes are assessed by taking into account five factors in exercising our judgement of prudency and efficiency and the likelihood that providing for additional funding to reflect the increase in costs will promote the s 52A purpose:

[155] Firstgas "Gas DPP4 2026: Firstgas views in response to Issues Paper" (24 July 2025), p. 10 &11.

C87.1 **Significance** - New operating expenditure that is not a significant increase to the current allowance is expected to be managed by the GPB. This approach maintains the incentives for GPBs to innovate or find efficiencies to better manage operating costs. In addition, we consider that natural variability within opex costs will mean that small increases in some opex costs are likely to be offset by small decreases in opex costs elsewhere. Requiring an opex step change to be 'significant' better gives effect to a relatively low-cost way of setting price-quality paths.

C87.2 **Adequately justified with reasonable evidence in the circumstances -** Providing evidence to support a level of certainty that the new operating cost will occur within the regulatory period, and the amount for the cost, are important aspects to the assessment of step changes. This approach provides for some discretion on information that GPBs can provide to support requests for step changes.

C87.3 **Not captured in the other components of the DPP allowance** - this factor prevents perverse outcomes where a GPB may be remunerated twice for a cost and prevents unnecessary costs to consumers.

C87.4 **A driver outside the control of a prudent and efficient supplier** – this factor is not so strict as to only cover events that are completely beyond GPB control but rather focuses on whether a prudent and efficient GPB would undertake the activity that gives rise to the cost. The reason we do not consider expenditure drivers that are directly under GPB control is because GPBs are able to choose how to spend their allowed revenue and may reprioritise within their regulatory allowance in order to undertake discretionary activities. This factor aims to give effect to the purposes of Part 4 that suppliers have incentives to improve efficiency and share the benefits with consumers, consistent with s 52A(1)(b) and (c). For clarity, there may be situations where a step change is appropriate where the cost is the choice of the GPB, but there are wider environmental/contextual factors driving the costs for GPBs.

C87.5 **Widely applicable** - to maintain the relatively low-cost nature of the DPP, step changes should be applicable to most GPBs, although there may be some circumstances where a step change that clearly satisfies the other factors could be assessed to be prudent and efficient.

C88 Consistent with our draft decision we have decided to maintain the 'widely applicable' factor to inform our assessment of step changes. We initially heard from submitters that there may be step changes in the gas context that are not widely applicable and there are comparatively fewer GPBs to establish a common set of step changes. We note that the factors are not determinative but rather used to inform our judgement of prudency and efficiency, this helps us exercise our judgement in promotion of the Part 4 purpose.

C89 We have applied discretion in considering whether or not the application of every factor in the assessment of a step change is appropriate on a case-by-case basis.

We approved step changes after seeking information from the gas pipeline businesses and considering submissions

C90 To identify potential step changes which could apply for DPP4, we sent an RFI to all GPBs. This approach is aligned with what we indicated in our issues paper, our approach for the EDB DPP4 reset process, and was consistent with the approach requested by GPBs.

C91 Ahead of the draft decision, we requested each GPB to use a template to provide information on proposed step changes – being both increases in costs or decreases from historical levels.

C92 Firstgas, Powerco and Vector responded with their proposed step changes. GasNet did not respond with any step change requirements.

C93 Following our assessment of these proposed step changes, our draft decision included approving the full amounts sought for step changes that we considered to be fully justified, and either partially approving or declining the requested amount where we did not consider the step change to be as well justified.

C94 We received submissions on the draft decision from Firstgas, Powerco and Vector seeking to further justify some of those step changes that were wholly declined or only partially approved. We did not receive any submissions from any non-GPB parties on our framework for assessing step changes or its application.

C95 We have carried out analysis on the additional information submitted. We note that a lot of the additional information provided by the GPBs is confidential. Accordingly, some of the analysis in this section does not refer to specifics of how either the GPB has quantified amounts for the step changes or how any adjustment factor we may have applied were derived.

Approved step changes

C96 Table C3 below summaries the step changes that we have approved for each GPB as part of our final decision. There are no step changes for GasNet.

Table C3 Summary table showing approved step changes by gas pipeline business

Step	Firstgas Transmission	Firstgas Distribution	Powerco	Vector
Capex-opex trade-off	✓			✓
Cyber-security	✓	✓		✓
SaaS	✓	✓		✓
Renewable gas			✓	
Station and compressor decommissioning	✓			

Capex-opex trade-off

C97 We have included a step change for identified and appropriately evidenced capex-opex trade-offs for FGT and Vector. In our assessment we considered information disclosed through RFIs and received as part of the submission processes. We have retained this decision from our draft decisions as we did not receive any submissions.

C98 While opex solutions may appear more costly in the short-term, they can help avoid committing to long-term investments that risk becoming stranded. In this context, such an approach could represent a prudent and efficient business decision.

C99 It is important for us to understand how these trade-offs are impacting both opex and capex forecasts in setting expenditure allowances and we have considered how GPBs are considering these trade-offs in their asset management planning processes.

C100 We are expecting a shift of expenditure from a more capital-heavy replacement and renewal programme towards expenditure on maintaining assets through opex. However, the materiality and timing of this shift over DPP4 is uncertain as it will depend on many factors. We consider the ability to shift expenditure will depend on a number of asset specific considerations including location, type, nature of expenditure required and customers on the network.

Approach for assessing capex-opex trade-off

C101 Assessing capex-opex substitution through step changes was supported by Powerco.[156]

C102 Firstgas also noted the lack of availability of historical data for capex-opex trade-offs makes it difficult to establish a standardised trend with confidence.[157]

C103 In our draft decision, we proposed to consider capex-opex trade-offs as part of our step change framework within the BST model. As noted above, this was supported by stakeholders.

C104 Accordingly, we have considered the capex-opex trade-off as part of our step change framework within the BST model and separately considered the extent of capex forecast for asset replacement and renewal (ARR) and RSE given these expenditure categories represent the capex areas most likely for substitution.

C105 We understand it can be challenging for GPBs 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. However, we do consider there should broadly be a relationship between the two. We have not provided a step change in opex if an offsetting decline in ARR and RSE capex is not demonstrated.

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[156] Powerco "Powerco response to the Gas DPP4 issues paper" (24 July 2025), p.12.
[157] Ibid, p.11.

Submissions on capex-opex trade-offs

C106 Our outline of capex/opex trade-off was broadly supported by stakeholders including GPBs and non-GPBs in the issues paper stage. We considered these submissions in our draft decision.[158]

C107 In submissions on our draft decision, Firstgas and Vector supported our capex-opex trade-off decisions (including our approach and quantum set).[159, 160] There were no other submissions.

Assessment outcomes

C108 We consider the proposed step change for Vector and FGT are significant, have a driver outside the control of a prudent and efficient supplier and are widely applicable.

C109 We have not provided for Powerco and Firstgas Distribution for capex-opex trade-off step changes requested as we consider there is a risk that it is included elsewhere in the expenditure allowance (specifically in capex forecasts) and the level of evidence to support was not consistent with other GPBs, and as such, we were not satisfied that the step change was likely to be prudent and efficient.

Vector

C110 We have accepted the step change proposed by Vector. Vector has identified within information provided under the RFI that following the development of a Condition Based Asset Risk Management (CBARM) model, it has transitioned from a traditional approach of full asset replacement to a data-driven, condition-based strategy focused on targeted intervention of asset subcomponents, without full replacement. It has also identified increases in routine and corrective maintenance to reduce the need for capex-intensive replacements and new installations.

C111 Vector has introduced significant capex-opex trade-offs for ARR opex, some of which are reflected in a 42% reduction in ARR capex compared to its 2024 AMP update over the DPP4 period. It has provided a clear strategy and has explained and quantified the changes in its 2025 AMP with supporting information provided in its response to our expenditure RFI.

Powerco

C112 We have declined Powerco's request for a step change due to increased opex activities which are focused on maintaining and renewing the network. Powerco represented that through its use of technology and innovation it can significantly improve understanding of asset condition and implement a more targeted approach to asset replacement and renewal (ARR). Powerco represented it had a reduction in routine corrective network maintenance costs, offset by a more proactive asset replacement programme to address leakages and losses - which are being detected at higher and more accurate rates due to new detection methods and modelling.

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[158] Commerce Commission "Gas DPP4 Draft decision reasons paper - Attachments A-H" (27 November 2025), paras C83-C88.
[159] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 21.
[160] Vector "Cross-submission on the default price-quality path for gas pipeline businesses beginning 2026 (12 February 2026), p. 9.

C113 While recognising that it is difficult to establish a direct mapping to value the capex-opex trade-off, we have not in this case been able to identify any offsetting impact within ARR capex of the proposed transition to a more heavily based opex programme. Noting Powerco is forecasting a significant uplift in ARR capex for climate adaption and resilience initiatives (assessed within Attachment B). Consistent with our draft decision, we are not convinced that providing for this expenditure is consistent with the "not captured in the other components of the DPP allowance" factor. Powerco did not submit on this draft decision.

Firstgas Transmission

C114 We have approved the step change requested for FGT. Firstgas have identified a range of capex-opex trade-offs including:

C114.1 management of technical change for refurbishing equipment and station coatings program becoming a targeted risk and condition-based response rather than capital refurbishment;

C114.2 shorter period management of geohazards risks to its pipelines; and

C114.3 implementing a programme of inspecting heaters rather than inspections completed as part of capital refurbishment projects.

C115 We note FGT is forecasting a material decline in the level of ARR on its pipeline network for the DPP4 period compared to historic levels.

Firstgas Distribution

C116 We have declined the step change requested for Firstgas Distribution; the core component of this work programme was for inspection and repairs related to its pre-85 pipe programme. It is not clear that the work programme is a deviation from existing practices which are being employed, and accordingly will already be recognised within the base allowance. We understand that Firstgas has been deploying a maturing approach to risk management including new corrective maintenance processes and leak surveys as part of its risk management of pre-1985 polyethene pipe and was funded for this in the previous reset.[161]

GasNet

C117 No RFI response was provided from GasNet, and accordingly no capex-opex trade-off step change has been provided. We observe that GasNet are not forecasting a material decline in ARR expenditure.

Including a step change for increasing cyber-security costs

C118 GPBs have noted their cyber-security costs are likely to increase to manage the increasing external cyber threat including with the transition to more cloud-based systems.

[161] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final reasons paper (31 May 2022), p.134.

C119 We have approved a step change for GPBs who requested a step change and provided sufficient information. This applies for FGT, Firstgas Distribution and Vector, for whom we have approved the full amount of their step changes.

C120 GPBs have provided evidence to support increasing cyber-security costs. While there are levels of current spend captured in the base year, there is evidence to support the proposed increases exceed inflation.

C121 We consider this step change is widely applicable and reasonably outside the control of a prudent and efficient supplier.

C122 In our draft decision, we considered that while most steps requested had been adequately justified with reasonable evidence in the circumstances, there was a risk that the proposed value of the FGT step change request reflects an inefficient level of current and forecasted spend, and we capped the level of step change allowed.

C123 In its draft decision submission, Firstgas provided additional information justifying its cyber-security work programme, including external expert evidence.

C124 We consider that Firstgas' evidence has now met the "adequately justified with reasonable evidence in the circumstances" factor. In this instance the programme and costs have been reviewed by experts from a respected agency, indicating that the work is prudent, and a clear work programme has been established and provided with reasonable costs based on the expert report benchmarking and is therefore likely to be prudent and efficient.

Include a step change for software as a service costs

C125 GPBs have indicated that they are increasingly looking to transition their current IT systems to a cloud-based SaaS model. This step was requested to recognise the costs associated with licensing or subscription fees, set up/implementation costs, and personnel/FTEs to monitor and administer the new systems.

C126 We consider SaaS costs are likely to be significant with the shift to cloud-based solutions forecast to come at a significant opex cost for GPBs – both initial installation costs and then ongoing subscriptions.

C127 We consider the step change is likely to be widely applicable and has a driver outside the control of a prudent and efficient supplier given our expectation on GPBs to appropriately upgrade systems over time to maintain and increase efficiency of operations.

Vector

C128 We have retained our draft decision to partially approve Vector's step change related to SaaS.

C129 We received submissions to our draft decision from Vector on this step change. Vector noted that:[162]

> the level of requested step change reflects the fact that digital costs have continued to outpace inflation and that the SaaS costs are now higher than when EDB DPP4 was determined. Vector noted that these are driven by the global change to subscription based pricing and modernising end of life systems resulting in a change from capex to opex, along with the need to deliver new digital solutions and securing its network from cyber threats.

C130 It also provided values for increased SaaS costs.[163]

C131 Our view is that Vector did not provide adequate further rationale and evidence to substantiate the level of increase requested and we are not confident the increase reflects an efficient level of costs. While it did provide an updated set of SaaS costs, these were noted as provisional and subject to change. Furthermore, there was limited explanation outside of the increased expense, and based on our analysis we did not consider the quantum of Vector's increases to be proportionate to broader trends in SaaS costs.

Firstgas Transmission and Distribution

C132 Our final decision is to approve the full amount sought by Firstgas for a step change for SaaS costs.

C133 In our draft decision, we approved the step change requested by FGT which relates to its Open Access Transmission Information System (OATIS). We declined the wider step change for SaaS costs applied for both FGT and Firstgas Distribution related to wider capability improvements. While a significant number of SaaS systems were identified in information provided, it lacked specificity to assess the costs and accordingly we consider it was not adequately justified.

C134 In its submission on our draft decision, Firstgas provided additional detailed information related to its SaaS work programme. This information demonstrated a defined and credible programme of work, supported by a coherent package of solutions for its implementation. The programme costs were expressed as quantified annual amounts and reflected a work programme that we consider is likely to be delivered during DPP4. We consider that this additional information addressed our earlier concerns, and that the proposed step-change was now adequately justified and is likely to reflect expenditure that is prudent and efficient.

Include a step change for the costs of station and decompressor decommissioning

C135 In our draft decision, we declined a step change for costs associated with asset and network decommissioning requested by FGT. We declined this step change as we did not consider it was appropriate to allow a step change for decommissioning costs when significant uncertainty exists around legal obligations on GPBs, and the scale and extent of costs likely to be incurred.

[162] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), para 80.

[163] Vector noted that these values were confidential.

C136 In its submission on the draft decision, Firstgas provided further evidence that it considered the work represented "prudent, near-term expenditure that prevents ongoing and unnecessary lifecycle costs, which would be inefficient costs for consumers to bear."[164] This includes "removing redundant or poorly utilised assets that no longer serve a functional or economic purpose."

C137 Firstgas has identified specific assets that are of limited use on its network or not being used anymore. It has considered the economics of continuing to maintain or replace these assets and has assessed that decommissioning these assets would reduce the lifetime cost to maintain these assets which currently provide limited economic benefit.

C138 We consider the evidence put forward by Firstgas in support of the proposed expenditure shows that this expenditure reflects lowest lifecycle costs and can be separately engaged with compared to wider decommissioning related costs. We consider the evidence provided means this is sufficiently justified and is likely to be prudent and efficient given these represent identified projects that are incurred to reduce lifecycle costs and is accordingly likely to be in the long-term benefit of consumers. We note these are specifically identifiable costs to manage lifecycle costs and do not represent funding for any broader potential decommissioning liability. Our final decision is to approve a step change for the costs of station and decompressor decommissioning for FGT.

Include a step change for renewable gas

C139 We have approved a partial step change for Powerco related to renewable gas expenditure. This accounts for an increased expectation of activity, but this is reduced to reflect an allocation of costs which more clearly relates to the regulated service.

C140 In its submission on the draft decision, Powerco provided additional information on the specific blended gas investigation projects it has planned in DPP4. While Powerco has provided details of the projects it is considering, we consider some of the projects appear to be more speculative based on project status within the wider project timeline.

C141 Powerco also note "There may also be other projects commenced later in the period or projects advanced by other parties that will inject into the network"

C142 While we have provided for some blended gas investigation costs as part of the base year, we recognise that Powerco is forecasting to spend over and above the amount provided for in the base year adjustment (being the level of the DPP3 allowance inflated to DPP4 values).

[164] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 26.

C143 Powerco has evidenced a likely programme of work related to connection of renewable gas facilities, with a focus on the typical stages of a biomethane project. Specific information on what the opex costs represent is limited with Powerco stating "Providing for regulatory allocation of investigation costs". Regulated suppliers are exposed to expensing work on investigating potential connections which don't materialise (i.e. work can't be capitalised into the RAB).

C144 However, we note that Powerco have both regulated and unregulated services with regard to some of these facilities and it not clear that the opex value represented relates to the regulated service as opposed to the unregulated service. We consider the proposed allocation split by Powerco is inappropriately high and is not reflective of the likely outcomes of a more detailed allocation process

C145 Accordingly, we have provided a partial approval of the value, representing one third of the requested step change to account for an increased expectation of activity than provided for in the base allowance but reduced to reflect a clearer allocation of appropriate costs to the regulated service.

Step changes we did not approve

C146 As part of our review of step change, we did not approve the following step changes. These are tabulated in Table C4 with our reasons.

Table C4 Analysis of step changes that we have declined

Description of potential step change	Analysis and reason for declining
Stakeholder engagement plans / consumer engagement, involving more direct customer and community engagement, tools and materials about gas and alternatives, which will also need to be informed by more in-depth research for consumer insights.	We consider informing customer decisions on options has value. We note there is currently a lot of mixed messages (reflected in consumer kōrero that the extent of different views makes making decisions harder for consumers). Although consumer engagement expense in aggregate is significant, engagement is taking place at present and is included in the base year. It is not clear that this expenditure could not be accommodated within existing resources previously focused on growth.
Capability uplift for improved forecasting and planning methodologies. Improving forecasting approach to better inform network investments including asset renewal activity and deployment of opex based solutions.	We consider that existing allowances provide for a GPB to undertake forecasting activities and network planning. While we understand networks will need to increasingly consider location based optioneering studies and risk assessments to understand the likelihood of network viability and potential end-of-life considerations We consider work of this nature is already occurring, which is reflected by the step change not being requested by many GPBs. We consider internal capability and competence is within a prudent GPB's control and is an issue which should have been considered and addressed over the preceding periods. While Firstgas provided additional evidence in its submission on the draft decision to support the programme of work. We consider it does not reflect work that is appropriate to be treated as an uplift in expenditure allowances given we expect all regulated suppliers to be constantly working to improve their network management within regulatory allowances.
Legal resource for Urbanisation. To comply with required standards and ensure safe operation in urban areas, pipelines will need additional protection. This will include planning advice, property and easement advice, legal advice and stakeholder engagement.	We are not clear that there is significant step change in the underlying driver of the costs between the base year and the DPP4 regulatory period. We consider the expenditure has not been adequately justified as required, and therefore reflects efficient expenditure, as we have been provided limited evidence to show that quantum of lines subject to urban encroachment has increased compared to current levels provided for within the base other than a statement to say there would be additional pipeline above existing pipeline in progress. While we understand increased urban sprawl will extend the length of pipeline required to be managed, we consider that costs related to pipelines where this was previously an issue will not be consistent over time and likely reduce, meaning the base allowance inherently will provide for different pipelines which require increased focus.

Our final decisions on trend factors

C147 The following sections set out our decisions on opex scale growth, cost escalation and opex partial factor productivity.

C148 Across these decisions, we have sought forecasts that we generally consider are statistically robust and reliable predictions of the drivers of GPB opex. Many of the decisions are technical in nature and are made in pursuit of our goal of accurate forecasting. This in turn results in opex allowances that balance incentives to find efficiencies under s 52A(1)(a), the sharing of those efficiencies with consumers under s 52A(1)(c), and limits on excessive profits under s 52A(1)(d).

C149 Following our review of factors that could influence the trend within the BST modelling, our decision is to apply the same trend factors we have applied in previous resets, with an adjustment to account for a likely non-linear correlation between decreases in ICP and reduction in network size. The absence of robust data sets for a declining market makes estimation of elasticity to declines in ICPs difficult in the present case.

C150 Our final decision is to set the trend factor to scale opex for GDBs by:

C150.1 setting a network scale trend factor based on historic relationship of network length to ICP growth by:

C150.1.1 weighting network length and ICP change equally at 50% in the elasticity model;

C150.1.2 applying a floor of 0% in scaling base opex for forecast of network length from ICP change; and

C150.1.3 applying an asymmetric treatment of ICP-related opex changes such that opex decreases are de-weighted to 25% of the impact implied by declining ICPs,

C150.2 setting a partial productivity factor of 0%; and

C150.3 escalate opex costs using the all industries labour cost (60% weighting) and a producers' price (40%) indices.

C151 Our final decision for the GTB is to set:

C151.1 the same trend factors for the partial productivity factor and cost escalation as the GDBs; and

C151.2 the network scale factor at 0%, consistent with the approach applied under DPP3. The GTB operates a highly integrated and capital-intensive network with limited new connections and different operational characteristics compared to GDBs with its opex influenced more by system-wide integrity and long-distance pipeline maintenance, rather than customer connections or urban network expansion or contraction.

Our decision on network scale trend factor (Decisions O6, O7, and O8)

C152 Similar to DPP3, we have determined a trend factor for the GDBs' opex based on changes in network scale. This is modelled by scaling base opex in real terms for estimates of network length and ICP change in each year of DPP4. The ICP change and network length estimates are modified by an elasticity factor that models their non-linear relationship with opex.

C153 However, there is a significantly different context for DPP4 than previous periods, where all GDBs are expecting declines in the number of ICPs connected to the network.

C154 This point has been noted in issues paper submissions from Frontier (for Vector) stating:[165]

> We consider the Commission's existing approach is no longer suitable given the forecast decline in customer numbers and volumes. The Commission's elasticity models of the relationship between network scale and opex are unlikely to produce accurate results in the context of falling customer numbers, a network that is no longer growing, and costs which are largely fixed. We consider a floor of 0% on the output growth factor would be a reasonable approach for DPP4 if the Commission continues with the BST approach.

C155 In its submission on the issues paper, Vector submitted:[166]

> Consumer numbers are expected to decline over the DPP4 period. This will result in a lower trend factor resulting in a lower opex allowance in real terms over DPP4 relative to the base year. This is a perverse outcome given an appropriate response to declining volumes and connections is for GPBs to increase opex (e.g. on maintenance rather than asset replacement).
>
> While the decline in opex allowances driven by the "number of consumers" factor could be small and there is likely little or no change in network length these impacts still need due consideration by the Commission when setting opex allowances.

C156 In its submission on the draft decision, Vector submitted again that it considers a floor of at least 0% on the scale factor between ICPs and opex to account for the impact of declining ICPs.[167]

C157 Its view was, there was no reason to assume costs will decline proportionally with disconnections. Vector noted:[168]

> GPBs must continue to meet the same safety and reliability standards irrespective of changes in customer numbers. The underlying physical network remains in place, requiring ongoing maintenance, inspection, and compliance. As a result, most operating costs are fixed or only partially variable, and essential functions (e.g. such as public safety management, emergency response, leak detection, statutory

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[165] Vector "Attachment A: Key issues for Gas DPP4 reset - Report for Vector" (prepared by Frontier Economics) (24 July 2025).
[166] Vector "Reset of the gas default price-quality path 2026: Issues Paper – Vector submission" (24 July 2025), para. 114.
[167] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), pp. 6-7.
[168] Ibid, p. 23.

> compliance, system operations, customer service, and incident readiness) must be maintained.
>
> Vector's move to an opex based operating model means opex will increase even though ICPs are declining. Failure to account for this in the base, step and trend creates a real risk that that opex allowances will be insufficient to cover additional maintenance required for an opex based asset management approach.

C158 Frontier on behalf of Vector:[169]

> The Commission has not explained why it expects a linear, symmetric relationship between connections and disconnections, nor why opex should decline as connections are lost. In practice, opex does not respond symmetrically to declining connections. While new ICPs can drive incremental costs, such as commissioning, customer onboarding, and possible network augmentation, disconnections do not result in equivalent cost savings.

Result of applying our previous elasticity approach in DPP4

C159 Historically, to forecast how increases in network length affect opex need, we used historical trends of network length and GDBs' ICP growth and the relationship between the two. GDBs do not forecast network length increases in their AMPs, so we estimated this relationship based on historical data.

C160 We quantify the relationship between opex growth and scale growth using elasticities, which give the percent change in cost for a given percent change in scale. For example, an elasticity of 0.9 means that a 10% increase in network scale is expected to give rise to a 9% increase in opex.

C161 We have used an elasticity modelling methodology set out in a 2013 Castalia report submitted as part of the 2013 gas DPP decision. [170]

C162 We have taken a composite scale variable (CSV) regression approach between total opex and a composite scale variable with an equal weighting of ICP count and network line length. In this approach, the elasticity is the slope of a standard least squares regression of ln(opex) vs. ln (CSV) where CSV = (ICP count)$^{0.5}$ x (line length)$^{0.5}$).

C163 For the dataset we used the GDBs' ICP forecasts as the forecast source instead of Concept Consulting (DPP3), aligning with the constant price revenue growth (CPRG) model.

C164 We have estimated an elasticity for DPP4 of 0.440. In DPP3 the estimated elasticity was 0.481. We determined that the CSV approach remains fit for purpose, as it continues to produce regression results that can be considered robust.

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[169] Frontier Economics "Key issues in Gas DPP4 Draft Decision – Report for Vector" (21 January 2026), p. 16.

[170] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final reasons paper (31 May 2022), para. A156

C165 The approach we have used to estimate the elasticity is to split network scale effects equally between ICP growth and network length increases, which is consistent with our approach in DPP3. We consider this remains appropriate for its application in trending opex in DPP4, given this reflects historical drivers of expenditure.

Specific considerations for DPP4

C166 Given GDBs are forecasting declining ICPs connected to their networks, particularly over later years within the DPP4 regulatory period, we considered the impact of declining ICPs on network length. We do not have a robust historical data series reflecting declines in ICPs with corresponding impacts on network length. 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 would not 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 unco-ordinated way.

C167 To address this risk, we are retaining the weightings but implementing a floor when forecasting network length so that it does not decline with reductions in ICPs, i.e. when estimating line length as an input to the model in the instance of declining ICPs we do not forecast a negative impact on network length. While this will not hold in perpetuity, i.e., network length will at some stage reduce with ICP disconnections, we consider in absence of a robust dataset to establish a proxy relationship this assumption is appropriate for DPP4.

C168 In our draft decision, we did not apply a floor of 0% for the impact of declining ICPs. We considered there was likely to be a symmetry of costs between increasing and decreasing ICPs and opex. We have considered Vector's submissions for applying a floor of 0% to account for the impact of declining ICPs in setting the network opex scale factor.

C169 As noted in the draft, we consider there is an expectation that elasticities should reflect both increases and decreases. However, we have considered Vector's submission and we also consider that the decrease in opex may not necessarily be on a 1:1 scale proportionate with increases. We consider that GPBs operating in a declining context would be actively looking for cost savings and as such, we consider there should be some downward pressure on the opex allowances in ICP trend factors.

C170 As such we have decided to apply an asymmetric treatment of ICP-related opex changes such that opex decreases are de-weighted to 25% of the impact implied by declining ICPs. This recognises the fact that a large portion of opex is likely to be fixed or only partially variable while still accounting for some downward pressure.

C171 Accordingly, forecast declines in ICPs will result in a downward trend in opex allowances to reflect the fact that only some portion of opex is likely to be variable in response to declining ICP numbers.

Our decision on the partial productivity factor (Decision O5)

C172 Our final decision is to maintain the partial productivity factor of 0% used in DPP3, consistent with that proposed in the draft decision.

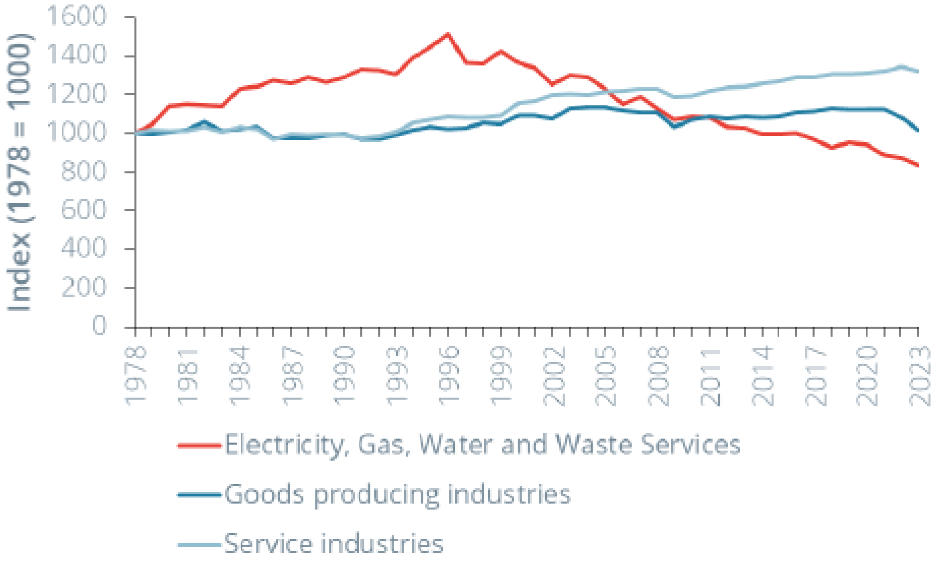
C173 We have found no evidence to indicate that the productivity of GPBs of natural gas pipeline services improved by more or less than the rest of the economy.[171]

Stakeholder submissions

C174 Vector commissioned and submitted an expert report from Frontier Economics. As part of the report, Frontier considered the partial productivity factor. Frontier provided the following analysis (and chart):[172]

> In DPP3, the Commission decided not to apply a productivity adjustment (i.e. 0%). This was based on an earlier finding that there was no evidence to indicate that the productivity of GPBs improved by more or less than the rest of the economy.
>
> We consider the Commission's approach in DPP3 remains appropriate for DPP4. The figure below shows multifactor productivity (MFP) in the utilities industry, which includes gas distribution, has continued to lag behind the goods and service industries. Since the late 1990's, MFP has declined in this sector, indicating there is no compelling reason to change from the Commission's approach in DPP3. Further, with the outlook for falling output and increasing opex, it will be difficult to achieve productivity growth. This doesn't reflect inefficiency for gas pipeline businesses, but rather is a consequence of an uncertain future network.

Figure 1: Multifactor productivity in New Zealand (1978-2023)



Source: Stats NZ, https://www.stats.govt.nz/information-releases/productivity-statistics-1978-2023/

[171] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final reasons paper (31 May 2022)
[172] Vector "Attachment A: Key issues for Gas DPP4 reset - Report for Vector" (prepared by Frontier Economics) (24 July 2025), Section 2.4.5

C175 Our view is that with the prospect of lower gas volumes and a shift towards a more opex focused work programme for the GPBs, it is difficult to predict and draw conclusions on the productivity of the gas sector and any forward-looking estimates of productivity. As the businesses shift to a more opex reliant work programme, it is likely that outputs would remain constant or decrease with an increase in costs from increased opex.

C176 We have also considered Frontier's submission and consider that this is consistent with our own analysis:

C176.1 we took a high-level approach to assessing productivity by taking the Stats NZ produced multifactor productivity index and comparing the compounded annual growth rate (CAGR) of the electricity, gas, water, and waste (EGWW) sector from 2018-2021 (when we set DPP3) and 2021-2024. We used this as a proxy to estimate productivity in the gas sector given it contributes to this index; and

C176.2 based on our calculation, the compound annual growth rate for EGWW has not changed since we set gas DPP3. Our calculated CAGR is -1.7% for both time periods.

Our decision on opex cost escalation factors (Decision O4)

C177 Our final decision is to inflate the GPB opex allowances for input price changes using the weighted average forecast change in:

C177.1 the 'all industries' Labour Cost Index (LCI) (at 60% weighting); and

C177.2 the 'all industries' Producer Price Index (PPI) (at 40% weighting).

C178 This is the same as our draft decision, noting that the latest available values for these forecasts are used in our final decision.

C179 We have not allowed an additional adjustment to reflect potentially higher costs in the gas sector compared to the sectors represented in the 'all industries' index forecasts.

C180 Changes in input prices affect the annual cost of providing a given level of service and are largely beyond the GPB's control.

C181 Given we provide allowances in nominal dollars, the real base opex and scaled opex trend, over DPP4, is required to be inflated to nominal opex using forecast changes in input prices over the DPP4 period.

Stakeholder submissions

C182 While Powerco[173] and Vector[174] submitted that a cost escalation adjustment is required to reflect historical inflation across all utilities and is likely to continue during DPP4 at the issues paper stage.

C183 We did not receive any submissions related to our draft decision on cost escalation, or further evidence to support an additional adjustment may be appropriate.

Labour cost index/producer price index weighting

C184 We did not receive any submissions on either the issues paper or our draft decision directly on whether it was appropriate to continue to apply the LCI/PPI indices which we applied in DPP3 or their weighting, noting Powerco's broader support on our approach to cost escalation noted in its submission above.

C185 Our final decision is to retain the gas DPP3 (and EDB DPP4) LCI/PPI weighting of 60%/40% and use the New Zealand Institute of Economic Research (NZIER) forecasts as we did in gas DPP3. While the current context is dynamic it is not clear there is a significant shift in the mix between labour costs and non-labour costs.

We have not provided an additional adjustment to labour cost index/producer price index

C186 In EDB DPP4, we applied an additional 0.3% per annum adjustment to reflect historical higher inflation in EGWW sector which we considered would be likely to persist in the medium-term.

C187 While we recognised that there may be higher inflation in EGWW for the EDB DPP4 reset, the drivers of EDB and GPB costs are not the same, and we are not convinced that the same inflationary pressures exist for GPBs.

C188 Our final decision is not to include a cost escalation adjustment.

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[173] Powerco "Powerco response to the Gas DPP4 issues paper" (24 July 2025), p. 13.
[174] Vector "Reset of the gas default price-quality path 2026: Issues Paper – Vector submission" (24 July 2025), para. 124.

Attachment D Addressing the risk of economic network stranding

Purpose of this attachment

D1 This attachment explains our decision for the fourth default price-quality path (DPP4) to mitigate gas pipeline businesses' (GPBs) risk of economic network stranding due to the expected long-term decline in demand for natural gas.

D2 It outlines:

D2.1 our decision to shorten regulatory asset lives for GPBs in DPP4 to complete the transition to economic network lives we began in the third default price-quality path (DPP3), including:

D2.1.1 our view of the long-term outlook for gas pipeline networks relevant to stranding risk in DPP4, including analysis of contextual developments since the DPP3 reset and feedback from stakeholders; and

D2.1.2 how we were guided by our long-term network stranding model and its 2050 and 2060 wind-down scenarios (and 33:67 weightings);

D2.2 how our decision satisfies the criteria in the gas distribution business (GDB) and gas transmission business (GTB) input methodologies (IMs) for adjusting the average regulatory asset lives for each GPB in DPP4, by:

D2.2.1 better reflecting economic asset lives; and

D2.2.2 better promoting the long-term benefit of consumers of gas pipeline services;

D2.3 the effect on the depreciation component of DPP4 allowable revenues and expectations of ex-ante financial capital maintenance (FCM) to support GPBs' incentives to continue investing efficiently during DPP4 to maintain safety and reliability standards and meet ongoing consumer demand; and

D2.4 the role that GPBs can play in managing their gas businesses and network assets to minimise exposure to network stranding risk ahead of the next DPP reset (commencing 1 October 2031).

Structure of this attachment

D3 In Table D1 we describe the structure of this attachment.

Table D1 Structure of this Attachment D

Title	Description of content
Overview of our DPP4 decision	Summarises our final decision to mitigate network stranding risk in DPP4 by shortening regulatory asset lives for GPBs, with key supporting information and reasons
How we assessed the stranding risk mitigation required for DPP4	Further detail on how we estimated, via scenario modelling, the DPP4 asset life adjustments, including considering publicly available information and feedback provided by stakeholders during the DPP4 reset process
Our stranding model inputs and parameters	Explains updates to our network stranding scenario model to make it fit for purpose for DPP4

Overview of our DPP4 decision

Network stranding risk in DPP4 continues to threaten the long-term benefit of consumers

D4 As we discuss in Chapter 2, a high-level of uncertainty surrounds the pace at which long-term demand for pipeline services will decline as New Zealand transitions to a low-emissions economy. This raises a risk of GPBs' large up-front investments in long-lived pipeline assets becoming economically stranded at some point in the future.[175]

D5 If network stranding risk is not adequately addressed, it will likely undermine incentives for GPBs to continue investing efficiently in pipeline infrastructure to meet the needs of current and future consumers.[176] This threatens the long-term benefit of gas pipeline consumers and the promotion of the Part 4 purpose in s 52A of the Act.

D6 For DPP3, we shortened average regulatory asset lives under the GDB and GTB IMs for each GPB to better reflect economic asset lives and better promote the Part 4 purpose. This mitigated economic stranding risk by accelerating GPBs' depreciation in DPP3 in line with a more realistic expectation of cost recovery compared with using longer estimated physical asset lives.

[175] Gas pipeline networks can become fully or partially economically stranded at the point at which a GPB does not expect to recoup network investment and operating costs (including depreciation and a normal rate of return) through revenues over time, thus not achieving expectations of ex ante FCM under our building blocks framework applied when setting a DPP. The ability to recover costs over time depends on the collective willingness and capacity of gas pipeline users to pay for required network charges.

[176] While the prospect of network-related costs being unrecoverable may not be imminent (ie, is unlikely to occur in DPP4), it is the expectation that this may occur in the future that signals an economic stranding event and threatens investment incentives.

D7 Our expectation at DPP3 was that a full transition to the new price levels implied by economic asset lives would occur over two DPP periods.[177] Updated long-term scenario modelling, discussed below, confirms that a material level of unmitigated stranding risk remains ahead of DPP4, and we should consider completing the transition by specifying shortened asset lives for DPP4 to promote the long-term benefit of consumers.

Our decision is to complete the transition to more realistic economic lives in DPP4 to mitigate demand risk

D8 Our final decision is to specify new asset life adjustment factors for each GPB for DPP4 under the GDB and GTB IMs to shorten average regulatory asset lives (relative to the regulatory asset lives brought forward from DPP3) to reflect economic asset lives.[178]

D9 This implements further mitigation of economic network stranding risk for GPBs (relative to our DPP3 decision) and supports incentives for ongoing investment in pipeline networks to meet the needs of current and future consumers of gas pipeline services by:

D9.1 aligning the period over which future costs are expected to be recovered with a more plausible timeframe over which natural gas networks might operate; and

D9.2 bringing forward the recovery of a portion of GPBs' RAB values (via depreciation) to DPP4, reducing the risk of future under-recoveries and maintaining expectations of FCM.

D10 Our DPP4 decision effectively completes the transition to more realistic regulatory asset lives for GPBs we began in DPP3, based on the latest information available to assess the extent of mitigation required in DPP4 via our long-term scenario modelling.

D11 In terms of possible alternatives for addressing stranding risk in DPP4:

D11.1 Consistent with the conclusions in the 2023 IM review, which we consider remain appropriate in DPP4, we have not proposed removing inflation indexation of the RAB, departing from the straight-line method for calculating regulatory depreciation under a DPP, or providing an ex-ante compensation mechanism;[179]

D11.2 Stakeholder proposals for implementing a cross-sector solution, whereby cost recovery of some portion of GPBs' RABs is shifted to consumers of electricity

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[177] Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), paras D49-D50.

[178] Under the GDB and GTB IMs for ID regulation, the shortened lives from DPP3 automatically flow through to DPP4 via the ID RAB to maintain higher levels of depreciation that commenced in DPP3. Our final decision implements additional risk mitigation by further shortening those asset lives in DPP4 (ie, greater depreciation is produced for DPP4 than just applying the already shortened DPP3 asset lives).

[179] We note that these alternative options may require amendments to the GDB and GTB IMs to implement. See: Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), paras 3.276-3.447. On inflation indexation, see Vector "Reset of the gas default price-quality path 2026: Issues Paper – Vector submission" (24 July 2025), paras 92-93; Entrust "Gas price reset needs to ensure investment cost-recovery in face of decreasing demand" (24 July 2025), p. 1, 6; Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision" (22 January 2026), paras 64-67.

lines services, would be a significant policy decision for the government to take and is out of scope for the DPP4 reset;[180] and

D11.3 We consider it to be in the interests of consumers of gas pipeline services for GPBs to maintain ex-ante expectations of FCM at this time. As we explain below, altering average regulatory asset lives in DPP4 maintains ex-ante FCM by providing a reasonable expectation of achieving a normal return over the economic lifetimes over which pipeline networks are assumed to be used.[181]

We have retained our 2050 and 2060 modelled scenarios to estimate the required adjustments to asset lives in DPP4

A range of factors contribute to estimates of long-term stranding risk

D12 There is no definitive source of information which indicates how demand for gas pipeline services, and therefore the collective willingness and ability of gas consumers to bear required network charges over time, will likely decline over the long-term.

D13 Instead, a range of factors influence the future prospects for reticulated gas use.

D13.1 The key factors are the availability and cost of producing gas, the effect of government policies (particularly in response to climate change), the economics of consumers transitioning to alternative forms of energy, developments in gas-dependent sectors (eg, electricity generation) and consumer preferences.

D13.2 Challenges when assessing the impact of these factors on the future outlook for gas pipeline networks include the long timeframes for the expected transition away from gas use, complexities and interdependence between the various factors listed above, and potential for rapid changes in circumstance to occur.

We retained our DPP3 scenarios model to estimate risk for DPP4

D14 Consistent with a relatively low-cost approach to setting a DPP, and the high degree of uncertainty surrounding the risk to be mitigated, we considered it appropriate to reapply our DPP3 long-term network stranding model to guide us in considering adjustments to average asset lives required in DPP4 to maintain GPBs' expectations of FCM.

D14.1 The model estimates a long-term revenue trajectory sufficient to allow GPBs to recover costs (including a normal rate of return) through network charges, based on assumptions about the profile of DPP maximum allowed revenues over time, consumers' collective willingness and ability to pay, and the level of costs.

D14.2 A key feature of the model is the inclusion of long-term assumed industry wind-down scenarios, which guide us in a plausible central estimate of long-term risk to be mitigated in DPP4 via asset life adjustments. The model is high-level and simplified, and is not intended to be predictive of eventual industry end-states.

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[180] This is discussed further in Attachment F.
[181] See paragraph D35.3.

D15 We emphasise that our objective has been to assess the extent of regulatory action in DPP4 that would best promote the long-term benefit of consumers under a range of plausible future outcomes and conditions of high uncertainty. This is a broad exercise, balancing information and competing views, and involving some element of judgement.

The 2050 and 2060 scenarios remain fit for purpose in DPP4

D16 Our view is that the extent of any adjustment to average asset lives in DPP4 is best estimated by retaining the two long-term industry wind-down scenarios from our DPP3 decision, and the corresponding 33:67 weightings used to combine their outputs.[182]

D16.1 We consider that a blend of these two scenarios reflects—approximately—the centre of the possible distribution of risk at this time.

D16.2 Eventual industry wind-downs which are shorter or longer than modelled (or other outcomes for the gas pipeline) are also possible.

D17 In adopting the two central scenarios, we updated the model inputs to reflect the most recent forecasts of GPB-specific costs, and aligned the short-term profile of allowable revenues with inflation forecasts and near-term demand projections (ie, CPRG).

D18 The key features of the two scenarios are summarised in Table D2.

Table D2 DPP4 network stranding model scenarios – final decision

Assumed network wind-down year	Near-term MAR profile	MAR in last year ÷ 2023 MAR	Long-term MAR profile	Opex in last year ÷ 2027 opex	Capex in last year ÷ DPP3 average capex	Weight allocated to scenario result
2050	Inflation, declining CPRG	20%	Linear	30%	20%	33%
2060	Inflation, declining CPRG and concave profile	20%	Concave (2% curve)	30%	20%	67%

We considered the most up-to-date information

D19 At the DPP3 reset, we said we expected to complete the transition to shorter economic asset lives over two regulatory periods, subject to undertaking a fresh assessment of stranding risk and implied economic asset lives at the time of the DPP4 reset.[183]

[182] Consistent with our high level approach and the current levels of uncertainty contributing to future stranding risk, we use "central" broadly, to indicate a middle position in a range, not the mean or median of a distribution in the precise statistical sense: see HoustonKemp "Form of control for gas distribution businesses in New Zealand – Report for Vector" (20 January 2026), p. 4-5.

[183] The asset life shortening we implemented at DPP3 provided approximately 50% of the total required mitigation assessed as being needed at that time to transition to new price levels. In this sense, our actions at DPP3 only partially mitigated the risk existing at that time. We said we would consider completing the transition in DPP4: Commerce Commission "Gas DPP3 – DPPs for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), paras X19, 6.28, 6.30, D49.

D20 In concluding that the two DPP3 wind-down scenarios remain fit for purpose in DPP4, and are plausible and reasonable ones for the DPP4 context, we considered:

D20.1 publicly available information affecting the outlook for the gas sector since the DPP3 reset;[184] and

D20.2 feedback received from interested persons in response to our open letter, issues paper, draft decision, and scenarios modelling workshop.[185]

D21 We also engaged with medium and large gas users, and held a kōrero with residential consumers and advocates prior to our DPP4 draft decision.[186]

Stranding risk has evolved but blended DPP3 scenarios remain central

D22 After analysing the available information, our assessment is that:

D22.1 The overall context and expected direction of travel for reticulated gas remains similar to that for DPP3 – ie, a significant long-term expected decline in demand for gas giving rise to uncertainty over the ability for GPBs to fully recover past and future network-related costs from the different classes of pipeline users to the extent the networks are used to satisfy demand for gas;

D22.2 Submitters suggested we either increase or decrease the extent of risk mitigation in DPP4 via asset life adjustment factors, for instance, by altering the scenarios or weightings in the stranding model brought over from DPP3;

D22.3 Although updated information is available and some sources of risk have evolved since DPP3, we consider:

D22.3.1 the impacts of tighter-than-expected gas supply conditions and rising wholesale gas prices are adequately recognised by our 2050 wind-down scenario, which remains suitably aggressive in DPP4 to capture accelerating near-term declines in pipeline usage and possibilities for an early industry shutdown as part of a central distribution of risk;

D22.3.2 the impact of government policy changes since DPP3—and future uncertainties about government policy, the economics of transitioning to alternative energies, and consumer preferences—have, on balance, not materially altered the risk profile in DPP4 so require no adjustment;

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[184] We describe the key information sources below at paragraphs D58 and D61. Since demand for gas pipeline services is determined by the demand for gas, our assessment has encompassed a range of information relevant to the wider outlook for natural gas markets in New Zealand.
[185] We are grateful for the information and feedback provided by stakeholders as part of the DPP4 reset process—often involving different and competing views on the current state of relevant factors affecting the long-term prospects of the gas industry and the implications for economic stranding of pipeline networks—which we have taken into account.
[186] The main findings from this engagement are summarised in Chapter 3.

D22.3.3 the potential for longer-term gas use, including for networks operating at reduced scale, is adequately recognised by our 2060 scenario; and

D22.3.4 the 33:67 blending ratio applied to the two scenarios at DPP3 remains appropriate in DPP4 to represent a central estimate of overall risk, and we do not consider that any material change has occurred in respect of prospects of future repurposing of networks for unregulated uses.

D23 We acknowledge the concerns expressed by gas users over affordability of reticulated gas, however we consider that our decision strikes an appropriate balance between the benefits of completing the transition to more realistic economic lives now in the long-term interests of consumers, against the impact of short-term price increases.[187]

D24 More detailed discussion of these points is contained at paragraphs D44 – D97 below.

Mitigating stranding risk increases DPP4 allowable revenues

D25 The asset life adjustment factors produced by the 33:67 blended outputs from our scenario modelling are set out in Table D3, where we quantify the increase in forecast depreciation for each GPB in DPP4 as a result.

Table D3 DPP4 network stranding mitigation – final decision ($m, nominal BBAR)

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	0.73	320.2	441.4	121.2
Firstgas Distribution	0.70	65.1	93.5	28.4
GasNet	0.57	6.9	12.1	5.2
Powerco	0.68	125.1	185.2	60.1
Vector	0.81	133.0	163.6	30.6
Sector total		**650.2**	**895.8**	**245.6**

[187] We think that greater adverse consequences would likely arise for consumers as a whole if we did not allow forecast depreciation and gas network charges to rise in DPP4.

D26 The asset life adjustment factors have changed from our draft decision due to updating input costs and other variables in our DPP4 stranding and financial models for GPBs' DY25 base year disclosures, asset age profiles in the base year, the DPP4 WACC determination, inflation forecasts, CPRG and final DPP4 capex and opex allowances. We also made a technical modelling correction to ensure the depreciation of DY25 commissioned assets is captured correctly in depreciation calculations.[188] The additional depreciation (due to applying adjustment factors) for the sector, after all input and modelling updates, is $245.6m (it was $248.1m for the draft decision).[189]

D27 The adjustment factors are substantially less than one for each GPB, indicating that if average asset lives were not shortened in DPP4 (or in future periods) material shortfalls in cost recovery from consumers could be expected over the lifetime that networks are assumed by our modelled scenarios to be used. This would not support GPBs' expectations of FCM and would threaten their incentives to keep investing efficiently to meet current and future demand.

D28 The shortened asset lives resulting from our DPP4 decision will automatically carry through to DPP5 as part of GPBs' ID reporting of rolled forward regulatory asset base (RAB) values.[190] As GPBs will record higher levels of depreciation in DPP4, the forecast RAB values used to set DPP5—and thus DPP5 allowable revenues—will be lower (all else equal).[191]

We are satisfied that gas input methodologies criteria are met

D29 We are satisfied that applying asset life adjustment factors to each GPB in DPP4 to complete the transition we began in DPP3, meets the relevant criteria in the GDB and GTB IMs, as it:[192]

D29.1 will better reflect economic asset lives; and

D29.2 will better promote the purpose of Part 4 for the long-term benefit of consumers.

D30 Adjusting regulatory asset lives alters depreciation allowances in DPP4 and produces building blocks allowable revenues for DPP4 consistent with a credible long-term revenue trajectory. This allows GPBs a reasonable expectation of achieving a normal return over the economic lifetimes over which their networks are assumed to be used.

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[188] See paragraphs D116-D118.

[189] Commerce Commission "Gas DPP4 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A- H" (27 November 2025), Table D3.

[190] To implement the asset life adjustments at the start of DPP4 (ie, DY27) for ID purposes, we specify the 'forecast depreciation of existing assets' (which differs to the forecast depreciation shown for *all* assets in Table D3) and 'transitional adjusted asset life for existing assets' for each GPB in the relevant DPP4 determinations. The transitional adjusted asset life is calculated by including non-depreciable assets in the numerator (although this does not imply that those assets are depreciable) so this should be taken into account by GPBs for compliance with the IMs for ID – see cl 2.2.8(5) of the GDB and GTB IMs.

[191] This is primarily a result of lower RAB values giving rise to an expected lower 'return on capital' building block within DPP5 allowable revenue calculations. This reflects that recovery of capital via allowable revenues has been accelerated in DPP4, leaving less capital to provide a return on to GPBs in DPP5.

[192] GDB and GTB IMs, cl 4.2.2(4).

D31 Applying asset adjustment factors in DPP4 to shorten regulatory asset lives (relative to DPP3) therefore better reflects economic asset lives.

D32 With respect to the long-term benefit of consumers:

D32.1 We consider that adjusting asset lives in DPP4 to mitigate uncertainty over future cost recovery under our building blocks framework and maintain expectations of FCM remains appropriate at this time to support incentives for GPBs to continue investing efficiently in their networks (including in replacement, upgraded, and new assets) to meet consumer demand – s 52A(1)(a).[193]

D32.2 Asset life adjustments that better reflect economic asset lives mitigate the risk of early network closures and reduce the risk of future consumer price shocks, giving consumers the confidence to continue using gas if they choose to. GPBs will therefore have incentives to provide services to consumers while demand exists, at a quality that reflects consumer demands – s 52A(1)(b).[194]

D32.3 Increasing allowable revenues via shortening regulatory asset lives is NPV-neutral with respect to GPBs' cost of capital over the lifetime of networks, so GPBs will remain limited in their ability to extract excessive profits, during DPP4 and at future DPP resets – s 52A(1)(d).

D33 Applying asset life adjustment factors in DPP4 to complete the transition to economic asset lives therefore better promotes the Part 4 purpose, compared to the option of not adjusting asset lives for DPP4.

D34 Given that overall gas pipeline usage has peaked ahead of DPP4 and is forecast by GPBs to fall, completing the transition to economic asset lives while the customer base is at its broadest (rather than deferring this action to a future reset) benefits consumers:

D34.1 it likely minimises levels of required pipeline charges over time; and

D34.2 it provides headroom to manage possible future price shocks for consumers as New Zealand moves further towards a decarbonised economy.[195]

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[193] The GDB and GTB IMs and our approach to setting prices under the BBM for DPP4 are underpinned by the ex-ante FCM principle. In the 2023 IM review we considered whether there were any viable alternatives to applying the ex-ante FCM principle at this time. We were not provided with any alternative IMs that would promote the s 52A(1) outcomes better than continuing to have IMs that are underpinned by the ex-ante FCM principle: Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), paras 3.276-3.447.

[194] Having more efficient pricing signals may discourage inefficient new connections, and would be expected to influence, to some degree, the decisions of gas consumers in DPP4 using gas and investing in gas-dependent infrastructure, including decisions about whether to repair or replace aging gas appliances or transition to other energy sources such as electricity or bottled gas for heating/cooking.

[195] With expectations of long-term declining demand, prices per unit of gas conveyed will rise if BBM costs remain steady (all else equal). Shortening average asset lives to bring forward cost recoveries to a time when more gas is being conveyed reduces the risk of price shocks and the extent to which future prices might be disproportionately higher. This mitigates risk that some future consumers may not be willing to pay required future pipeline charges. It may also be more equitable for consumers over time.

Residual risk remains for GPBs to manage in DPP4 and beyond

D35 Fully transitioning to economic asset lives in DPP4 will support a reasonable expectation for GPBs of recovering the cost of past and future investments, but it does not guarantee full capital recovery over the lifetime of their pipeline assets.

D35.1 DPP regulation provides for an ex-ante expectation of recovery over the upcoming regulatory period and GPBs are exposed to forecasting risks ex-post;[196]

D35.2 If events arise which cause GPBs' costs to rise significantly above forecasts, or a material fall in demand occurs relative to our assumed wind-down scenarios (eg, due to a future policy-led phase-out of natural gas use, or consumers placing less value on gas because of health- or climate-related concerns), GPBs may be exposed to unmitigated stranding risk to the extent that price increases required to recover costs exceed consumers' willingness or ability to pay.

D35.3 GPBs ultimately bear risk over time as our decision-making framework seeks to preserve an expectation of FCM only to the extent it promotes the Part 4 purpose.[197]

D36 We accept that GPBs are unlikely to be able to materially influence overall demand for natural gas (or many of the specific factors that contribute to long-term network stranding risk). However, there are opportunities for GPBs to mitigate or manage the *impact* of market outcomes on their businesses during DPP4 and beyond.

D37 In other words, GPBs' actions will be important and GPBs can mitigate some aspects of stranding risk by adapting their business practices to changing circumstances.

D38 Examples of GPBs taking action to innovate, reduce net costs, increase efficiencies and build resilience in ways that can mitigate the impact of long-term stranding risk include:

D38.1 changes in asset management planning, assessing capex/opex trade-offs, and other changes to investment or operational decision-making;[198]

D38.2 progress in blending and injecting renewable gases to supplement and potentially extend the economic lifetimes of existing pipeline assets;[199]

D38.3 review of policies on capital contributions and system growth;

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[196] Limited exceptions exist as set out in the GDB and GTB IMs – eg, pass-through costs, wash-ups, annual inflation adjustments to price paths, and some price path reopeners.

[197] Commerce Commission "Part 4 Input Methodologies Review 2023 – Framework paper" (13 October 2022), paras 4.24-4.27.

[198] See Attachment F.

[199] For example, Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), pp. 22-26, 44-54.

D38.4 tariff design, restructuring and policies;[200]

D38.5 developing understanding of customer characteristics, particularly for GDBs where a greater number of smaller-scale mass-market customers exist;

D38.6 initiatives to better quantify risk exposure across network geographies and assets, eg, targeting accelerated depreciation to more at risk parts;[201] and

D38.7 tactical network rightsizing assessments, and ongoing work in the areas of disconnections and decommissioning.[202]

D39 We consider that residual exposure of GPBs to some downside risk is likely efficient and in the long-term interests of gas pipeline consumers. We will continue to monitor the activities of GPBs and support further development in these areas as required.

Risk levels can be assessed at the next price path reset

D40 Although we consider our final decision is compatible with the evolving risk profile at this time, factors impacting on stranding risk will likely develop further and relevant new information may have a material impact on expectations of FCM at future DPPs.[203]

D41 We expect to make another assessment—and consider what regulatory actions, if any, need to be taken to promote the Part 4 purpose—as part of the DPP5 reset for the period commencing 1 October 2031.[204]

D41.1 We may choose to adapt our long-term scenario model and consider adjusting average regulatory asset lives (either shortening or lengthening as required) to reflect economic asset lives and mitigation required.

D41.2 Alternatively, we may consider implementing a different approach consistent with the GDB and GTB IMs and our regulatory decision-making framework at the time which promotes the long-term interest of consumers.

D42 If a major event with adverse effects were to occur during DPP4 then DPP reopeners contained in the GDB and GTB IMs may allow for price path to be amended to mitigate the effect of that event on a GPB.[205]

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[200] Our DPP4 revenue allowances are price limits, not targets. GPBs are in the best position to actively understand demand dynamics and are incentivised to maintain connections on their networks to contribute to the ongoing costs of providing their services.

[201] GPBs have the flexibility to adjust asset lives for specific assets (or asset types) in their ID RABs to align with a GPB's own assessment of stranding risk and asset lives for its network – as long as the overall effect of the GPB's adjustment across all assets equates to the implied average remaining asset life and depreciation forecasts produced by our modelling: GDB and GTB IMs, clause 2.2.8(5).

[202] See Attachment F.

[203] Much of stakeholders' feedback in DPP4 has been on implications of tighter-than-expected gas supply conditions and high gas prices. However, at future resets, other factors such as changes in consumer preferences or the economics of transitioning to alternative energy sources, may become more prominent, including some types of issues or events which cannot reasonably be foreseen at this point.

[204] We will also have completed our scheduled review of the Part 4 IMs by that date.

[205] See Part 4 Subpart 5 of the GDB and GTB IMs.

D43 Each GPB also has the option of applying for a customised price-quality path (CPP) (within DPP4) with evidence to support tailoring its price path to particular circumstances and better meeting its needs and those of its consumers.[206]

How we assessed the network stranding risk mitigation required for DPP4

We provide further detail about our approach for DPP4

D44 In this section, we provide further detail about our approach to mitigating economic network stranding risk in DPP4, including:

D44.1 the nature of the risk to be mitigated for GPBs and the challenges we face in estimating the extent of mitigation required when resetting a DPP;

D44.2 how our long-term network stranding scenarios model informed our DPP4 decision;

D44.3 information and analysis we relied on to estimate risk mitigation for DPP4, including how feedback received from stakeholders as part of the DPP4 reset process was taken into account; and

D44.4 the updates we made to building block cost inputs and other modelling parameters and calculations.

Setting DPP revenue allowances under conditions of high uncertainty

D45 There is a high degree of uncertainty surrounding the decline in long-term demand for reticulated natural gas in New Zealand, with a wide range of possible outcomes that impact on the risk of network stranding and estimates of economic lives of pipelines.

D46 Particular challenges, which have influenced our approach to setting revenue allowances in DPP4 for GPBs, include:

D46.1 **Long-term timeframes**: Some costs to recover from consumers are known today (eg, value of existing assets), but future expenditure and revenue profiles which might optimise the capacity of consumers to bear total network costs over time is unknown and difficult to forecast over long timeframes (decades).

D46.2 **Complex range of interdependent factors**: The demand for gas pipeline services is derived from the overall demand for gas in New Zealand, and this depends on a variety of economic and other factors (see paragraph D54) that can be difficult to quantify and may interact (producing cascading effects).

[206] A CPP can provide further flexibility for how pipeline assets can be depreciated, and allows for the provisions of the GDB or GTB IMs to be varied by agreement. For example, a more granular analysis of risk or customer impacts might be possible in supporting information and modelling.

D46.3 **Potential for large and rapid changes**: Events may occur that materially and rapidly change dynamics of gas markets, and changes may occur frequently.[207] For instance, policy-led changes, or changes in consumer preferences due to climate-related concerns, could be significant and variable over time.[208]

D47 These aspects make forecasting costs and recoveries relevant to assessing stranding risk difficult. Given the relatively low-cost nature of DPP regulation, our estimation of risk and mitigation in DPP4 must necessarily be simplified and high-level – a broad assessment with some element of judgement, based on readily available information.

D48 We emphasise that our objective in DPP4 has not been to predict the likely future end-state of the gas industry in New Zealand, nor to model all possible industry outcomes or mitigate *all* risk of future network stranding for GPBs. Rather:

D48.1 we have sought to assess the extent of regulatory action in DPP4 that would best promote the long-term benefit of consumers of gas pipeline services under a range of plausible future outcomes and conditions of high uncertainty;

D48.2 the extent of stranding risk mitigation for DPP4 is part of a wider package of final decisions on regulatory settings – eg, level of DPP4 expenditure allowances, availability of price path reopeners; and

D48.3 we have estimated the risk that we consider falls broadly in the centre of a plausible distribution based on current information. Shorter or longer eventual industry wind-downs than the two that we have modelled (or other outcomes) are possible.[209]

D49 As we discuss at paragraphs D40 – D43 above, we will have an opportunity to reassess the outlook for GPBs at the next price path reset, and make further adjustments to regulatory asset lives, and/or consider other regulatory responses, at future resets based on understandings of risk and the prevailing context at the time.

[207] The Iran war illustrates how external shocks can affect markets (and possible LNG delivery and pricing) in ways that were not appreciated even a few months prior.

[208] For instance, actions of the government could theoretically mandate a network wind-down or closure within a short timeframe, or otherwise directly intervene in gas markets. We have previously also noted that pressure can be placed on business gas users to operate in environmentally sustainable ways, eg, due to the preferences of that businesses' customers and stakeholders. See: Commerce Commission "Gas DPP4 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A- H" (27 November 2025), para D55.1.

[209] As future circumstances are highly uncertain and the factors that contribute to stranding risk will evolve further over time, we must accept that, in hindsight, any view of the long-term future of the industry in DPP4 will not turn out to be entirely correct. However, we consider our stranding model sufficiently meets our objectives for DPP4.

Mitigation for DPP4 was arrived at after considering stranding model and most up-to-date information

Our long-term stranding scenario model informed our decision

D50 Since a definitive source of information about how demand for gas pipeline services (and the collective willingness and capacity of gas users to pay for required network charges) will likely decline over time does not exist, we were guided in our assessment of risk mitigation in DPP4 by updating the stranding model used for DPP3.

D50.1 The model is a tool that estimates the extent of asset life shortening required for each GPB for a DPP to achieve long-term expectations of ex-ante FCM and support incentives for efficient investment, using some sector-wide and GPB-specific financial data and basic projections about levels of opex and capex required under some assumed long-term network wind-down scenarios.[210]

D50.2 The two scenarios adopted in the model for DPP3 were the progressive wind-down and eventual cessation of network operations for each GPB at 2050 and 2060 respectively. The outputs for each scenario were blended using a 33:67 ratio when determining the asset life adjustment factors to specify for each GPB in DPP3. The same modelling approach was adopted for GDBs and the GTB.

D51 We consider that adopting the DPP3 model, and updating it for the most recent available information, meets our objectives and is appropriate for the DPP4 reset, as:

D51.1 The model aligns with expectations of a progressive wind-down and possible eventual cessation of gas pipeline services as New Zealand transitions to a decarbonised economy over the coming decades;

D51.2 The flexibility to include multiple scenarios, and blend their outputs, reflecting a range of assumptions, is consistent with the nature of the uncertainty facing the sector and with making an overall decision for the DPP4 period;

D51.3 Modelling the scenarios we consider lie within the broadly central distribution of risk, as was done for DPP3, will support GPBs' (and their investors') expectation of FCM, and therefore sufficient incentives to invest for DPP4;[211] and

D51.4 High-level modelling, using some readily available generic and GPB-specific inputs, is consistent with a relatively low-cost DPP, and has proved workable

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[210] Each scenario modelled a long-term declining profile of pipeline revenues expected to be sufficient to allow GPBs to recoup total pipeline costs (including a normal return) over time. Specifically, the profile was assumed to fit within the collective willingness and capacity for consumers of gas pipeline services to pay, at all points in the modelled scenario. For a more detailed description of the stranding model, including the assumptions underpinning it, see Commerce Commission "Gas DPP4 reset 2026 - Issues paper – Attachments A - E" (26 June 2025), Attachment C.

[211] While other industry outcomes (eg, earlier network closures, or a longer-term 'steady state' network operation with a reduced footprint) are possible, we consider these are less central and do not need to be explicitly factored into mitigation to maintain reasonable expectations of FCM.

under Part 4 – eg, in GPBs translating average asset life adjustments to specific ID asset lives which are rolled forward to the base year for the next reset.

D52 We are aware that other agencies (and some submitters) have undertaken their own modelling of gas sector outcomes. As discussed in our analysis below, aspects of those models have produced useful insights for us to consider. However, other models' objectives and/or assumptions differ to those we have for the DPP4 reset. We have chosen to update and reapply our DPP3 stranding model in DPP4.

We considered what long-term scenarios the model should cover

A range of factors affect the outlook for gas pipelines in New Zealand

D53 As discussed above, a key aspect of our assessment of risk to mitigate in DPP4 is the long-term industry scenarios to include in our stranding model. These are selected based on our view of the current context and long-term outlook for the reticulated natural gas during New Zealand's transition to a decarbonised economy.

D54 The main factors identified to date that influence demand for gas (and therefore of pipeline services) over the long-term, and therefore influence our choice of relevant industry scenarios as central in estimate of risk, are:

D54.1 availability of gas to supply to various customer segments, and the associated costs of producing, transporting, and retailing it (which determine gas prices);

D54.2 policy measures introduced by the current or future governments, particularly those in response to climate change and fossil fuel use;

D54.3 possibilities for gas consumers transitioning to alternative sources of energy for heating or cooking (or to alternative feedstocks for industrial manufacture);

D54.4 economic interdependencies with other sectors such as electricity (eg, gas required intermittently for generation 'firming' in dry years); and

D54.5 consumer preferences towards (or against) using natural gas as an energy source or as an input in manufacturing or business operations.

D55 Any assessment needs to include assumptions about the total building block costs to be recovered from consumers of pipeline services over time to ensure an expectation of FCM, and the profile of revenue recovery over successive price path resets.

D56 Lastly, whether pipelines might be repurposed to generate unregulated revenues (eg, to carry alternative gases) is also relevant, as consumers should not expect to be paying for the capital costs associated with these activities as part of regulated revenues.[212]

Our DPP4 draft decision recognised an evolving risk profile but retained DPP3 scenarios

D57 In our draft decision for DPP4 we concluded that sources of stranding risk for GPBs, with respect to the various factors listed above, had likely evolved since DPP3.

[212] See paragraph D86.2.

D58 In our analysis we:

D58.1 listed the sources of publicly available information we had considered, including the information and feedback we received from stakeholders;[213]

D58.2 summarised our view of the current 'state of play' for both the long-term direction of travel for the industry and for specific developments such as short-term supply challenges and the 'peak' reached in gas consumption;[214] and

D58.3 examined, in detail, the economic logic and arguments raised by submitters for placing either more emphasis in our scenario modelling on an earlier industry wind-down, or a later industry wind-down scenario.[215]

D59 Our draft decision concluded that retaining the assumed 2050 and 2060 network wind-down scenarios (with corresponding 33:67 weightings) in our stranding model, and updating them for the most recent cost estimates, would provide a suitable central estimate of the economic network stranding risk mitigation to adopt in DPP4.[216]

We received a range of feedback on our DPP4 draft decisions

D60 Stakeholders expressed a range of views in written submissions and cross-submissions on our draft decision. Some submitters reiterated points raised previously in feedback on our open letter or issues paper, however some relevant new information and analysis was also provided. We discuss submitter views in more detail below, including how these views have been taken into account in reaching our final decisions.

Recent developments in the gas sector

D61 Since we received submissions and cross-submissions on our draft decision:

D61.1 The Gas Industry Company (GIC) 2026 Gas Supply and Demand Study shows projected gas consumption falling (in absolute terms, and relative to projections at 2025) for all segments for the 10-year forecast period to 2036;[217]

D61.2 The latest industry data for 2026 from GIC and Ministry of Business, Innovation and Employment (MBIE) show gas production and estimates of reserves have declined relative to 2025;[218]

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[213] Commerce Commission "Gas DPP4 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A- H" (27 November 2025), paras D38, D66-D74.
[214] Ibid, paras D45-D59.
[215] Ibid, paras D75-D114.
[216] Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper" (27 November 2025), para 3.59, D115-D117.
[217] GIC "2026 Gas Supply and Demand Study" (March 2026).
[218] GIC "Quarterly Report" (March 2026); MBIE "New Zealand's petroleum reserves - Overview as at 1 January 2026 (1 January 2026).

D61.3 The Maui gas field, which supplies New Zealand's largest natural gas user – Methanex, is nearing the end of its economic life and is expected to close around the end of 2026. Methanex is likely to close at approximately the same time;[219]

D61.4 Procurement of a liquefied natural gas (LNG) import terminal has been under consideration by the government, following impacts on prices and supply chain for foreign-sourced oil and LNG by the Iran war.[220] Latest indications are that it will proceed;[221]

D61.5 A number of new offshore oil and gas exploration permits are under consideration by MBIE following the government's reversal of the 2018 oil and gas offshore exploration ban;[222] and

D61.6 GIC briefed the incoming Minister of Energy on key issues affecting the New Zealand gas industry.[223]

Stranding risk has evolved but the 2050 and 2060 scenarios remain fit for purpose in DPP4 as a central estimate of risk to mitigate

Stranding risk in DPP4 threatens incentives to invest and long-term benefit of consumers

D62 Our overall view, similar to that at DPP3, is that expected long-term declining demand for reticulated natural gas in New Zealand signals a potential economic network stranding risk for GPBs that undermines incentives for continuing investment.

D62.1 The risk arises from the high degree of uncertainty over the pace/profile of that decline, and whether sufficient collective willingness and ability of consumers of gas pipeline services will exist to pay for required network charges over time.

D62.2 Unless network stranding risk is adequately addressed such that GPBs hold a reasonable long-term expectation of FCM in DPP4, the incentives for GPBs to continue investing efficiently in pipeline infrastructure to meet the needs of current and future consumers will be undermined.[224]

D62.3 This threatens the long-term benefit of consumers of gas pipeline services and the promotion of the Part 4 purpose in s 52A of the Act.

[219] RNZ "OMV signals end of Maui gas field this year" (24 April 2026).
[220] The Iran war, which was not predicted at the time of the DPP4 draft decision, is also likely to increase economy-wide prices in New Zealand.
[221] New Zealand Government, Hon Simeon Brown "New gas data supports action to keep lights on" (14 May 2026).
[222] New Zealand Government, Hon Shane Jones "Fourth petroleum permit application enters competitive process" (12 May 2026).
[223] GIC "Briefing to incoming Minister for Energy" (April 2026).
[224] While the prospect of network-related costs being unrecoverable may not be imminent (ie, is unlikely to occur in DPP4), it is the expectation that this may occur in the future that signals an economic stranding event and threatens investment incentives. Other desirable incentives under s 52A may also be adversely affected such as incentives for GPBs to innovate, improve long-term efficiency or provide services of a requisite quality demanded by consumers.

D63 The following sections supplement our detailed analysis contained in the DPP4 draft decision, focussing on the implications of the recent information listed above and taking account of the information and views contained in submissions and cross-submissions received on our DPP4 draft decision.[225] We have not attempted to respond to all aspects of stakeholder feedback – instead concentrating on the key points raised.

Overall context and long-term direction of travel for reticulated gas remains the same

D64 Our understanding of the context for longer-term reticulated gas use in New Zealand was confirmed by recent information and submissions, namely:

D64.1 A significant overall decline in natural gas connections and consumption is expected in the long-term, with resulting economic lives of existing and future pipeline assets likely being shorter than assumed physical lives;[226]

D64.2 High levels of uncertainty exist over the future role of gas in New Zealand's energy mix and how quickly demand for pipeline services—and the associated capacity for pipeline customers to absorb required network charges—might decline across parts of existing networks/subnetworks or customer segments, eg, industrial, commercial and residential;[227] and

D64.3 It is prudent to assume some material continued network investment is required over coming decades by GPBs to maintain pipeline service quality and satisfy levels of consumer demand.[228] Incentives under Part 4 regulation for GPBs to continue investing efficiently in pipeline networks therefore remain relevant.

Some submitters argued either for an increase or decrease in risk mitigation in DPP4

D65 A main view expressed by some GPBs (and their expert advisors) was that falling gas production, reductions in estimates of future available reserves and rising (and volatile) gas prices, indicate that stranding risk has increased since the DPP3 reset.

D65.1 These GPBs submitted that the supply and demand context for gas in New Zealand has changed materially and larger adjustments to regulatory asset lives are warranted to sufficiently mitigate risk in order to maintain reasonable expectations of FCM and support investment incentives.[229]

[225] A full record of submissions and feedback received from stakeholders is contained on our website.
[226] See, for example, Mercury "Submission on Gas DPP4 Draft Decision" (16 January 2026); Powerco "Gas DPP4 draft decision - stability as the transition becomes clearer" (22 January 2026). For the assumed physical asset lives, see Schedule A of the GDB and GTB IMs.
[227] See, for example, Rewiring Aotearoa "Rewiring Aotearoa submission on the Gas DPP4 reset 2026 - Draft Decision" (22 January 2026); Energy Resources Aotearoa "Cross-submission on the Gas Default Price-Quality Path 4" (12 February 2026). We discuss below how expectations of near-term supply and demand have changed since the DPP3 reset, including higher (and more volatile) prices observed for delivered gas.
[228] See, for example, Mercury "Submission on Gas DPP4 draft decision" (16 January 2026); Fonterra "Submission - Gas DPP4 Draft Decision" (22 January 2026); NZ Steel "Re: Submission on Gas DPP4 draft decision" (22 January 2026).
[229] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 3; Firstgas "Gas DPP4 2026: Firstgas views in response to submissions" (12 February 2026), p. 13; Vector "Gas

D65.2 Vector and Firstgas suggested adding an early wind-down scenario (in the 2040s) to our stranding model, or placing more weight on the 2050 scenario, as part of a central view of risk.[230] This would shorten DPP4 asset lives more than our draft decision, advance more depreciation to DPP4, and increase revenues.

D66 Vector and Firstgas also cited continued uncertainty over government policies on climate change and longer-term use of gas as a factor indicating increased risk.[231]

D67 MGUG and Greymouth Gas pointed to the government support announced in 2025 for further investment in gas exploration and drilling, possibilities for imported gas, and progress in producing biogas for blending, as indicating a longer potential future for gas pipeline networks and less need to accelerate capital recovery in DPP4.[232]

D68 Feedback we received from a range of consumers (and advocates) was that rising costs and affordability are key concerns in DPP4. MGUG submitted that increases in pipeline charges are difficult for large users to absorb and can result in adverse consumer outcomes (eg, premature disconnections) as well as wider economic/social harms.[233]

The impacts of tighter gas supply remain adequately recognised by our 2050 scenario

D69 We acknowledge that tighter-than-expected gas supply conditions have emerged since the DPP3 reset, with a further decline in both natural gas production and estimates of domestic reserves becoming apparent since our DPP4 draft decision:

D69.1 New Zealand gas production of 19.9 PJ in the March 2026 quarter was 13% lower than the December 2025 quarter (inclusive of planned and unplanned outages).[234] Annual production has fallen in each year since 2022;[235] and

D69.2 Estimates of New Zealand 2P available gas reserves from MBIE decreased 23% from 948 PJ at 1 January 2025 to 731 PJ at 1 January 2026.[236] This is explained by

Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), para 49-53; Vector "Cross-submission on the default price-quality path for gas pipeline businesses beginning 2026" (12 February 2026), para 28.

230 Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 2; Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), pp. 3, 18-19 and para 55; Frontier Economics "Key issues in Gas DPP4 Draft Decision – Report for Vector" (21 January 2026), p. 15.

231 Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 9; Axiom Economics (report prepared for Vector) "Form of control for Gas Distribution Businesses – A report for Vector" (15 October 2025), pp. 4-5.

232 Greymouth Gas "Re: Gas DPP4 2026 - Draft Decision" (22 January 2026); MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026); Methanex "Methanex submission on Gas DPP4 reset 2026 - Issues Paper" (28 July 2025).

233 MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026). See also Greymouth Gas "Re: Gas DPP4 2026 - Draft Decision" (22 January 2026); NZ Steel "Re: Submission on Gas DPP4 draft decision" (22 January 2026); Fonterra "Submission - Gas DPP4 Draft Decision" (22 January 2026).

234 GIC "Quarterly Report" (March 2026)

235 MBIE "New Zealand's petroleum reserves – Overview as at 1 January 2026" (1 January 2026). See also Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 8.

236 https://www.mbie.govt.nz/assets/Data-Files/Energy/petroleum-reserves/petroleum-reserves-1-jan-2026.xlsx. 2P reserves are Proven and Probable reserves of gas in the ground, having a 50% certainty of being recovered given the technological and economic factors at the time of estimation.

total prior year use/extraction (-108 PJ) and revised total field estimates for Pohokura (-129 PJ) and Mangahewa (+39 PJ).[237]

D70 As a risk factor, constrained supply could be viewed as distinct from demand declining due to decarbonisation.[238] We understand that the current supply outlook arises from lower yields from ageing main gas fields and underperformance of new drilling or wells – but also that less gas exploration or development has been undertaken.[239] A mix of technical and economic factors are therefore at play, and future availability of gas will likely be influenced by government climate policies and overall consumer appetite for natural gas use which impact on the extent of upstream investment and activities.

D71 In any event, lower supply means less consumer demand able to be met, lower pipeline utilisation and a reduction in consumers' collective capacity to pay for required network charges (all else equal). Higher prices paid for gas may also erode capacity to pay. The effects of constrained gas supply therefore need to be considered, and given the direct impact of lower supply on consumption and collective ability to pay it has weighed somewhat more strongly in our assessment of stranding risk in DPP4.[240]

D72 At a high-level, it illustrates the dynamics of a market adjusting to progressively lower expectations of consumption, and serves as a reminder that wider economic effects can result. For pipeline stranding risk, future tight supply and potentially higher costs of bringing additional gas to market to satisfy consumer appetite for gas were identified as part of the relevant factual matrix at DPP3 and in this sense influenced our choice of stranding scenarios.[241] This source of the risk for stranding, in other words, is not new and was accounted for in the DPP3 scenario modelling.

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[237] MBIE "New Zealand's petroleum reserves – Overview as at 1 January 2026" (1 January 2026). The estimates account for the Maui field reaching end-of-life (around the end of 2026).

[238] Frontier Economics (report prepared for Vector) "Key issues in Gas DPP4 Draft Decision" (21 January 2026), "driven largely by the transition to a low emissions economy, but in New Zealand also due to supply conditions", p. 13.

[239] GIC "Quarterly Report" (March 2026), p. 3; GIC "Briefing to Incoming Minister for Energy" (April 2026), p. 2, "[t]here is gas in the ground to meet our needs, but investment is needed to develop it"; MBIE "New Zealand's petroleum reserves – Overview as at 1 January 2026" (1 January 2026), p. 3. See also Boston Consulting Group's report into New Zealand's energy system, cited by Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission " (22 January 2026), para 52.

[240] Longer-term declines in demand are likely permanent (ie, demand is not expected to 'rebound'), particularly in respect of consumers that disconnect (rather than choose to reduce consumption).

[241] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), paras 3.3.4-3.3.5 (see also, paras 3.53-3.55). We discussed GIC's 2020 estimate of $300 to $500 million of investment needed every three to five years to bring existing reserves to market and maintain production levels. We noted inherent uncertainties that surround future discoveries and production, the prospect of higher future production costs, and the risk that insufficient investment will be committed to discovering and producing reserves to ensure demand is met. The amounts involved now to secure sufficient gas to meet current demand may be considerably larger.

D73 Vector and Firstgas have submitted however, that the overall expected decline in demand is larger, and has commenced earlier, than expected due to tightening supply, and the risk of network stranding to mitigate in DPP4 is now materially higher than was recognised at DPP3.[242]

D74 Our view—taking account of the most recent information—is as follows.

D74.1 We acknowledged in our DPP4 draft decision that an overall decline in demand is likely to commence earlier than GPBs expected at the DPP3 reset. Updated information on production and available reserves in DPP4 supports this.

D74.2 We noted that our 2050 scenario models significant linear reductions in the revenues recovered from consumers (to approximately half) over three regulatory periods (including DPP4) and a complete shutdown of reticulated gas networks within five regulatory periods (ie, within 25 years).[243] For context, the latest estimates of CPRG adopted for GDBs in the DPP4 price path show an expected decline in consumer demand for pipeline services of between 4% and 13% by the end of DPP4 (depending on the particular GDB).[244] We continue to regard our 2050 scenario as relatively aggressive in modelling an early industry wind-down.

D74.3 The extent of willingness and capacity to pay for pipeline use cannot be observed, nor are we aware of a dataset that would support a reliable quantitative estimate in DPP4. We therefore need to rely on some assumptions.[245] In our DPP4 draft decision, we noted that:

D74.3.1 Willingness to pay varies across customer segments, with electricity generation and mass-market residential/small commercial consumers collectively likely to exhibit some of the highest levels (Figure D1).[246]

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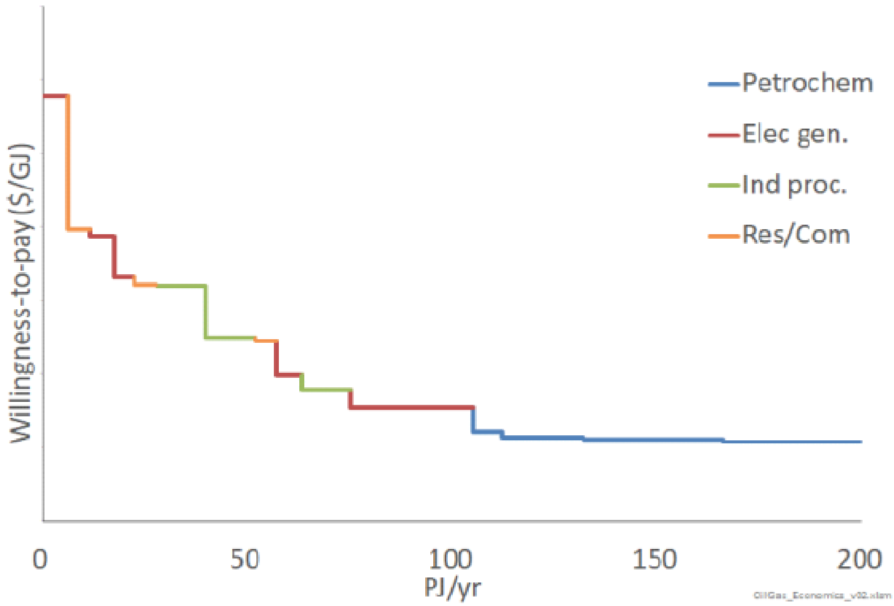
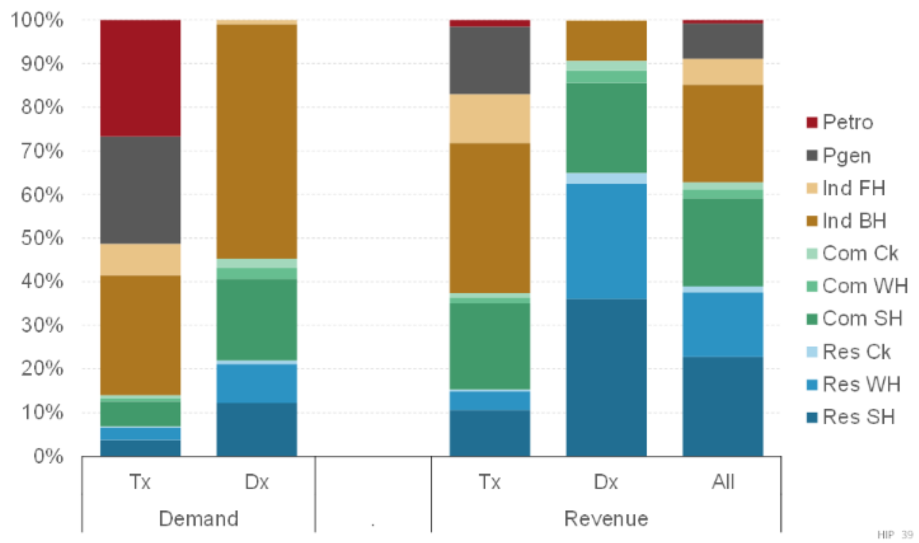
[242] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 8; Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission " (22 January 2026), paras 5, 49-51; Vector "Cross-submission on the default price-quality path for gas pipeline businesses beginning 2026" (12 February 2026), para 6.
[243] Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A - H" (27 November 2025), para D93.1. Percentage reduction is calculated in real terms, and we assume each regulatory period will be 5 years in duration.
[244] See paragraph A40 and Table A2.
[245] Given the extent of simplification in our modelling overall and the consumer composition described below which would indicate a large margin available, we do not see significant value in attempting to quantify estimates of aggregate willingness to pay (and its likely trajectory over time in response to market conditions). However, this could be done under a CPP, and the resulting price path or other settings modified if there was value in this (eg, reflecting a GPB's strategy to reduce reliance of some customers on gas in order to optimise longer-term recoveries).
[246] Concept Consulting "Long-term gas supply and demand scenarios – 2019 update" (16 September 2019), p. 31; Powerco "Submission on Gas DPP4 Open Letter" (13 March 2025), p. 3.

Figure D1 Stylistic representation of the demand-curve for gas



D74.3.2 Mass-market customers are comprised of a large number of individuals or smaller businesses, but as a whole they consume the least amount of gas while paying for the majority of pipeline costs (Figure D2).[247]

Figure D2 Sectoral split of gas demand and contribution to pipeline revenue



Source: Concept analysis drawing upon MBIE, Commerce Commission, First Gas, and EECA data

[247] Concept Consulting "Gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses" (prepared for the Commerce Commission, 22 August 2025), p. 4. This is due in part to the relatively high capital intensity of supplying small customers relative to the volumes they consume. Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A - H" (27 November 2025), para D91. We also noted at para D94.3 that some smaller customers may be suitable candidates for blended biomethane or other green gases that come online (albeit at a higher price reflecting higher production costs) to meet their future needs.

D74.4 We are not aware of any evidence suggesting collective willingness to pay is close to being exhausted. We think it reasonable to assume:

D74.4.1 the near-term effects of declining connections on longer-term pipeline viability would not be material – as gas customers who exit first in response to the impact of tightening supply (including relatively large-volume users) can be assumed to have contributed relatively little to aggregate willingness and capacity to pay;[248] and

D74.4.2 longer-term domestic supply-side constraints would need to be both major and sustained beyond DPP4, and not offset by other sources, to adversely affect demand to an extent that threatens GPBs' financial viability under the assumptions used in modelling our 2050 wind-down.[249]

D75 Lastly, we have examined other examples of quantitative modelling as possible cross-checks for our analysis above. They provided some insights, but did not substantively add to (or cause us to revise) our assumptions or conclusions for DPP4.

D75.1 The GIC 2026 Gas Supply and Demand Study shows projected gas consumption falling for all (broadly defined) consumer segments over the 10-year forecast period to 2036. Projections were made under scenarios that either excluded or included LNG imports (assumed to commence from 2028).[250] The purpose of the study was to explore implications for gas markets and customer segments (eg, prices and extent of switching) so that trade-offs and risks over the medium-term can be considered for gas policy. Constrained supply was the primary driver for lower projected consumption, where a decline to 32 PJ annually for households and businesses (excluding electricity generators, Methanex and

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[248] Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A - H" (27 November 2025), para D92. We concluded that the short-term net loss of 'headroom' in willingness to pay above required revenues would therefore be small. In terms of customer segments, we commented at para D89 of our draft decision that demand for bulk gas from industrial and large users would likely be most affected initially from supply-side constraints (due to a general inability to absorb large increases in cost inputs and/or scale back consumption), together with demand from those households and SMEs whose consumption is most influenced by price.

[249] Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A - H" (27 November 2025), paras D93-D94. Methanex suggested at our scenario modelling workshop that an 'S-shaped' longer-term consumption curve might arise (and be appropriate to adopt for a long-term modelled MAR profile), where demand either holds up, or falls away more rapidly, depending on where in the overall trajectory of decline the industry is (and which customer group is being modelled). See also: Methanex "Submission on Gas DPP4 Issues paper" (28 July 2025), pp. 7-8. We note that the (2% concave) curve adopted for the 2060 long-term MAR profile recognises a possible greater ability of future remaining consumers to absorb price increases than those existing in the near-term (including during DPP4).

[250] GIC "2026 Gas Supply and Demand Study" (March 2026), p. 4.

Ballance) is forecast, which is 63% of 2027 consumption of 51 PJ.[251] [252] With LNG imports, consumption falls to 78%, and prices stabilise in real terms around 2026 prices (rather than rising).[253] Additional charts were provided showing switching away from gas over the 10-year forecast period is more gradual for residential than for small and medium-sized enterprises (SMEs), with 73% of residential consumption forecast to remain at 2035 (87% with LNG imports) compared to 45% of SMEs (89% with LNG imports).[254] It is difficult to make direct comparisons with our modelling because of the differences in forecast timeframes[255] and because our modelling does not rely on forecast gas supply/demand or on gas prices. But the GIC study does confirm a relatively large proportion of households, SMEs and all but the largest business users, are expected to remain over the medium-term (ie, exhibit sufficient willingness and capacity to pay).

D75.2 The most recent GIFWG modelling is designed as a "stress test" of our DPP4 draft decision settings by modelling financial outcomes from three alternative industry futures that straddle either ends of our central wind-down scenarios. It demonstrates how an additional dimension can be added to modelling ("the coverage / scope and scale of networks"),[256] but also how outputs are sensitive to assumptions.[257] Shortfalls in capital returned (and negative cash flows) through regulated revenues were predicted in each of the alternative scenarios, primarily due to assumptions around limits on consumer willingness to pay network charges over time – based on estimates of alternative energy costs (eg, switching to electricity) and a 'placeholder' margin added to reflect non-price factors, future gas throughput and prices of gas.[258] Another significant

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[251] The underlying data and detailed assumptions are not publicly available. We note the report was prepared before the latest MBIE data on gas reserves (at 1 January 2026) was published.

[252] The study also notes that the existence of dry year risk could drive further demand reductions, eg, retailers accelerating electrification and gas switching to derisk their gas portfolios: GIC "2026 Gas Supply and Demand Study" (March 2026), pp. 7, 10.

[253] GIC "2026 Gas Supply and Demand Study" (March 2026), pp. 8, 10-11.

[254] Ibid, p. 14.

[255] The study does make some high-level longer-term predictions (eg, a continued contraction of households and SME demand to about 25% of current levels out to 2050) but uncertainty is higher and the underlying data for those predictions is not publicly available. GIC "2026 Gas Supply and Demand Study" (March 2026), p. 14.

[256] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 11.

[257] GIFWG (report prepared for Vector, Powerco & Firstgas) "Attachment A: Refreshed Analysis Paper – Financial implications of stylised gas network winddown and retreat scenarios" (12 February 2026), pp. 1, 6, 15. Three scenarios were modelled: an assumed 2040 supply-driven wind-down, and two versions of longer-term network operation at smaller scale – with and without availability of some renewable and imported gas.

[258] Substantial future decommissioning/disconnection costs are assumed to exist and be recoverable from consumers, and changes in estimates of 'intermediary' inputs (eg, gas throughput and gas prices) in response to market behaviours are not modelled. GIFWG (report prepared for Vector, Powerco & Firstgas) "Attachment A: Refreshed Analysis Paper – Financial implications of stylised gas network winddown and retreat scenarios" (12 February 2026), p. 33. In previous modelling submitted in response to our Issues Paper, GIFWG noted that willingness to pay is "notoriously difficult" to assess and estimates can be subject to wide variance. It originally included a 10% margin on estimated energy conversion costs to account for positive non-price characteristics – "consumer stickiness, amenity value, and other desirable characteristics of using gas appliances (e.g., instantaneous hot water)", but

assumption for this modelling was that further adjustments to regulatory depreciation (or other mitigations) did not occur after DPP4. We note that this modelling did not examine whether a 2050 industry wind-down with a linear long-term decline in revenues would be expected to allow GPBs to recover building block costs and normal profits under the model's various assumptions.

D76 These exercises show that it is possible to model industry outcomes with more detail, but each model reflected the specific purpose(s) for which it was undertaken and were underpinned by a collection of views and assumptions about the current and future context. As noted above, our scenario modelling that informs asset life adjustments in DPP4 is simplified to suit our objectives for DPP4 and relies on high-level assumptions which we consider are appropriate given the high degree of uncertainty existing at DPP4.[259] We found nothing in the examples above to suggest our assumption about there being sufficient future collective willingness and ability to pay for pipeline charges under our modelled 2050 scenario was manifestly incorrect.

D77 Our conclusion is that despite tighter supply-side conditions emerging since DPP3, our 2050 scenario remains suitably aggressive in DPP4 to capture—as part of a broadly central distribution of risk— accelerating near-term declines in pipeline usage and the possibility of an early industry shutdown. As we discuss below, its inclusion supports a manageable increase in mitigation in current circumstances, and with a large customer base still expected to exist from the end of DPP4 there is scope to mitigate further risk at DPP5 (or earlier in response to an application by a GPB for a CPP) if warranted.

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increased that to 25% in the updated modelling submitted in response to our draft decision: GIFWG (report prepared for Firstgas, Powerco & Vector) "Attachment 2: Gas Transition Analysis Paper" (16 June 2023), p. 13-14, 48-49. See also Firstgas, Powerco & Vector "Letter to the Commerce Commission - Submission on Gas DPP4 Draft Decision" (22 January 2026), footnote 6.

[259] We have not, for instance attempted to analyse or represent the interdependencies that exist between factors affecting stranding risk, and within consumer segments over time: see Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A - H" (27 November 2025), para D95. At present, we regard a closure of both Maui and Methanex as broadly neutral for the long-term view (being a step change in both near-term demand and supply affecting the gas transmission network), but can reassess the effects at DPP5 once more information is available. Submitters, for example, observed that industry scale and a source of some demand-side flexibility (eg, in dry years) would reduce, and that viability of the transmission network may become more closely linked to distribution networks. We acknowledge that prospects for future upstream investment may be affected, and average prices paid for delivered gas may increase (for both larger and smaller consumers).

D78 Lastly, we note that Vector, Firstgas and Entrust suggested there is a need to provide for an earlier industry wind-down scenario in the early-to mid-2040s on the basis that earlier GIFWG modelling showed negative net cash flows arising for GPBs by that date under an assumed 2050 wind-down.[260] However, that modelling applied a lower margin (10%) to electricity conversion costs when estimating the limits to cash revenues able to be recovered from consumers, and we would expect the model to now return materially higher net cash flows if the GIFWG's current margin estimate (25%) were applied.[261]

Uncertainty over government policies and other factors remain broadly similar in DPP4

D79 As we noted in our DPP4 draft decision, government policy toward gas exploration has changed since DPP3 and arrangements for future imports of gas are progressing.[262] This could offset to some degree the decline in domestic gas production and reserves.[263]

D80 On balance, these developments have not changed our overall assessment of network stranding risk in DPP4, particularly because policies can take some time to translate to physical changes in gas supplies (and can be revised by future governments).

[260] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), p. 6, para 54; Firstgas "Firstgas views in response to draft decision" (22 January 2026), p. 11-12; Entrust "Gas price reset to ensure investment cost-recovery in face of decreasing demand" (21 January 2026), p. 1.

[261] We also observe that although net cash flows in any year can affect an entity's operating ability, longer-term profitability is usually regarded as the primary measure of economic viability. With respect to Vector's cross-submission suggesting the latest GIFWG modelling shows GPBs could realistically become cash flow negative as early as RY38, this arises in the context of the modelled scenario itself assuming an early shut-down (at 2040): Vector "Cross-submission on the default price-quality path for gas pipeline businesses beginning 2026 Gas DPP4 draft decision" (12 February 2026), paras 9-11.

[262] Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A - H" (27 November 2025), para D88.2.

[263] The GIC 2026 Supply and Demand Study forecast a greater amount of gas used to generate electricity over next 10 years if LNG imports were available. Although availability of LNG would effectively cap domestic gas prices at (currently high) international prices, and may replace Methanex as a source of demand flexibility/ reallocation of supply, some submitters saw it as having only a minor impact on long-term pipeline viability, eg, since it would not directly serve mass-market consumers connected to distribution networks: Frontier Economics "Key issues in Gas DPP4 Draft Decision – Report for Vector" (21 January 2026), p. 12; Rewiring Aotearoa "Rewiring Aotearoa submission on the Gas DPP4 reset 2026 - Draft Decision" (22 January 2026), pp. 1-2; Vector " GPB DPP 2026 issues paper: Vector cross-submission" (14 August 2025); Firstgas "Firstgas views in response to draft decision" (22 January 2026), pp. 9-10; Firstgas "Gas DPP4 2026: Firstgas views in response to submissions" (12 February 2026), pp. 2, 10, 15-16. See also modelling in GIFWG (report prepared for Vector, Powerco & Firstgas) "Attachment A: Refreshed Analysis Paper – Financial implications of stylised gas network winddown and retreat scenarios" (12 February 2026).

D81 Consistent with our DPP4 draft decision, we consider that the pipeline stranding risks from other policies implemented by current or future governments remain difficult to predict, but the extent of uncertainty does not appear to be materially different in DPP4 to that faced at DPP3.[264] Nor have we observed any significant change in the economics of consumers transitioning to alternative energies or renewable fuels in the future,[265] or changes in consumer preferences or sentiment towards (or away from) gas.[266]

D82 Although a high degree of uncertainty exists, we have concluded that overall risk from these sources has not materially increased or decreased since our DPP4 draft decision.

The potential for longer-term gas use is adequately recognised by our 2060 scenario

D83 As we observed in our DPP4 draft decision, the prospect of some material level of reticulated natural gas use continuing beyond the 2050 net zero carbon emissions target was one of the primary reasons for introducing the 2060 wind-down scenario to recognise longer economic network lives as part of the central distribution of risk.[267]

D84 We have concluded that there have been no significant developments indicating a change in the possibilities for using gas pipelines beyond 2050—including in conveying biomethane or other renewable gases to mass-market segments and/or for longer-term network operations at reduced scale[268]—and these possibilities remain adequately recognised by retaining the 2060 wind-down scenario in our scenario modelling.

Blended modelling outputs for each scenario comprise a central estimate of risk

D85 With respect to the blending of scenarios to produce a central estimate of long-term risk in DPP4, we consider that a 33:67 ratio applied at DPP3 remains appropriate.

D86 The key reasons are that:

D86.1 Adopting a blended output has regard to a range of assumptions which we consider to be consistent with the nature of the risk to be mitigated and surrounding uncertainties. For instance, the 2060 wind-down scenario assumes a moderately (2%) concave decline in consumer willingness to pay reflecting a possible greater ability of some future consumers to absorb price increases than under the straight-line profile adopted for the 2050 scenario; and

D86.2 Placing more weight on the 2060 scenario (67%) than the 2050 scenario (33%) remains appropriate to recognise the possibility of gas use continuing past New

[264] A general election is scheduled for 7 November 2026 (and a subsequent general election is expected to occur during DPP4) and future government policies could be more or less supportive of gas use. Political parties can have markedly different climate policies, with no multiparty support for specific medium- to long-term climate measures.
[265] Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A - H" (27 November 2025), paras D57-D58.
[266] Ibid, paras D55-D56.
[267] As discussed below, another reason was to acknowledge that a longer wind-down scenario could be seen as a possible proxy for an earlier wind-down scenario with some residual value.
[268] See MGUG "Re: Gas DPP4 Reset 2026" (22 January 2026), paras 16, 29; Fonterra "Submission - Gas DPP4 Draft Decision" (22 January 2026); Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), pp. 22-24.

Zealand's 2050 legislative target for net carbon zero emissions[269]—for example, for some hard-to-abate industrial uses—but also to acknowledge that, at a high-level, a longer wind-down scenario could be seen as a possible proxy for an earlier wind-down scenario with some residual value.[270] We received no specific information or evidence on possible residual value in stakeholder feedback, nor are we aware of any material developments in this area, and so consider it remains as relevant today as a factor as it did at the DPP3 reset.

D87 We have not placed weight on Brookfield's recent acquisition of Clarus group businesses as evidence of market views on stranding risk in DPP4, as transaction terms are not public and it is not clear what expectations or underlying factors motivated the acquisition. We discuss this further at paragraphs 2.48 – 2.50.

D88 Similar to our DPP4 draft decision, we do not see a compelling case for either increasing or decreasing the extent of risk mitigation at this time by re-weighting the scenarios.[271]

D89 Lastly, we heard from a range of stakeholders and consumer representatives that energy affordability, in the context of economy-wide cost pressures, is a key concern for gas consumers in DPP4.

D89.1 Adjusting the extent of risk mitigation delivered in DPP4 (eg, by re-weighting the two scenarios with a greater emphasis on a later wind-down) would lower DPP4 prices for pipeline users (all else equal) and in that sense provide some short-term price relief and potentially reduce the risk of sub-optimal decisions by gas consumers to reduce consumption or exit the gas market.

D89.2 However, reducing the extent of near-term price increases would defer risk mitigation to a later time, and our view when faced with falling network demand is that the higher costs falling on a smaller consumer base in the future would likely have adverse consequences for consumers in aggregate over time.[272]

[269] Climate Change Response Act 2002, s 5Q.

[270] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para D46. The residual value may arise from the repurposing of existing pipelines to convey gases that are not natural gas (eg, hydrogen) and are therefore currently not regulated by Part 4. Any such residual value should reduce the amount of capital (and depreciation) required to be recovered from consumers of regulated gas pipeline services over time.

[271] Our analysis above of whether the impacts of tighter gas supply remain adequately recognised by our 2050 scenario responds to the suggestion by Firstgas that scenarios could be re-weighted towards an earlier wind-down due to constrained supply conditions.

[272] As we discussed in our draft decision, any increase in prices in the short term will affect demand and may lead to some consumer disconnections, particularly among those already considering switching away from gas. However, we consider that continuing to address stranding risk in DPP4 should avoid underinvestment by GPBs, degraded service quality, and premature network closure, and should result in a higher level of continued connections over the long term than would have occurred had we not mitigated the risk to the same degree. Deferring mitigation when demand is reducing would also make it more difficult to implement further mitigation if required. Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A - H" (27 November 2025), para D98.1.

D90 We believe we have got the balance broadly right for DPP4 – and in delivering what we consider to be a prudent and manageable increase in mitigation in DPP4 we have completed a significant transition for the industry to more realistic network lives and a depreciation profile suited to the circumstances. This should promote the long-term benefit of consumers by ensuring GPBs have sufficient incentives to continue to provide a safe and reliable supply of natural gas until pipelines are no longer needed.

D91 Based on the information available to us at this time and the reasons outlined above, including consideration of the affordability concerns expressed by large and medium-sized gas consumers, our final decision is that retaining the 2050 and 2060 scenarios and the associated 33:67 ratio applied at DPP3, remains appropriate and reflects mitigation of a suitably central estimate of risk in the current circumstances.

D92 As we note at paragraphs D40 – D43, we expect to make another assessment—and consider what regulatory actions, if any, need to be taken to promote the Part 4 purpose—as part of the DPP5 reset for the period commencing 1 October 2031. With a large customer base still expected to exist by the end of DPP4 there should be scope to mitigate further risk at that time if warranted.

Building blocks cost inputs and other modelling parameters

We updated stranding model inputs for the most recent financial and economic data available

D93 We consider that adopting the latest financial and economic data inputs for the stranding model, and maintaining consistency with the forecasts in the DPP4 financial model where relevant, gives appropriate estimates of future building block costs for GPBs to recover to maintain reasonable expectations of FCM at this time.

D94 The updated inputs for the DPP4 stranding model comprise: [273]

D94.1 Opening and closing RAB values from GPB-specific ID disclosures for the base year (DY25), and associated asset age profiles sourced from GPB-specific RFIs;

D94.2 The final 5-year WACC estimate determined for DPP4 and updated inflation forecasts; and

D94.3 Final opex and capex allowances for the DPP4 period, and AMP opex and capex values (with adjustments) for the following 4 years (2032 – 2035).

D95 As discussed in our draft decision, we have also aligned the CPRG estimates used to shape the profile of the MAR for DPP4 under each of the two modelled scenario with those in the DPP4 financial model (together with forecast inflation, and a linear/concave decline from the beginning of the DPP4 period to the assumed wind-down date).[274]

[273] See Attachments B, C and G.

[274] Commerce Commission "Gas DPP4 reset 2026 Default price-quality paths for gas pipeline businesses from 1 October 2026 - Draft decision reasons paper - Attachments A - H" (27 November 2025), para D100.

D96 We received no submissions in respect of our draft decisions on these matters.

D97 The forecast depreciation produced for DPP4 by applying the updated asset life adjustment factors from the stranding model after these updates were made is shown in Table D3 of this Attachment.

Technical modelling and implementation

D98 We received a number of technical queries from GPBs about the forecasting and implementation of DPP4 stranding risk and mitigation via our models.[275]

D99 Broadly, submitters expressed concern that the various assumptions or calculations applied to calculate asset-related components of DPP4 allowable revenues may not deliver the required level of mitigation for DPP4 when compared to out-turn (eg, assumed lives of DPP asset additions, effects of inflation on forecast depreciation).

D100 For the reasons set out below, we consider it appropriate not to change any aspect of the models or regulatory settings in relation to the submissions we received. However, it is possible that some of the issues raised could be considered further as part of the next Part 4 IM review (due to be completed by the end of 2030 at the latest).

D101 We also describe a technical correction we have made in respect of the calculation of depreciation for assets commissioned in the base year (ie, DY25), which we identified during an internal quality assurance review of the financial and stranding models.

Modelled DPP asset life for forecast additions

D102 Our models adopt an assumed 45-year asset life for forecast additions, and apply the relevant asset life adjustment factor to it when forecasting depreciation. Specifically, the DPP3 asset adjustment factor is applied for additions forecast to occur in DPP3, and the DPP4 adjustment factor is applied to additions forecast to occur in DPP4. The 45-year asset life we adopt is consistent with clause 4.2.2(3)(b)(ii) of the GDB and GTB IMs.

D103 We received submissions from Vector, Powerco and Firstgas:

D103.1 Vector submitted that the actual useful lives of additions will be “considerably lower” than the 45 years specified in the IMs (eg, due to potentially greater future investment in shorter-life digital assets), that the models calculate less than required depreciation in DPP4 by not applying both the DPP3 adjustment factor and the DPP4 adjustment factor, and that this results in uncompensated depreciation under ID in DPP4 that is not washed-up. Vector suggests amending the GDB and GTB IMs to correct this treatment. It also notes that if adjusted lives adopted for additions in DPP4 were projected forward the assets would have

[275] A number of incorrect assumptions about the models’ operation made by Castalia (report prepared for MGUG) “Evidence-based assessment of accelerated depreciation of gas transmission and distribution networks” (22 January 2026) were addressed by HoustonKemp "Form of control for gas distribution businesses in New Zealand – Report for Vector" (20 January 2026).

significant residual value in the 2050s. Vector recommends setting the assumed asset life for additions such that it expires in the assumed wind-down year.[276]

D103.2 Powerco submitted that both the DPP3 adjustment factor and the DPP4 adjustment factor should be applied to additions from the start of DPP4 to reflect that under ID provisions GPBs are required to assign the same life to additions as existing assets – which have already been shortened in DPP3.[277]

D103.3 Firstgas submitted that, in practice, the assets commissioned during DPP4 will be assigned a life that reflects both the DPP3 and DPP4 accelerated depreciation factors and will depreciate more rapidly than expected in the DPP4 asset stranding model and financial model.[278]

D104 The 45-year assumed life for additions specified in the GDB and GTB IMs is a simplification for the purpose of implementing the relatively low-cost DPP form of regulation. It is unlikely to exactly match the average of the regulatory asset lives subsequently assigned by GPBs to actual additions under ID requirements.

D105 We reviewed the IM settings applying in respect of mitigating economic network stranding risk in the 2023 IM review, and after considering submissions from interested stakeholders decided not to amend the existing IM provisions.

D105.1 We noted that changing depreciation method for DPPs would likely add complexity to the DPP process (contrary to s 53K of the Act).[279]

D105.2 However, we acknowledged that the 45-year simplifying assumption for DPP asset additions may be too long, and that options such as applying different adjustment factors to existing assets and forecast additions could be revisited if better data was available to assess it.[280]

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[276] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), p. 6; paras 57-59; Vector “Cross-submission on the default price-quality path for gas pipeline businesses beginning 2026 Gas DPP4 draft decision” (12 February 2026), paras 12-13.
[277] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), p. 27.
[278] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 17.
[279] Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), para 3.283.
[280] Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), footnote 238. The default 45-year asset lives was established as part of the same process that also established Schedule A assumed physical asset lives for ID reporting.

D106 We considered ID data on how lives for new assets were adjusted in practice during DY23 and DY24 by GPBs when implementing the DPP3 stranding risk mitigation in their ID asset registers. The data show a range of asset lives applied by GPBs to additions, varying across GPBs and disclosure years depending on particular capex projects completed. Many assets with assumed physical lives of 50 – 80 years were still being added to the RAB, and some appreciable RAB value was still associated with new assets having adjusted lives of 30 or 35 years, or more. However, non-network assets for these years generally had shorter (adjusted and unadjusted) lives, and for some GPBs made up a relatively large portion of the value of assets commissioned.[281] Overall, it was difficult to discern a common pattern or trend across the data, and variances between GPBs and between years illustrate the challenges in trying to approximate a single asset life assumption for DPP purposes. We note that no specific evidence was provided in submissions during the DPP4 reset process in support of an assumed depreciation life for additions that differed to the 45-year assumption specified in the GDB and GTB IMs.

D107 We consider this matter is best considered and progressed at the next Part 4 IM review when suppliers or other interested persons will have the opportunity to gather more information and present their views. In the interim, alternative depreciation methods remain available in CPPs for existing assets and/or forecast additions if the result, supported by evidence, would better promote the Part 4 purpose.[282]

D108 With respect to submitters' assertions that both the DPP3 adjustment factor and the DPP4 adjustment factor should apply to forecast asset additions in DPP4, we note that clause 4.2.2(3)(b)(ii) of the GDB and GTB IMs contemplates that only the asset adjustment factor for the DPP period in question is applied to the assumed 45-year life for additions. Also, our expectation (based on the high-level example provided by Powerco in its submission[283]) is that applying both the DPP3 and DPP4 asset adjustment factors to calculate depreciation for additions in DPP4 would not materially affect BBARs for DPP4. We have decided not to change this setting in our model for DPP4, and can consider including it for consideration at the next Part 4 IM review.

[281] The relative RAB values of network and non-network assets which might contribute to a weighted average asset life, can depend on factors like an individual GPBs' capital contributions policies (which reduce the net value of new network assets reported under ID) or the extent to which (predominantly non-network) assets are shared with other activities (and so are subject to the cost allocation provisions in the GDB and GTB IMs).

[282] See cl 5.3.8 of the GDB and GTB IMs. A CPP can also allow for the provisions of the GDB or GTB IMs to be varied by agreement between the supplier and the Commission.

[283] Powerco "Gas DPP4 draft decision – stability as the transition becomes clearer" (22 January 2026), p. 27.

D109 Lastly, we confirm the stranding model *does* truncate the assumed lives of asset additions that would otherwise extend beyond the wind-down date in the relevant industry scenario being modelled. However, the effect of applying the single blended asset factor produced by the stranding model to both existing assets and forecast additions in the DPP financial model—given the relative size and average age of these two broad categories of assets in DPP4—means that assumed 45-year lives for additions are not shortened proportionately to the same extent as existing assets. While the correct target amount of forecast depreciation is generated across DPP4, it is theoretically possible to project out the asset life expiry date for additions with adjusted lives in the DPP4 modelling, and observe that it is past 2050 (or 2060). This highlights that those additions are eligible for successive asset life adjustments at future resets (actual additions will form part of the existing RAB in the next DPP) to produce the required mitigation for future DPPs.[284]

Impact of inflation out-turn on intended risk mitigation

D110 Firstgas and Vector submitted that the requirement under ID reporting provisions in the GDB and GTB IMs to pass the DPP4 asset life adjustments through to individual assets in the RAB to achieve the modelled depreciation may lead to more or less stranding mitigation being delivered for GPBs than we intended due to the effect of inflation.[285]

D111 We understand the concern to be that:

D111.1 Inflation forecasts are used in our DPP models to inform the ex-ante calculation of revaluations, depreciation and asset life adjustment factors which are inputs into DPP4 allowable revenues – and therefore affect the "forecast depreciation for existing assets" and "transitional adjusted asset life for existing assets" specified in the DPP determination for ID implementation purposes.[286]

D111.2 Ex-post inflation that is higher (or lower) than forecast in the models will deliver lower (or higher) amounts of mitigation in real terms than forecast – due to GPBs being required to adjust ID asset lives at the start of the DPP period to satisfy overall compliance requirements based on the "forecast depreciation for existing assets" and "transitional adjusted asset life for existing assets" specified in the DPP determination, which is based on the models.

D112 Firstgas recommended the forecast depreciation specified in the DPP determination be adjusted to reflect actual CPI when implementing asset life adjustments. Vector suggested that removing indexation of the RAB would resolve the issue.

[284] There is also no explicit limit on the asset lives selected for assets by a GPB when passing the DPP4 asset life adjustments through to individual assets in the RAB for ID purposes, ie, asset life expiry dates for particular assets could in theory remain, or be extended, past 2050 or 2060 as long as the overall constraints in cl 2.2.8(5) of the GDB and GTB IMs are met. If the asset life adjustment and stranding model approach is applied again at future DPPs an opportunity will exist to further adjust the lives.
[285] Vector "Reset of the gas default price-quality path 2026: Issues Paper – Vector submission" (24 July 2025), para 92; Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), pp. 17-18; Vector "GPB DPP 2026 issues paper: Vector cross-submission" (14 August 2025), para 13.
[286] Clause 2.2.8(5) and (6) of the GDB and GTB IMs.

D113 We consider that mismatches between the forecast mitigation and actual mitigation delivered are avoided as a result of DPP revenues automatically being adjusted for actual inflation by the price path provisions fo GDBs and the GTB.

D113.1 As explained in our 2023 IM review, GDBs' price paths apply lagged actual inflation to the price path profile and the GTB revenue cap is washed-up for actual inflation for all years of the DPP period;[287]

D113.2 Inflation-indexing the revenue allowances in this way, or compensating for changes in inflation through a wash-up, effectively minimises GPBs' exposure to inflation risk for underlying allowable revenue components such as RAB revaluations and depreciation, and supports expectations of real FCM.[288]

D114 Additionally, ensuring that the inflation forecasts in the DPP model are applied as part of GPBs' demonstration of ID compliance with required asset life adjustments in the first year of DPP4 will ensure that exposure to inflation out-turn is minimised. This seems possible under the existing IM provisions, which require adjusted ID depreciation to be "equivalent" to the value in the DPP.[289]

D115 We do not consider that we should change the way that forecast depreciation is specified in the DPP determination for these reasons – nor consider removing RAB indexation in relation to the mitigation of network stranding risk in DPP4.[290]

Technical correction to depreciation of base year additions

D116 Following an internal quality assurance review of the DPP4 financial and stranding models, we identified a technical modelling correction required to ensure that depreciation of commissioned assets arising in the base year (ie, DY25) is captured in forecasting for DPP4. We had indicated by a text field in the models published at the time of our DPP4 draft decision that the calculations were subject to review.[291] No stakeholder submitted on this aspect of the modelling (although, as discussed above, we did receive submissions in relation to the 45-year assumed life for additions).

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[287] Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), para 4.79 and footnote 481.

[288] Ibid, para 4.178.

[289] Clause 2.2.8(5)(a)(i). Similarly, the remaining average asset life in the first year of the DPP period must be calculated such that it "approximates" the value specified in the DPP determination – cl 2.2.8(5)(ii).

[290] See our reasons in Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), paras 3.426 – 3.429, which we consider remain appropriate for the DPP4 reset.

[291] Commerce Commission "Gas DPP4 Draft decision - Financial modelling suite" (27 November 2025), Financial model – RAB:A26, Stranding model – RAB:A26

D117 In essence, the formulas in both the financial model and stranding model were not including the commissioned assets reported by GPBs under ID for DY25 in the roll forward asset totals, and this had the effect of incorrectly calculating forecast depreciation from DY26 onwards. We have corrected this error for our final decision models: DY25 commissioned asset values are now being depreciated using the 45-year assumed life with the appropriate (DPP3 or DPP4) adjustment factor applied, and total forecast depreciation amounts for DPP4 have increased as a result. In the absence of further information about the nature of the DY25 additions we consider this is a reasonable treatment to apply for the DPP4 reset.

D118 The net changes to forecast depreciation and total additional depreciation resulting from all input and modelling updates since our DPP4 draft decision is shown for each GPB in Table D3 and described in paragraph D26.

Attachment E Quality standards

Purpose of this attachment

E1 This chapter sets out our final decisions on quality standards, and outlines what we have considered in coming to these decisions for gas transmission businesses (GTBs) and gas distribution businesses (GDBs).

Structure of this attachment

E2 In Table E1 we describe the structure of this attachment.

Table E1 Structure of this Attachment

Title	Description of content
The Act requires us to set quality standards for regulated gas pipeline businesses (GPB)	We set out the statutory requirements for the quality standards
Our final decision is to retain the current quality standards	We describe our final decisions and our reasons for making those decisions, including our consideration of points made to us by stakeholders in submissions on our draft decisions

The Act requires us to set quality standards for regulated gas pipeline businesses

E3 We set quality standards for gas pipeline businesses (GPBs) while setting a default price-quality path as required by the Act. The provisions of the Act that are directly relevant to gas quality standards are:

E3.1 s 52A(1)(b) – sets out incentives to improve efficiency and provide services at a quality that reflects consumer demand. It is the most relevant subsection of the Part 4 purpose when it comes to quality standards.

E3.2 s 53K – sets out the purpose of default/customised price-quality regulation. It states that default price-quality paths should be set in a relatively low-cost way.

E3.3 s 53M(1)(b) – requires us to set quality standards when setting a DPP. At the same time, we have wide flexibility, with s 53M(3) allowing us to set quality standards in any way we consider appropriate.

E3.4 s 53M(2) – price-quality paths may provide incentives for suppliers to maintain or improve quality of supply. Incentives may include, but are not limited to: penalties, rewards, consumer compensation, and reporting requirements.

Our final decisions are to retain the current quality standards

Decisions QS1 and QS2

E4 Our final decision is to retain the current quality standards that apply to the GTB and the GDBs. To meet the quality standards:

E4.1 for the GTB and GDBs, the time taken to respond to any emergency must be less than 180 minutes;

E4.2 for the GTB and GDBs, the percentage of emergency responses taking longer than 60 minutes must not be greater than 20%;

E4.3 the number of major interruptions for the GTB must not exceed zero; and

E4.4 if there is a major interruption, that the GTBs must provide a detailed publicly available report.

Decision QS3

E5 Our final decision is not to introduce new quality standards for the GTB and GDBs for DPP4.

E6 Our final decisions are unchanged from our draft decisions.

What we heard from stakeholders

Uneconomic part of networks and low pressure

E7 A number of draft decision submitters noted that lower revenues due to reduced expenditure allowances, and demand risk would ultimately affect network quality outcomes.[292]

E8 Vector noted that "there is a limit to the amount of expenditure a GPB can reduce without compromising a safe and reliable supply. If revenue is consistently under recovered due to variations in forecast, efficient investment will be compromised" warning that "gas networks in New Zealand have no obligation to supply gas to customers." [293]

E9 Vector stated that if maintenance costs exceed revenues then "GDBs may choose to shut down parts of the network prematurely, leaving businesses and residential consumers without gas supply before viable alternatives are available." [294]

E10 Gas retailer Mercury also highlighted its concern about uneconomic parts of networks suggesting that more work needs to be done to identify "those parts of the network which could become uneconomic to supply due to a lack of sufficient customers" and that "a staged and well-planned retirement of these segments is preferable to disorderly "death spiral"".[295]

[292] Oxera "Suitability of a revenue cap for GDBs under DPP4 – Prepared for Vector Limited" (20 January 2026), pp. 4, 8, 16-17; Frontier "Key issues in Gas DPP4 Draft Decision – Report for Vector" (21 January 2026), p. 17, Axiom "Form of control for Gas Distribution Businesses - A report for Vector" (15 October 2025), pp. 8-9, p.13 and p. 15, Houston Kemp "Form of control for gas distribution businesses in New Zealand – Report for Vector" (20 January 2026), p. 17.
[293] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), pp. 11, 13.
[294] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), p. 13.
[295] Mercury "Submission on Gas DPP4 Draft Decision" (16 January 2026), p. 2.

E11 Further Mercury noted the Chorus copper approach may be appropriate for the gas industry stating that:[296]

> The early development of a withdrawal of service code so consumers are protected from network resizing which may trigger significant capital costs for them. A similar approach was established for the withdrawal of copper by Chorus and may be appropriate for the gas sector, along with broader consideration of appropriate arrangements to safeguard consumers during the transition.

E12 Mercury also suggested that gas pipeline pressures need to be monitored more closely to ensure there is no derogation in customer quality of service, but does not identify if this is an issue it is experiencing as a retailer at present.[297]

E13 We note the concern about the possibility of supply quality degrading if revenues decrease, and that some parts of networks may become uneconomic to maintain. While we have no evidence that this is presently an issue, we do note submitters have raised this as a possibility.

E14 We will continue to monitor this situation and while we have decided against change in this reset we will consider how we might address uneconomic parts of networks before the next reset.

E15 In our issues paper we considered if certain metrics such as the Customer Average Interruption Duration Index (CAIDI) should be monitored more closely.[298] CAIDI is a key measure to understand how quickly a supplier restores service after an interruption. It helps them identify areas where restoration processes need improvement and allows them to prioritise investments in infrastructure or procedures to reduce interruption durations. We require CAIDI to be disclosed by GDBs under information disclosure (ID) regulation.

E16 We will continue to monitor CAIDI performance through ID when more data becomes available, as it may provide more insight into potential unreliability in uneconomic parts of networks, or a conclusion that outage response times are increasing, to ensure that gas quality and supply is maintained at a level consumers demand.

Major interruptions and gas leaks

E17 Firstgas Transmission (FGT) submitted on the gas leak definition we proposed in our draft decision and the existing major interruptions quality standard.[299]

E18 Firstgas agreed with our proposal to define a gas leak as "an escape of natural gas from gas infrastructure assets, which has the potential to cause an emergency, interruption or incident" noting that this definition is "reasonable and fit for purpose" and that there is insufficient evidence to justify a gas leak quality standard at this time.[300]

[296] Mercury "Submission on Gas DPP4 Draft Decision" (16 January 2026), p. 2.
[297] Ibid, p. 2.
[298] CAIDI = total duration of customer interruptions / total number of customer interruptions.
[299] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), pp. 7-8.
[300] Ibid, p. 8.

E19 While other regulatory requirements incentivise the avoidance of gas leaks, we do not intend to introduce a gas leak quality standard at this time. We will continue to monitor both the transmission and distribution sectors for gas leak issues.

E20 Firstgas suggested that there may be some issues with the existing major interruptions quality standard, specifically that it "should consider consumer impacts to avoid incentivising networks to provide levels of reliability and resilience that are no longer appropriate."[301]

E21 Firstgas noted that the existing definition of major interruption has the potential to capture events that are smaller than the quality standard first intended. As an example, Firstgas suggest that the current definition may capture the impact of smaller events that affect a single consumer for a short period. If the interruption is "just before a delivery point, then it will be only the consumers served by that delivery point that will be affected. At a small delivery point, there may only be a small number of commercial consumers to curtail under the Critical Contingency Regulations."[302]

E22 However, despite this scenario Firstgas acknowledges that "any changes to the major interruption standard would need to be carefully considered and consulted upon, which may not be possible in the current DPP process."[303]

E23 On this basis, Firstgas has accepted the retention of the current standard, since any alternative measure would need to be "carefully analysed and well justified". However, Firstgas believes that it would be appropriate for us to 'limit the circumstances when the quality standard applies to situations that meet an ordinary definition of "major"' because with the current approach it "would be incentivised to make investments that reduce reliability risk but are excessively costly for the minor benefits".[304]

E24 While we have decided to make no change to the current standard and Firstgas acknowledges that at this stage in the DPP process, we will monitor the application of the current standard and may engage with Firstgas directly over DPP4 to monitor the operation of the current standard.

Our assessment taking into account stakeholder views

E25 In reaching our final decision, our reasons for maintaining the DPP3 quality standards settings for DPP4 include that:

E25.1 GPBs reliability and quality outcomes have not significantly worsened over time. The total number of outages, emergencies experienced by customers, and the resulting number of complaints have either remained stable or decreased;

E25.2 there are other regulations and incentives that ensure that GPBs maintain quality of service such as the Gas Act 1992, the Gas (Safety and Measurement) Regulations 2010, and the Gas Governance (Critical Contingency Management)

[301] Ibid, p. 2.
[302] Ibid, pp. 47-48.
[303] Ibid, p. 48.
[304] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), p. 48.

Regulations 2008. GPBs also have commercial incentives to maintain their quality of service such as:

E25.2.1 the reputational impact of quality problems;

E25.2.2 the costs involved in responding to and repairing any damage; and

E25.2.3 the revenue lost from undelivered services during an interruption.

E25.3 we are not satisfied we need to change the quality standards because the current quality standards are fit for purpose.

E26 In reaching our final decision, we considered stakeholder feedback to our draft decision, but this did not persuade us that a change was necessary to better promote the long-term benefit of consumers.

E27 Based on our analysis, we consider that the current quality standards are promoting the long-term benefit of consumers and the provision of services at a quality they demand. We consider the standards do not need to be changed, although we will continue monitoring gas quality and metrics using ID data over DPP4.

Gas sector quality outcomes are relatively stable

E28 In the gas DPP4 issues paper we noted that our recently published report on GPB performance, concluded that, in general, gas sector quality performance has either been stable or improving.[305]

E29 Since the gas DPP3 commenced on 31 May 2022, all GDBs and the GTB have met the DPP3 quality standards.

E30 In our issues paper we presented some analysis and noted that while none of the observed individual GPB quality trends appear to justify additional quality measures at this point, some GPB quality performance metrics may need to be monitored more closely in the future.[306]

E31 For example, we noted that:

E31.1 Powerco's CAIDI has been steadily worsening since 2013. CAIDI is the average time it takes to restore service to customers following an outage. An increasing CAIDI trend indicates customers subject to outages are on average without supply for longer; and

E31.2 FGT detected gas leaks, emergencies and incidents relating to gas specification. All appear to be trending upwards, although incidents are not numerous over the period analysed and due to the limited data set it is not clear this is a trend.

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[305] Commerce Commission "Trends in gas pipeline businesses' performance" (18 February 2025).

[306] Commerce Commission "Gas DPP4 - Issues paper – Attachments A - E" (26 June 2025), para A74-A106.

E32 Additionally, as a threshold for change, we would need to be satisfied that imposing any new quality measure promotes the long-term benefit of consumers. One relevant consideration is whether the value a new quality measure provides exceeds the cost including the complexity of implementing and administering it.

E33 In Attachment F, we discuss how we might address potential large-scale future network decommissioning costs (or disconnection costs). Disconnections may impact quality outcomes, and the quality settings we might consider in future resets, if there are sufficient disconnections that parts of network become uneconomic to maintain.

There are other regulatory measures and commercial incentives driving gas sector reliability

E34 Gas pipelines are subject to a wide range of regulation, in addition to Part 4 of the Commerce Act 1986 that we administer.

E35 Other regulatory agencies also have responsibilities for the natural gas industry. The Gas Industry Company (GIC) is the natural gas industry's co-regulator, established under the Gas Act 1992.[307] It is responsible for administering governance arrangements for the downstream natural gas industry from processing through to retail.

E36 Ministry of Business, Innovation and Employment (MBIE) has a central role in governing, monitoring, and advising on the wider natural gas market, and assessing recommendations made by the GIC.

E37 WorkSafe New Zealand is responsible for the Health and Safety in Employment (Pipelines) Regulations 1999.[308] It is also responsible for monitoring and enforcement of safety standards set out in the Gas Act (or within regulations made under the Gas Act).

E38 GPBs are also incentivised to avoid problems with the quality of the regulated service because of commercial incentives like:

E38.1 the reputational impact of quality problems;

E38.2 the costs involved in responding to and repairing any damage; and

E38.3 the revenue lost from undelivered services during an interruption for GDBs.

No quality standards related to consumer disconnection

E39 Our final decision is to not take any specific action or make any new provisions in the DPP4 price-quality paths in relation to consumer disconnections. This is unchanged from our draft decision.

[307] Gas Act 1992, available here.
[308] Health and Safety in Employment (Pipelines) Regulations 1999, available here.

E40 In submissions on our draft decision, we received information on disconnection policies and costs from a range of stakeholders, including GDBs (Vector and Powerco) and a gas retailer (Mercury). These submissions illustrate differences in current approaches to disconnections and associated costs and note the use of different terminology particularly in relation to temporary and permanent disconnections and the implications of each.

E41 This information has improved our understanding of current practice, and consistent with our view in the draft decision, we consider that further information gathering and monitoring is an appropriate first step.

E42 We have discussed disconnection issues with the GIC, and we expect these matters to be within scope of its newly launched Future of Gas Infrastructure workstream. We will continue to engage with the GIC and stakeholders as this work progresses and will consider whether any regulatory response is appropriate in future, informed by improved information and observed outcomes.

Attachment F Future issues not affecting our DPP4 final decisions

Purpose of this attachment

F1 The purpose of this attachment is to describe issues raised by submitters during our default price-quality path (DPP4) consultation process which we have considered, but which have not affected our final decisions for DPP4. We recognise that these issues could play a role in the development of regulatory policy for future price-quality paths or other Part 4 regulation.

F2 The four issues are:

F2.1 the treatment of future network rightsizing practices;

F2.2 the treatment of potential large-scale future network decommissioning costs;

F2.3 the treatment of non-depreciable easements; and

F2.4 a proposed cross-sector solution for addressing the impact of declining demand for gas pipeline services (GPBs).

Structure of this attachment

F3 We describe the structure of this attachment in Table F1.

Table F1 Structure of this attachment

Title	Description of content
Regulatory treatment of network rightsizing (Decision F1)	Why we are not considering network rightsizing as an issue for DPP4. Part 4 (and other consumer-related) issues for network rightsizing will be considered in a process separate to the DPP4 reset.
Potential large-scale future network decommissioning costs (Decision F2)	Why we are not considering a specific allowance for potential future large-scale network decommissioning costs (or changing any other existing regulatory setting) for DPP4.
Non-depreciable easements (Decision F3)	Why we are not considering the depreciation treatment of non-fixed life easements for DPP4. We are deferring consideration of the depreciation treatment of easements until after the DPP4 reset.
Cross-sector solution for addressing the impact of declining demand (Decision F4)	Why we are not considering a proposed conceptual solution for addressing the impact of declining gas demand identified by Greymouth Gas. It is out of scope for the DPP4 reset.

Regulatory treatment of network rightsizing (Decision F1)

F4 Consistent with our draft decision, we will consider network rightsizing as part of a regulatory process separate to the DPP4 reset process. In comparison with stranding risk, which we identify has both immediate and longer-term implications, we consider network rightsizing does not require changes to the regulatory settings in DPP4.

F5 We noted in our issues paper that any regulatory response to network rightsizing might require amendments to the gas distribution businesses (GDB) and gas transmission business (GTB) input methodologies (IMs).[309] For this reason, all or part of our consideration of the Part 4 issues will be best considered by us through our next Part 4 IM review (due to be completed by the end of 2030 at the latest). However, implications for consumers of rightsizing of networks are expected to be broader than Part 4 and that the separate regulatory process will require coordination with the Ministry of Business, Innovation and Employment (MBIE) and Gas Industry Company (GIC).

What we heard from stakeholders

F6 In their submissions and cross-submissions on our issues paper-

F6.1 Powerco supported deferring consideration of network rightsizing issues;[310] and

F6.2 MGUG submitted that gas pipeline businesses (GPBs) are not prevented from pursuing network rightsizing strategies. However, MGUG suggested we consider requiring approval for a GPB to remove service.[311]

F7 We received the following submissions on our draft decision:

F7.1 Mercury (submission) –

> On behalf of our retail customers, we would support...more work being done on identifying those parts of the network which could become uneconomic to supply due to a lack of sufficient customers. A staged and well-planned retirement of these segments is preferable to disorderly "death spiral".[312]

F7.2 New Zealand Steel (submission) –

> Attachment F to the reasons paper comments on future issues not affecting the DPP4 draft decision. We suggest two of these are relevant to current consideration. The first point relates to rightsizing. If stranding risk is a current issue, then so is rightsizing.[313]

F7.3 Firstgas (submission) –

> We also agree that there appear to be no regulatory changes needed during DPP4 to account for network rightsizing, provided that sufficient expenditure allowances are in place to fund specific anticipated activities...We agree with the Commission's plan to

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[309] Commerce Commission "Gas DPP4 reset 2026 - Issues paper" (26 June 2025), paras 2.31 – 2.33; Commerce Commission "Gas DPP4 - Issues paper – Attachments A -E" (26 June 2025), paras E4 – E19.
[310] Powerco "Powerco response to the Gas DPP4 Issues paper" (24 July 2025), p. 11.
[311] MGUG "Re: Gas DPP4 2026 – Views in response to issues paper" (28 July 2025), p. 7.
[312] Mercury "Submission on Gas DPP4 draft decision" (16 January 2026), p. 2.
[313] New Zealand Steel "Re: Submission on Gas DPP4 draft decision." (22 January 2026), p. 2.

monitor disconnection costs...We agree with the Commission's assessment of low materiality for the regulatory arrangements in DPP4 and therefore its conclusion to have this out of scope.[314]

F7.4 Rewiring Aotearoa (submission) –

Policy intervention is needed to improve customer outcomes: Policy could support a staged approach to distribution network retirement, starting with parts of the network with dwindling demand where costs to maintain supply greatly outweigh revenue recovery. Targeting support can help to switch remaining customers to alternative fuel types in these areas. Policy could also restrict new residential and commercial gas connections.[315]

F7.5 Firstgas (cross-submission) –

Given their view of declining gas demand, Mercury and Rewiring both advocate for a well-managed withdrawal of gas pipeline services...We broadly agree with the sentiment expressed above and we remain open-minded about the role regulation may have to play in setting minimum standards for an orderly wind-down of areas of the gas network. Mercury and Rewiring both appear to appreciate that these matters are effectively out of scope for DPP4.[316]

F7.6 Powerco (cross-submission) –

Powerco has assessed the health of all our networks and plans to progress one decommissioning project during DPP4 which will inform understanding on processes, costs and benefits of future network decommissioning. Network rightsizing or partial decommissioning is not yet urgent or material enough to require an allowance to be provided in the DPP4 period. However, we support the intention for a separate regulatory project to investigate rightsizing and decommissioning in advance of the DPP5 period.[317]

Our assessment taking into account stakeholder views

F8 The submissions generally support our draft decision to consider the issue of rightsizing separately from our DPP4 decisions.

F9 On other related matters raised in submissions (for example, Firstgas' submission on in-period decommissioning costs), these have been considered in our expenditure decisions for DPP4.

F10 We understand rightsizing practices have not yet been implemented by any GPB, and that plans to do so are still in their formative stages. As such, we consider network rightsizing unlikely to be a material consideration for the DPP4 reset.

[314] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), pp.40, 46.
[315] Rewiring Aotearoa "Rewiring Aotearoa submission on the Gas DPP4 reset 2026 – Draft Decision" (22 January 2026), p. 3
[316] Firstgas "Gas DPP4 2026: Firstgas views in response to submissions" (12 February 2026), p.17-19.
[317] Powerco "A stable regulatory environment is the best response to issues raised in submissions" (12 February 2026), p. 5.

F11 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 do not currently have the ability to develop a withdrawal code for GPBs. Therefore, we have engaged with MBIE and GIC to highlight emerging issues from network rightsizing to consider whether appropriate protections are needed for consumers (eg, a withdrawal code). Depending on the outcome of those interactions, we will then consider any necessary Part 4 IM implementations in the next IM review.

F12 Based on its recent consultation on its workstream and levy, we expect GIC's proposed FY2027 'Future of Gas Infrastructure' workstream will traverse this issue and is expected to advance coordination with MBIE and other stakeholders.[318]

Potential large-scale future network decommissioning costs (Decision F2)

F13 We have not made a specific price path allowance or new price path mechanism in relation to potential large-scale future decommissioning costs for the gas DPP4 reset.

F14 We do not have sufficient information about the basis for future decommissioning liabilities, or the likely type or scale of the costs. Therefore, we are not satisfied that it is in consumers' interests to progress a specific solution for DPP4.

F15 We may consider the treatment of decommissioning costs as part of the next Part 4 IM review (due to be completed by the end of 2030 at the latest) or as part of the DPP5 reset, when it is possible that further information and greater clarity for the gas sector with regard to this issue may have emerged. We would expect this information to include, for example, whether the GPBs have by then recognised decommissioning liabilities or contingent liabilities for Generally Accepted Accounting Practices (GAAP) accounting purposes.

F16 In the meantime, we note there is some flexibility provided by the existing gas IMs to respond to new developments during DPP4 in that new levies, or other material costs in respect of new legislative or regulatory obligations may qualify as "pass-through costs" or trigger a "change event" price-quality path reopener. In instances of large forecast revenue effects, the option of a customised price-quality path (CPP) is also available for any GPB to better tailor the price-quality path.

[318] GIC website "Consultation on Gas Industry Co FY2027 Work Programme and Levy" (18 December 2025), p. 10, 4.2 Gas Industry Co FY2027 Work Programme – Strategic Issues: Viability of Networks: "In FY2027 we intend to: • Investigate the impacts on consumers of the continued decline in gas production, including the future of infrastructure and costs; and • Consider whether consumer costs could be reduced by 'right sizing' the network for future loads (eg by allowing networks to be run at lower pressures or with fewer compressors)."

F17 We have referred issues raised by submitters in relation to network decommissioning costs to the Council of Energy Regulators at MBIE (the regulatory system's governance group), due to the likely wider policy implications affecting New Zealand's energy sector and security.

What we heard from stakeholders

F18 Our draft decision was not to make a specific allowance for potential large-scale future decommissioning costs in DPP4, or to change any existing regulatory setting for DPP4.

F19 The key reason we cited in our draft decision was the lack of critical information needed to understand and assess the nature of the problem and propose suitable regulatory responses for DPP4.

F20 The requirements and processes for network decommissioning are not yet defined or well understood, and in making our draft decision we did not have information about the basis for decommissioning obligations or the type and scale of costs. For example, none of the GPB submitters on our issues paper had indicated that they had undertaken an assessment of potential decommissioning liabilities for GAAP purposes or had plans to do so.

Submissions on our Draft decision

F21 Prior to our draft decision, on our June 2025 issues paper we heard the following from submitters:

F21.1 Acting now to address this issue is important while the overall customer base is at its broadest, even in the face of uncertainties;[319] and

F21.2 Early exploration of this issue and possible options during DPP4 is desirable.[320, 321]

F22 Submitters questioned whether:

F22.1 the risks/costs of decommissioning have already been internalised by GPBs as part of decisions to purchase businesses or install new assets;[322] and

[319] Firstgas "Gas DPP4 2026: Firstgas views in response to Issues Paper" (24 July 2025), pp. 17-20; Firstgas "Gas DPP4 2026: Firstgas views in response to Issues Paper submissions" (14 August 2025), pp. 2, 22-23; Vector "Reset of the gas default price-quality path 2026: Issues Paper – Vector submission" (24 July 2025), pp. 6-8; 36-39; Vector "Attachment A: Key issues for Gas DPP4 reset" (prepared by Frontier Economics) (24 July 2025), pp. 34-37; Vector "GPB DPP 2026 issues paper: Vector cross-submission" (14 August 2025), pp. 17-19. See also: Entrust "Gas price needs to ensure investment cost-recovery in face of decreasing demand" (24 July 2025); Entrust "Cost recovery needs to be managed in a fair and equitable manner" (13 August 2025).

[320] Firstgas, Powerco & Vector "Letter to the Commerce Commission – Response to Gas DPP4 Issues paper" (24 July 2025), pp. 2, 5-6.

[321] Powerco "Powerco response to the Gas DPP4 issues paper" (24 July 2025), p. 16.

[322] Methanex "Methanex submission on Gas DPP4 reset 2026 - Issues Paper" (28 July 2025), p. 9.

F22.2 providing for these costs in the building blocks framework undermines incentives to defer abandonment which is not optimal for gas consumers.[323]

F23 On our draft decision we then heard from the following submitters:

F23.1 Vector, Powerco and Rewiring Aotearoa accepted the problem is broader than our Part 4 mandate and suggested we progress work on policy settings in DPP4 with government policymakers such as MBIE;[324, 325, 326]

F23.2 Vector suggested that we consider now how to reopen the DPP4 price path if we reach the conclusion after further policy work that decommissioning costs should be recognised in DPP4;[327, 328]

F23.3 Entrust (Vector's major shareholder) reconfirmed its view that we should consider decommissioning costs as part of the DPP4 determination and not wait until DPP5;[329]

F23.4 Firstgas continued to advocate for an industry decommissioning fund to be established (although we have no powers under Part 4 to establish such a fund, require contributions, or ring fence revenues);[330]

F23.5 Firstgas, Powerco and Vector submitted to us a report commissioned from GPA Engineering to provide a desktop study to quantify the potential scale of decommissioning (and associated disconnection) costs if the reticulated gas distribution networks were to be decommissioned;[331, 332] and

F23.6 MGUG and Greymouth Gas agreed with our draft decision not to make any provision for costs in DPP4, on the basis that gas consumers should not bear additional costs or risks of decommissioning liabilities under Part 4.[333] [334]

[323] MGUG "Re: Gas DPP4 2026 – Views in response to issues paper" (28 July 2025), p. 36. See also: Fonterra "Fonterra submission on Gas DPP4 reset 2026r" (24 July 2025), p. 1.
[324] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), p. 7, 8, 26-27.
[325] Powerco "A stable regulatory environment is the best response to issues raised in submissions" (12 February 2026), p. 5.
[326] Rewiring Aotearoa "Rewiring Aotearoa submission on the gas DPP4 reset 2026 – Draft Decision" (22 January 2026), p. 3.
[327] Vector "Gas Default Price Quality Path beginning 1 October 2026: Draft Decision – Vector submission" (22 January 2026), p. 7.
[328] Vector "Cross-submission on the default price-quality path for gas pipeline businesses beginning 2026" (12 February 2026), p. 9-11.
[329] Entrust "Submission to the Commerce Commission regarding the gas DPP4 Draft Decision" (21 January 2026), p. 1.
[330] Firstgas "Gas DPP4 2026: Firstgas views in response to draft decision" (22 January 2026), Section 5.
[331] Firstgas, Powerco and Vector "Letter to the Commerce Commission" (22 January 2026).
[332] GPA Engineering "If New Zealand Were To Decommission Its Gas Distribution Networks: What Might It Cost?" prepared for and submitted by Powerco, Firstgas and Vector, (22 January 2026)
[333] MGUG "Re: Cross-submission on Gas DPP4 draft decision." (12 February 2026), p. 4.
[334] Greymouth Gas "Re: Cross-submission on Gas DPP4 draft decision" (11 February 2026), p. 3-5.

Our assessment taking into account stakeholder views

F24 The treatment of costs involved with the potential large-scale future decommissioning of gas networks under our building blocks model (BBM) framework has not been raised substantively at any previous gas default price-quality path (DPP) reset.

F25 In our draft decision, we considered that a main challenge we faced in considering the implications of eventual network decommissioning under Part 4 regulation was the high degree of uncertainty over the nature of decommissioning liabilities, and the type/scale of costs involved for GPBs:

F25.1 Requirements and processes around decommissioning are not yet well defined or understood. Further, the legal or other basis on which GPBs would incur costs (and the possible contribution to those costs by other parties) is unclear; and

F25.2 There is no reliable estimate of the costs involved or when they would likely be incurred. The costs may vary across GPBs, depending on the state of their networks at the time of retirement.

F26 In addition, we have noted the novel nature of some of the solutions discussed by submitters on our open letter (eg, the suggested establishment of a ringfenced industry decommissioning fund) and that further consideration would be required about how, if these ideas were to be implemented, they would interface legally and practically with our regulatory regime.

We are not satisfied that introducing a solution for DPP4 would promote the long-term benefit of consumers

F27 We have come to the overall view that there is still insufficient information available about the commercial, policy and regulatory issues surrounding potential large-scale decommissioning of gas networks to conclude that by progressing a specific Part 4 regulatory solution for the gas DPP4 reset would promote the long-term benefit of gas consumers.

F28 Progressing a specific Part 4 regulatory solution as part of DPP4 would pose greater risks to gas consumers in light of the current uncertainty, than not progressing a specific solution.

F29 Our treatment of decommissioning (ie, to make no specific allowance or introduce any other mechanism) can, at this time, be distinguished from our general approach to mitigating stranding risk by accelerating depreciation of past investments in the regulatory asset base (RAB).

Overall policy problem is still undeveloped

F30 After multiple rounds of industry/public consultation and feedback (ie, DPP4 open letter, issues paper, modelling workshop, draft decisions) on decommissioning costs it appears that GPBs and other affected parties are still only beginning to develop their understanding of what might be involved in terms of the scope and processes for eventual gas network retirement. We expect this will be advanced under the GIC's new 'Future of Gas Infrastructure' work programme.

F31 There are remaining fundamental unanswered questions about how network decommissioning should be best planned, co-ordinated and implemented. These have a significant public policy aspect. The objective is to optimise the outcomes of network decommissioning for consumers and the economy.

F32 The GPA Engineering desktop study undertaken for the Gas Infrastructure Futures Working Group (GIFWG) is the best and most recent information currently available on possible gas network decommissioning in New Zealand:[335]

F32.1 It provides a high-level, indicative estimate (NZ$193m, expressed in 2025 dollars) of the potential costs involved in decommissioning and associated customer disconnections of distribution networks under an 'optimal' process;

F32.2 However, it explicitly excludes consideration of costs and other matters related to "renewable gas infrastructure development, electricity network upgrades, customer conversion expenses, appliance replacement costs, and wholesale market effects"; and

F32.3 GPA Engineering also notes that its study "represents one piece of a complex, interconnected transition where decisions in any single area have cascading effects on costs and policy outcomes across the broader energy system".

F33 New Zealand is not alone in facing this issue. In Australia the Australian Energy Market Commission (AEMC) recently published a directions paper for consultation which set out the AEMC's proposed policy direction for reforming the gas pipeline economic regulatory framework in the National Gas Rules.[336] Its conclusions include the following statement which aligns with our views on decommissioning costs:[337]

> The [AEMC's] analysis indicates that the NGR economic regulatory framework alone cannot fully address all the impacts of uncertain and declining gas demand on consumers and service providers. There will be a role for governments in supporting gas consumers and service providers through the energy transition, including through clearer jurisdictional policy signals, addressing service obligations, supporting consumers and planning for potential network decommissioning, where appropriate.

[335] GPA Engineering "If New Zealand Were To Decommission Its Gas Distribution Networks: What Might It Cost?" prepared for and submitted by Powerco, Firstgas and Vector, (22 January 2026)
[336] The AEMC's role is to be the rule maker, market developer and expert adviser to Governments in the National Energy Market (NEM).
[337] AEMC "Directions paper – National Gas Amendment (Gas Networks in Transition) Rule" (19 March 2026), p v.

Liability of gas pipeline businesses for decommissioning costs is not yet established

F34 Importantly, where the risks and costs of decommissioning should lie from both a commercial and public policy perspective has not been determined. As a result, it is not clear if GPBs will be likely to incur future net costs which ought then to be eligible for recovery from current or future gas consumers over time.

F35 The GPA Engineering study was a hypothetical costing exercise. It is helpful in establishing an estimate of the potential costs involved. However, the GPBs have not provided evidence on the legal nature of the decommissioning obligations for GPBs. Public policy issues are involved in the allocation of responsibility for customer disconnections and overall network 'make safe' costs.

F36 From an accounting perspective no GPB has made disclosure (or other market disclosures) of future decommissioning cost liabilities. Only Vector publicly discloses its (consolidated) electricity and gas financial statements which show no provisions, asset impairments or contingent liabilities. In the absence of submissions to this effect, we have assumed that no GAAP provisions or impairments have yet been recognised by any other GPB, nor any contingent liability disclosed in financial statements.

F37 It is possible that the processes and timing for gas network decommissioning will be seen by policymakers as sufficiently critical to New Zealand's wider energy security that a specific regime to address the issues associated with decommissioning costs is established.

F38 Specific issues that might be considered within such a regime could include whether mandatory directions as to when and how retirement of networks in whole or in part should proceed and whether some or all economic costs/risks of doing so are passed through to persons other than the GPBs.

F39 Gas network retirement is likely to involve large cost outlays, and the timing of network retirement will affect demand for electricity and costs of industrial and commercial production. It may be that the quantum of decommissioning costs is so significant that there is no realistic prospect of gas consumers being able to bear these over time through prices in the face of reducing demand.

F40 The Firstgas, Powerco and Vector joint submission noted that the GPA Engineering estimates were very sensitive to assumptions about scope. For instance, based on experience in Australia, costs for GDBs could increase to $584m (from $193m) if infrastructure is also required to be removed permanently from customer premises instead of just isolating it.

F41 In the interests of an orderly energy transition, it may be, as a public policy matter, that groups other than GPBs and gas consumers end up bearing some or all costs related to decommissioning, eg, by way of a levy on other energy sector participants, by taxpayers or, in the case of disconnection costs, paid directly by property owners.

Consistency in how we are acting across DPP4 decision-making

F42 Our decision not to provide for specific allowances for decommissioning costs can be reconciled with our treatment of the stranding risk of the RAB (ie, which is through accelerated recovery of depreciation). The key difference is that for decommissioning there is significant uncertainty over the existence of the liability itself, not just whether it might be able to be recovered over time in the face of declining gas demand. More specifically:

F42.1 accelerated depreciation applies to the RAB, which is comprised of known past costs. GPBs' expectation of recovery of the RAB from gas consumers, together with opportunity cost represented by the WACC, is the orthodox application of the Commission's BBM of regulation under Part 4 of the Act. Acceleration of recovery is net present value (NPV)-neutral for GPBs over time, and does not add additional costs to the overall PV cost envelope to be recovered from gas consumers; and

F42.2 by contrast, the up-front recovery of future potential decommissioning costs would increase the expected net cost envelope to be recovered from gas consumers over time (so increases the NPV of expected recoveries). Uncertainties relate to both the future existence of the obligations and the quantum of costs *and* the ability of those costs to be recovered over time given reducing gas demand.

F43 We have acknowledged that in matters of cost recovery it is generally desirable to act while the consumer base is at its widest in order to maximise prospects of recovery and reduce the risk of adverse price impacts for future consumers.

F44 Firstgas submitted in its submission on our issues paper that making some provision for decommissioning costs now is better than waiting for better information in DPP5, even if the estimate of costs turns out to be ±50% wrong in DPP4.[338] However, we consider there is a risk of policy overreach under Part 4 if we act in DPP4 to implement a specific solution in isolation from broader public policy settings:

F44.1 it is unclear at this stage if the Part 4 regime is the most appropriate regulatory framework to deal with decommissioning issues for GPBs or gas consumers (especially in the context of a relatively low-cost DPP-setting process); and

F44.2 wider policy issues about the desirability of network retirement within NZ's overall energy transition, its management, coordination and monitoring, and who should ultimately bear costs/risks within the economy arguably fall outside of our Part 4 mandate.

[338] Firstgas "Gas DPP4 2026: Firstgas views in response to Issues Paper" (24 July 2025), p. 19-20.

Existing flexibility to deal with developments during DPP4

F45 Although not progressing a specific solution for DPP4 for possible decommissioning costs, we have examined the existing gas IMs to see what options there are for catering for developments within DPP4, eg, if greater clarity on liabilities or regulatory and policy issues were to emerge during the regulatory period. For example, Vector suggested that we should consider now how to reopen the DPP4 price path if we were to reach the conclusion after further policy work with MBIE that decommissioning costs should be recognised in DPP4.

F46 Our observations are:

F46.1 if costs were to arise for gas consumers (or other energy market participants) for decommissioning, eg, via a levy or other charge, then no provision for decommissioning costs would be required to be included for GPB price-quality paths;

F46.2 the existing definition of “pass-through costs” extends to any “levies ... payable under regulations made under the Gas Act 1992.” This would automatically cover new costs imposed for GPBs if, for instance, the Government was to introduce a gas decommissioning regime or implement a fund, and levies were to become payable by GPBs during DPP4;

F46.3 consideration of a ‘change event’ price-quality path reopener would be triggered if a material amount of costs were to be imposed on GPBs as a result of a new “legislative or regulatory requirement” occurring during DPP4 which “is not explicitly or implicitly provided for in the DPP”. A reconsideration of a price path can be initiated either by the GPB in question or us, and the price path (or quality standards) adjusted to mitigate the effect of the new cost; and

F46.4 a CPP is available to all GPBs to effectively reopen the DPP and substitute a more tailored price path and/or quality standards based on an assessment of a GPB’s individual circumstances.

Summary

F47 In summary, the main benefits to acting in DPP4 is maximising chances of recovery from consumers and lowering the price increases required in DPP5 and beyond to address a decommissioning liability. However, attempting to apply the limited tools we currently have under a Part 4 DPP to a policy problem of uncertain dimensions could result in an ineffective Part 4 regime for gas or cause some wider harm, eg, impeding development of other public policy development or inadvertently contributing to a liability for GPBs. Some of these risks are significant, with economic consequences that are largely irreversible.

F48 We have made decisions to accelerate depreciation on the RAB, which is contributing to some degree of price increases for consumers during DPP4. In this context, on balance, given the uncertainty about the extent of legal obligations for decommissioning and the potential development of policy obligations to allocate and determine the extent of decommissioning obligations, and in light of the GPB's own lack of financial recognition of future liabilities we consider it would be premature to impose a financial contribution on consumers to fund future decommissioning costs.

F49 The above factors suggest that acting in DPP4 on the basis of the information that is available is not likely to be in the long-term interests of gas consumers.

Regulatory treatment of non-depreciable easements (Decision F3)

F50 Firstgas requested that we review the status of non-fixed life easements as non-depreciable assets in the GDB and GTB IMs as part of the DPP4 reset, and submitted that changing the IM treatment for DPPs is necessary to better reflect its easements' economic life.[339] [340]

F51 Our final decision is we do not consider there is a compelling and urgent rationale for making a change to the IMs at this time.[341] We are deferring consideration of the depreciation of non-fixed life easements for possible consideration in the next IM review.

F52 All IMs must be reviewed at least once every seven years, as mandated by s 52Y. This process is key to delivering on the s 52R certainty purpose of IMs, while at the same time allowing the regime to mature and evolve in response to changing circumstances.

F53 Given the certainty purpose of the IMs and the scheme set out in the Act to promote this purpose, we must carefully assess what amendments are appropriate to consider outside the statutory IM review cycle. As noted previously, the predictability the IMs provide is key to promoting the s 52A purpose and, in particular, incentives to invest as required under s 52A(1)(a).

F54 However, it is important that the IMs are fit for purpose going into a price-quality path reset, particularly as under s 53ZB(1) IM amendments made after a price-quality path is determined (other than in limited circumstances) will not affect the price-quality path until the next reset.

F55 Leading up to a price-quality path reset, we may therefore need to consider which topics are appropriate to consult on as potential s 52X amendments in order to identify changes to the IMs that are necessary to ensure that the DPPs are workable and effective in promoting the outcomes in s 52A.

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[339] Firstgas "Gas DPP4 2026: Firstgas views in response to open letter" (13 March 2025), p. 3. See also Firstgas, Powerco & Vector "Gas DPP4 2026 – Views in response to open letter" (13 March 2025), p. 4.

[340] The existing treatment is specified in Gas Transmission Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 36 and Gas Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 37, clause 1.1.4, definition of "fixed life easement"; clause 2.2.5(3); clause 5.3.7(3).

[341] As set out in our recent paper "Proposed amendments to input methodologies for Gas Distribution Services – Amendments related to the 2026 Gas default price-quality path – Draft decision reasons paper" (2 April 2026), Chapter 3 Decision making framework, we will consider fundamental changes to the IMs out of the seven-year IM review cycle only where we consider there is a compelling and urgent rationale for doing so. This change relates to the asset valuation IM and depreciation. Therefore, we consider it is a fundamental change.

F56 We generally focus on two types of amendments outside of the statutory IM review cycle:

F56.1 those that support incremental improvements to price-quality paths; and

F56.2 those that enhance certainty about – or correct technical errors in – the existing IMs.

F57 We do not generally consider it appropriate to consider 'fundamental' changes outside of the statutory IM review cycle. Fundamental IMs are generally those that define the fundamental building blocks used to set price-quality paths (listed in s 52T(1)(a)), and that are central to defining the balance of risk and benefits between suppliers and consumers.

F58 However, we can and will reconsider fundamental building blocks IMs where there is a compelling and urgent rationale for doing so.

F59 In deciding whether to make IM amendments as part of the gas DPP4 price-quality path setting processes, we used a decision-making framework developed over time to support our decision-making under Part 4 of the Act. In respect of each draft amendment we consider whether it would:

F59.1 promote the Part 4 purpose in s 52A of the Act more effectively;

F59.2 promote the IMs purpose in s 52R of the Act more effectively (without detrimentally affecting the promotion of the s 52A purpose); and/or

F59.3 significantly reduce compliance costs, other regulatory costs, or complexity (without detrimentally affecting the promotion of the s 52A purpose).

F60 Our view set out in our draft decision was that the information provided in submissions did not establish an urgent or compelling reason to undertake an out of cycle review of the GDB and GTB IMs treatment of easements (or other non-depreciable land assets) ahead of DPP4.

F61 In the absence of information establishing the likely materiality of this issue for DPP4, or any other urgent or compelling reason to initiate an IM amendment consultation process ahead of the DPP4 reset, our draft decision was to defer the review of the treatment of non-depreciable easements to the next Part 4 IM review.

F62 We noted that any change to the IM treatment of easements for DPP purposes would also likely require consideration of changes to the IMs for ID and CPPs. There may also be implications for the other sectors we regulate. Considering the matter as part of the next Part 4 IM review would allow us to comprehensively address these matters.

What we heard from stakeholders

F63 In its submission on our draft decision, Firstgas requested that we review the status of non-fixed life easements as non-depreciable assets in the IMs as part of the DPP4 reset, and it submitted that changing the IM treatment for DPPs is necessary to better reflect the economic life of its easements.[342]

F64 Firstgas engaged Deloitte to provide analysis on the issue.[343] Its modelling shows that the change to allow depreciation on easements in DPP4 would not have a material forecast pricing impact on consumers in DPP5. Conversely, not considering the issue until the next IM review and then potentially allowing for depreciation from the commencement of DPP5 would not have a material increase in the forecast pricing impact on consumers in DPP5.

Our assessment taking into account stakeholder views

F65 Firstgas framed its IM amendment request as a consistency issue with the accelerated depreciation we have allowed for other assets. However, the request effectively came in two parts: recognition of depreciation where none exists at present, and then application of accelerated depreciation based on a hypothetical end date of 2050.

F66 We identified that the outcome Firstgas sought would require an out of cycle change to a fundamental IM, which we will only consider where there is an urgent or compelling reason to do so.[344]

F67 After considering the Firstgas submission on our draft decision and supporting analysis by Deloitte, we conclude there may be case for change. However, we note there is only a relatively small percentage difference in the consumer bill effect from deferring the matter to consider it in the next IM review and potentially commencing depreciation from DPP5 rather than in DPP4. Our final decision confirms our draft decision not to make a change to the IMs at this time.

F68 There is potential to argue for an IM amendment so that all easements are depreciable. However, Firstgas provided no detailed information on the nature of its non-depreciable easements, nor provided information on how we might approach assigning asset lives to those easements. We also note that the way in which Firstgas and Deloitte proposed to treat the easements under the IMs in the aggregate would be inconsistent with the current treatment of easements in the IMs, which is on a case-by-case basis.

F69 Our view in summary is:

F69.1 the quantitative analysis so far indicates that the issue is not so material that it requires an out of cycle IM amendment;

F69.2 this is not causing a particular issue in terms of the Part 4 purpose; and

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[342] Firstgas, Gas DPP4 2026: Firstgas views in response to draft decision (22 January 2026), p. 3, 12-16.
[343] Deloitte "Clarus Group, A review of the depreciation of non-fixed duration easements" (January 2026).
[344] Commerce Commission "Proposed amendments to input methodologies for Gas Transmission Services, Draft decision reasons paper" (27 November 2025), para 3.20.

F69.3 it is not clear what the Part 4 benefit and the long-term benefit for consumers would be from making this change.

F70 We therefore conclude that the facts do not currently meet our procedural threshold of a compelling and urgent rationale for an out of cycle change to the IMs.

Cross-sector solution for addressing the impact of declining demand for gas pipeline services (Decision F4)

F71 Greymouth Gas submitted on our issues paper that it had identified a conceptual solution for dealing with the impact of declining supply and demand for GPBs and gas consumers. Broadly, the concept involves revaluing GPB RABs and shifting the cost recovery of the revalued portion to consumers of electricity lines services. Greymouth Gas suggested that we evaluate the proposal and engage with stakeholders as part of the DPP4 reset.[345]

F72 In our draft decision we concluded 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 its cross-submission, it is best considered as part of wider government policy processes.

What we heard from stakeholders

F73 In relation to Greymouth Gas's proposal, MGUG submitted on our issues paper that we should pause our current approach to setting DPP4 and "revise [our] views on workable solutions that might productively address all stakeholder concerns."[346]

F74 Vector submitted on our issues paper that -

> We consider this proposal would be outside the remit of the Commission to implement, however, it provides an example of the need for continued engagement between the Commission and wider government on how to best manage the energy transition and address the very real potential for asset stranding undermining the regulatory compact.[347]

F75 In its submission on our draft decision, Greymouth Gas asked:[348]

> The Commission said Greymouth's solution is out of scope of its regulatory regime – but what does this mean? Does this require a policy steer to impose costs of one regulated service on consumers of another?

[345] Greymouth Gas "Re: Gas DPP4 2026 – Views in response to issues paper" (27 July 2025); Greymouth Gas "Re: Gas DPP4 2026 – cross-submission" (13 August 2025).
[346] MGUG "Re Gas DPP4 2026 – Cross-submission in response to Issues paper" (14 August 2025), p. 6. See also pp. 2, 6-7.
[347] Vector "GPB DPP 2026 issues paper: Vector cross-submission" (14 August 2025), p. 19.
[348] Greymouth Gas "Re: Gas DPP4 2026 – Draft Decision" (22 January 2026), p.3.

Our assessment taking into account stakeholder views

F76 This proposal is out of scope of our regulatory regime (and therefore the DPP4 reset). It would take a government policy decision to impose costs of one regulated service on consumers of another, and, as noted by Vector in its cross-submission, it would require legislative change and is best considered as part of wider government policy processes. We have referred the Greymouth Gas proposed solution to MBIE due to the wider policy implications affecting NZ's energy sector and security.

Attachment G Other inputs into the financial model

Purpose of this attachment

G1 The purpose of this attachment is to describe the inputs to the financial model we must include in addition to our forecasts of opex and capex discussed in other attachments, including weighted average cost of capital (WACC), consumer price index (CPI), and forecasts of disposals and other regulated income.

High-level approach

G2 Our approach has been to largely repeat the forecasting methods used in the third default price-quality path (DPP3), with adjustments to shorten the timeframe used to calculate historical averages to better capture changes in the gas industry. We also checked that inputs remain consistent with the current input methodologies (IMs). We explain below where we have taken an approach that differs from or is not explicitly set out in the IMs.

G3 We did not receive any submissions on our DPP4 issues paper or our DPP4 draft decisions directly relevant to the forecasting methods discussed in this attachment.

Decisions on inputs

Final decision on cost of capital (Decision M1)

G4 We set the WACC separate to our DPP reset decisions. The final WACC that will apply for DPP4 was required in the IMs to be determined by us not later than 1 April 2026 and be published in a separate determination no later than one month later.[349]

G5 We set out below the parameters we used in the WACC determination to calculate the WACC estimates for the purposes of our final DPP4 decisions.

Table G1 Parameters for estimate of WACC

Parameter	Value
Risk-free rate	3.91%
Average debt premium	1.09%
Leverage	41%
Asset beta	0.41
Equity beta	0.69
Tax-adjusted market risk premium (TAMRP)	7.0%
Average corporate tax rate	28%
Average investor tax rate	28%
Debt issuance costs	0.20%
Cost of debt	5.20%
Cost of equity	7.64%
Standard error of mid-point WACC estimate	0.0112
Mid-point vanilla WACC	6.64%
Mid-point post-tax WACC	6.04%

[349] Cost of capital determination for gas pipeline businesses' DPP4 [2026] NZCC 8.

Forecasts of Consumer Price Index as an input

G6 The price path is determined on a nominal basis, consistent with the DPP CPI-X approach outlined in s 53O and s 53P of the Act. When using a building blocks allowable revenue (BBAR)/ maximum allowable revenue (MAR) model to determine starting prices, we require a forecast of CPI to project annual revenues for each year of the DPP4 period. Because the asset valuation IM requires the RAB to be revalued at the rate change of CPI, we also require a forecast of CPI to determine BBAR.

G7 The approach we must use is determined by the IMs. For both the rate of change of forecast CPI for regulatory asset base (RAB) revaluations and the rate of change for the price path calculation, the IMs require us to base our CPI forecasts on the Reserve Bank of New Zealand forecasts of inflation issued as part of its Monetary Policy Statement immediately prior to the determination of the WACC for the DPP.[350]

G8 The results of our approach for the final decision, which are based on the latest available information, are set out in Table G2 below.[351]

Table G2 Forecasts of CPI

Pricing year ending in calendar year	2027	2028	2029	2030	2031
Revaluation rate, June year-end	2.00%	2.00%	2.00%	2.00%	2.00%
Revaluation rate, September year-end	2.00%	2.00%	2.00%	2.00%	2.00%
Inflation rate, lagged, September year-end	2.91%	2.40%	2.00%	2.00%	2.00%
Inflation rate, not lagged, September year-end	2.10%	2.00%	2.00%	2.00%	2.00%

Final decision on forecasts of disposed assets (Decision M2)

G9 Our decision is to include an allowance for disposed assets based on historical levels. A disposed asset is an asset that is, or is forecast to be, sold or transferred, but is not a lost asset.[352, 353] We are required to forecast disposed assets because disposed assets are removed from the RAB when rolling forward the RAB value.

[350] Gas Distribution Services Input Methodologies Determination 2012 [2012] NZCC 27, clause 1.1.4(2), 'CPI'; Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28, clause 1.1.4(2), 'CPI'.
[351] Reserve Bank of New Zealand Te Pūtea Matua "Monetary Policy Statement 2026" (18 February 2026). CPI growth is assumed to be 2% beyond the Reserve Bank's published horizon. This is in accordance with the Monetary Policy Committee Remit mid-point inflation target.
[352] Gas Distribution Services Input Methodologies Determination 2012 [2012] NZCC 27, clause 1.1.4(2), 'disposed asset'.
[353] Gas Transmission Services Input Methodologies Determination 2012 [2012] NZCC 28, clause 1.1.4(2), 'disposed asset'.

G10 To reach our final decision, the forecast value of disposed assets in each year of the regulatory period has been forecast in real terms as being equal to the historical average real value of disposals (derived from ID actual values). The real forecast time series has then been converted to a nominal time series by adjusting for forecast CPI changes. These results are set out in Table G3 below.

Table G3 Forecasts of disposed assets (nominal $000)

Supplier	2027	2028	2029	2030	2031
Firstgas Transmission	266.9	272.2	277.7	283.2	288.9
Firstgas Distribution	0.3	0.3	0.4	0.4	0.4
GasNet	0.0	0.0	0.0	0.0	0.0
Powerco	193.8	197.7	201.6	205.6	209.8
Vector	437.9	446.7	455.6	464.7	474.0

G11 The treatment of gains or losses on disposals as 'other regulated income' is noted below.

Final decision on forecasts of GDBs' other regulated income (Decision M5)

G12 Our decision is to include an allowance for other regulated income based on historical levels. Other regulated income is defined in the IMs, and is income associated with the supply of gas distribution/transmission services, including gains or losses on disposed assets, but excluding:[354, 355]

G12.1 income through prices;

G12.2 investment related income;

G12.3 capital contributions; and

G12.4 vested assets.

G13 To forecast the value of other regulated income for our final decision, we first calculated the historical average real values of gain or loss on disposal as a ratio, subject to a maximum loss cap of 100%. The forecast for other regulated income is then derived by summing the calculated gain or loss with GDB's forecast regulated income. The resulting values are set out in the table below.

[354] *Gas Distribution Services Input Methodologies Determination 2012* [2012] NZCC 27, clause 1.1.4(2), 'other regulated income'.
[355] *Gas Transmission Services Input Methodologies Determination 2012* [2012] NZCC 28, clause 1.1.4(2), 'other regulated income'.

Table G4 Forecasts of other regulated income (nominal $000)

Supplier	2027	2028	2029	2030	2031
Firstgas Distribution	374.0	381.5	389.1	396.9	404.8
GasNet	51.4	52.4	53.4	54.5	55.6
Powerco	1,879.8	1,917.3	1,955.7	1,994.8	2,034.7
Vector	-126.4	-128.9	-131.5	-134.1	-136.8

Final decision on forecasts of other building blocks cost inputs (Decision M3)

G14 In our calculations of the revenue building blocks, there are some building blocks where we have relied on actual ID data as the base for our calculations before making necessary adjustments to reflect GPBs' forecasts, our policy decisions and timing considerations. Some of these base values include the RAB, depreciation, other regulated income and other related components.

G15 Where we have used actual ID data, our final decision is to use 2025 actual ID values (either as the basis for our own calculations or directly as an input) as this represents the most up-to-date representation of expected profitability.

Attachment H Framework for setting the default price-quality path

Purpose of this framework

H1 This attachment describes the decision-making framework we have applied in resetting the default price-quality paths (DPPs) for gas pipeline services.

H2 This is a conceptual framework to guide and explain our decision-making, without mechanically determining our decision-making. We consider this strikes the right balance between prescription and flexibility in light of potential unforeseeable circumstances that may arise over time.

H3 This framework was adapted from the decision-making framework chapter in our gas DPP3 decisions published in May 2021.[356] This attachment is substantively similar to that framework, with minor adjustments. Accordingly, many interested parties will already be familiar with the substance of this framework.

H4 To explain this framework, we discuss:

H4.1 the requirements for setting DPPs under Part 4 of the Commerce Act 1986 (the Act);

H4.2 the overarching objectives in the Act that are relevant when setting a DPP;

H4.3 the relevant gas input methodologies (IMs); and

H4.4 our framework for making DPP reset decisions, which includes the key economic principles of Part 4 regulation.

Requirements for setting DPPs under Part 4 of the Commerce Act 1986

H5 Under Part 4, gas pipeline businesses (GPBs) are subject to two forms of regulation in respect of their supply of gas pipeline services:

H5.1 our information disclosure (ID) regulation, under which GPBs are required to publicly disclose information relevant to their performance;[357] and

H5.2 default/customised price-quality regulation, under which price-quality paths set the maximum prices or revenues that GPBs can charge and set standards for the quality of the services that each GPB must meet.[358] This incentivises GPBs not to reduce quality to maximise profits under their price paths.

H6 When we reset a DPP, Part 4 specifies several requirements we must follow:

[356] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022: Final Reasons Paper" (31 May 2022), ch 2.
[357] Commerce Act, ss 52B and 55C.
[358] Commerce Act, ss 52B, 53M and 55D.

H6.1 the regulatory rules and processes, referred to as IMs, which we are required to apply when determining the prices and quality standards applying to the supply of gas pipeline services;[359]

H6.2 what must be specified in the DPP determinations;[360]

H6.3 the content and timing of DPPs;[361] and

H6.4 requirements when resetting DPPs.[362]

H7 We must consider the Part 4 purpose and what DPP regulation is intended to achieve when making our decisions. We discuss these objectives and how we are required to use them to set DPPs in the next section of this attachment.

How we apply Part 4 of the Commerce Act when setting a default price-quality path

Purpose of Part 4

H8 Part 4 provides for the regulation of the price and quality of goods or services in markets where there is little or no competition, and little or no likelihood of a substantial increase in competition.[363]

H9 Section 52A of the Act sets out the purpose of Part 4 regulation in respect of the regulated goods or services:

> s 52A Purpose of Part
>
> (1) The purpose of this Part is to promote the long-term benefit of consumers in markets referred to in s 52A by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services—
>
> (a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and
>
> (b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and
>
> (c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and
>
> (d) are limited in their ability to extract excessive profits.

H10 Our decisions must therefore promote the long-term benefit of consumers of gas pipeline services. Section 52A guides us that this is to be achieved by promoting four outcomes that are considered consistent with those of competitive markets.

[359] Commerce Act, s 52S(b)(ii).
[360] Commerce Act, s 53O.
[361] Commerce Act, s 53M.
[362] Commerce Act, s 53P.
[363] Commerce Act, s 52.

H11 As defined in the Act, a consumer means "a person that consumes or acquires regulated goods or services".[364] This includes both the direct acquirers of the gas pipelines services and those persons that indirectly consume those services via the purchase of natural gas.

H12 In practice, when setting a DPP, it is important to note:

H12.1 we do not focus on replicating all the potential outcomes or mechanisms of workably competitive markets, but on promoting the s 52A outcomes;[365]

H12.2 none of the objectives listed in s 52A(1)(a) to (d) are paramount, and they are neither separate nor distinct from each other or s 52A(1) as a whole. Rather, we must exercise judgement in balancing the outcomes in s 52A(1)(a) to (d);[366] and

H12.3 when exercising our judgement, we are guided by what best promotes the long-term benefit of consumers of gas pipeline services.[367]

H13 In certain instances, our ability to exercise judgement will be constrained, because we must make our decisions according to specific legal requirements. For example, we must apply:

H13.1 the gas IMs, which promote the outcomes in s 52A and certainty for suppliers and consumers in relation to the rules, requirements, and processes that apply to the regulation of gas pipeline services; and

H13.2 the mandatory requirements in the Act. For example, s 53M(4) provides that a regulatory period must be five years, while s 53M(5) provides that we may set a shorter period if we consider that it would better meet the purposes of Part 4, but the term may not be less than four years.

Purpose of default/customised price-quality regulation

H14 Section 53K of the Act sets out the purpose of default/customised price-quality regulation:

> The purpose of default/customised price-quality regulation is to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances.

H15 We have taken this purpose to mean that:

H15.1 DPPs are to be set in a relatively low-cost way, and are not intended to meet all the circumstances that a GPB may face; and

H15.2 customised price-quality paths (CPPs) are intended to be tailored to meet the particular circumstances of an individual GPB.

[364] Commerce Act, s 52C.
[365] Major Gas Users' Group Inc v Commerce Commission [2024] NZHC 959 at [14] and [168].
[366] Wellington International Airport Ltd v Commerce Commission [2013] NZHC 3289 at [684].
[367] Wellington International Airport Ltd v Commerce Commission [2013] NZHC 3289 at [165], [222], [684], [686] and [761].

H16 To meet the relatively low-cost purpose of DPP regulation, we must take into account the efficiency, complexity, and costs of the DPP regime as a whole when resetting the DPP. What this means in practice will vary over time and between sectors.

H17 We have developed a combination of low-cost principles, including applying the same or substantially similar treatment to all suppliers on a DPP where this is workable. These principles include:

H17.1 if we are satisfied that using historical information provides a useful proxy for forecast conditions, setting starting prices and quality standards or incentives with reference to historical levels of expenditure and performance;[368]

H17.2 where possible, using existing information disclosed under ID regulation, including suppliers' own asset management plan (AMP) forecasts; and

H17.3 limiting the circumstances in which we will reopen or amend a DPP during the regulatory period.

H18 Our application of the low-cost principles is subject to our specific obligations under the IMs and the Act.

Input methodologies

H19 To make our gas DPP decisions, we must apply the following key gas IMs:[369]

H19.1 specification of price;

H19.2 cost allocation;

H19.3 asset valuation; and

H19.4 treatment of taxation.

H20 We must also apply the Cost of Capital IM when we estimate the weighted average cost of capital (WACC) that will apply to the DPP regulatory period. We are required to estimate the WACC no later than six months before the start of a regulatory period. We do this as part of a separate process to the DPP reset.

Interaction of climate change policy with the Section 52A purpose

H21 New Zealand is targeting zero greenhouse gases (excluding biogenic methane for which there are separate provisions) on a net accounting emissions basis by 2050 (2050 target), as set out in s 5Q of the Climate Change Response Act 2002 (CCRA).[370]

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[368] In periods of significant uncertainty, we recognise that historical information could be an unreliable source of information for the purpose of forecasting certain inputs.

[369] These IMs are set out in the Gas Distribution Services Input Methodologies Determination 2012 (as amended) and the Gas Transmission Services Input Methodologies Determination 2012 (as amended).

[370] In October 2025, the Government announced that it would target biogenic methane levels of 14 to24 per cent below 2017 levels by 2050. The Climate Change Response (2050 Target and Other Matters) Amendment Act 2025 received Royal Assent on 16 December 2025. See Beehive website.

H22 Section 5ZN of the CCRA provides:

> If they think fit, a person or body may, in exercising or performing a public function, power, or duty conferred on that person or body by or under law, take into account—
>
> (a) the 2050 target; or
>
> (b) an emissions budget; or
>
> (c) an emissions reduction plan.

H23 The purpose of s 5ZN is to allow the 2050 target and emissions budgets to influence broader government decision-making where they are relevant. Parliament left it to decision-makers (acting reasonably) to determine whether and how to take climate change mitigation into account.

H24 We are required to exercise our powers within the scope of our legislative framework, and to make decisions to promote the Part 4 purpose contained in s 52A of the Act. Section 5ZN allows us to take those considerations—the 2050 target, emissions budget, and emissions reduction plan (ERP) into account in the context of fulfilling our statutory purpose, which is to promote the long-term benefit of consumers of gas pipeline services by promoting outcomes consistent with those in workably competitive markets.[371]

H25 However, we cannot have regard to the factors in s 5ZN where doing so would detract from the Part 4 purpose.

H26 Matters that arise from climate change policy might also be relevant to our gas DPP decisions in the ordinary course outside of the ambit of s 5ZN. If climate change legislation was to impose obligations on regulated businesses, and we considered this to be relevant to our decisions or part of the relevant factual context, then we would take this into account in setting the DPP based on ordinary administrative law principles.

Our role to consider or support a transition to alternative gases is limited

H27 Under Part 4 of the Commerce Act, we regulate gas pipeline services. That is, the conveyance of natural gas by pipeline.

H28 The term natural gas is not defined in the Commerce Act, which may give rise to uncertainty about whether the conveyance of alternative gases or gas blends falls within the regulated service, for the purpose of regulation under Part 4.

H29 Having considered this issue, we remain consistent in our view that blends of biogas or hydrogen with natural gas could be considered 'natural gas' and can be included in the definition of gas pipeline services where:

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[371] Ministry for the Environment "Our journey towards net zero: New Zealand's second emissions reduction plan 2026-2030" (2024).

H29.1 natural gas is the most significant component of the gas or blend; and

H29.2 conveying the gas or blend does not require a pipeline or appliance conversion.

H30 Unless the above criteria are met, our view is that conveying alternative gases by pipeline cannot be considered a gas pipeline service for the purpose of Part 4.

H31 In line with our statutory purpose, our regulation remains focused on promoting the long-term benefit of consumers of gas pipeline services. That is, consumers in the market for the conveyance of natural gas. Accordingly, our regulatory role does not extend to promoting or facilitating the conveyance of alternative gases or a transition away from natural gas, except where doing so does not detract from the long-term benefit of consumers of gas pipeline services.

H32 Where changing circumstances suggest that regulation should be extended to new goods or services, the Commerce Act contemplates that this should be considered and implemented through the legislation. For example, at the date of our draft DPP decision, the Minister for Energy had signalled potential amendments to the Commerce Act to clarify the definition of natural gas and, therefore, the scope of the regulated service.[372]

Our framework for making decisions on gas DPP resets

H33 Our intent is to apply a consistent decision-making framework to gas DPP resets, applying the same approaches used in previous DPP resets except where we consider making changes would:

H33.1 better promote the purpose of Part 4;[373]

H33.2 better promote the purpose of DPP regulation;[374] or

H33.3 reduce unnecessary complexity and compliance costs.

H34 We consider the Part 4 purpose to be the most important consideration for our decisions. Therefore, we will not make a change on the basis of the other above criteria where we consider that doing so would detract from that purpose.

H35 We have adapted this framework from previous regulatory projects, including IM Reviews and Electricity and gas Reset decisions.[375] We consider maintaining our approach helps ensure regulatory certainty and consistency with the low-cost purpose of the DPP.

A 'building blocks' approach to price-quality regulation

H36 As discussed in more detail in Attachment A, our price-quality regulation under Part 4 is based on a building blocks method.

[372] Hon Simon Watts, Minister for Energy "Speech to the Biogas Bridge Forum" (Wellington, 23 July 2025).
[373] Commerce Act, s 52A.
[374] Commerce Act, s 53K.
[375] For example, see Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022: Final Reasons Paper" (31 May 2022), ch 2.

H37 The building blocks method creates financial incentives which align regulated suppliers' interests with those of their customers in reducing costs and becoming more efficient. This alignment of incentives is achieved over regulatory control periods, where the maximum revenues (or prices) for delivering the regulated services over the regulatory control period are specified up-front.

H38 Setting the maximum revenues (or prices) in this way provides an ex-ante opportunity for the regulated provider to earn its allowed return. The allowed return under a building blocks approach is the best estimate of the return that an efficient firm has an ex-ante opportunity to earn in a workably competitive market (sometimes referred to as a 'normal return'). Where regulated suppliers outperform their allowed returns by becoming more efficient, they enjoy the benefit of these efficiencies (in the form of higher profits) with the efficiencies shared with consumers at the next reset in the form of reduced revenues (or prices).

H39 The building blocks method is also used as part of ID regulation to underpin the assessment of returns which helps us and other interested parties in assessing whether the outcomes in s 52A are being met.

H40 We have developed a decision-making framework and set of economic principles over time to support our decision-making under Part 4 when we determine the values of the specific building blocks under the IMs.

H41 These have been consulted on and used as part of prior processes and help provide consistency and transparency in our decisions.

H42 However, we recognise that issues may arise over time and that we need to be open to modifying or changing our approaches where this would better promote the purpose of Part 4.

H43 While we recognise the uncertainty in the gas sector and that demand for piped natural gas in New Zealand is likely to decline over time, we still consider that our existing approaches to price-quality regulation described above would likely best give effect to the purpose of Part 4 in the current context.

Economic principles

H44 We have three key and longstanding economic principles that we have regard to in setting DPPs under Part 4. We consider that these are useful analytical principles that can help us reach decisions that promote the Part 4 purpose. They can also help promote regulatory predictability by signalling to stakeholders how we are likely to approach relevant decisions. However, if the principles cease to be consistent with the Part 4 purpose in a specific situation, we will not continue to apply them.

H45 The three principles are:

H45.1 *Real financial capital maintenance (FCM)*: we provide regulated suppliers with the ex-ante expectation of earning their risk-adjusted cost of capital (a 'normal return'). This provides regulated suppliers with the opportunity to maintain their financial capital in real terms over timeframes longer than a single regulatory period. However, price-quality regulation does not guarantee a normal return over the lifetime of a regulated supplier's assets.

H45.2 *Allocation of risk*: ideally, we allocate particular risks to regulated suppliers or consumers depending on who is best placed to manage the risk. In order to determine the regulatory settings in price-quality regulation that will give effect to the FCM principle, we consider the allocation of risk. We aim to allocate risks to the party best placed to manage them. Managing risks includes:

H45.2.1 actions to influence the probability of occurrence where possible;

H45.2.2 actions to mitigate the costs of occurrence; and

H45.2.3 the ability to absorb the impact where it cannot be mitigated.

H45.3 Regulated suppliers have various risk management tools at their disposal, including insurance, investment in network strengthening/resilience, hedging, contracting arrangements and delaying certain decisions eg, when to make large investments. Once the risks are allocated between regulated suppliers and consumers, we compensate regulated suppliers and consumers accordingly through the price-quality path we set.

H45.4 *Asymmetric consequences of over- and under- investment*: we apply FCM recognising that usually there are asymmetric consequences to consumers of regulated energy services, over the long-term, of under-investment.

H46 We elaborated on each of these principles and how they should be applied in the context of price-quality regulation in our 2023 IM Review framework paper.[376]

[376] Commerce Commission "Part 4 Input Methodologies Review 2023 Framework paper" (13 October 2022).

Glossary

Term or abbreviation	Description
2023 IM review	Second statutory input methodologies review completed in December 2023
2050 target	New Zealand's target to achieve net zero emissions of greenhouse gases by 2050
AER	Australian Energy Regulator
ALENZ	Aluminium Extruders of New Zealand
AMP	Asset management plan
ARR	Asset replacement and renewal
BBM	Building blocks model
BBAR	Building blocks allowable revenue
BST modelling	Base-step-trend opex modelling
CAGR	Compounded annual growth rate
CAIDI	Customer average interruption duration index
Capex	Capital expenditure
CC	Consumer connection
CCC	Climate Change Commission
CCUS	Carbon capture, utilisation and storage
CGPI	Capital goods price index
Commerce Act	Commerce Act 1986
Commission	The Commerce Commission/*Te Komihana Tauhokohoko*
CPI	Consumer price index
CPP	Customised price-quality path
CPRG	Constant price revenue growth
DPP	Default price-quality path
DPP1	Default price-quality path for the first regulatory period (1 October 2013 – 30 September 2017)
DPP2	Default price-quality path for the second regulatory period (1 October 2017 – 30 September 2022)
DPP3	Default price-quality path for the third regulatory period (1 October 2022 to 30 September 2026)
DPP4	Default price-quality path for the fourth regulatory period (the regulatory period commencing 1 October 2026)
DY20xx	Disclosure year 20xx
EDB	Non-exempt regulated electricity distribution business
EDB DPP4	EDB default price-quality path for the fourth regulatory period (1 April 2025 to 31 March 2030)
EECA	Energy Efficiency and Conservation Authority
EGWW	Electricity, gas, water and waste sector
ERP	New Zealand's first emissions reduction plan 2022-25
ERP2	New Zealand's second emissions reduction plan 2026-30
FCM	Financial capital maintenance
Firstgas	First Gas Limited, a regulated natural gas transmission and distribution business
Fonterra	Fonterra Co-operative Group Limited
GAAP	Generally accepted accounting practice
Gas Act	Gas Act 1992
Gas IMs	Input Methodologies for gas pipeline services: Gas Distribution Services Input Methodologies Determination 2012 (as amended) and the Gas Transmission Services Input Methodologies Determination 2012 (as amended)
GasNet	GasNet Limited, a regulated natural gas distribution business
GDB	Regulated natural gas distribution business
GIC	Gas Industry Company Limited

GIFWG	Gas Infrastructure Future Working Group
Government	New Zealand Government/ *Te Kāwanatanga o Aotearoa*
GPB	Gas pipeline business, being either a GDB or GTB
Greymouth Gas	Greymouth Gas New Zealand Limited
GTAC	Gas transmission access code
GTB	Regulated natural gas transmission business
GTP	Gas transition plan
ICP	Installation control point
ICT	Information and communication technology
ID	Information Disclosure
IMs	Input Methodologies
IM review	Statutory Input Methodologies Review
IRIS	Incremental rolling incentive scheme
LCI	Labour cost index
MAR	Maximum allowable revenue
MBIE	The Ministry of Business, Innovation and Employment/*Hīkina Whakatutuki*
MGUG	Major Gas Users' Group
NN	Non-network
NPV	Net present value
NZIER	New Zealand Institute of Economic Research
OCR	Official cash rate
Ofgem	The Office of Gas and Electricity Markets
Opex	Operating expenditure
Part 4	Part 4 of the Commerce Act 1986
Powerco	Powerco Limited, a regulated natural gas distribution business
PPI	Producer price index
PQ	Price-Quality
RAB	Regulatory asset base
RBNZ	Reserve Bank of New Zealand/*Te Pūtea Matua*
RFI	Request for information between the Commission and regulated GPBs, which may contain confidential information
RNG	Renewable natural gas
RSE	Reliability, safety and environment
RTE	Response time to emergencies
SaaS	Software as a service
the Act	Commerce Act 1986
TAMRP	Tax-adjusted market risk premium
UDL	Utilities Disputes Limited/*Tautohetohe Whaipainga*
Vector	Vector limited, a regulated natural gas distribution business
WACC	Weighted average cost of capital
WAPC	Weighted average price cap
WIP	Work in progress
WorkSafe	WorkSafe New Zealand/*Mahi Haumaru Aotearoa*
x-factor	The rate of change in prices. If prices are increasing, then the value of x will be negative when applying a CPI-X approach