Form of control for gas distribution businesses in New Zealand

Report for Vector

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Executive summary

The New Zealand Commerce Commission (the Commission) published on 27 November 2025 its draft decision on default price-quality paths for gas distribution businesses (GDBs) over the five-year regulatory period starting 1 October 2026 (DPP4).

As part of this draft decision, the Commission intends to continue subjecting GDBs to a weighted average price cap (WAPC), whereby:

- the Commission will set maximum revenues and quality standards for each GDB for the regulatory period; and
- limits on allowed revenue during the period effectively increase (or decrease) if actual demand is higher (or lower) than expected demand.

The second point above contrasts with the Commission's draft approach for the gas transmission business (GTB), which is subject to a revenue cap. The GTB's 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.

We explain in this report that a WAPC and a revenue cap affect consumers differently, ie:

- a WAPC allocates long term risks to consumers, such that consumers face lower price volatility in the short term (within a regulatory period) but higher price volatility in the long term (across regulatory periods); and
- a revenue cap allocates short-term risks to consumers, such that consumers face higher price volatility in the short term (within a regulatory period) but lower price volatility in the long term (across regulatory periods).

Vector has engaged us to review and comment on the Commission's draft decision. The focus of our review is the economic reasoning that underpins the Commission's draft decision to apply a weighted average price cap to GDBs.

Financial capital maintenance

The Commission identifies ex-ante real financial capital maintenance (FCM) as a useful principle for guiding its decision-making. Under FCM, the risks to regulated suppliers should be balanced between potential upside and downside over time. This is necessary to ensure that regulated suppliers expect to earn a normal rate of return on an ex-ante basis.

The Commission's building block framework promotes FCM in the long run by allowing regulated suppliers to recover their full risk-adjusted cost of capital on an asset after it has been depreciated fully. However, this can take several decades due to the long economic lives of regulated infrastructure assets.

The Commission recognises that the long-term outlook of declining gas use presents a risk that GDBs may not expect to recover the cost of their investments fully. To that end, the Commission has attempted to mitigate this risk by adjusting depreciation to reflect economic asset lives.

However, FCM will not be achievable once building block prices exceed customers' maximum willingness to pay, since GDBs will be economically constrained from setting prices at levels that provide an expectation of earning normal returns on an ex-ante basis and maintaining their financial capital in real terms over time.

Because FCM is an ex-ante condition, this can occur years before GDBs are unable to recover their annual building block revenue requirement from customers, when:

- building block prices are expected to exceed gas customers' maximum willingness to pay in future years; but
- building block prices are already close to gas customers' maximum willingness to pay, such that there is little scope to raise the current level of building block prices through accelerating depreciation or raising the rate of return on capital.

This inability to achieve FCM can materialise very quickly due to the potential for a 'death spiral' to occur, whereby falling demand leads to higher building block prices, which further reduces demand.

The Commission has implemented accelerated depreciation based on its modelling of two long-term scenarios that it considers to be 'central'. These scenarios assume pipeline services will cease fully by 2050 and 2060 respectively. However, we observe that 'expected' (or mean) returns will be lower than 'central' (or median) returns or 'most likely' (or modal) returns when the distribution of potential outcomes is negatively skewed, which is the case when asset stranding risks are present.

In such circumstances, regulated businesses risk earning subnormal returns on an ex-ante basis and potentially can incur substantial losses depending on the extent of asset stranding. They do not receive any potential upside for taking on risks since regulation constrains them from earning corresponding supernormal returns even if there were to be positive developments in the industry. This asymmetry in potential outcomes has the largest impact on expected or mean returns, which are probability weighted, while having comparatively less impact on median and modal returns.

Consequently, even if one accepts the Commission's assumptions that the 2050 wind-down and 2060 wind-down scenarios are central in terms of the distribution of stranding risks, the Commission's application of its building block model may not achieve FCM.

If FCM is no longer achievable, then lifting regulation will be consistent with the purpose of part four of the *Commerce Act 1986* (the Act). This is because the regulatory framework achieves the purpose of part four of the Act by addressing market power and incentives for cost efficiency under circumstances where demand is stable or growing. However, the framework may be ineffectual under alternative settings where market power is low enough that suppliers do not expect to recover their costs over the long run, such that the framework limits the scope for suppliers to manage the recovery of their costs over time in the most efficient and effective way.

Under such conditions, continuing with the current form of regulation will contradict the purpose of the Act since regulated suppliers will have no incentives to innovate and to invest when their ex-ante expectation involves earning subnormal risk-adjusted returns.

This is problematic because the Commission foresees ongoing appetite for gas from households, businesses and power generation for at least the next 20 years, which presents an ongoing critical need or reliable gas pipeline services. An early shutdown of GDB networks will thus be detrimental to consumers and gas customers, who will be unable to continue consuming distributed gas after the GDBs shut down.

The Commission can take steps to extend the timeframe over which FCM continues to be achievable, which incentivises GDBs to delay shutting down their networks. Such steps may include:

- adjusting various building block parameters, eg:
  - bringing forward depreciation;
  - adjusting inflation indexation; and/or
  - allowing a higher rate of return on capital that mitigates the asymmetric risks associated with asset stranding; and/or
  - allowing GPBs to choose their form of pricing regulation, ie, a weighted average price cap, a revenue cap or a hybrid of the two; and/or

- loosening or lifting economic regulation, for example, by removing price and revenue constraints while retaining quality constraints.

In our view, the Commission should be cautious about taking an overly conservative approach for DPP4, because of the potential for its actions to have asymmetric consequences. The Commission has considered the issue of asymmetric outcomes in the context of percentiles for the rate of return on capital, where it evaluates the costs and benefits of setting the weighted average cost of capital too high versus too low.

In the context of GDBs:

- taking conservative actions during early stages of a decline in gas demand means that the Commission may need to take more aggressive action if the decline turns out to be faster than expected, which will have outsized effects on the smaller customer base in future DPPs; but
- the impact of taking overly aggressive steps in DPP4 can be reversed easily in future DPPs.

Consistent with the Commission's reasoning on WACC percentiles, this asymmetry suggests that the Commission should be cautious about taking an overly conservative approach. Instead, the Commission should consider taking a more aggressive approach for DPP4.

In our opinion, allowing GDBs to choose their form of pricing regulation is an appropriate approach that will contribute towards extending the timeframe over which FCM continues to be achievable.

Mitigating errors in volume forecasts

FCM can be achieved readily if demand for a regulated service is sufficiently stable and predictable over a long time horizon. However, the current conditions for GDBs are such that:

- there is a high level of uncertainty surrounding the pace at which future demand for pipeline services may decline as New Zealand transitions to a low-emissions economy, which makes it difficult to generate volume forecasts that are accurate and/or that can be estimated with precision; and
- there is a finite timeframe before the industry winds down given its current trajectory, such that there will only be five to seven pricing periods remaining (including DPP4) if the industry winds down by 2050 or 2060.

This finite time horizon before the industry winds down increases recovery risks for GDBs on an ex-post basis, since large forecasting errors in any single regulatory period can have material impacts on the net present value of total future cash flows.

Investors will require additional compensation to take on these additional risks. However, this additional risk can be ameliorated by shortening the length of the regulatory period, consistent with the Commission's reason in DPP3.

Allowing GDBs to choose their form of pricing regulation will reduce some of these tail risks and enable investors to expect returns that are closer to normal returns on an ex-ante basis. In this respect, a revenue cap has similar impact to a shortening of the regulatory reset period, since both reduce a regulated business's exposure to volume forecast errors. Shifting from a price cap to a revenue cap for GDBs will reduce the cost recovery risks associated with the finite time horizon before industry wind-down. This in turn will allow GDBs to finance their operations efficiently.

In addition, shifting GDBs towards revenue cap regulation can benefit consumers in two important ways, namely by:

- reducing inter-period pricing volatility for consumers, which is likely to be more impactful for the long-term interests of consumers, since long-term price stability provides more accurate and predictable market signals that put consumers in the best position to evaluate longer term decisions regarding whether to incur substantial expenses on gas appliances and/or whether to invest in electrifying their homes; and

- signalling to investors that the Commission is committed to achieving FCM, which promotes regulatory certainty for GDBs and other businesses regulated under the part four regime, thereby:
  - incentivising regulated businesses to continue making efficient investments in their infrastructure; and
  - allowing regulated businesses to raise capital efficiently.

Precedent on the form of control

In the 2016 and 2023 input methodologies the Commission detailed several reasons for retaining a WAPC for GDBs, including that:

- a WAPC incentivises GDBs to pursue new gas connections and grow throughput;
- a WAPC better reduces the risk of inefficient expenditure and provides a stronger incentive to tailor expenditure to changes in demand, which can include managing demand risk to some extent through adjusting spending on operating and capital expenditure; and
- GDBs are best placed to manage within-period demand risks since they can promote gas and influence demand.

However, these considerations may no longer weigh in favour of maintaining a WAPC.

First, there is increasing evidence that incentivising gas connections is no longer beneficial for consumers in the long term, given:

- the Climate Change Commission's view that consumers should be protected from the costs of locking in new fossil gas infrastructure; and
- the Commission's decision to decline system growth capital expenditure for all GPBs in DPP4.

Second, when gas demand is declining, GDBs subject to a revenue cap have some incentive to incur efficient expenditure to retain customers, since doing so would maximise the GDB's ability to recover its costs and thus minimise the extent of asset stranding. Generally, GDBs have an incentive to incur expenditure up to the point where the avoidable cost of retaining an additional customer is equal to the marginal future revenue that can be charged until the customer disconnects, with the comparison being carried out in present value terms.

When demand is declining and regulated businesses face the risk of asset stranding, GDBs have no incentive to reduce costs at the expense of service quality, since this will reduce the value of future revenues that can be recovered from a customer until said customer eventually disconnects. This in turn will reduce the present value of the business's future cash flows.

It follows that GDBs will continue to face incentives to incur efficient expenditure to retain customers and provide services at a quality they demand, even after switching to a revenue cap.

Third, it is unclear that GDBs are best placed to manage within-period demand risks, since demand for gas distribution services will be driven primarily by government policy and the pace of New Zealand's transition to a low-emissions economy, instead of the actions taken by GDBs.

In addition, we consider that consumers in aggregate are well placed to bear the within-period price volatility arising from errors in demand forecasts because:

- the risks associated with high-impact-low-probability events that result in large forecast errors are best spread across the diverse base of customers instead of being borne fully by an individual business; and
- the customers that continue to remain connected to the gas network are likely to be relatively price inelastic compared to those customers that have disconnected, and are less likely to reduce their

demand for gas distribution services in response to price increases, particularly given the minority contribution of transmission and distribution pipeline charges to residential gas bills.

We note that the Australian Energy Regulator's (AER's) recent decisions acknowledge the complexity of balancing risks between consumers and service providers given high uncertainty around demand forecasts, and are more consistent with the reasoning that we have set out earlier in this report.

This can be seen in one final decision and two draft decisions where the AER has approved a hybrid mechanism that combines a WAPC with 50 per cent risk sharing for volumes that deviate above or below forecasts by more than five per cent.

Notably, the AER has rejected alternative tariff variation mechanisms as part of these decisions, including:

- a proposed revenue cap mechanism;
- a proposed WAPC mechanism; and
- an alternative proposal to adopt a hybrid mechanism with wider thresholds of 10 per cent.

1. Introduction

The New Zealand Commerce Commission (the Commission) published on 27 November 2025 its draft decision on default price-quality paths for gas distribution businesses (GDBs) over the five-year regulatory period starting 1 October 2026 (DPP4).

As part of this draft decision, the Commission intends to continue subjecting GDBs to a weighted average price cap (WAPC), whereby:[1]

- the Commission will set maximum revenues and quality standards for each GDB for the regulatory period; and
- limits on allowed revenue during the period effectively increase (or decrease) if actual demand is higher (or lower) than expected demand.

The second point above contrasts with the Commission's draft approach for the gas transmission business (GTB), which is subject to a revenue cap. The GTB's 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.[2]

We explain in this report that a WAPC and a revenue cap affect consumers differently, ie:

- a WAPC allocates long term risks to consumers, such that consumers face lower price volatility in the short term (within a regulatory period) but higher price volatility in the long term (across regulatory periods); and
- a revenue cap allocates short-term risks to consumers, such that consumers face higher price volatility in the short term (within a regulatory period) but lower price volatility in the long term (across regulatory periods).

Vector has engaged us to review and comment on the Commission's draft decision. The focus of our review is the economic reasoning that underpins the Commission's draft decision to apply a WAPC to GDBs.

In the remainder of this report we discuss:

- the eventual outcomes where financial capital maintenance (FCM) cannot be maintained for gas pipelines businesses in section 2;
- transitioning towards an environment where FCM cannot be maintained in section 3; and
- precedent on the choice of revenue cap against a WAPC in section 4.

[1] 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 3.14.

[2] 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 3.14.

2. Achieving financial capital maintenance

In sections 2.1 to 2.3 below we explain that:

- risks to regulated suppliers should be balanced between potential upside and downside over time in order to achieve FCM;
- FCM may not be achievable for GDBs in the long run due to asset stranding and asymmetry of potential outcomes; and
- if FCM is no longer achievable, then loosening regulation will be consistent with the purpose of part four of the *Commerce Act 1986* (the Act).

2.1 FCM requires balancing upside and downside risks

The Commission's framework paper for its 2023 input methodologies defines principles that provide useful guidance for making decisions.[3] One of these principles is ex-ante real FCM, which the Commission explains is:[4]

> …that regulated suppliers should have the ex-ante expectation of earning their risk-adjusted cost of capital (ie, a 'normal return'), and of maintaining their financial capital in real terms over timeframes longer than a single regulatory period.

The Commission notes that the aim of price quality regulation is not to guarantee normal ex-post returns for regulated monopoly infrastructure, but rather that a typically efficient firm would expect to earn at least a normal rate of return over time on an ex-ante basis.[5]

Central to FCM is the principle that the risks to regulated suppliers should be balanced between potential upside and downside over time. This is necessary to ensure that regulated suppliers expect to earn a normal rate of return on an ex-ante basis.

For example, if the Commission subjects regulated suppliers to downside risks without allowing them to benefit from upside risks that are commensurate in expectation, then regulated suppliers will expect to earn less than their risk-adjusted cost of capital and FCM will not be achieved.

Further, consistent with the purpose of part four of the Act, an effective regulatory regime should reward regulated suppliers for superior performance, eg, by allowing them to retain some of the benefits associated with outperforming efficiency benchmarks while passing on the remaining benefits to consumers.[6]

2.2 FCM may not be achievable for GDBs in the long run due to stranding

The Commission promotes FCM by applying a building block framework, in which regulated suppliers:

- maintain a regulatory asset base (RAB) thatreflects the unrecovered value of their efficient capital expenditure;
- receive a return of capital by depreciating the assets in their RAB once and only once; and
- receive a normal return on the value of their undepreciated assets as measured by their RAB, whereby the rate of return is equal to their opportunity cost of capital.

[3] Commerce Commission, *Part 4 Input Methodologies Review 2023 | Framework paper*, 13 October 2022, pp 46-47.

[4] Commerce Commission, *Part 4 Input Methodologies Review 2023 | Framework paper*, 13 October 2022, p 47.

[5] Commerce Commission, *Part 4 Input Methodologies Review 2023 | Framework paper*, 13 October 2022, p 47.

[6] *Commerce Act 1986*, section 52A(1).

In sections 2.2.1 to 2.2.2 below, we explain:

- the potential for a 'death spiral' to occur, in which case FCM will no longer be achievable under building block regulation; and
- that FCM will not be achievable under the Commission's modelling of 'central' scenarios, since the distribution of potential outcomes is asymmetric.

2.2.1 Potential for a death spiral to occur

The building block framework promotes FCM in the long run only, since regulated suppliers expect to recover their full risk-adjusted cost of capital on an asset after it has been depreciated fully.

This tends to occur over many regulatory periods because the Commission generally matches depreciation profiles to the economic lives of the regulated assets, which can span several decades in the case of infrastructure assets.

In addition, the Commission has historically applied various methodological choices with the effect of backloading cost recovery, including:

- indexing the RAB, such that compensation for inflation is rolled into the RAB annually and recovered over time as the RAB depreciates instead of being recovered fully in the year that inflation occurs; and
- consolidating all regulated assets into a single RAB value and using their combined weighted average remaining life to calculate depreciation, which backloads cost recovery compared to alternative approaches that feature a more granular set of asset classes with separate asset lives and depreciation profiles.[7]

These methodological choices do not change the net present value of maximum allowable revenues calculated using the Commission's model. However, backloading cost recovery in this way has the effect of reducing maximum allowable revenues in earlier years while raising it in later years.[8]

Under conditions where gas demand is growing, this backloading of revenues will smooth prices for gas consumers, since it:

- reduces revenues in earlier years when the customer base is smaller; and
- raises revenues in later years when demand is higher and revenues can be spread over a larger customer base.

Conversely, the opposite occurs when gas demand is declining, in which case backloading revenues will tend to increase price volatility for gas consumers by requiring higher revenues to be spread over a smaller customer base.

The Commission recognises that the long-term outlook of declining gas use presents a risk that GDBs may not expect to recover the cost of their investments fully. To that end, the Commission has attempted to mitigate this risk by adjusting depreciation to reflect economic asset lives.[9]

[7] The Commission's model contrasts with that of the Australian Energy Regulator's post-tax revenue model, which accommodates up to 50 asset classes that depreciate individually. The model only gives service providers the option of adopting more granular year-by-year tracking methods that further reduce the backloading of depreciation. See: Australian Energy Regulator, *Gas distribution service providers post-tax revenue model handbook*, Final decision, April 2021, pp 14, 19.

[8] The Office of the Tasmanian Economic Regulator observes that applying a value based weighted average approach produces longer average asset lives, which backloads regulatory depreciation. See: Office of the Tasmanian Economic Regulator, *2018 water and sewerage price determination investigation*, Final report, May 2018, p 154.

[9] 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 X8.

However, bringing forward depreciation in this way only changes the profiles of the maximum allowable revenues and thereby the prices that GDBs are legally allowed to set, ie, the price caps. These are distinct from the prices that profit-maximising GDBs can actually recover from consumers, whereby:

- maximum allowable revenues and price caps are subject to constraints arising from the applicable legal and regulatory frameworks; and
- maximum revenues and prices that GDBs can actually recover from consumers are subject to economic constraints based on a range of factors such as:
  - gas customers' maximum willingness to pay to consume gas, which in turn is affected by consumer preferences and government policies on energy usage; and
  - the costs of other services along the gas supply chain, which in turn affect gas customers' maximum willingness to pay for gas distribution services.

When the expected maximum allowable revenues and price caps derived from the Commission's building block model exceed gas customers' maximum willingness to pay, then FCM is no longer achievable. Because FCM is an ex-ante condition, this can occur years before GDBs are unable to recover their annual building block revenue requirement from customers, when:

- building block prices are expected to exceed gas customers' maximum willingness to pay in future years; but
- building block prices are already close to gas customers' maximum willingness to pay, such that there is little scope to raise the current level of building block prices through accelerating depreciation or raising the rate of return on capital.

In such circumstances, GDBs will be economically constrained from setting prices at levels that provide an expectation of earning normal returns on an ex-ante basis and maintaining their financial capital in real terms over time. Instead, the expectation in such a scenario is that some of their assets will be stranded.

Further, this inability to achieve FCM can materialise very quickly due to the potential for a 'death spiral' to occur, whereby:

- falling gas demand requires maximum allowable revenues to be spread across a smaller customer base, which leads to higher price caps;
- increasing prices further reduce gas demand by inducing some customers to reduce their gas usage or to disconnect from the gas distribution network entirely if the total cost of consuming gas exceeds their willingness to pay; and
- the reduced gas demand subsequently leads to even higher price caps.

2.2.2 Central scenarios will not achieve FCM when the distribution of outcomes is asymmetric

The Commission implements accelerated depreciation based on its modelling of two long-term scenarios that it considers to be central:[10]

> To inform our assessment we developed a simplified long-term building blocks cost and recoveries model which drew on available GPB-specific data combined with some basic assumptions and projections (eg, future opex and capex).
>
> Within this model we presented two long-term scenarios, which assumed a full cessation of pipeline services by 2050 and 2060 respectively. **We considered these were likely to be central in terms of the distribution of stranding risks.[133]**
>
>> [133] That is, we considered both a 2040 wind-down and a 2070 wind-down were plausible scenarios, but that these fall on either end of a spectrum of possibilities. We also considered

[10] Commerce Commission, *Gas DPP4 reset 2026*, Issues paper – Attachments A - E, 26 June 2025, para C12.

> that being guided by two primary scenarios (rather than a single scenario) involves drawing on a wider range of assumptions reflecting the existing uncertainty, consistent with making an overall decision. (emphasis added)

'Expected' (or mean) returns will differ from 'central' (or median) returns and 'most likely' (or modal) returns when the distribution of potential outcomes is asymmetric. This distinction can be seen in figure 2.1 below, which shows that the mean of a negatively skewed distribution is lower than the median and the mode.

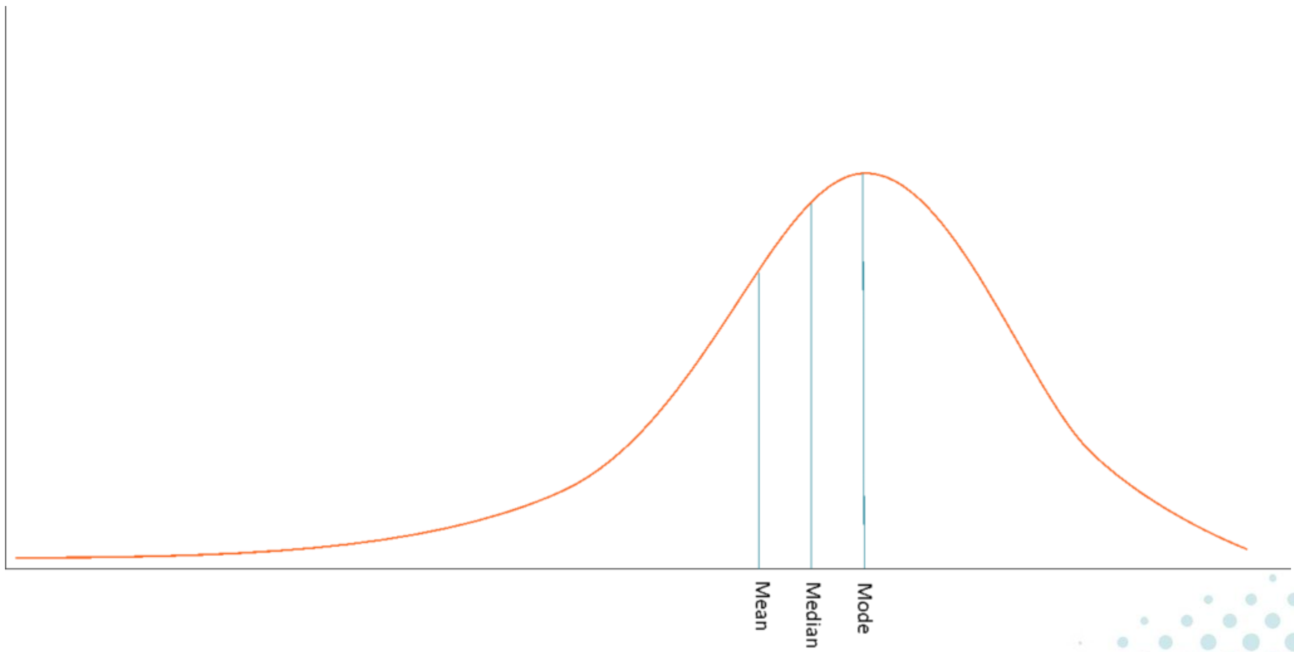
When asset stranding risks are present, the building block regulatory framework results in a range of returns that is negatively skewed, since regulated businesses are prevented from earning more than normal returns but are subject to negative tail risks from potential asset stranding.

In such circumstances, regulated businesses risk earning subnormal returns and potentially can incur substantial losses depending on the extent of asset stranding. However, they do not receive any potential upside for taking on such risks since regulation constrains them from earning corresponding supernormal returns even if positive developments were to arise within the industry. For example, regulation constrains GDBs from earning supernormal profit even if there were to be sufficient demand for renewable gases to be transported through their existing gas pipeline networks.

This asymmetry in potential outcomes has the largest impact on expected or mean returns, which are probability weighted, while having comparatively less impact on median and modal returns.

Consequently, even if one accepts the Commission's assumptions that the 2050 wind-down and 2060 wind-down scenarios are central in terms of the distribution of stranding risks, the Commission's application of its building block model may not achieve FCM. GDBs will form an expectation of subnormal returns on an ex-ante basis, whereby the negatively-skewed distribution of potential returns leads to expected returns that are lower than the returns calculated based on the Commission's central scenarios.

Figure 2.1: Mean and mode in a negatively skewed distribution



Source: Corporate Finance Institution, https://corporatefinanceinstitute.com/resources/data-science/negatively-skewed-distribution/, accessed 5 January 2026.

2.3 Regulation should be loosened before FCM becomes unachievable

In section 2.2 above we explain that regulated suppliers will have an expectation of earning subnormal returns on an ex-ante basis over the long run once FCM is unachievable.

The Commission's regulatory framework achieves the purpose of part four of the Act by addressing market power and incentives for cost efficiency under circumstances where demand is stable or growing. However, the framework may be ineffectual under alternative settings where market power is low enough that suppliers do not expect to recover their costs over the long run, because it limits the scope for suppliers to manage the recovery of their costs over time in the most efficient and effective way.

Under such conditions, continuing with the current form of regulation will contradict the purpose of the Act since regulated suppliers will face no incentives to innovate and to invest when their ex-ante expectation involves earning subnormal risk-adjusted returns.[11]

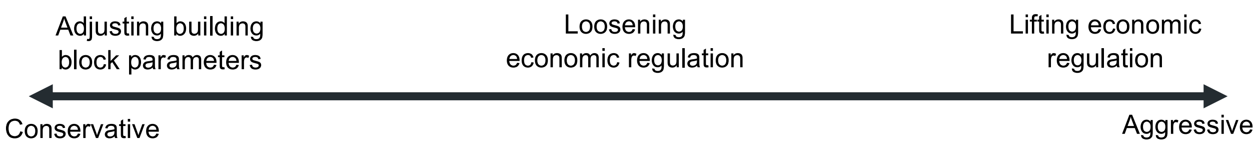
This is problematic because the Commission foresees ongoing appetite for gas from households, businesses and power generation for at least the next 20 years, which presents an ongoing critical need or reliable gas pipeline services.[12] An early shutdown of GDB networks will thus be detrimental to consumers and gas customers, who will be unable to continue consuming distributed gas after the GDBs shut down.

The Commission can take steps to extend the timeframe over which FCM continues to be achievable, which incentivises GDBs to delay shutting down their networks. Such steps may include:

- adjusting various building block parameters, eg:
  - bringing forward depreciation;
  - adjusting inflation indexation; and/or
  - allowing a higher rate of return on capital that mitigates the asymmetric risks associated with asset stranding; and/or
  - allowing GPBs to choose their form of pricing regulation, ie, a weighted average price cap, a revenue cap or a hybrid of the two; and/or
- loosening or lifting economic regulation, for example, by removing price and revenue constraints while retaining quality constraints.

These steps reflect a spectrum of interventions between conservative and aggressive actions, as depicted in figure 2.2 below.

Figure 2.2: Illustration of interventions



The magnitude of the steps that the Commission will need to take varies with the timing on which it implements these changes. The earlier the Commission begins taking steps to maintain FCM while it remains achievable, the less aggressive its actions will need to be. Conversely, if the Commission delays taking action, then it risks making FCM unachievable.

[11] See: *Commerce Act 1986*, section 52A(1).

[12] 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 X6.

We observe that the Commission has modelled the same scenarios from the DPP3 reset when setting asset lives for GPBs.[13]

The Commission made this decision after considering:[14]

- the emergence of tighter-than-expected gas supply due to recent declines in domestic gas production and lower estimated future gas reserves;
- continued uncertainty over government policy response to climate change and future use of natural gas; and
- increasing prospects for renewable 'green' gases to meet some future demand and potentially help extend the economic life of networks.

In our view, the Commission should be cautious about taking an overly conservative approach for DPP4 because of the potential for its actions to have asymmetric consequences for GDBs and for consumers. The Commission has considered similar issues in the context of percentiles for the rate of return on capital. We describe this in box 2.1 below.

Box 2.1: Rate of return on capital percentiles derived from the impact of asymmetric outcomes

The Commission recognises that the weighted average cost of capital (WACC) it calculates is an estimate of the true cost of capital for regulated businesses, and that it cannot observe whether it has set the WACC too high or too low.

There may be an asymmetry between the costs and benefits of setting the WACC too high versus too low, whereby:

- setting the WACC below the true cost of capital will limit regulated businesses' ability to earn excessive profits, but may lead to underinvestment that results in outages if allowed to accumulate over time; and
- setting the WACC above the true cost of capital may lead to overinvestment or may allow regulated businesses to earn supernormal returns at the expense of consumers.

This asymmetry arises because a WACC that is too high leads to higher bills for consumers but a WACC that is too low can be even more costly if it leads to outages.

The Commission thus refers to a WACC uplift as a potential tool for mitigating the risk of underinvestment. The 2023 input methodologies applies:

- the 65th WACC percentile for electricity distribution businesses and Transpower; and
- the 50th WACC percentile for gas pipeline businesses.

Source: Commerce Commission, Part 4 input methodologies review 2023 – Final decision, Cost of capital topic paper, 13 December 2023, paras 6.4-6.11 and table X1.

In the context of GDBs, taking conservative actions during early stages of a decline in gas demand means that the Commission will need to take more aggressive actions in future if the decline turns out to be faster

[13] 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.

[14] 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 3.58.

than expected, ie, the demand for gas is over-estimated, by which point there may be irreversible consequences on FCM.

Aggressive future actions can be expected to have substantial effects on GDBs and on the smaller customer base in future DPPs, ie:

- GDBs will face greater asset stranding risks and will have even less ability and incentive to continue investing in their networks, as compared to the current circumstances; and
- the smaller base of future customers:
  - will have to pay materially higher prices since there will no longer be any opportunity to recover GDBs' costs from customers that have sine disconnected from the network; and
  - may have made irreversible investments on gas appliances that they otherwise would not have made if the Commission had instead taken a more aggressive approach for DPP4 in anticipation of a faster decline in gas demand.

Conversely, if the Commission takes actions in DPP4 that turn out to be overly aggressive and the decline in gas demand is slower than expected, ie, the demand for gas is under-estimated, then such steps can be reversed easily in future DPPs. For example, the Commission can decelerate depreciation in future DPPs if gas demand is materially more robust than expected at the start of DPP4.

This results in an asymmetry between the costs and benefits of being too aggressive versus too conservative when taking action during the current early stages of a decline in gas demand, where:

- taking actions that are too conservative may give rise to outsized and irreversible effects on GDBs and customers; and
- taking actions that are too aggressive is likely to be reversed easily in future DPPs.

Consistent with the Commission's reasoning on WACC percentiles as set out in box 2.1 above, this asymmetry suggests that the Commission should be cautious about taking an overly conservative approach. Instead, the Commission should consider a more aggressive approach for DPP4.

In our opinion, allowing GDBs to choose their form of pricing regulation is an appropriate approach that will contribute towards extending the timeframe over which FCM continues to be achievable. We discuss this further in section 3 below.

3. Mitigating errors in volume forecasts

In sections 3.1 to 3.3 below, we explain that in an environment where FCM cannot be achieved, a revenue cap could mitigate the impact of potential errors in volume forecasts. We explain that:

- the finite time horizons before the industry winds down increases ex-post recovery risks for GDBs, since large forecasting errors in any single regulatory period can have material impacts on the net present value of total future cash flows;
- the problems associated with finite time horizons can be addressed with revenue caps, which has similar impact to a shortening of the regulatory reset period; and
- shifting GDBs to a revenue cap can benefit consumers by reducing inter-period pricing volatility and by promoting regulatory certainty for GDBs and other regulated businesses, in turn incentivising them to continue making efficient investments and allowing them to raise capital efficiently.

3.1 Finite time horizons increase risk of volume forecast errors

The Commission's long-term stranding model assumes industry wind-down by 2050 and 2060.[15] If these assumptions are correct, there is only a limited number of pricing periods before the industry winds down. This increases the 'tail risk' of total ex-post cash flows across future pricing periods differing materially from expected total cash flows.

Investors will require additional compensation to take on these additional risks, otherwise the Commission's building block model will no longer generate maximum allowable revenues that incorporate normal returns for investors.

Allowing GDBs to choose their form of pricing regulation will reduce some of these tail risks and enable investors to expect returns that are closer to normal returns on an ex-ante basis.

As we explain in section 2 above, the Commission considers that:[16]

- FCM involves regulated suppliers having an expectation of earning normal returns on an ex-ante basis and maintaining their financial capital in real terms over timeframes longer than a single regulatory period; and
- price quality regulation does not aim to guarantee normal ex-post returns for regulated monopoly infrastructure, but a typically efficient firm would expect to earn at least a normal rate of return over time on an ex-ante basis.

These objectives can be achieved readily if demand for a regulated service is sufficiently stable and predictable over a long time horizon.

Under such conditions, the Commission can work with regulated businesses to develop demand forecasts that are reasonably accurate. At the start of each regulatory period, regulated businesses will have an expectation that FCM will be achieved:

- for that regulatory period, assuming that demand forecasts are unbiased; and
- across subsequent regulatory periods, assuming that any observed differences between outturn and forecast demand in a single regulatory period:

[15] 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 D14-D15.

[16] Commerce Commission, *Part 4 Input Methodologies Review 2023 | Framework paper*, 13 October 2022, p 47.

> - is relatively small, such that the resulting revenue shortfalls or surpluses incurred over an individual regulatory period will not have a material impact on the net present value of cash flows across all regulatory periods;
> - will cancel out over multiple regulatory periods; and/or
> - subsequently can be used as new information to improve and calibrate forecasts in subsequent regulatory periods, resulting in more accurate forecasts in future regulatory periods.

However, these conditions currently do not apply to GDBs.

First, instead of gas demand being stable and predictable, the Commission's draft decision states that there is a high level of uncertainty surrounding the pace at which future demand for pipeline services may decline as New Zealand transitions to a low-emissions economy.[17]

This makes it difficult to generate volume forecasts that are accurate and/or that can be estimated with precision, such that it is unclear whether the Commission's volume forecasts provide GDBs with expectation that FCM will be achieved over DPP4 on an ex-ante basis.

Second, instead of a long time horizon for gas demand, there is a finite timeframe before the industry winds down given its current trajectory. Consistent with this, the Commission's long-term stranding model assumes industry wind-down by 2050 and 2060,[18] in which case if five-year pricing periods continue to be used, then:

- a 2050 industry wind-down means there are only five pricing periods remaining, including DPP4; and
- a 2060 industry wind-down means there are only seven pricing periods remaining, including DPP4.

This finite time horizon before the industry winds down increases recovery risks for GDBs on an ex-post basis. For example, if a large forecasting error were to occur for DPP4, such that outturn demand is materially lower than forecast, then this can have a material impact on the net present value of total cash flows received over DPP4 and the remaining pricing periods until industry wind-down.

That is, the limited number of remaining pricing periods increases the 'tail risk' of total ex-post cash flows from DPP4 onwards differing materially from expected total cash flows. This heightened tail risk corresponds to the negatively-skewed asymmetric distribution of returns discussed in section 2.2.2 above, where asset stranding risk creates downside exposure and leads to expected returns that are lower than those calculated based on the Commission's central scenarios.

These tail risks can be reduced by allowing GDBs to choose their form of pricing regulation.

3.2 Problems with finite time horizons can be addressed with revenue caps or shorter regulatory resets

One method to ameliorate the problems associated with the finite time horizon before industry wind-down is to shorten the length of the regulatory period, such that:

- potential volume forecast errors in each regulatory period are likely to be smaller in magnitude, eg, the potential forecast error observed in a single year is likely to be smaller than the potential total forecast error observed over a five-year period; and
- the Commission can respond more rapidly to new information on changes in industry demand conditions, which it can use to improve and calibrate its subsequent volume forecasts.

[17] 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 D4.

[18] 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 D14-D15.

This potential solution is consistent with the Commission's decision to set a regulatory period of four years for DPP3, for which the Commission states that:[19]

> The shorter regulatory period will allow us to consider the effects of Government policy decisions and relevant market changes sooner in the next DPP.

The Commission also states for DPP3 that GPBs may be dissuaded from investing in their networks if there is a greater risk that their investments will not be recovered, and that this uncertainty may be mitigated through a shorter regulatory period:[20]

> In our view, a shorter regulatory period better promotes the Part 4 purpose. As noted above, there is a lack of a clear picture of the direction of the industry in the coming years, creating a substantial amount of uncertainty.
>
> This uncertainty may dissuade GPBs from investing in maintaining a safe and reliable network, if they believe there is greater risk that they will not be able to recover their investment.
>
> By shortening the length of the regulatory period, and mitigating the effect of this uncertainty, we may provide GPBs with incentives to invest efficiently (consistent with section 52(A)1(a) of the Act).

This is consistent with our observations in section 3.1 above, where we explain that investors require additional compensation to take on these risks.

In this respect, a revenue cap has similar impact to a shortening of the regulatory reset period, since both reduce a regulated business's exposure to volume forecast errors.

In this way, shifting from a price cap to a revenue cap for GDBs can reduce the cost recovery risks associated with the finite time horizon before industry wind-down. This in turn will allow GDBs to finance their operations efficiently.

3.3 Impact on consumers

In the 2023 input methodologies, the Commission characterised the difference between a price cap and a revenue cap in terms of risk sharing between a regulated business and its customers. According to the Commission, a revenue cap exposes consumers to demand uncertainty risks:[21]

> Unlike in 2016, our main concern for GDBs is now demand uncertainty risk. This differs from the main concern we had with quantity forecasting risk for EDBs that prompted us to change EDBs form of control in the 2016 IM Review. **In the current context, moving to revenue cap for GDBs would expose consumers to more demand uncertainty risk and not eliminate the need for demand forecasts at price resets.** Short- and long-term demand forecasts would still be needed to set expenditure allowances. (emphasis added)

However, shifting GDBs towards revenue cap regulation can benefit consumers in two important ways.

First, revenue cap regulation reduces inter-period pricing volatility for consumers, ie, pricing volatility across regulatory periods. This occurs because prices calculated under revenue cap regulation respond more quickly to changes in demand, while weighted average price caps only update demand inputs at the start of each pricing period.

[19] Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2022*, Final reasons paper, 31 May 2022, p 59.

[20] Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2022*, Draft reasons paper, 10 February 2022, paras C67-C69.

[21] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper*, Part 4 Input Methodologies Review 2023 – Final decision, 13 December 2023, para 3.498.

Reducing inter-period pricing volatility is likely to be more impactful for the long-term interests of consumers, since long-term price stability provides more accurate and predictable market signals that put consumers in the best position to evaluate longer term decisions regarding whether to incur substantial expenses on gas appliances and/or whether to invest in electrifying their homes.

This contrasts with a WAPC that reduces within-period volatility while increasing inter-period volatility, which may send consumers incorrect signals regarding the long-term cost of such decisions.

The Commission states in its 2023 input methodologies that inter-period price movements can be greater under a revenue cap, which can occur if a decline in the WACC offsets the impact of a decline in demand:[22]

> In practice we can only provide a degree of price certainty for one regulatory period at a time. Starting price adjustments at future resets depend on a number of inputs, many of which are only known closer to the time of a reset. It is possible that inter-period price movements could be greater under a revenue cap (eg, a decline in WACC offsets the starting price impact of a decline in demand).

However, the Commission's example relies on the assumption that the future decline in gas demand coincides with a fall in the WACC, which effectively corresponds to a forecast that the WACC will decline up to 2050 or 2060 under the Commission's central scenarios for industry wind-down.

While we do not express an opinion on the direction of the WACC in future years, we note that inter-period price movements will be greater under a price cap if the WACC were to remain stable or increase over future pricing periods instead.

As such, unless it can be established that the WACC is expected to decline in future years until industry wind-down, revenue cap regulation is likely to reduce inter-period volatility for consumers.

Second, shifting GDBs towards revenue cap regulation signals to investors that the Commission is committed to achieving FCM. This is because, as we explain in section 3.1 above, the limited number of remaining pricing periods before industry wind-down increases the tail risk of total ex-post cash flows for DPP4 onwards differing materially from ex-ante expected total cash flows. Shifting GDBs towards revenue cap regulation is thus consistent with FCM since it reduces these tail risks and enables investors to expect ex-ante normal returns.

In its framework paper for the 2023 input methodologies, the Commission states its view that key economic principles including FCM do not amount to a 'regulatory compact':[23]

> We do not consider the key economic principles amount to a 'regulatory compact' between us and regulated suppliers that might bind us to accepting the outcome of applying the principles to a proposed decision. However, to the extent the key economic principles continue to assist us to give effect to the section 52A purpose and outcomes we would not depart from them lightly. The Part 4 regime was intended to provide greater certainty over time, and we accept that wholesale rejection of principles we have consistently applied may affect this certainty.

We agree with the Commission about the need for caution against departing from the principle of FCM. Reducing regulatory certainty in this manner increases the perception of regulatory risks, not just for GDBs but also for other businesses regulated under the part four regime.

Such increased perceptions of regulatory risk would be likely to undermine the incentives for regulated businesses to continue making efficient investments in their infrastructure, while also reducing their ability to

[22] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper*, Part 4 Input Methodologies Review 2023 – Final decision, 13 December 2023, para 3.511.

[23] The Commission lists three key economic principles that it considers relevant to its decision-making under the part 4 regime, namely: ex-ante FCM; allocation of risk; and asymmetric consequences of over- or under-investment. See: Commerce Commission, *Part 4 Input Methodologies Review 2023,* Framework paper, 13 October 2022, paras 4.2, 4.27.

raise capital efficiently. In turn, this will harm consumers over the long term and will not promote the section 52A purpose statement.

4. Precedent on the form of control

In sections 4.1 to 4.2 below, we explain that:

- the Commission's previous reasons for maintaining a WAPC for GDBs are now less applicable in light of changed operating conditions; and
- recent precedent from the Australian Energy Regulator (AER) provides reasoning that supports shifting away from a WAPC, with the AER's preference to adopt a hybrid mechanism with 50 per cent risk sharing for volumes that deviate from forecasts by more than five per cent.

4.1 The Commission's previous reasons for maintaining a WAPC are now less applicable

In the 2016 and 2023 input methodologies the Commission detailed several reasons for retaining a WAPC for GDBs, including that:

- a WAPC incentivises GDBs to pursue new gas connections and grow throughput;[24]
- a WAPC better reduces the risk of inefficient expenditure and provides a stronger incentive to tailor expenditure to changes in demand, which can include managing demand risk to some extent through adjusting spending on operating and capital expenditure;[25] and
- GDBs are best placed to manage within-period demand risks since they can promote gas and influence demand.[26]

We explain in sections 4.1.1 to 4.1.3 below that these reasons are now less applicable to the current and future operating conditions of GDBs.

4.1.1 Incentivising gas connections is no longer beneficial for consumers in the long term

In its 2016 input methodologies, the Commission stated that the main reason for maintaining a WAPC is the incentive it provides for GDBs to pursue new gas connections and grow throughput.[27]

The Commission considered that incentivising new connections was in the long-term interest of consumers since:[28]

- it would provide them the option of using gas, particularly if it was a more cost-effective option for them compared to using only electricity as their energy supply; and
- growing the gas distribution customer base would spread the costs over a larger number of customers.

[24] Commerce Commission, *Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower*, 20 December 2016, paras 221-224.

[25] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision*, 13 December 2023, paras 3.456-3.462, 3.466.2-3.466.3. Commerce Commission, *Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower*, 20 December 2016, paras 225-230.

[26] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision*, 13 December 2023, paras 3.466.1, 3.466.4. Commerce Commission, *Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower*, 20 December 2016, paras 229-230.

[27] Commerce Commission, *Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower*, 20 December 2016, para 221.

[28] Commerce Commission, *Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower*, 20 December 2016, para 222.

However, these considerations may no longer weigh in favour of maintaining a WAPC. Instead, there is increasing evidence that incentivising gas connections is no longer beneficial for consumers in the long term.

First, the New Zealand government has considered eliminating fossil gas use in residential, commercial and public buildings since 2021, whereby:

- the Climate Change Commission recommended that the government set a date to end the expansion of pipeline connections in order to safeguard consumers from the costs of locking in new fossil gas infrastructure;[29] and
- the New Zealand government agreed with the need to communicate clearly the direction of travel for fossil gas but considered that further work was required to avoid unintended consequences and mitigate potential distributional impacts.[30]

The Climate Change Commission's subsequent July 2025 recommendations do not specify a ban on new gas connections. Nevertheless, the Climate Change Commission observes that:[31]

- industry stakeholders have a growing appetite to switch from fossil gas, which is driven partially by concerns over gas prices and availability; and
- there is an opportunity for further reductions in the third emissions budget period, ie, 2031 to 2035, from the phase out of fossil fuels in buildings.

In response, the New Zealand government states that:[32]

- it agrees that reducing emissions from buildings is a priority; and
- its focus is on creating the right conditions for change by streamlining consenting processes and improving access to data and information.

The Climate Change Commission's recommendations and observations as set out above indicates that incentivising new connections may no longer be in the long-term interest of consumers. Instead, the Climate Change Commission considers that consumers should be protected from the costs of locking in new fossil gas infrastructure.

Second, the Commission has decided to decline system growth capital expenditure for all GPBs in DPP4 because:[33]

- it is not satisfied that the evidence demonstrates a need to provide for system growth from any GPB;
- all GPBs are forecasting the number of connections and gas volumes conveyed to decline over DPP4; and
- for localised areas of growth, GPBs can seek capital contributions from the relevant parties or apply for a capacity event reopener.

This draft decision suggests that the Commission no longer considers incentivising new connections to be in the long-term interest of consumers.

[29] Climate Change Commission, *Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025*, 31 May 2021, p 287.

[30] New Zealand Government, *Aotearoa New Zealand's first emissions reduction plan: The Government's response to He Pou a Rangi – Climate Change Commission's recommendations*, May 2022, p 40.

[31] Climate Change Commission, *Assessing progress towards meeting Aotearoa New Zealand's emissions budgets and the 2050 target*, Monitoring report: Emissions reduction, July 2025, p 91.

[32] New Zealand Government, *Government Response to the Climate Change Commission Report*, Monitoring report: Emissions reduction 2025, October 2025, p 15.

[33] 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 3.28.

It follows that the Commission's main reason for maintaining a WAPC for GDBs in its 2016 input methodologies, ie, incentivising new gas connections and growing throughput, is no longer applicable.

4.1.2 A revenue cap incentivises efficient expenditure when demand is falling

In its 2023 input methodologies, the Commission states its draft reasoning that, compared to a revenue cap, a WAPC provides suppliers with a stronger incentive to tailor expenditure to changes in demand:[34]

> Under a revenue cap, once the price-quality path is set, suppliers have lower financial incentives to spend to retain customers or provide services at a quality they demand and stronger incentives to reduce costs. With a falling demand these stronger incentives to reduce costs may reduce their focus on providing services at a quality that customers demand.
>
> Although suppliers can also be expected to manage their expenditure under a revenue cap, their incentives to spend efficiently to provide services at a quality consumers demand, and to optimise their expenditure plans during a DPP, are likely to be stronger under a WAPC. For example, if the actual demand turns out to be lower than the forecast, under a WAPC, suppliers recover less money and therefore have a strong incentive to reprioritise expenditure to find efficiencies and make savings. Whereas, under a revenue cap suppliers can increase prices to recover revenue up to the revenue cap.

The Commission further suggests that being exposed to manageable risk under a WAPC is likely to provide stronger incentives to invest and operate efficiently.[35]

The Commission concludes in its final decision that:[36]

> Our view remains unchanged from the draft decision, that on balance a WAPC is more likely to promote efficient expenditure by GDBs in the context of expectations of declining demand/ uncertain pace of decline.

We disagree with the Commission's reasoning. In our view, this reasoning only applies under conditions where gas demand is growing. It does not apply under present conditions where gas demand is declining. We explain the basis for this conclusion below.

GDBs have an incentive to incur expenditure up to the point where the avoidable cost of retaining an additional customer is equal to the marginal future revenue that can be charged until the customer disconnects, with the comparison being carried out in present value terms.

When gas demand is growing, GDBs subject to a revenue cap will have less incentive to incur efficient expenditure to maximise utilisation, since doing so would increase the GDB's costs without changing its revenues.

However, when gas demand is declining, GDBs subject to a revenue cap continue to face incentives to incur efficient expenditure to retain customers, since doing so would maximise their ability to recover their costs and thus minimise the extent of asset stranding.

This contradicts the Commission's reasoning that suppliers under a revenue cap can increase prices to recover revenue shortfalls, with the difference being that:

[34] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision*, 13 December 2023, paras 3.460-3.461.

[35] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision*, 13 December 2023, para 3.466.2.

[36] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision*, 13 December 2023, para 3.503.

- under conditions where demand is growing, building block prices will always be lower than the marginal customer's maximum willingness to pay, in which case a regulated business can increase the present value of its cash flows by reducing its costs at the expense of service quality; but
- under present conditions where demand is declining and regulated businesses face the risk of asset stranding, building block prices will eventually exceed the marginal customer's maximum willingness to pay, such that reducing costs at the expense of service quality will:
  - reduce the value of future revenues that can be recovered from the existing customer base; and
  - reduce the present value of the business's future cash flows.

It follows that GDBs will still face incentives to incur efficient expenditure to retain customers and provide services at a quality they demand, even after switching to a revenue cap.

4.1.3 Risk management and consequences of demand forecasting error

In its 2023 input methodologies, the Commission states its draft reasoning that risks should ideally be allocated to suppliers or consumers depending on who is best placed to manage them. Such risk management includes:[37]

- taking actions to influence the probability of risks eventuating, where possible;
- taking actions to mitigate the costs of occurrence, such as by adjusting their operating and capital expenditure; and
- having the ability to absorb the impact where it cannot be mitigated.

Regarding the first point above, we consider that demand for gas distribution services is mostly outside GDBs' control and there is little that GDBs can do to influence the probability of asset stranding risks occurring. Instead, demand for gas distribution services will be driven primarily by government policy and the pace of New Zealand's transition to a low-emissions economy.

This is consistent with the Commission's observation in the 2023 input methodologies that the form of control is no longer the primary driver of new connections and volume growth for GDBs:[38]

> We do not consider the choice of form of control remains a primary driver of new connections and volume growth for GDBs. The marginal incentive to increase connection numbers and grow throughput provided by a WAPC is likely to be significantly diminished as natural gas use is expected to decline over the long-term.

We also note that the Commission previously reasoned in the 2016 input methodologies that the relatively low correlation between population growth and gas customer numbers was indicative of GDBs' ability to influence the uptake and use of gas:[39]

> Concept Consulting's report on the relative long-term demand risks between electricity and gas networks indicated that the more discretionary nature of gas versus the essential nature of electricity has been reflected in rates of customer connection/disconnection to the respective networks. **It found that there appears to be a much tighter correlation between electricity customer numbers and population growth than gas customer numbers and population growth. This suggests that electricity will continue to be supplied and used regardless of whether or not there is any incentive to promote it and market it, but the same does not apply for gas distribution as gas is a somewhat more discretionary fuel.** (emphasis added)

[37] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision*, 13 December 2023, paras 3.463-3.464.

[38] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision*, 13 December 2023, para 3.514.1.

[39] Commerce Commission, *Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower*, 20 December 2016, para 223.

However, this correlation is expected to reverse, with gas demand projected to decline as New Zealand transitions to a low-emissions economy, while Statistics New Zealand projects the country's population to continue increasing from approximately 5.3 million in 2024 to between 6.1 million and 7.2 million in 2051 and to between 6.61 million and 9.05 million in 2078.[40]

Applying the Commission's reasoning from the 2016 input methodologies, this negative correlation between population growth and gas demand shows GDBs can no longer influence the uptake and use of gas.

Regarding the second and third points above, the Commission states that GDBs can manage the consequences of forecast error more effectively than consumers:[41]

> Having regard to this principle, we considered that suppliers can mitigate the cost and/or absorb the impact on profitability of the demand risk by adjusting their expenditure (opex and capex). GDBs are better placed than consumers to manage the consequences of forecast error (the difference between forecast and actual quantities supplied) rather than the actual change in demand. Exposure to this risk gives suppliers increased incentives to spend efficiently.

However, we consider that consumers in aggregate are well placed to bear the within-period price volatility arising from errors in demand forecasts.

First, the risks associated with high-impact-low-probability events that result in large forecast errors are best spread across the diverse base of customers instead of being borne fully by an individual business. This is because such large forecast errors can have material impact on the present value of an individual business's future cash flows and affect its ability and incentive to continue operating.

If the financial impact of a large demand forecast error were to induce a GDB to shut down early, then such an outcome is likely to be detrimental to its customers, as compared to a counterfactual in which the impact of the demand forecast error is spread across the customer base.

Second, the customers that continue to remain connected to the gas network are likely to be relatively price inelastic compared to those customers that have disconnected. This suggests that:

- the remaining customers are likely to derive substantial value from accessing gas distribution services and will face substantial harm if a GDB were to shut down early; and
- spreading the financial impact of a large demand forecast error across the remaining customers is less likely to reduce their demand for gas distribution services and thus would be economically efficient compared to requiring an individual GDB to bear this risk fully.

Finally, transmission and distribution pipeline charges together comprise only about one-third of residential gas bills,[42] which further reduces the impact that taking on such risks will have on consumer decisions.

4.2 The AER prefers a hybrid approach

The Commission notes that the Australian Energy Regulator (AER) recently approved a hybrid price-path mechanism for Jemena Gas Network's (JGN's) 2025-30 price path reset.[43] This mechanism is a WAPC with 50 per cent risk sharing for volumes that deviate above or below forecasts by more than five per cent.[44]

[40] StatsNZ, https://www.stats.govt.nz/information-releases/national-population-projections-2024base2078, accessed 6 January 2026.

[41] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision*, 13 December 2023, para 3.464.

[42] 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 X10.

[43] 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 3.77.

[44] Australian Energy Regulator, *Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030): Overview*, Final decision, May 2025, p 41.

The AER has since made two additional draft decisions for Evoenergy and Australian Gas Networks' (AGN's) network in South Australia. Both draft decisions were published one day after the Commission's draft decision for DPP4, and adopt a hybrid price-path mechanism similar to that approved for JGN.

These recent decisions acknowledge the complexity of balancing risks between consumers and service providers given high uncertainty around demand forecasts, and are more consistent with the reasoning that we have set out earlier in this report.

As part of these decisions, the AER has rejected alternative tariff variation mechanisms as part of these decisions, including:

- Evoenergy's proposed revenue cap mechanism;
- AGN's proposed WAPC mechanism; and
- AGN's alternative proposal to adopt a hybrid mechanism with wider thresholds of 10 per cent.

These decisions show the AER's strong preference for adopting a hybrid approach over a WAPC or a revenue cap.

We summarise the reasons for the AER's decisions in sections 4.2.1 to 4.2.3 below.

4.2.1 Jemena Gas Networks

JGN was subject to a WAPC for its 2020-25 access arrangement. However, JGN proposed a hybrid mechanism for 2025-30 that shared volume risks equally with customers on any revenue over or under recovery driven by volumes being more than 5 per cent higher or lower than forecast.[45]

The AER's final decision accepts this proposal, noting that stakeholders support JGN's proposed hybrid approach.[46]

The AER also states in its draft decision that the hybrid tariff variation mechanism:[47]

- reflects the changed regulatory context for providing gas transportation services, given that the national gas objective now includes an emissions reduction element; and
- balances concerns of potential tariff year-on-year volatility.

4.2.2 Evoenergy

Evoenergy is subject to a WAPC for its 2021-26 access arrangement. For its 2026-31 access arrangement, Evoenergy proposes to switch to a revenue cap tariff variation mechanism for gas transportation services.[48]

Evoenergy submits that its regulatory and operating environment differs materially from that of other gas distributors and has changed substantially during its 2021-26 access arrangement period due to stronger electrification policies by the Australian Capital Territory government, stronger customer electrification intentions and a highly seasonal demand profile from its predominantly residential customer base.[49]

[45] Australian Energy Regulator, *Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030): Attachment 10 – Reference tariff variation mechanism*, Final decision, May 2025, p 3.

[46] Australian Energy Regulator, *Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030): Attachment 10 – Reference tariff variation mechanism*, Final decision, May 2025, p 3.

[47] Australian Energy Regulator, *Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030): Attachment 10 – Reference tariff variation mechanism*, Draft decision, November 2024, p 5.

[48] Australian Energy Regulator, *Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, p 19.

[49] Australian Energy Regulator, *Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, pp 19-20.

Evoenergy also cites several justifications for its proposed change in approach, including to:[50]

- ensure revenues recovered from customers reflect no more and no less than the AER approved allowance;
- remove demand forecasting risk for both customers and Evoenergy by updating the demand forecast annually throughout the period, for actual, estimated and updated forecast demand;
- providing for consistent regulatory arrangements between gas and electricity energy substitutes for its customers, which will facilitate an efficient energy transition, provide effective price signals, and enable a total energy bill hedge as energy prices adjust in line with the pace of transition;
- avoiding price variability between regulatory periods by allowing prices to incrementally adjust annually reflecting the actual pace of the transition relative to the forecast; and
- ensuring consistency of Evoenergy's incentives with the Australian Capital Territory emissions reduction policy.

The AER's draft decision rejects Evoenergy's proposed revenue cap mechanism, which the AER considers will lead to annual tariff volatility due to revenue true-ups. Instead, the AER considers that the hybrid mechanism implemented by JGN will:[51]

- best reduce the incentive inherent to a WAPC to encourage gas consumption; and
- protect consumers against large price increase if demand falls faster than forecasts.

The AER concludes that this hybrid mechanism will reflect the changed regulatory context for providing gas transportation services, given the emissions reduction element that is now included in the national gas objective, while balancing concerns of potential tariff year-on-year volatility.[52]

4.2.3 Australian Gas Networks (SA)

AGN is subject to a WAPC for its 2021-26 access arrangement. For its 2026-31 access arrangement, AGN:[53]

- proposes to retain its WAPC mechanism; and
- proposes a hybrid mechanism if the AER rejects the WAPC mechanism, under which any incremental revenue gain or loss relative to forecast revenue beyond a 10 per cent threshold will be shared between AGN and customers on an equal basis.

AGN's alternative hybrid mechanism is similar to that which the AER approved for JGN, except that AGN has changed the threshold to 10 per cent. AGN submits that JGN's five per cent threshold will place too much burden on customers during times of lower demand, since higher prices will be passed through too quickly.[54]

Stakeholders also support AGN's proposal to retain the WAPC.[55]

[50] Australian Energy Regulator, *Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, p 19.

[51] Australian Energy Regulator, *Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, pp 22-23.

[52] Australian Energy Regulator, *Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, pp 22-23.

[53] Australian Energy Regulator, *Australian Gas Networks (SA) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, p 15.

[54] Australian Energy Regulator, *Australian Gas Networks (SA) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, pp 15-16.

[55] Australian Energy Regulator, *Australian Gas Networks (SA) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, p 17.

However, the AER's draft decision rejects AGN's proposed WAPC mechanism in favour of a hybrid mechanism with a five per cent threshold.[56]

The AER arrives at the same conclusions from its decisions for JGN and Evoenergy, namely that a hybrid mechanism:[57]

- reduces the incentive to grow gas demand and thus aligns better with emissions reduction objectives compared to a price cap mechanism; and
- mitigates potential tariff year-on-year volatility that can be a feature of revenue cap regulation.

The AER also considers that AGN's proposed 10 per cent thresholds are too broad and that it is unlikely for demand to fall outside these thresholds. As such, AGN's specified hybrid mechanism effectively maintains a WAPC without removing the inherent incentive for AGN to grow demand.[58]

The AER's draft decision thus reduces AGN's proposed 10 per cent thresholds to five per cent, consistent with its decisions for JGN and Evoenergy.[59]

[56] Australian Energy Regulator, *Australian Gas Networks (SA) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, p 15.

[57] Australian Energy Regulator, *Australian Gas Networks (SA) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, p 17.

[58] Australian Energy Regulator, *Australian Gas Networks (SA) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, p 18.

[59] Australian Energy Regulator, *Australian Gas Networks (SA) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, Draft decision, November 2025, p 15.

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