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Commerce Commission
Wellington 6011
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Dear Matthew

GPB DPP 2026 issues paper: Vector cross-submission

1. This is Vector's cross submission on the Commerce Commission's (Commission) issues paper for the default price-quality path beginning 2026.

2. Vector's submission on the issues paper raised the following critical issues to ensure this reset delivers a price-path that supports the long-term benefit of consumers:
   - Maintaining ex ante FCM in the face of heightened stranding risk;
   - Grappling with the very real issue of an inability to forecast volumes with sufficient confidence that is prerequisite to operationalising a price cap and, accordingly, ensuring the regulatory settings appropriately manage short term demand risk;
   - Ensuring the approach to setting expenditure allowances is able to reflect a step up in opex. Vector's 2025 AMP reflects a shift to an opex based operating model; and
   - Addressing decommissioning costs now to avoid burdening remaining customers with exponential price increases if networks winddown.

3. These key themes were a focus for most submitters. We also note broader policy issues were also focus for many submitters, in particular the need for a gas transition plan. While outside the remit of the Commission, this highlights the need for ongoing conversation between the Commission and wider Government on policy issues to support the long-term benefit of consumers during the energy transition.

Stranding risk

4. We consider submissions presented a continuation of strong evidence showing GPB stranding risk has increased since the last reset as a result of the uncertain supply context and continued policy uncertainty. This evidence supports the need for the Commission to adjust its depreciation model to ensure an expectation of ex ante FCM is maintained.

5. As raised at the workshop and our submission, we consider the depreciation model should be updated to recognise a potential winddown date in the early 2040s. This would reflect when GPBs could realistically be cashflow negative.

6. It was reassuring to hear the CEO of Australia's Major Gas Users group last week confirm on stage at the 2025 ACCC Regulatory Conference the absolute criticality of the "regulatory compact" for existing investments in gas network infrastructure. He noted the importance of ensuring regulated gas network infrastructure investors continue to be assured of both their return on and of capital investment of sunk investment despite growing uncertainty over the usage of gas. He emphasised this was the clear basis that existing infrastructure was invested in and the clear need for regulators to respect the regulatory compact.

<u>Gas supply issues</u>

7. We note there has been significant further media commentary around gas supply issues since submissions on the issues paper.[1] Most notably, the Resources Minister has sought advice on rationing gas supplies to keep some businesses operating. This followed Balance Agri-Nutrients stating it may need to temporarily close its Taranaki plant due to being unable to secure an affordable gas supply.

8. The Business Energy Council has warned of a "major de-industrialisation crisis" escalating following the results of its Optima survey of New Zealand businesses on gas.[2] This is consistent with the Commission's recently published engagement with large users which found "their contracted gas prices had increased dramatically."[3]

9. The Commission's engagement also found businesses were experiencing contracting and market challenges including that, "A typical experience was going out to market and receiving a single or no tenders for gas contracts."[4]

10. We acknowledge the views around the impact of gas supply were not unanimous from submitters. Methanex argued:

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[1] For example see: https://businessdesk.co.nz/article/economy/shane-jones-looking-at-gas-rationing-for-beleaguered-industrial-users; https://thespinoff.co.nz/the-bulletin/12-08-2025/why-ending-the-offshore-drilling-ban-wont-solve-new-zealands-gas-crisis; https://www.rnz.co.nz/news/business/569349/major-gas-users-group-to-meet-with-resources-minister-shane-jones-over-supply; https://www.rnz.co.nz/news/political/569445/minister-shane-jones-looks-to-coal-as-businesses-grapple-with-gas-shortage; and https://www.rnz.co.nz/news/business/569691/industrial-gas-users-hobbled-by-falling-supply-rising-prices

[2] https://bec.org.nz/businessnz-calls-for-government-to-put-foot-down-on-gas/

[3] Commerce Commission, *What rising gas prices mean for NZ businesses: Insights from our discussions with medium to large gas users, as part of the reset of gas pipeline charges (Gas DPP4 2026)*

[4] Ibid

"*We don't believe that production or reserves risks are new risks – gas production and reserves uncertainties have always existed as an underlying and systemic industry risk. In this respect we consider the risk is already captured (or should have been captured) within existing GPB business models, including their decisions to purchase existing assets and install new assets.*

Going further there is no reason to conclude that the current gas production constraint is not temporary in nature. Even if gas production does not fully recover (or even if it declines further) it may well attain a sustainable plateau that remains sufficient to maintain the greater part of existing pipeline revenues for the long-term without requiring further acceleration.

While the current production constraints and recent reduction in gas reserves is challenging, it is worth recalling that a similar set of circumstances occurred in the early 2000s when gas reserves and deliverability declined steeply. This caused Methanex to indefinitely close its Motunui plant and for electricity generators to actively plan for LNG importation. There was no expectation at the time that the gas supply dynamics would reverse yet within the space of a few years gas reserves and deliverability had dramatically increased.

Electricity generators consequently abandoned their plans for LNG importation and Methanex was able to recommission all its plants and restore full rate production."

11. We consider it is unlikely that supply constraints (or other factors creating stranding risk) will prove to be temporary. Recent media coverage provides even more evidence on the unprecedented impact of ongoing gas supply constraints. However, if this proves to be temporary, the Commission could change the adjustment factor to reflect these updated circumstances at the next DPP reset.

12. We consider evidence in the current environment clearly points to heightened stranding risk and, if left unaddressed, will impact investor behaviour and GPB incentives to invest.

13. Although gas supply uncertainty has significantly heightened stranding risk, it is not the only contributor. Uncertainty around the future of gas in the energy transition (both in terms of government policy towards net zero and consumer behaviour) remains a key concern necessitating action to maintain the expectation of ex ante FCM.

14. ReWiring Aotearoa's submission provided data on the cost effectiveness for consumers of switching to electricity. ReWiring Aotearoa noted that:

"*The majority of homes and many businesses can save money from day one, by swapping gas space and water heating for financed electric options. This is because the savings from no longer paying gas bills are higher than the cost of electric space and water heating and finance repayments for these appliances. Investing in natural gas in homes doesn't make economic sense anymore for New Zealanders*."

<u>The risk of asset stranding has not been compensated through historical WACC allowances</u>

15. We note Greymouth Gas submitted that:
    a) unlike DPP3 where the risk was non-systematic, the risk heading into DPP4 is systematic;
    b) systematic risk has historically been dealt with in the WACC; and
    c) the Commission has already given GPBs an asset beta uplift for systematic risk

16. The Commission has already considered this issue in depth and has concluded that GPBs have not been compensated for bearing stranding risk through the WACC allowance. For example, in its Final Reasons Paper for the DPP3 gas reset, the Commission stated that:

    "*With expectations of declining demand in the long-term, current DPP settings imply increasing prices in real terms over time. This implies an increased risk that consumers may at some point in the future not be willing to pay the required charges. Furthermore, operations may cease prior to full recovery of the RAB, irrespective of consumer willingness or ability to pay.*

    GPBs are not compensated for the likely extent of the current risk under existing DPP settings. Risks relating to climate change policies which affect the natural gas industry are likely to be non-systematic risk and so are not compensated through the parameters that determine the WACC in the Gas IMs. *Regardless of wider economic conditions, the impact of decarbonisation efforts on GPBs is likely to be negative and material.*[5] [Emphasis added]

17. Furthermore, the Commission has been explicit that the uplift in the beta allowance for GPBs has not compensated for the stranding risk borne by those businesses. For example, in its Draft Reasons Paper for the DPP3 gas reset, the Commission explained the following:

    "*The WACC compensate suppliers for 'systematic' risks only and stranding risk may be partly systematic for GPBs. Systematic risk refers to market-wide risks which affect all risky investments. In our 2016 statutory IM review we acknowledged it is plausible that adverse economic shocks could potentially accelerate disconnections increasing economic network stranding risk.*

    We did not consider that stranding risk alone would justify an asset beta uplift. However, when combined with other factors, primarily the higher income elasticity of demand for natural gas, we considered there remained support for an upwards adjustment to the natural gas asset beta and allowed an asset beta uplift of 0.05 for GPBs relative to EDBs and Transpower (down from the 0.10 adjustment we allowed in 2010).
    …

    While some economic stranding risk is systematic, 'non-systematic' factors are likely to pose a more material stranding risk for DPP3. Non-systematic risk refers to risks which

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[5] Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2022 Final Reasons Paper*, (31 May 2022), paras. C37-38

affect an individual company or sector of the economy. In particular there is a risk of government policy changes and shifts in consumer demand for natural gas that specifically lead to economic network stranding for GPBs. We consider that the current Gas IMs do not currently provide adequate compensation for these types of risk.[6]

18. In other words, the Commission explains that:
    - Only the systematic (i.e., non-diversifiable) component of stranding risk is compensated through WACC allowances. There is no way that non-systematic component of stranding risk can be compensated via WACC allowances;
    - Any such compensation that GPBs have received in the past have been modest; and
    - The current Gas IMs (including the WACC IM) does not provide adequate (full) compensation for non-systematic stranding risk, which can only be dealt with through non-WACC means.

19. We agree with the Commissions conclusions on this issue.

20. As noted above, Greymouth Gas asserts that whilst the stranding risk faced by GPBs during DPP3 was non-systematic in nature, the stranding risk that is now faced by GPBs in DPP4 is systematic in nature.

21. In response to this, we note that:
    - No evidence has been provided to support its claim that the stranding risk faced by GPBs at the present time is wholly (or even substantially) systematic in nature.
    - Demand for the services delivered by GPBs is declining and highly uncertain over the future due to climate change policies that have encouraged a shift away from the use of natural gas in favour of electricity, and because of gas supply shortages.
    - None of these drivers of stranding risk are related to the state of the general economy. Hence, the stranding risk currently faced by GPBs is non-systematic in nature.
    - Moreover, if Greymouth Gas is correct that there has been an increase in systematic risk faced by GPBs (from DPP3 to DPP4), that would imply the WACC allowance for GPBs should be increased.

<u>Relationship between gas supply and asset stranding risk for GDBs</u>

22. MGUG submitted that: "*Reductions in potential gas supply however is a greater issue for industry and large users than it is for the mass market segment. The mass market underpins GDB revenue security. A focus on gas supply and volume as a driver of GPB economic stranding risk continues to be misplaced*."

6 Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2022 Final Reasons Paper*, 10 February 2022, paras. 6.17-6.20.

23. MGUG noted that "*75% of GDB revenue comes from mass market connections where the total annual demand for gas only reaches 9 PJ pa, an amount of gas easily available into the future, especially when domestic output is coupled with biogas development, and potentially LNG import*." MGUG suggests that because this mass market demand of 9 PJ pa could be supplied by domestic supplies, potentially supported by biogas or imported LNG, stranding risk is seriously overestimated.

24. Assessing stranding risk based on a comparison of total gas demand for mass market customers with total available supply of gas to the domestic market is not a useful way for assessing stranding risk. There are two reasons for this.

25. First, a comparison of total gas demand for mass market customers with total available supply of gas to the domestic market is not a like-for-like comparison. This comparison does not help understand the extent of stranding risk due to available gas supply. It may well be the case that available supply of gas is sufficient to meet mass market demand, but this does not mean there is no risk of supply shortages to mass market customers. By this logic, it would be possible to compare the gas demand of each individual category of customers (mass market, industrial, gas generation) with total available gas supply, observe that total available gas supply is greater than demand for any individual category of customers, and conclude that there is no risk of supply shortages to any customers, even if total demand exceeds total supply. Clearly this does not follow. The risk of supply shortages can only be assessed by comparing total demand for gas with total available supply of gas.

26. It is also important to realise that in the event that gas supply is insufficient to meet total demand, it would be expected that those customers with the lowest willingness-to-pay would be the customers that would be first stop using gas. The willingness-to-pay of customers will be influenced by the cost of available alternatives such as electrification: the lower the cost of these alternatives the lower will be customers willingness-to-pay. It is generally considered that the relative cost of electrification is lower for mass market customers than it is for industrial customers, in which case mass market customers are likely to be the first to electrify in the event that shortages of gas emerge and prices increase. This highlights precisely the risk to GDBs of asset stranding due to gas supply shortages: while mass market customers may use a relatively small amount of gas, they contribute the majority of GDB's revenues. If these mass market customers are most at risk of electrifying due to supply shortages then there is a clear risk to GDB's revenues from asset stranding.

27. Furthermore, while reductions in gas supply may have the largest initial impact on large users, supply uncertainty paints a bleak picture for all customers which will impact the behaviour of smaller customers. For example, smaller customers are less likely to

reinvest in gas appliances where there is uncertainty about supply. Indeed, Consumer NZ has advised consumers to replace gas appliances with electric at end of life.[7]

28. We note that if only residential consumers remained on our network in PY25, this would have resulted in a circa 70% price increase for these consumers. This would impact stranding risk as it would impact customer willingness to pay.

29. Second, supply-side shortages are not the only driver of stranding risk faced by GDBs. As discussed above, supply-side shortages can materially impact revenues for GDBs and therefore contribute to stranding risk, but so too can other drivers not related to supply-side shortages. In particular, other factors that can result in customers leaving the network include:
    - changes in policy, particularly policies to reduce emissions;
    - changes in customer preferences, reflecting an increase in the preference for electrical appliances;
    - changes in technology and costs, including the increasing availability; and improved performance of heat pumps and induction cooking and changes in the prices of gas and electricity.

30. An assessment of stranding risk also requires consideration of the effect that these factors will have on future gas demand.

<u>Stranded asset risk and workably competitive markets</u>

31. MGUG's submission comments in multiple places that addressing stranded asset risk for GDBs is inconsistent with the outcomes of a workably competitive market.[8] The implication to be drawn is that in competitive markets the supplier manages stranded asset risk rather than passing it onto customers, such that if regulation is to mimic competitive markets, the costs of managing stranded asset risk should not be allocated customers.

32. Contrary to the views expressed by MGUG, a regulatory response to stranded asset risk is entirely consistent with the outcomes of a competitive market.

33. The main reason why addressing stranded asset risk through regulation is consistent with the outcomes of a workably competitive market is that in both instances investment will not occur without a reasonable expectation of earning a normal return on investments. In competitive markets where stranded asset risk is a possibility, a reasonable assurance of cost recovery, and so an expectation of earning a normal return on investment, can be achieved in one of two ways:

[7] See: https://thespinoff.co.nz/the-bulletin/12-08-2025/why-ending-the-offshore-drilling-ban-wont-solve-new-zealands-gas-crisis

[8] see paras 22, and para 69.

- The firm can bear the stranded asset risk itself, however, it will only do so where the expected risk adjusted return is sufficiently high to compensate for that risk. That is, if pre-entry prices are not high enough to compensate for stranded asset risk firms will not enter the market and will instead invest their funds elsewhere. Notably, the size of the stranding risk that prices compensate for will turn on the expected payoff period for the investment, with larger and longer-lived assets imposing much more risk, and so higher pre-entry returns, than smaller investments with shorter payoff periods; and
- Customers can provide a reasonable assurance of cost recovery through long-term contracts. This is a common approach for large infrastructure assets which tend to involve substantial costs and so longer payoff periods. Under this approach customers will agree to pay for the full cost of an investment over certain period of time, such as 10-15 years, before an investment is made irrespective of how much of the service they end up using, or whether they continue to use the assets for all of that period of time.[9]

34. In either case, in a workably competitive market, customers are bearing costs associated with stranded asset risk. This is either through higher prices where the supplier bears the risk, or through providing an assurance that customers will fund the full cost of an investment irrespective of their own use through a long-term contract.

35. In New Zealand, economic regulation, including for gas distribution businesses, more closely resembles the long-term contracting arrangement. While an explicit contract between customers and suppliers for cost recovery is not in place, the regulatory framework and regulatory compact that provides for FCM intends to serve that purpose. This expectation from the framework, agreed between the regulator and GDBs, is designed to provide confidence of cost recovery and therefore motivate investment. The benefit to customers from this approach, in addition to investment occurring in assets that they value the use of, is that they face substantially lower prices than would occur if businesses were required to bear stranded asset risk such that this had to be embedded in returns in order to motivate service provision.

Impact of accelerated depreciation on consumers

36. A concern from submitters opposed to accelerated depreciation was that higher prices would contribute to demand destruction.

37. MGUG submitted that, "*Delivered gas prices have risen significantly since 2022. Accelerated depreciation and GPB pricing methodologies have contributed to this through exponential increases in gas transport costs and increasing unaffordability is being*

[9] We note that such contracts also deliver benefits to customers in addition to lower prices. This is that they also have a reasonable assurance that the service will be available for the duration of the agreement, and so can make corresponding investments that rely on the service in question.

reflected in the data. A continuation of accelerated depreciation in DPP4 (particularly for sunk assets) will continue to compound the transport charges in delivered gas to further unsustainable levels for consumers."

38. We have further considered the potential impact of accelerated depreciation on consumer bills. Our joint cross-submission with Powerco and First Gas provides analysis on the impact of accelerated depreciation versus wholesale prices. This analysis shows the impact of wholesale prices are orders of magnitudes higher than that of accelerated depreciation.

39. We consider it is unlikely that price increases associated with accelerated depreciation would have a significant impact on consumer behaviour when considered in the context of major price rises caused by gas supply uncertainty.

40. As set out in Entrust's submission, "*Vector's gas distribution pipeline charges have reduced in both nominal and real terms since 2013; with a reduction of $220 per customer or 30% in real terms*."

41. First Gas Limited's submission considered the impact of accelerated depreciation and the drivers of consumer behaviour in detail. First Gas submitted:

> "*Our view is that the price effects of accelerated depreciation during DPP3 were significantly less impactful than the changes in the availability of gas, which have driven volatility into wholesale gas prices. This is illustrated by the fact that commercial and industrial retail gas prices in recent years (MBIE data runs through to 2024) have risen much faster than residential prices. This suggests to us that the DPP3 settings have not yet been a major contributor to affordability pressures for residential consumers, and that Commission's approach has been prudent, proportionate and has not caused network defection that would undermine the purpose of accelerated depreciation*.
>
> …
>
> *Residential consumers use the most network and contribute the bulk of network revenues. If higher network charges were the primary cause of retail price rises we would expect to see proportionately larger price increases for residential consumers. The opposite appears to be in evidence (see below table), when comparing the latest quarter (March 2025) with the two previous March quarters (2023 and 2024) in which the impact of accelerated depreciation might have had an impact. The percentage increase facing residential consumers aligns with the wholesale price increase in the same period*
>
> *….*
>
> *Similarly, if increases in gas network tariffs were hugely significant for gas retail pricing, we would expect to see mass market gas retailers struggling to pass-on higher input costs and feeling the pinch of growing costs through lower retail margins... Rather than rising input costs depressing retail margins we see margins steady (Mercury) or growing (Contact and Genesis). Analysis by Forsyth Barr confirms this is the case for Genesis with 12-month rolling gross margins stepping up for gas sales.*"

42. It is worth noting that the step change associated with implementing accelerated depreciation has already occurred in DPP3 (i.e. going from no accelerated depreciation to

accelerated depreciation). It is likely that, even with adjustments to the model accelerate recovery, there will be even less impact in DPP4.

43. We also note that while Commission's engagement with large consumers found that "*pipeline (and lines) cost increases add to the financial pressure businesses are already facing,*" it also found that "*There was a concern as more end users transition away from gas, the shrinking customer base will reduce the ability of lines companies to spread costs, likely resulting in higher charges for remaining users and further undermining the users' financial viability*."[10]

Managing short-term demand risk

44. The gas supply situation is unprecedented and presents an overwhelming and fundamental challenge for the Commission in this reset. Vector maintains the uncertainty with forecasting future volumes is now so high, the ability for a regulator to retain price cap regulation is untenable. The Commission, through its observation status on the Energy Framework, has heard clear concern about the state of the gas market and Vector believes the Commission cannot simply continue with a framework that relies so critically on accurate forecasts to deliver a fair return for investors.

45. Concern about forecasting in the current environment and the need for appropriate mechanisms for GDBs to manage short-term demand risk was a key point raised by GPB submissions.

46. Powerco submitted that:

"*Forecasting in the current New Zealand environment is particularly complex with the unique supply-side considerations, alongside electrification trends and decarbonisation policies. Frontier highlights how forecasting has become significantly more challenging since the DPP3 forecasting was done*."

47. Similarly, First Gas highlighted:

"*During DPP3, actual demand consistently deviated form forecast levels across customer categories. In RY23, variances ranged from 1% positive deviation to an 18% shortfall for large industrial customers. In RY24, actual demand was 4% above for mid-sized commercial customers and 22% below for large industrial customers. For the first nine months of RY25, demand has been 2% above forecasts for small commercial and 9% below for large commercial customers. On average, actual demand was 8% below forecast in RY23, 10% below in RY24, and 2% above forecast year-to date in RY25. The variances reflect the inherent difficulty in forecasting demand in an environment of uncertainty and evolving customer behaviour. This uncertainty reinforces the need for a flexible regulatory approach, e.g., an adjustment mechanism that can accommodate material, unforeseen demand shifts*."

[10] Commerce Commission, *What rising gas prices mean for NZ businesses: Insights from our discussions with medium to large gas users, as part of the reset of gas pipeline charges (Gas DPP4 2026)*

48. Powerco and First Gas both supported the Commission investigating an adjustment mechanism to manage forecast risk. We consider a revenue cap is the appropriate mechanism in the current environment supported by (symmetric) re-openers where there are material variations in forecast. The reasons the weighted average price cap was originally put in place are no longer applicable. Faced with significant forecasting risk a revenue cap is the appropriate mechanism to address this risk while maintaining incentives to invest.

49. Any decision to not move to a revenue cap is sub-optimal in our view. However, we would support further investigation of a hybrid mechanism in line with the AER's decision on Jemena (with appropriate adjustments for the New Zealand context) as a transitional step to a revenue cap being implemented.

GDB pricing methodology

50. We have carefully considered concerns raised by MGUG and Nova about Vector's connection policies. We remain of the view that our policies to recover 100% of the cost of both connections and disconnections are appropriate in the current environment. This avoids any cross-subsidisation from existing customers of new connections or disconnections at a time when there is a significant uncertainty as to the future of gas. In addition, there is now a high chance new connecting parties will not stay on the network long enough to benefit existing consumers and therefore they should pay the full cost to connect. Parties leaving earlier than expected when they connected should also at least pay their disconnection costs rather than leave these costs for remaining consumers to pay.

51. Nova submitted, "*Nova is concerned that Vector, at least, appears to be limiting or discouraging new consumer connections. While this may be rational from a GDB perspective, it undermines the cost-sharing benefits of a broad customer base and risks driving up prices for remaining users*."

52. MGUG raised broader concerns around GPB pricing:

    "*It should be clear from this that gas volume is a poor proxy for stranding risk for GDBs. The mass market is the easiest sector for GDBs to service well beyond 2050. Inexplicably this is also the segment that seems to be taken most for granted by GDBs through their Pricing Methodology as we discuss under Network Charges. We suggest that this is because the demand risk is not being properly shared between consumers and suppliers.*

    GDBs operate under a weighted average price cap because they can influence demand (i.e. their revenue) and should have incentives to grow, or at least prevent "degrowth". Some of them appear to have turned this around by shifting the incentives to encourage disconnection. Residential connections (their most stable and profitable segment) used to be incentivised by socialising the cost of new connections.

Now with one GDB in particular, the connecting party is asked to pay upfront, creating an immediate disincentive for connection growth. Further pricing policies continue to load recovery on fixed day charges, substantially punishing low users, and incentivising them to disconnect. While this might seem sensible if the immediate future picture is for no gas transported, or insufficient gas transported to cover operating costs, this is not the present outlook for New Zealand. It is also not an outlook that (some) GDBs are otherwise promoting publicly outside of this regulatory forum, as they push biogas and hydrogen projects as opportunities for repurposing their gas pipeline assets."

53. MGUG's submission identifies that pricing policies are increasingly using fixed day charges. MGUG argues that fixed pricing is incentivising customers to disconnect and that this approach is only appropriate in circumstances where no gas is transported, or insufficient gas is transported to cover operating costs.

54. However, given declining demand for gas, an increasing reliance on fixed charges is consistent with economically efficient price signals for the use of gas pipeline services.

55. An efficient price structure is one that mimics the structure of costs caused by consumption; or more specifically, the marginal costs of supply. That is, if costs change when an extra unit of a good or service is consumed, then this should be reflected in the price. Where economies of scale and scope are present marginal costs will sit below average costs. This means for gas pipelines with substantial sunk assets, setting prices based on long-run marginal cost will always leave a residual amount that is not recovered through the efficient usage charge. Economic principles suggests that this residual amount should be recovered through the least distortionary means possible. That is, in a way that does not change incentives for the efficient use of the service.

56. In the current environment of declining demand for gas distribution pipelines, gas use by customers is driving virtually no long run marginal costs. For instance, Vector is not forecasting any system growth projects over the next 10 years. We note also that the Commission has stated that peak charging signals are less valuable in gas than electricity. The implication is that, with declining demand, when and how much current customers consume is not driving long run marginal costs. The correct signal for this outcome is a usage price at or near zero.

57. With an efficient usage charge at or near zero, it means that a substantial residual cost must be recovered related to costs that do not vary with usage, most notably sunk fixed costs. A fixed daily charge is an accepted method for recovering these costs because it does not distort signals for the efficient use of gas. Conversely, if these costs were recovered through the usage charge it would mean that prices sit above the efficient costs of supply and so would serve to discourage otherwise efficient gas consumption.

58. As we have noted in previous IM Review and DPP3 reset submissions, we asked the Commission to move GDBs to a revenue cap to mitigate forecasting risk. The

Commission declined to do so but, in their decision, suggested GPBs could mitigate this risk by adjusting their pricing policies and adjusting the ratio of line and volume charges.[11]

Cost of new connections

59. MGUG and Nova also expressed concern that recovering the cost of new connections upfront disincentivises connection growth and undermines the benefits of a larger customer base.

60. We accept that promoting network growth can deliver benefits for customers, including by reducing average prices. However, it is equally important that new connections do not cause existing customers to subsidise the connection of new customers or increase the size of the stranded asset risk. Upfront connection charges can address each of these issues by making sure new customers pay at least the incremental costs they cause, and potentially also a contribution to shared costs for the existing assets they will benefit from.

61. Our pricing strategy is not intended to discourage new connections. Indeed, we do not consider GPBs have any influence over the material drivers of connections or disconnections in the current market context (such as the impact of supply uncertainty and the net zero transition).

62. That said, we don't consider a regulatory incentive to grow connections supports the long-term benefit of consumers in the current context of heightened stranding risk or in the context of the net zero transition. While GPBs will continue to investigate options for re-purposing such as biogas, there remains significant uncertainty about this pathway.

63. Vector has increased its capital contributions policy to recover 100% of the cost of new connections from the connecting party. As the Commission's issues paper noted:

    "*As delivered gas volumes decline, there is less justification for expenditure to grow the gas networks. In this new context, we expect GPBs are developing commercial and asset management strategies aligned to a more uncertain, but declining outlook for future gas use.*

    Capital contribution policies should reflect the current sector outlook and be designed so that costs are only incurred where they are efficient, showing a demonstrable benefit to the customer base.

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[11] Commerce Commission, *Default Price Quality-Paths for Gas Pipeline Businesses from 1 October 2022: Final Reasons Paper* (May 2022) at E37

Some level of capital expenditure may be necessary to maintain the network where consumer demand remains, however it should also be aligned with the network's future declining outlook"[12]

64. Vector's capital contributions policy reflects this and resulted in zero system growth expenditure in our 2025 AMP.

65. We also note ReWiring Aotearoa's submission that:

"*New connections, for example for households within 20 metres of a gas main in the street, are not charged to establish the connection. This means the cost for new connections are subsidies by the existing gas customers in New Zealand.*

New customers should be charged upfront for the full cost of their connection."

66. We note our capital contributions policy for the GDB is consistent with our capital contributions policy for the EDB. While the market context in the EDB sector is very different, both reflect a view that existing customers should not cross-subsidise connecting customers and that customers can benefit from an overall lower RAB.

<u>Australian connections framework</u>

67. MGUG's submission cites the Australian approach in several places. We note the approach in Australia seems to be directed towards customers paying more upfront for connections primarily due to stranded asset risks.

68. The Essential Services Commission of Victoria (ESCV) implemented a new connection framework for gas distribution networks that requires the full cost of a connection to be paid for upfront. In making this change, the ESCV indicated that this change will: "*mange the risk that customers may electrify their appliances and reduce or stop using gas over the next two decades.*" [13]

69. Following this change, a rule change request is now being considered by the Australian Energy Market Commission (AEMC) to change the gas connection arrangements based on the view that the current arrangements increase asset stranding risk in the context of declining demand on gas distribution networks. [14] The proposed change would reflect the arrangements in Victoria and require customers pay the full cost of connection upfront.

Disconnection costs

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[12] Commerce Commission, *Gas DPP4 Reset 2026: Issues Paper* (26 June 2025) at 3.11 – 3.13

[13] ESCV, '*Essential Services Commission Gas Distribution System Code of Practice review: Final decision*', 9 May 2024, p.3

[14] See: https://www.aemc.gov.au/rule-changes/updating-regulatory-framework-gas-connections

70. We have also carefully considered concerns from MGUG, Consumer NZ and ReWiring Aotearoa that GPBs are increasing the cost of disconnections.

71. MGUG submitted the Commission should pursue regulation of disconnection services similar to Australia.[15]

72. ReWiring Aotearoa submitted:

"*Disconnection fees (for permanent disconnection) should therefore be set at or below the cost of disconnection and options to pay $0 upfront disconnection fees with amortised repayments offered to all consumers. Gas distribution businesses should offer subsidised capped permanent disconnection fees to households where occupants have Community Services Cards or Super Gold Combo Cards, or live in areas which are included by EECA as eligible for Warmer Kiwi Homes subsidies (low-income areas). The Commission should allow socialisation of the subsidies portion of these disconnections*."

73. Consumer NZ submitted:

"*Households face significant costs, often between $1,000 and $2,000, to have gas meters permanently removed. In some cases, retailers are continuing to charge former customers fixed daily gas fees even after they have fully electrified and ceased using gas, until the meter is physically removed. This creates a financial barrier, particularly for lower-income households, to exiting the gas network*."

74. As discussed in our submission, Vector has changed its disconnection policy to recover 100% of the cost of disconnections. We consider this is needed to avoid unfairly burdening the wider customer base in an environment where disconnections are likely to increase.

75. It is worth noting that, in relation to disconnection and abolishment rules in Australia, the AEMC is currently considering two rule variation proposals put forward by consumer advocacy groups to avoid cross-subsidisation in the context of gas network decline. The Justice and Equity Centre submitted a proposal which would include a requirement for cost reflective pricing in disconnections to avoid socialising disconnection costs.[16]

76. The Justice and Equity Centre's rule change proposal states:

"*In its most recent decisions the AER's approach (as noted earlier) has been to respond to potential safety concerns which may result, by subsidising permanent disconnection costs and socialising the difference across remaining consumers. In making this decision the AER has acknowledged it is not sustainable. It is also inconsistent with the long-term interests of gas consumers, as it involves ongoing*

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[15] At para 28

[16] See: https://www.aemc.gov.au/rule-changes/establishing-regulatory-framework-gas-disconnections-and-permanent-abolishment

(and future) gas network consumers carrying costs caused by those ceasing to be gas consumers. Further, as customers who can afford to leave the network do so, remaining customers will be left facing higher and higher gas bills. This raises questions about equity if permanent disconnection costs are socialised across the network, leaving the customers who are unable to electrify paying the electrification costs of others in addition to their own at a later time…

We support the general principle that the beneficiary of a service should pay for the service, and that costs should be recovered from the causer or proponent of the activity which incurred those costs. These principles should be consistently applied to disconnection services.

Socialisation of permanent disconnection costs is inequitable, particularly in the context of increased rates of permanent disconnection. Similarly, inefficiently high costs for permanent disconnection contribute to an inefficient disincentive to remain connected to the network, with households delaying electrification, and potential implications for cost and emissions."[17]

77. While we consider overall consumer welfare is best supported by avoiding cross-subsidisation, we recognise the concern raised by Consumer NZ that higher disconnection charges could create a financial barrier for lower-income households to exit the gas network. Our consumer research (submitted with Powerco and First Gas) highlighted consumers' expectation that government could potentially play a role supporting vulnerable customers transition from the gas network.[18]

78. Consumer NZ submitted:

"*We recognise the Commerce Commission cannot address the full scope of these challenges alone. However, it can help lead the conversation and call for coordinated government action.*

We urge the commission to:
a) formally recommend that the Government develop a national gas transition strategy
b) support a mechanism for targeted financial assistance for low income household disconnection and transition costs
c) discourage new residential connections to the gas network
d) explore transitional regulatory models, including sunset regulation, and demand risk-sharing or a declining revenue cap aligned with managed network decommissioning."

79. While outside the scope of the DPP reset, we agree social policy will be important to support vulnerable customers during the energy transition and ongoing dialogue between the Commission, government and stakeholders will be a necessary part of this.

[17] Justice and Equity Centre, *Gas Distribution Network Rule Change Request: Fit for purpose gas disconnection arrangements* (9 May 2025), page 6 – 7

[18] Pinstripe Leopard, *What's fair? Qualitative research topline findings of the views of residential and business natural gas customers: prepared for Vector, Powerco and First Gas Limited* (July 2025), page 14

Decommissioning costs

80. All GPBs submitted on the need to consider decommissioning costs in DPP4.

81. We agree with First Gas' submission that:

> "*We do not agree that uncertainty about the nature and quantum of the costs is a significant barrier to this topic being addressed in DPP4. These are significant uncertainties, but are overwhelmed by the clear need to act sooner rather than later. If gas demand decreases in a straight line to zero in 2050, then the five years of DPP4 will see 37% of all future gas usage. If the end-date is instead 2040 or 2060, then DPP4 will see 57% or 27% of all future gas usage, respectively. In either case, failure to act now will greatly exacerbate the burden on future gas users. If the gas users present during DPP4 are to contribute toward future large-scale decommissioning activities, the Commission must act to provide an appropriate allowance*."

82. Methanex, MGUG and Fonterra argued against recognition of decommissioning costs.

83. MGUG stated that it would be "*particularly egregious for GPBs to push an aggressive degrowth strategy to favour their EDB assets … and then to claim decommissioning costs from the customers that they are abandoning*." MGUG's suggestion seems to be based on MGUG's view that the behaviour of GPBs – particularly accelerated depreciation – that encourages customers to leave the network. This is not the case. GPBs are seeking to accelerate depreciation in response to the risk that broader factors result in customers leaving the network, including:
    - Changes in policy, particularly policies to reduce emissions;
    - Changes in customer preferences, reflecting an increase in the preference for electrical appliances;
    - Changes in technology and costs, including the increasing availability and improved performance of heat pumps and induction cooking and changes in the prices of gas and electricity;
    - The risk of future gas supply shortages.

84. GPBs are not in a position to materially influence these broader factors. The effect of these factors is to increase the risk that GPBs will be unable to recover their efficient costs, contrary to the principle of FCM.

85. MGUG's principle reason to oppose decommissioning costs being recovered from consumers is that requiring consumers to pay for decommissioning costs undermines the incentives seen in competitive markets, which lead firms to try to defer abandonment. This is not the case and represents a misunderstanding of competitive markets and a misunderstanding of the incentives to defer abandonment.

86. In respect of competitive markets, decommissioning costs will be recovered from customers. The reason is the same as the reason that in competitive markets the costs of stranded asset risks will be recovered from customers: in competitive markets, investment

will not occur without a reasonable expectation of earning a normal return on investment. In competitive markets where there is a prospect of decommissioning costs a reasonable assurance of a normal return can be delivered in two ways:

- The firm can bear all of the decommissioning cost itself, however, it will only do so where the expected risk adjusted return is sufficiently high to compensate for those costs. That is, if pre-entry prices are not high enough to compensate for decommissioning costs firms will not enter the market and will instead invest their funds elsewhere; and
- Customers can provide a reasonable assurance of cost recovery through long term contracts. This is a common approach for large infrastructure assets which tend to involve substantial costs and so longer payoff periods. Under this approach customers will agree to pay for the full cost of an investment, including decommissioning costs, over certain period of time.

87. In either case, in a workably competitive market, customers are paying for the costs of decommissioning. This is either through high prices where the supplier bears the risk, or through a long-term contract.

88. In respect of incentives to defer abandonment, the incentive arises in competitive markets because deferring abandonment costs results in a delay in costs being incurred. This incentive to delay decommissioning costs being incurred exists independently of the recovery of decommissioning costs. As we observed, firms in a competitive market would expect to recover decommissioning costs during the life of the project either because entry occurs only when market prices are high enough to compensate for all costs (including decommissioning costs) or because pricing under a long-term contract provides for the recovery of decommissioning costs. Firms in a competitive market that have recovered their decommissioning costs in this way still have an incentive to defer abandonment because deferral allows them to defer incurring costs; the firms can retain the amount they have recovered to fund their decommissioning costs while those decommissioning costs are deferred.

89. For these reasons requiring customers to pay for decommissioning costs is entirely consistent with the outcomes of a competitive market and is entirely consistent with businesses continuing to have an incentive to defer abandonment. Allowing GPBs to recover decommissioning costs over the life of the asset is consistent with the outcomes that would be expected in competitive markets, and allowing this recovery will not affect the incentive that GPBs may have to defer abandonment to avoid incurring decommissioning costs.

90. Methanex and Fonterra's submissions also argued decommissioning costs should not be borne by customers. Methanex's central point seems to be that the GPBs should have already factored decommissioning costs into their business plans, and therefore should not now seek to recover these costs from consumers. Fonterra similarly argued that these costs should be met by shareholders on the basis the costs are resulting from strategic decisions on asset retirement.

91. These arguments fail to recognise the nature of pricing regulation and are contrary to the FCM principle. Regardless of the expectations of GPBs about their future exposure to decommissioning costs, it is clear that GPBs have not been able to recover decommissioning costs to date. No allowance for these costs has been made, either through expenditure allowances or through the allowed rate of return. The need for decommissioning costs is now becoming clear, so it is appropriate to provide an allowance for GPBs to recover these decommissioning costs. If allowance is not provided for GPBs to recover these decommissioning costs this would be counter to the FCM principle and counter to the expectation of GPBs that there will have the opportunity to recover their efficient costs.

92. We also note Greymouth Gas proposed a solution based on Dr Ron Ben-David's May 2025 paper which would involve gas asset stranding recovery through the electricity RAB. 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.

93. Questions about the broader role of government in managing stranding risk and decommissioning costs should not preclude the Commission taking action now to address these risks now. Any decommissioning costs recovered now will reduce the burden on consumers later on and allow recovery from a greater customer base.

94. First Gas's submission (also quoted above) provides analysis for illustrative purposes on the potential impact of recovery of decommissioning costs over different time periods.[19] This analysis demonstrates deferring recovery until a later period is more burdensome and inequitable than beginning recovery in the 2026 period.

Opex / capex trade-off

95. There appeared to be broad agreement from submitters that the Commission should make greater use of AMPs to inform expenditure allowances.

96. MGUG submitted that:

> "*We support the Commission reviewing GPBs AMPs to understand how their investment strategies are being adapted to optimise expenditure on their networks, and therefore how the AMPs can inform Commission setting of the expenditure allowances. We would expect the Commission to use independent advice from suitably qualified providers to assist in this assessment*."

97. Similarly, Fonterra submitted that:

[19] See page 17 - 18

> “*Fonterra supports the Commission’s shift in emphasis from capital-intensive renewals programmes to lower cost opex maintenance strategies. By relying on up-to-date AMP forecasts (Rather than an automatic historic average) and allowing capex-to-opex substitution, the Commission’s draft approach should ensure renewals projects that are only justified by keeping the RAB high are avoided. Figure B2 underlines why – that historic average often bears little resemblance to what the networks now expect to spend. Going forward, each GPB will have to spell out and justify every block of capital in its AMP if it wants the Commission to include it in allowable revenue*.”

98. Fonterra’s submission is consistent with Vector’s approach in shifting to an opex based operating model. It also highlights the significant uncertainty in the sector and heightened stranding risk.

99. We agree that making better use of AMPs will support more efficient expenditure setting, particularly in the current environment where historic expenditure will not predict future expenditure. In the context of a declining network, the key issue will be to set appropriate opex allowances as maintenance increases as investment in assets will exacerbate the stranded asset problem.

Yours sincerely

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