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Transpower and Gas Manager
Commerce Commission
Wellington 6011
By email: infrastructure.regulation@comcom.govt.nz

Dear Matthew

Cross-submission on the default price-quality path for gas pipeline businesses beginning 2026

1. This is Vector's cross submission on the Commerce Commission's draft decision on the default price-quality path for gas pipeline businesses beginning 2026 (GPB DPP4).

2. This cross-submission contains no confidential information, and we are happy for it to be published on the Commission's website.

3. Our submission to the draft decision focussed on the following areas which we consider are critical to delivering a price-quality path that supports the long-term benefit of consumers:
   - Managing stranding risk;
   - In period demand risk; and
   - Appropriate opex allowances, in particular our concern that the approach to the "trend" in the base, step and trend will not deliver an efficient level of opex as it assumes opex will decline proportionally with ICPs.

4. Our cross submission is largely focussed on these key issues. We have also highlighted stakeholder comments on decommissioning costs, capital contributions and disconnections.

Managing stranding risk

5. Creating an appropriate depreciation profile reflecting the outlook for the gas sector was a key concern for most submitters.

6. GPBs remain aligned that accelerated depreciation is the appropriate pathway to manage stranding risk. We agree with First Gas's submission which highlighted the negative outlook for gas compared to DPP3:

   "*In our view, the weight of changes since 2022 has clearly increased the risk of asset stranding. The changes include:*
   - *Sharp declines in gas production and reserves: production declined for 8 straight quarters through to September 2025 and is predicted to fall below 100 PJ in 2026. At paragraph D86 of the draft decision, the Commission points to supply-side factors that were considered at the DPP3 reset. However, the rate and extent of the decline in gas production has been much faster and deeper than anyone expected back in 2022 – a time when producer forecasts expected supply to increase to more than 200 PJ per year.*
   - *Significant increases in delivered gas prices, driven by constrained supply and higher retail gas margins (as well as passing through higher network charges): our submission on the DPP4 issues paper identified that increasing retail gas margins have been*

reported throughout DPP3, especially for residential consumers. We infer from the evidence that a shortage of gas supply is driving these price increases.
• Changes in gas distributor policies and procedures: including decreases in longlived asset capital expenditure, initial steps towards network right-sizing, and increasing capital contributions for new connections.
• Vocal consumer advocates pushing for households to disconnect from gas networks: based on claims that we have reached a "tipping point" where electricity can replace gas for household uses and both save money and reduce emissions.
• Promised subsidies for electrification: Political parties campaigning in the 2023 general election on providing households with financial incentives to replace gas appliances."[1]

7. Mercury summarised the outlook for the gas sector as:

   "*The gas market is changing rapidly, driven by declining natural gas supply from ageing fields and shifting demand as customers either exit New Zealand or move to alternative fuels. In this context we support a managed, fair transition that enables our customers to electrify when it suits their circumstances, while ensuring those that are unable to afford the up-front capital costs of electrification are not left bearing a disproportionate share of GPBs' costs*.

   In relation to the Commission's draft DPP4 decision, Mercury:
   • Agrees that it is prudent to assume that gas will be around for the next 20 years, taking into account the prospects of further production from existing wells, LNG imports and biogas development;
   • Agrees that the actual economic life of existing gas infrastructure is likely to be much shorter than its physical life and that it is appropriate to continue the accelerated depreciation approved in DPP3 so as to reduce the risks of costs being recovered primarily from a smaller future customer base;"[2]

8. ReWiring Aotearoa's submission also highlighted increasing uncertainty for gas:

   "*there is increasing uncertainty over the ongoing role of gas in our energy mix, particularly post 2040, and that it is important to acknowledge in this current price path reset.*

   Domestic gas supply expectations have been significantly revised down by MBIE and gas price pressure is accelerating fuel switching for firms who have viable alternatives.

   Current political activity has added to uncertainty over the future role of gas transmission and distribution. This includes exploring LNG import and seeking expressions of interest on a $200 million fund to incentivise domestic gas exploration, production and storage.

   We do not anticipate investment in LNG import facilities to benefit the majority of New Zealand industrial and large commercial gas users because the cost of imported LNG would be higher than the current elevated domestic gas prices. As the Commerce Commission notes in its decision paper "a range of medium to large businesses, across

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[1] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Firstgas-Submission-on-Gas-DPP4-Draft-decision-22-January-2026.pdf page 8-9
[2] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Mercury-Submission-on-Gas-DPP4-Draft-decision-16-January-2026.pdf page 1

different sectors, described facing significant cost pressures and operational challenges due to elevated energy prices."

Gas price pressure would persist with investment in LNG facilities and likely result in similar patterns of fuel switching and business closure."[3]

Inputs to the accelerated depreciation model

9. Our joint cross-submission with First Gas and Powerco provides GIFWG's refreshed scenario modelling.

10. This shows that, consistent with the original analysis, accelerated depreciation helps but does not fix the underlying viability problem created by structural demand decline. The refreshed analysis shows risk has heightened compared to DPP3: financial pressure appears earlier, lasts longer, and becomes more sensitive to small changes in volumes and the wholesale gas price.

11. We strongly recommend the Commission take this analysis into account in its final decision on accelerated depreciation. Our submission recommended the Commission add an earlier winddown scenario to reflect when GPBs could realistically become cashflow negative. GIFWG's refreshed scenario modelling shows this could now be as early as RY38.

Treatment of asset additions and inflation in the accelerated depreciation model

12. Our submission recommended updates to the way the depreciation adjustment factor is applied to additions that results in less than required depreciation. If projected forward this would result in those additions having significant residual value in the 2050s.

13. First Gas similarly recommended:

- "*The Commission reduces the life of new assets by both DPP3 and DPP4 accelerated depreciation factors*" on the basis "*This would correct the discrepancy between the accelerated depreciation factors applied to new and existing assets, reflecting the cumulative effect of decisions to accelerate depreciation on the assumed life of new assets*"; and
- "*The Commission changes the approach to compliance with accelerated depreciation allowances to remove the impact of inflation on acceleration factors*."[4]

Opposition to accelerated depreciation from major users

14. We acknowledge the major gas users (including through the MGUG), along with Greymouth Gas and Optima Energy remained opposed to accelerated depreciation. We understand key concerns related to:
    - Whether price increases driven by accelerated depreciation was causing stranding risk due to affordability challenges;

[3] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Rewiring-Aotearoa-Submission-on-Gas-DPP4-Draft-decision-22-January-2026.pdf, Page 1-2

[4] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Firstgas-Submission-on-Gas-DPP4-Draft-decision-22-January-2026.pdf, page 3

- Whether the acquisition of Clarus by Brookfields demonstrated investors had a different view to the Commission on stranding risk;
- Whether the accelerated depreciation assumptions were overly pessimistic given EY's forecast and government policy around LNG imports.

Accelerated depreciation is not creating stranding risk or creating a death sprial

15. The affordability of gas and whether accelerated depreciation was creating a "self fulfilling prophecy" was a key concern. For example, Castalia's report for MGUG stated:

    "*Overall, while the Commission argues that accelerated depreciation is necessary to preserve the incentives for network owners to ensure the necessary re-investment and maintenance of the network, the Commission's approach risks causing the very stranding it seeks to address. Significant increases in network prices in the short term, combined with near-term constraints on gas supply, invite a dynamic demand response to accelerate the decline in gas usage instead of bridging the sector to alternative gas supplies.*"[5]

16. We acknowledge affordability is a key concern for consumers and that accelerated depreciation will contribute to price increases in DPP4. However, accelerated depreciation is needed to avoid unmanageable price increases for consumers in later periods. Accelerated depreciation is therefore the approach that will best minimise costs to consumers and avoid price shocks over the longer term.

17. This was further explained in Frontier's report (submitted by Vector to the draft decision consultation):

    "*While the Commission understandably expresses concern about short-term price impacts, delaying depreciation does not protect consumers. Instead, it merely shifts the burden onto a shrinking number of future customers who have fewer alternatives, lower ability to switch, and face higher network prices due to a contracting customer base. As we previously argued, this pattern is inequitable and inconsistent with both efficient cost allocation and FCM. Recovering a greater share of depreciation earlier, while customer numbers remain higher, minimises the severity of future price shocks and avoids the risk of unrecoverable sunk cost as demand continues to decline. Finally, the Commission itself acknowledges that current prices are well below willingness-to-pay and that prices can rise and still remain below the willingness to pay.*

    Combined with the fact that accelerated depreciation is a relatively small contributor to total pipeline prices at a time when the customer base remains relatively broad, there is little evidence to suggest that appropriately paced acceleration now would materially accelerate disconnection. To the contrary, a smoother, more stable long-term price path is likely to provide greater certainty for remaining customers and reduce the price-shock-driven disconnections that occur under back-loaded depreciation profile."[6]

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[5] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Castalia-report-prepared-for-MGUG-Evidence-based-assessment-of-accelerated-depreciation-of-gas-transmission-distribution-networks-22-Janua.pdf, page 6

[6] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Frontier-Economics-report-prepared-for-Vector-Key-issues-in-Gas-DPP4-Draft-Decision-21-January-2026.pdf, page 14

18. Vector, First Gas and Powerco engaged Houston Kemp to assess Castalia's (for MGUG) analysis and claim that accelerated depreciation was causing stranding risk. We have provided Houston Kemp's analysis as part of our joint cross-submission.

19. Houston Kemp's report explains that:
    - Castalia's modelled prices and depreciation profile is stylised and not predictive of what would occur in practice due to assumptions made by Castalia about the depreciation of existing assets. In practice, the Commission can review and adjust asset lives at future resets, which would smooth outcomes and avoid volatility modelled by Castalia.
    - Castalia's report makes inconsistent assumptions about the potential for a death spiral. Castalia alternately claims: (a) death-spiral risk is negligible and (b) near-term price increases can trigger self-fulfilling decline. However, both cannot be true.
    - The risks of acting too early versus too late are asymmetric. Taking actions that are too early can be reversed. However, acting too late is irreversible and could give rise to outsized effects on GPBs and their customers.

20. We consider Houston Kemp's analysis should provide comfort to stakeholders that accelerated depreciation is not causing a death spiral. Accelerated depreciation remains necessary to support the long term benefit of consumers.

<u>Brookfield's acquisition of Clarus</u>

21. Brookfield's acquisition of Clarus was raised by submitters opposed to accelerated depreciation.

22. For example, Castalia's report for MGUG argued Brookfield's acquisition of Clarus showed the "*market valuation of Firstgas is not consistent with investor perception of stranding risk or with the financial model adopted by the Commission*."[7]

23. We do not consider the transaction provides any indication that investor perception of stranding risk differs from the Commission.

24. We consider the transaction indicates investor confidence in the regulatory regime and investor expectation that the Commission will deliver ex ante FCM using accelerated depreciation. This would be consistent with the High Court decision affirming the use of accelerated depreciation to deliver ex ante FCM.

<u>Stranding assumptions are not overly pessimistic</u>

25. Submitters opposed to accelerated depreciation were also concerned that the assumptions around demand decline and stranding risk were overly pessimistic.

26. Castalia's report cited the demand scenarios by EY for the Gas Industry Company as being less pessimistic than the Commission. Castalia also argued that:
    "*The Commission's entire approach is based on a scenario in which the market essentially does not respond to the need for or the incentive to adjust to current market trends, such*

[7] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Castalia-report-prepared-for-MGUG-Evidence-based-assessment-of-accelerated-depreciation-of-gas-transmission-distribution-networks-22-Janua.pdf page 7

as efforts to remove regulatory barriers, investments in biogas, and the development of LNG import options."[8]

27. Optima Energy similarly submitted:
"*Moreover, the assumptions behind calculation of accelerated depreciation levels represent only one broad scenario at a given point in time. The supply situation is variable, if not volatile. For example, if an LNG terminal is installed the volume of gas flowing through pipelines could exceed current assumptions by a wide margin. This would result in windfall gains for owners, while their downside risk has been constrained or capped*"[9]

28. We disagree the assumptions are overly pessimistic. Although there are some factors that point to an ongoing role for gas past 2050, the weight of evidence clearly shows a more negative outlook for gas and that stranding risk has increased since DPP3.

Announcement of LNG import facility

29. Since the draft decision submissions closed, the Government has announced it is progressing to commercial contracting for an LNG import facility as a back-up source to reduce the impact of dry-year risk for electricity and that the facility could be operational as early as 2027 or 2028.[10]

30. We do not expect this would materially change the outlook for gas pipelines. Submissions from ReWiring Aotearoa (quoted above) and First Gas highlighted why LNG imports are unlikely to alleviate stranding risk.

31. Frontier's report for Vector similarly explained:

"*Second, while the Commission places weight on "householder stickiness" and the potential for LNG imports, we previously noted, and reiterate here, neither factor provides a durable basis for assuming a long pipeline life. LNG exposure will tie New Zealand's gas prices to international markets, likely increasing, not reducing, price pressures faced by domestic consumers. This dynamic strengthens, rather than weakens, the case for accelerated recovery. Importantly, household stickiness does not mitigate the sector-wide structural decline in production and reserves; at most it delays, by a short margin, the timing at which customers exit the network in response to rising delivered gas prices*."[11]

32. In addition, GIFWG's refreshed scenario analysis incorporates a scenario involving ongoing network operation through renewable gas and LNG. GIFWG analysis shows that this would moderate the speed of deterioration but would not materially change the long-term viability of GPBs. Even in the most positive scenarios (i.e. where networks continue through a combination of renewable gas and LNG), GPBs face long periods of low or near-zero net cash flows and declining creditworthiness.

Other forecasts

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[8] Ibid

[9] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Optima-Energy-submission-on-Gas-DPP4-Draft-decision-22-January-2026.pdf, page 3

[10] https://www.beehive.govt.nz/release/delivering-lng-support-energy-security

[11] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Frontier-Economics-report-prepared-for-Vector-Key-issues-in-Gas-DPP4-Draft-Decision-21-January-2026.pdf, page 14

33. Submitters such as Castalia for MGUG also highlighted EY's forecast for the GIC as differing from the Commission. However, we do not see any reason to prefer EY's forecast compared to the Commission's independent forecast from Concept Consulting. Concept's forecast is more recent (i.e. 2025 rather than EY's 2024 forecast) and is consistent with GPB forecasts.

34. We also note ReWiring Aotearoa's submission which recommended the Commission use EECA's national Regional Energy Transition Accelerator (RETA) analysis as an input. ReWiring Aotearoa submitted:

"*Given the drop in battery technology prices, which can reduce network connection requirements, cost and investment timelines, and improvements in heat pump technology, this updated analysis could highlight faster and more affordable pathways for electrification of industrial and commercial gas users*."

In-period demand risk

35. We strongly recommend the Commission include a mechanism to manage in-period demand risk (i.e. a hybrid mechanism or re-opener). A key risk to consumers under the current form of control is the potential for inefficient investment and exposure to price shock between regulatory periods. This is because consumers do not receive periodic pricing adjustments in response to changes in demand and therefore consumers cannot reasonably anticipate how prices may change with each regulatory period. This will create uncertainty for consumers making decisions about investing in (e.g.) new appliances.

36. Powerco's submission highlighted a similar risk to consumers and advocated the Commission amend the change event re-opener to address this.

37. Powerco's analysis found:

"*We have modelled the potential DPP5 impact if residential demand was at the level modelled by the Commission for network stranding, compared to our modelled ICP forecast (refer Figure 1). This found that Powerco's revenue at the end of RY31 could be $8 million less than what was assumed at the start of DPP4. With a WAPC, this under recovery would be Powerco's loss, but would have impacts on how we forecast and run our business. A switch to an ICP forecast more aligned to the Commission's model at the time of the reset for the DPP5 period (RY32-36) could create a price increase of $42 per residential ICP starting at RY32. Correcting for this demand reduction in RY32 could result in a price shock of 10% in addition to any other price changes necessary from RY32*."[12]

38. Powerco's analysis is consistent with Frontier's analysis for Vector. Frontier's report found that:

"*We have demonstrated the effect referred to here using a simple version of the New Zealand revenue and pricing model over two regulatory periods. Here, we show the impact of a 2% annual over-forecast of demand (see Figure 2). What it shows is that if demand drops faster than forecast in regulatory period one, price outcomes will vary under a revenue cap and a price cap. Under a revenue cap, prices will increase during the*

[12] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Powerco-Submission-on-Gas-DPP4-Draft-decision-22-January-2026.pdf, page 9

regulatory period, reflecting the more up-to-date information on demand and efficient costs. Under a price cap, prices will not increase, continuing to reflect outdated information on demand and efficient costs. At the commencement of the subsequent regulatory period, customers will be exposed to a much more significant price shock under a price cap than a revenue cap.

Specifically, in 2031 customers would be paying over 10% less than what the true cost-reflective price for the pipeline service should be. That is, in 2031 when customers evaluate whether to remain connected to gas or not in light of prevailing costs, their assessments will be inaccurate by at least this margin. The reality being that in the following year customers will incur a significant price increase. This substantially increases the likelihood of customers making decisions about ongoing gas consumption they otherwise might not have made."[13]

39. Powerco recommended the following to address the potential for price shock:

"*A reopener process provides the opportunity for both the event and impact for both consumers and the GDB to be assessed by the Commission through that reopener process. An adjusted reopener could be an effective mechanism available which ensures that:*
• Maintains incentives to invest at a quality consumers want – GDBs have confidence to continue to invest in a safe and reliable network, as there is certainty that safety values are in place should sudden changes occur that weren't anticipated at the time the reset
• Consumers of today and tomorrow are protected – it is in the long-term interests of today's consumers and tomorrow's consumers to ensure consumers don't pay unnecessarily upfront through allowances, for scenarios that might not eventuate. A flexibility mechanism will provide options to manage that uncertainty.
• Manages price volatility within the period – provides a mechanism to manage pricing within the period and avoid a price shock at the beginning of the DPP5 period (refer section 1.2)
• Scrutiny at lower cost compared to CPP process – It also allows the Commission to provide proportionate scrutiny to in-period changes, to ensure that customers are protected from inefficient expenditure, without the level of scrutiny of a CPP that may not be justified.

In our submission on the Issues Paper we recommended a simple adjustment to the 'change event' provisions to include reasonable changes in revenue. We strongly recommend this change, or similar changes to provide opportunity for a reopener related to demand reduction, be adopted for the DPP4 period…An expectation for price smoothing could also be incorporated in providing an adjusted mechanism. We also recommend the reopener threshold be reset at $1 million recognising the nature of uncertainty and need for flexibility options in DPP4. Demand risk mechanisms should also be further considered ahead of DPP5."[14]

40. In our view, a hybrid mechanism in line with that provided for in some Australian regulatory determinations would best support the long-term benefit of consumers. This would have the same benefits to consumers as Powerco's proposed approach but also be less administratively burdensome (as it could be triggered automatically), would provide better certainty for consumers and suppliers; and would apply symmetrically.

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[13] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Frontier-Economics-report-prepared-for-Vector-Key-issues-in-Gas-DPP4-Draft-Decision-21-January-2026.pdf, page 9

[14] Ibid, page 10

41. However, we also support Powerco's proposed approach as a material improvement to the status quo to protect consumers from price shock.

42. We consider the analysis from Powerco and Frontier (for Vector) provide strong justification for the Commission to implement a mechanism to manage in-period demand risk as part of the final decision.

Appropriate opex allowances

43. The need for appropriate expenditure to support the long-term benefit of consumers was another key theme in submissions from GPBs, including the substitution of opex for capex. For example, First Gas submitted:

    "*We support the Commission's position on substituting opex for capex. We appreciate that the draft decision recognises the value of this flexibility, as it enables gas pipeline businesses to respond to uncertainty and manage risk in a way that promotes the long-term interests of consumers. In particular, we consider the development of short-term interventions to defer or avoid significant long-term investments to be both appropriate and necessary. This approach minimises the risk of asset stranding, ensures continued safety and reliability of supply and helps maintain affordability for consumers during a period of declining demand.*

    We view this as an important step toward future DPP resets and for GPBs to remain adaptive to changing market conditions."

44. We strongly agree that opex/capex substitution can support the long term benefit of consumers and have switched to a more opex based asset management approach.

45. As raised in our submission, we are concerned that the approach to the "trend" in the base, step and trend undermines this approach. The Commission has not applied a floor of 0% for the impact of declining ICPs (in contrast to line length) as it considers there is a likely to be a symmetry of costs between declining ICPs and opex.

46. However, we see no reason to assume costs will decline proportionally with disconnections. For example, when a customer 'disconnects' (rather than the service pipe being 'decommissioned') the service pipe remains in place. Inspection and maintenance must continue for the disconnected customer.

47. Accordingly, we strongly recommend the Commission apply a floor of at least 0% to account for the impact of declining ICPs.

Decommissioning costs

48. GIFWG engaged GPA to undertake a desktop review into potential decommissioning costs. Our joint submission with Powerco and First Gas highlighted:

    "*GPA's preliminary estimate is that the total net present cost of decommissioning and customer disconnection could be around $193 million, comprising approximately $123 million for network decommissioning and $70 million for customer disconnections.3 These are material costs – especially given that if full decommissioning was to occur it would happen at a time when there were very few, if any gas, consumers remaining on our networks. Based on experience in Australia, GPA also estimates that the net present cost could increase to $584 million if disconnection requires permanently removing all gas infrastructure from consumer properties (not just isolating them) – highlighting just how sensitive cost estimates are to the assumed scope of activities involved.*

GPA's analysis provides a useful starting point for future analysis on decommissioning, including stakeholder engagement on potential network-wide decommissioning, and how this should or could be delt with within the regulatory framework"[15]

49. We consider there is strong consumer benefit in acting early on decommissioning costs since there is a wider customer base to recover these costs from.

50. Some submissions recommended a role for Government policy in the managing decommissioning costs. For example, ReWiring Aotearoa advocated:

"*There are various risks associated with revenue recovery, affordability and how decommissioning of gas networks are paid for, for example:*
1. Given current gas demand uncertainty, network assets may still become stranded (cashflow negative) despite the earlier cost recovery proposed in the draft decision, and gas distribution businesses have no obligation to supply remaining customers at a loss. This creates a financial liability for the Government who may need to underwrite any cashflow negative gas distribution network until the last customers could be transitioned away from gas and support customers to switch to alternatives.
2. The cost recovery from customers remaining on gas distribution networks could escalate as more and more customers disconnect, and costs are spread over a much smaller customer base. This could create affordability issues for lower income households and renters who have less access and control over electrification of their properties and are more likely to be stuck with high cost residential gas appliances as gas price increases.
3. There are no cost recovery provisions for gas pipeline businesses to fund decommissioning of networks at end of life and the cost of this could become a liability for tax payers.

Government funding could be set aside as a backstop solution that could be used as needed overtime to support a managed gas transition. The fund could target support for a staged gas network decommissioning, when this would maximise consumer benefits. For example the fund could:
1. Proactively help fund staged network decommissioning (for example funding decommissioning of parts of gas distribution networks with dwindling demand and target fuel switching support to any remaining customers).
2. Write down some of the gas distribution asset value and reduce revenue recovery.
3. Fund the final stage of gas distribution network decommissioning if not undertaken by gas pipeline businesses at the end of gas network life.

The fund could help avoid an unplanned liability for tax payers to decommission gas networks and ideally avoid costs associated with an unmanaged gas transition associated with stranded gas network assets. Although if this outcome did occur the fund could help support customers in this circumstance. This could be done via allocating funds to underwrite operation of stranded gas network assets until remaining customers are moved off gas (and supporting these customers to switch).

The fund would not be needed immediately and could be grown through investment in electrification loans. This would provide a win-win by supporting households to access affordable capital that could be used to invest in household electrification and solar that

[15] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Firstgas-Powerco-Vector-Letter-to-the-Commerce-Commission-Submission-on-the-Draft-DPP4-Decision-22-January-2026.pdf, page 1-2

would currently save on average $1,800 per year and help these homes avoid affordability issues associated with increasing gas prices."[16]

51. We strongly encourage the Commission to work with wider Government policy makers such as MBIE to consider the best way to manage decommissioning costs. We consider this work should begin as soon as possible as consumers will benefit from early action.

Capital contributions

52. Vector recovers 100% of the cost of connecting to the gas network. We consider this is in the long term benefit of consumers by avoiding any cross-subsidisation of connection costs.

53. We were pleased to see other stakeholders appeared to endorse this approach.

54. Mercury submitted that it:

    "*Agrees that existing customers should not bear any costs associated with new gas connections and that all new connections be self-funded.*"[17]

55. ReWiring Aotearoa submitted:

    "*Whilst we acknowledge that there will be benefits from more customers connecting to the gas distribution network as ongoing costs can be shared over a large pool of customers, we think on balance it is in the best interest of gas customers to require new connections to cover the full capital cost of their connection up-front.*"[18]

Disconnections

56. We acknowledge there was concern from some stakeholders about the cost of disconnection and potential barriers to electrification.

57. ReWiring Aotearoa submitted:

    "*As Rewiring noted in previous submissions - customers can be hit with the full cost to close off the connection of the gas pipe on their property from the gas network pipeline. This full decommission of the connection involved digging at the edge of the property to manually close off the connection. This means the pipes on the property are no longer live (i.e. filled with gas). We have heard that this cost can be up to $3,000. The other option is simply to turn off the connection at the meter on the property. This option only costs around $300, and whilst the gas pipelines on the property are still live - the risk here is the same as when the household is using gas.*

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[16] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Rewiring-Aotearoa-Submission-on-Gas-DPP4-Draft-decision-22-January-2026.pdf, page 4-5

[17] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Mercury-Submission-on-Gas-DPP4-Draft-decision-16-January-2026.pdf, page 1

[18] Available: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Rewiring-Aotearoa-Submission-on-Gas-DPP4-Draft-decision-22-January-2026.pdf, page 2-3

Some gas distribution networks require their customer to undertake the higher cost $3,000 option, and some retailers may still charge customers a daily charge if they do not undertake the permanent costly full connection decommissioning. Others allow customers to choose if they want to fully decommission their connection and pay the cost of this, or take the lower cost alternative and turn off at the meter.

We think all customers should get to choose between paying around $3,000 vs $300 to disconnect from gas with no further ongoing gas charges. This is something that the Commerce Commission should progress, including through engagement with other government agencies, following the DPP4 reset."

58. Vector has moved to a full disconnection policy where we recover 100% of the cost of disconnections. In line with our views on connections, we consider consumer interests are best served by avoiding cross-subsidisation between customers.

59. However, customers retain choice between permanent disconnection or the less expensive option of removing the meter but leaving the pipes live (at least on Vector's network). Although we note in some circumstances, due to the nature of the works, it is not possible to solely disconnect at the meter.

Yours sincerely

[redacted]

Richard Sharp
GM Economic Regulation and Pricing