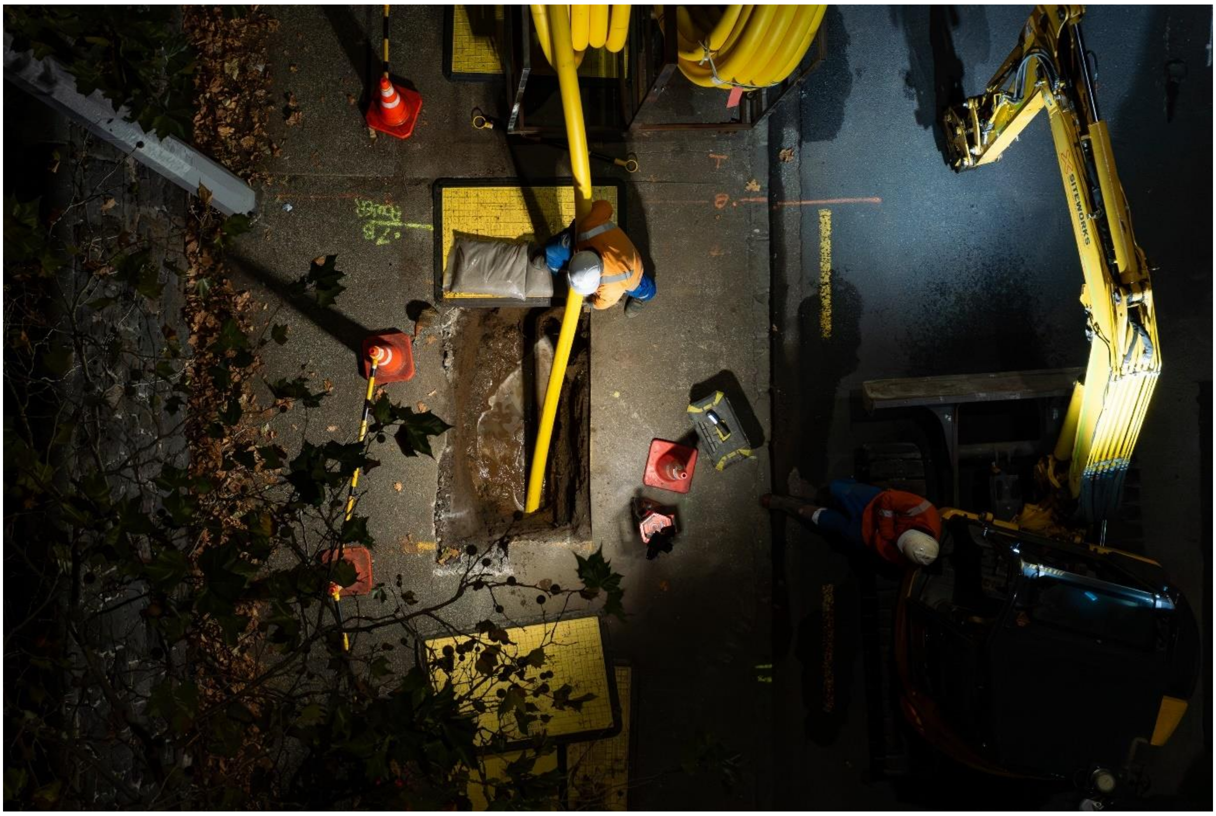
Gas Default Price Quality Path beginning 1 October 2026: Draft Decision

Vector submission



22 January 2026

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

2. We have submitted an expert report from Frontier Economics responding to the Draft Decision, along with expert opinions from Houston Kemp, Oxera and Axiom Economics on in-period demand risk as part of our response to this consultation.

3. We have provided some confidential information attached as Appendix One and Two. This relates to updated information for our SaaS step change request and suggested input to the CPRG forecast. The information contained in Appendix One and Two is confidential and commercially sensitive and should not be published on the Commission's website or otherwise publicly disclosed.

4. Other than Appendix One and Two, none of this submission is confidential and we are happy for it to be published on the Commission's website.

Executive summary

5. The Draft Decision has largely retained the settings from DPP3. We consider this goes some of the way to manage issues in the gas sector. However, the emergence of supply side constraints (and resulting market and policy uncertainty) has materially changed the context since DPP3.

6. We recognise affordability is a key concern for consumers and that the DPP must strike a difficult balance between minimising price increases, providing the appropriate price signals to consumers and delivering a revenue profile maintains the principle of ex ante FCM, allowing GPBs to invest and maintain their networks to ensure a safe and reliable gas supply. This all needs to be achieved in the context of declining and highly uncertain demand. We consider the current context necessitates further action from the Commission to preserve incentives to invest and support the long-term benefit of consumers.

7. In terms of process, we commend the Commission for seeking consumer perspectives through targeted engagement. We found the scenario modelling workshop useful as it gave stakeholders an opportunity to share and discuss different perspectives on possible demand scenarios. We consider the consultation period would benefit from additional workshops on other key topics.

8. We were encouraged the Commission has recognised that moving to a more opex focused operating model can support the long-term benefit of consumers. However, we are concerned the Commission's approach to the "trend factor" used in the base, step and trend approach will undermine efficient allowances if retained in the final decision. We do not consider there is any reason to assume costs will decline proportionally with disconnections.

9. The table below summarises Vector's position on key issues for the Draft Decision.

Issue	Vector view
In-period demand risk	<u>CPRG forecast</u> We support the Commission's decision to use GPB demand forecasts as an input to the CPRG. Our submission provides additional and updated information on the inputs for the CPRG that we recommend the Commission use to ensure the CPRG is based on the most accurate and up-to-date information. <u>Managing in-period demand risk</u> Although we agree GPB forecasts are the best information available, it is extremely difficult to forecast connections and volume in the current environment. We consider DPP4 needs to include a mechanism to manage in-period demand risk to protect the long term benefit of consumers. Our expert reports from Houston Kemp, Oxera, Axiom Economics and Frontier Economics all describe the negative consumer outcomes produced by a weighted average price cap. We consider from an economic perspective it is clear a revenue cap is the appropriate form of control in the current environment. However, we recognise consumers may not accept all in-period demand risk being allocated to them at a time of significant price increases. Accordingly, we strongly recommend the Commission introduce a wash-up mechanism (e.g. a "hybrid" form of control or, at a minimum, a re-opener) to address in-period demand risk. This would go some way to mitigating the increased demand risk faced by suppliers, while more equally sharing demand risk between suppliers and consumers. Failure to address in-period demand risk in DPP4 will compromise the long term benefit of consumers by: • Compromising incentives to invest and the financeabillity of the notional firm if demand/connection growth is less than forecast.

	The under recovery of building block revenues within a DPP period compromises ex ante FCM as building block revenues foregone cannot be recovered in future periods. Forecasting errors within a DPP period under the WAPC form of control can have a significant impact on the net present value of cashflows creating a greater risk of not achieving ex ante FCM; • Compounding the risk that consumers face large price shocks in later regulatory periods. Under the WAPC form of control starting prices are set on an expectation of forecasted demand delivering the required building block revenues in the DPP. After initial starting prices are set, subsequent prices are only permitted to increase by CPI i.e. there is no adjustment to prices for changes in demand. If prices are set too low within a DPP period, then this can result in a significant step up in prices between DPPs. Lower prices within a DPP can also result in consumers investing in appliances expecting that current prices reflect future prices and then are surprised by significant increases in prices when building block revenues are reset at the next DPP; • Creating inappropriate incentives to grow connections and gas volumes in the context of asset stranding risk and government objectives to achieve net zero carbon emissions; • Incentivising GDBs to move to more fixed pricing which could be counter to desirable social and environmental outcomes that could be achieved by prices more linked to consumption; and • Compromising net zero objectives and electrification. Under-investment in the gas sector risks a disorderly energy transition. It could also lead to increased emissions from gas networks (due to e.g. increased fugitive emissions). We understand the Commission did not pursue a hybrid mechanism or a re-opener on the basis stakeholders had not quantified the potential risk to consumers resulting from a demand shock. We consider a key risk to consumers from the current WAPC form of control is the potential for inefficient investment and

	consumer price signals and exposure to price shock between regulatory periods. Frontier's report explains that under a WAPC, consumers do not receive periodic pricing adjustments in response to changes in demand. This means 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. Frontier's report demonstrates this effect showing the impact of a 2% annual over-forecast in demand: • Prices will increase under a revenue cap (reflecting more up to date information on efficient costs) but remain fixed in a price cap. • At the subsequent regulatory period, consumers would be exposed to a much more significant price shock under a price cap than revenue cap. • By 2031, customers under a price cap would be paying 10% less than what the true cost reflective price for the pipeline should be. • This means customers in 2031 making investment decisions about being connected to the gas network in light of prevailing costs would be basing their decisions on information that is inaccurate by at least this margin. These customers would experience a significant price increase in the next year. • Customers may also prematurely leave the network if they experience a price shock between periods (i.e. if they misinterpret a one-off correction between periods as an ongoing trend). We consider the additional evidence quantifying risk to consumers contained in Frontier's report should provide sufficient justification for the Commission to pursue a hybrid mechanism (or at a minimum a re-opener) as part of the final decision.
Stranding risk	The draft decision maintains the same accelerated depreciation profile as DPP3. We agree accelerated depreciation remains a critical and appropriate option to manage stranding risk however, the current revenue profile is only a partial solution to the level of stranding risk faced by GPBs.

	As raised in response to the issues paper, GIFWG modelling shows networks could become cashflow negative by 2042. This would mean networks would become uneconomic well before the Commission's assumed winddown date in the 2050s. We recommend the model be updated to include a scenario where networks winddown in the early 2040s in response to negative cashflow. We note the draft decision did not appear to engage with modelling showing the potential for networks to become cashflow negative in the early 2040s. We also note that the way the depreciation adjustment factor is applied to additions results in less than required depreciation in DPP4 that if projected forward would result in those additions having significant residual value in the 2050s. This is exacerbated by the Commission using a useful life for depreciating additions of 45 years whereas the actual useful life of additions is considerably lower. This results in uncompensated depreciation in DPP4 that is not ever washed up in future periods.
Operating expenditure	The Commission's draft decision on step changes recognises that Vector's opex/capex trade-off step change supports the long-term benefit of consumers. However, 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. There is 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. GPBs must continue to meet the same safety and reliability standards irrespective of changes in customer numbers. The underlying physical network remains in place, requiring ongoing maintenance, inspection, and compliance. As a result, most

	operating costs are fixed or only partially variable, and essential functions (e.g. such as public safety management, emergency response, leak detection, statutory compliance, system operations, customer service, and incident readiness) must be maintained. Accordingly, we strongly recommend the Commission apply a floor of at least 0% to account for the impact of declining ICPs. Vector's move to an opex based operating model means opex will increase even though ICPs are declining. Failure to account for this in the base, step and trend creates a real risk that that opex allowances will be insufficient to cover additional maintenance required for an opex based asset management approach. This would not be in the long term benefit of consumers. In addition, the Draft Decision did not accept the full amount of Vector's requested step change for SaaS. We have provided additional information in Appendix One to demonstrate the need for this step change.
Capital expenditure	Overall, we support the Commission applying more targeted scrutiny to individual capex categories rather than the broad cap that has been used in previous years. Making greater use of AMP forecasts will support the long-term benefit of consumers by providing a better reflection of the evolving circumstances in the gas sector. We also acknowledge the Commission's sensible views on capital contributions which is in line with Vector's recognising that "growth should pay for growth" and existing customers should not be burdened with costs caused by connecting parties.
Decommissioning costs	We appreciate that the Commission has recognised decommissioning costs are an issue and that acting sooner can support the long term benefit of consumers. However, the Draft Decision is not to introduce an allowance for decommissioning costs as the Commission does not have sufficient information on the basis of future decommissioning liabilities or the scale of the costs.

	GIFWG has submitted a report by GPA which estimates the cost of decommissioning could be around $193 million NZD (as a baseline estimate based on the most theoretically efficient pathway) This figure is significant and highlights the need for action as soon as possible to avoid significant price increases later for the declining customer base. If the Commission cannot act during this DPP reset, we urge it to commence work as soon as possible as part of a separate process. If a separate process is undertaken the Commission should consider now, how it would reopen the DPP4 price path, if the conclusion from that process was that decommissioning costs should be recognised in DPP4. We acknowledge the solution may need to involve policy makers such as MBIE to determine a solution. We would welcome the opportunity to be part of conversations with the Commission and wider government on decommissioning. In our view, it is crucial that steps are taken now to avoid an unmanageable burden on consumers and networks later on when the need for full scale network decommissioning arises.
Starting price	We agree with the Draft Decision to base starting prices on the Commission's assessment of current and projected profitability, rather than rolling over prices. We agree with the Commission this will better reflect the evolving operating environment of the gas sector than the alternative.
Innovation	The Commission's Draft Decision is not to introduce an innovation allowance for GPBs to pursue renewable gases. We continue to consider that an innovation allowance would support the long-term benefit of consumers by providing greater incentives for GPBs to invest in innovative solutions that could re-purpose the network. We agree with the Commission's position that GPBs "*have a natural incentive to extend the useful life of their networks in*

	order to continue to operate and remain in business and invest where it is economic to do so." However, the current level of in-period demand risk creates a disincentive to invest in innovation. If GPBs continually under recover revenue in-period, they will need to pull back "discretionary" investment such as that on less certain innovations.

In-period demand risk

10. We support the Commission's decision to use GPB volume forecasts as the input to the CPRG. We agree with the Draft Decision that –
    - GPBs are forecasting demand the best possible information as they have the best information on existing customers, potential customer enquiries, customer willingness to pay and other trends;
    - The most recent forecasts reflect the most up to date expectations of demand; and
    - The Commission's independent testing of forecasts show they are reasonable.

11. We have suggested some updated inputs on the CPRG forecast in Appendix Two that would provide a more accurate and up-to-date picture for the CPRG.

12. Although we agree GPB forecasts are the best possible information available, it is extremely difficult to forecast demand and connection growth in the current environment.

13. As the Commission is aware, we consider a key shortcoming is the current regulatory regime lacks any mechanism to mitigate in period demand risk.

14. Our expert reports from Oxera, Houston Kemp, Axiom Economics and Frontier describe harm to consumers from in-period demand risk created by the current form of control.

15. We consider it is clear from an economic perspective that a revenue cap is the appropriate form of control in the current environment. However, we recognise that consumers may not be willing to be allocated all in-period demand risk in an environment of significant cost increases.

16. Accordingly, we strongly recommend the Commission pursue a symmetric mechanism to address in-period demand risk. The risk that demand or connection growth differs significantly from forecast is high and creates the real prospect of winners and losers of both network owners and consumers.

17. If the Commission does not address in-period demand risk, a key risk for consumers is exposure to price shock and the potential for consumers to make inefficient investment decisions due to a lack of up-to-date pricing signals. This is because the weighted average

price cap does not provide any periodic price adjustment responding to changing demand over time.

18. We consider the best option would be a hybrid mechanism (in line with that approved by the AER). However, a re-opener would also be better than the status quo.

19. Failing to address in-period demand risk will compromise the long term benefit of consumers by:
    - Compromising incentives to invest and the financeabillity of the notional firm if demand/connection growth is under-forecast;
    - Compounding the risk that consumers face large price shocks in later regulatory periods in the absence of price signals provided by more gradual increases in prices in response to falling demand;
    - Creating inappropriate incentives to grow connections and gas volumes in the context of asset stranding risk and the need to move to net zero carbon emissions;
    - Incentivising GDBs to move to more fixed pricing to alleviate volume risk which may counter desirable social and environmental objectives that may be achieved by more consumption based pricing; and
    - Compromising net zero objectives and electrification. Under-investment in the gas sector risks a disorderly energy transition. It could also lead to increased emissions from gas networks (due to e.g. increased fugitive emissions)

The risk that out-turn volumes or connections differ significantly from forecast is a major concern in DPP4

20. Our expert economic reports provide further description of the current New Zealand context and the magnitude of forecast risk.

21. Axiom Economics report explained how current uncertainties are interdependent and cascading:

    "*The uncertainties…are all deeply interconnected. The decline of Māui tightens supply; tighter supply influences Methanex's production decisions; those decisions affect system balancing and tariff recovery; and all are shaped by policy signals and other exogenous factors such as the scope, scale and timing of the potential LNG initiative. Small shifts in one area can cascade through the others, magnifying volume forecasting error.*

    At one extreme, if new exploration occurs and proves successful and the LNG project is delivered efficiently, New Zealand could maintain a viable gas market for an extended period, supporting relatively stable distribution volumes. At the other, if production ceases abruptly, exploration does not happen or disappoints, Methanex exits, and electrification accelerates, throughput could decline precipitously – potentially approaching zero beyond the medium term"

22. Oxera's report quantified recent volatility in gas consumption based on MBIE's quarterly data, finding that:

"*Across all sectors, the coefficient of variation is 10% for gas over the period 2013 to 2020, compared with 5% for electricity. The difference in variability between gas and electricity is even larger if most recent years (2021–25) are included. During this period, supply shortages have significantly reduced gas deliverability, leading to lower industrial consumption. When the years 2021–25, i.e. years with increasing supply shortages, are included, overall gas consumption variability increases to 14%, while electricity consumption variability remains unchanged at 5%. Across the individual sectors, the variation in gas consumption then consistently exceeds that of electricity including in the 'Other' category.* ***This indicates that gas demand is becoming more volatile over time.***"[1] [emphasis added]

23. Oxera further explained:

"*Volatility in gas consumption is likely to increase further, not only because gas supply is becoming more uncertain, but also because a significant share of gas in New Zealand is used for electricity generation (about one third in 2024). As renewable energy penetration increases, gas can be reasonably expected to play an evolving role: overall demand will tend to decline, but consumption might become increasingly volatile as gas transitions from being a baseload fuel to a critical backup fuel that provides flexibility and security in a renewables-dominated system.*"[2]

GPBs cannot adequately manage their risk through the current regulatory settings

24. The Draft Decision suggested that GPB's can manage demand risk through:
    - "*Management of expenditure;*
    - *Restructuring pricing;*
    - *Application for a CPP; and*
    - *Application for a capacity re-opener*"[3]

25. We recognise these options are available and have a role to play in managing demand risk. However, they are not sufficient to provide GPBs with confidence the regulatory framework enables them to manage significant variations in demand from forecast.

26. In terms of the options suggested by the Commission, we note that:

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[1] Oxera, *Suitability of a Revenue Cap for GDBs under DPP4: Report Prepared for Vector Limited* (20 January 2026), page 14

[2] Ibid

[3] At A50.1 – A50.4

- **Management of expenditure**: Vector has, and will continue to, manage its expenditure in line with this risk. However, there is a limit to the amount of expenditure a GPB can reduce without compromising a safe and reliable supply. If revenue is consistently under recovered due to variations in forecast, efficient investment will be compromised.

- **Restructuring pricing**: Vector has already implemented a greater use of fixed charges in response to in-period demand risk so our ability to further use pricing to manage this risk is limited. There are also downsides to fixed pricing in terms of the dilution of pricing signals to consumers.

- **Application for a CPP**: This option is uncertain and administratively burdensome for the GPB and Commission. We consider a hybrid mechanism or re-opener would be more proportionate than a CPP for in period demand risk. A CPP is designed to allow a distributor to depart from the generic DPP when its circumstances require different investment, quality standards, or revenue allowances. We are not aware of it being presented previously by the Commission as a tool to address uncertainty or risk around future demand—instead, it is primarily a tool for funding higher or differently timed expenditure, or dealing with catastrophic events.

- **Capacity re-opener:** Our understanding is this would not be available for a scenario where volumes or connections are lower than forecast which is a key risk for GPBs to manage in DPP4. We would be grateful for the Commission to clarify if it believes it would.

A weighted average price cap provides the wrong incentives and will undermine the long term benefit of consumers in the current environment

27. Houston Kemp's expert report explains the form of control and forecast error has an impact on whether ex ante FCM can be achieved in the context of a declining network. Houston Kemp explains:

    "*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."[4]

28. Oxera's report provides detail on the risk of under-investment and its potential to undermine the energy transition. Oxera noted that:

"*The transition to a decarbonised energy system is characterised by significant uncertainty regarding the long-term availability of, and demand for, gas, as well as the infrastructure investment required to support it. The NZCC recognises that 'the main forward-looking issue for GPBs is how to recover capital costs in a declining market'.*

Under a price cap regime, uncertainty around future gas volumes and consumption patterns creates substantial downside risk that could prevent GDBs from adequately recovering their costs. When revenue becomes unpredictable, these businesses face constraints on their ability to invest in essential network activities, including maintenance, right-sizing infrastructure to match declining demand, and retrofitting pipelines for future fuels such as biogas or hydrogen. These investments are crucial for ensuring an orderly energy transition, as GDBs must adapt their networks to accommodate decarbonisation efforts while maintaining security of supply in an energy system that increasingly relies on intermittent renewable sources.

Unlike in some other jurisdictions, gas networks in New Zealand have no obligation to supply gas to customers. This reality, combined with volume uncertainty under a price cap, creates relatively weak incentives for GDBs to invest in maintenance or replacement of network infrastructure. The NZCC mentions 'managing expenditure' as a tool GDBs can use to address the demand risk. However, delaying or cancelling essential work due to cost reasons could result in negative consequences for consumers. In the worst case, if maintenance costs exceed long-term revenues from a declining client base, GDBs may choose to shut down parts of the network prematurely, leaving businesses and residential consumers without gas supply before viable alternatives are available. Such premature shutdowns could trigger a disorderly transition with cascading effects. Accelerated electrification of gas use-cases could outpace electricity network capacity, leading to potential quality and reliability issues on the electricity side. This uncoordinated transition—where future energy plans are potentially disrupted by premature gas network closures—represents a further cost to consumers that could materialise if GDBs face pressure to systematically underinvest."[5]

29. Oxera further explains:

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[4] Houston Kemp, *Form of Control for New Zealand Gas Businesses: Report for Vector* (20 January 2026), iii

[5] Oxera, *Suitability of a Revenue Cap for GDBs under DPP4: Report Prepared for Vector Limited* (20 January 2026), pages 14-15

"a price cap increases GDBs' revenue uncertainty and exposes them more directly to volume risk. This may lead to underinvestment in gas networks, potentially not only causing a disorderly transition, as discussed above, but also delaying emissions reductions.

Facing binding price caps and uncertain demand, network operators may rationally defer or scale back maintenance and renewal expenditure, and reduce or delay investment needed to prepare networks for low-carbon gases (e.g. biomethane or hydrogen). Both behaviours have potential climate and social cost implications.

Fugitive emissions (i.e. gas leaks or escapes from the pipelines) are one example of how network quality directly affects decarbonisation efforts. So far, under a relatively stable customer base, the existing regulatory regime has been effective in supporting sufficient investment to maintain a well-performing network—gas leaks on transmission and distribution networks have fallen over time.36 Continuing this trend, and avoiding increases in fugitive emissions and associated abatement costs despite the expected decline in gas demand, requires ongoing incentives for investment in leakage prevention, detection, and repair.

Price caps may also discourage investment in making the network 'transition-ready'. This might encompass adapting infrastructure to safely transport renewable gases, integrating with decentralised energy systems, or supporting flexible, lower-carbon use patterns. If networks cannot be confident of recovering these costs within a capped-price framework, they are more likely to delay or minimise such investments.

A more flexible framework that focuses on stable revenue recovery rather than strict price caps is better aligned with net zero goals because it provides gas networks with a more appropriate incentive structure."[6]

A mechanism to manage in-period demand risk is needed to support the long term benefit of consumers

30. We strongly recommend the Commission implement a hybrid mechanism or, at a minimum, a re-opener.

31. These mechanisms would support the long term benefit of consumers by:
    - Going some way to mitigate the disincentive to investment created when outturn volumes/connections differ from forecast resulting in lost revenue over the period;
    - Minimising price shocks for consumers at later resets; and
    - These mechanisms could be symmetric (i.e. also triggered if volumes/connections significantly outperformed forecast resulting in additional in-period revenue) so would more equally share in-period demand risk between consumers and GPBs.

[6] Ibid, pages 16-17

32. The Commission's draft decision is not to introduce a hybrid mechanism or re-openers. Our understanding is this was due to a lack of evidence quantifying the level of risk to consumers that would justify introducing either of these mechanisms.

33. Our expert report from Frontier Economics has estimated the potential risk for consumers resulting from a large demand shock.

34. Frontier's report explains:

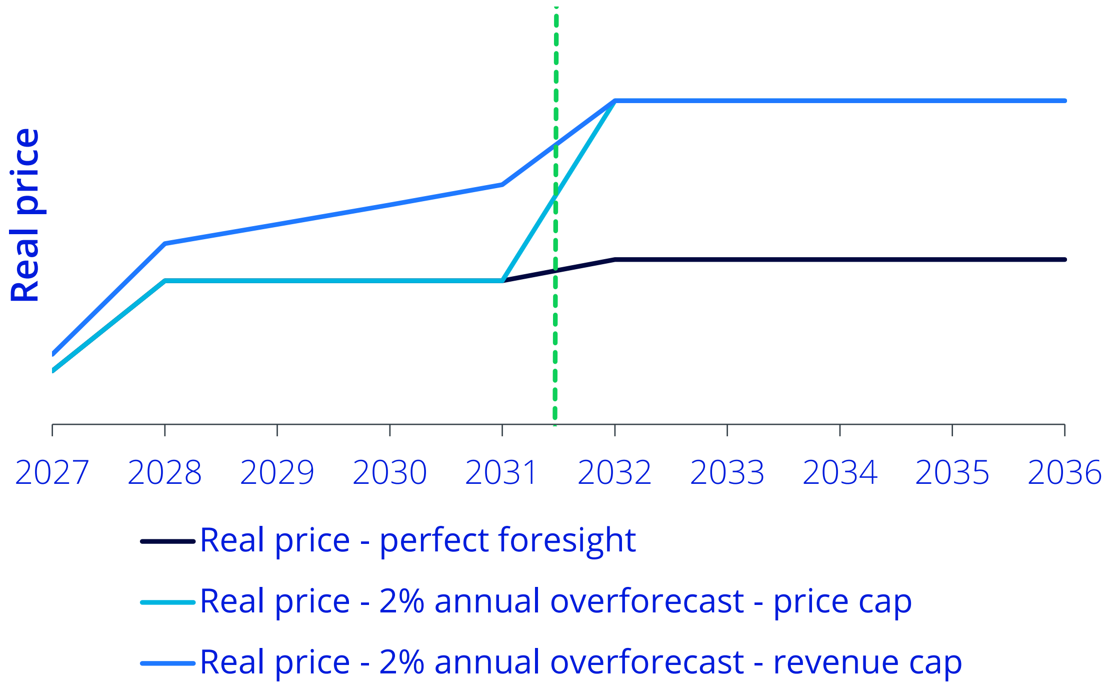
"*In response to the Commission's observation that it has not received submissions quantifying the risk to consumers' long-term benefit arising from demand risk, we submit that risks posed by demand volatility under a WAPC framework are both material and multifaceted, with important implications for consumer outcomes and market efficiency over time.*

The primary risk to consumers resulting from declining demand under a WAPC is the potential for inefficient investment decisions and exposure to price shocks between regulatory periods. These risks stem from the lack of periodic price adjustment that respond to changing demand over time. With prices fixed during the regulatory period under a WAPC, consumers do not receive pricing signals that reasonably reflect up-to-date information. This means that consumers cannot reliably anticipate how prices may shift at the end of the period, leading to uncertainty when making decisions about investing in new appliances or equipment. This lack of transparency means consumers may inadvertently commit to energy solutions based on outdated price signals, undermining their ability to make informed choices that align with their long-term interests. The key implication being that the trend in prices, rather than the absolute level at any given moment, is what matters most for customer signalling and prudent investment.

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 Error! Reference source not found.). 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 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.

Furthermore, the price shock that occurs between regulatory periods under a WAPC may cause some customers to prematurely abandon gas even if remaining connected to the gas network would have remained in their long-term interest. For instance, customers may misinterpret a one-off correction between regulatory periods as part of a persistent and regular trend, prompting them to switch technologies inefficiently.

Figure 1: Impact on prices from a 2% annual over-forecast under a price cap and a revenue cap



Source: Frontier Economics

By contrast, a revenue cap approach offers annual price adjustments that track demand changes, greatly enhancing price transparency for consumers. This form of control enables consumers to make better-informed decisions and reduces the likelihood of being caught off guard by significant price increases at regulatory resets. Because prices are updated each year in response to actual demand, any changes in costs are reflected incrementally rather than in large, abrupt shifts. This annual recalibration ensures that price signals remain current and visible to customers, allowing them to anticipate and respond to changes more effectively. As a result, consumers are better equipped to plan and invest in energy solutions with confidence, having regard to the general trend in prices over time."

35. We note the Commission's consumer research found mixed messaging in the sector was creating confusion for consumers where, "*consumers are unable to make informed decisions about their energy use due to inconsistent messaging, lack of transparency, and*

limited access to clear information. This confusion is compounded by the absence of a national strategy and accessibility challenges, particularly for low income groups."[7]

36. Supporting an approach that enables networks to provide better price signalling would assist in providing more clear messaging for consumers.

Taking steps to address in period demand risk is consistent with the direction of travel of regulators internationally

37. Internationally, regulators are grappling with the best mechanisms to manage in period demand risk for gas networks and their consumers.

38. Our expert reports describe the direction of travel internationally is to take steps to address in period demand risk arising from forecast volatility rather than leave networks to bear all risk.

39. Houston Kemp's report notes that:

"*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*."

40. Oxera's report discusses European regulatory precedent, finding:

"*Given New Zealand's net zero commitments, reductions in natural gas consumption should be encouraged, not disincentivised through a framework that rewards volume growth.*

International precedent strongly supports this regulatory framework transition. As examples, 22 out of 28 European countries use a revenue cap for gas distribution networks, with only six European countries retaining a price cap."[8]

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[7] Commerce Commission, *Summary of our kōrero with residential gas consumer advocates* (September 2025), page 4

[8] Oxera, *Suitability of a Revenue Cap for GDBs under DPP4: Report Prepared for Vector Limited* (20 January 2026), page 27

41. The Commission applies a revenue cap as the form of control for the GTB in New Zealand.

42. Axiom Economics report explains:

“*There is an increasing incongruity in New Zealand’s regime. Gas transmission has long been regulated under a revenue cap on the basis that demand is difficult to forecast, largely outside the supplier’s control and capable of moving materially within a regulatory period. Those are precisely the conditions now facing gas distribution. If the rationale that justified a revenue cap for transmission was sound then, it is difficult to see why the same logic does not now apply – perhaps even with greater force – to distribution.*

As Frontier explained in its report, the criteria the Commission relied on for transmission map directly onto the distribution context today. Forecasting is fragile; the principal drivers of volume are exogenous and financeability depends on a predictable pathway to recover efficient costs over time. Retaining a price cap for GDBs in these circumstances creates a form-of-control asymmetry that is hard to reconcile with the principle of allocating risk to the party best able to manage it.”

43. Accordingly, we consider introducing a mechanism to address in-period demand risk would be consistent with regulatory practice internationally.

CRPG model

44. We recommend some updates to the Commission’s CPRG model that would provide a more accurate and up-to-date picture of Vector’s volume and connection forecast.

45. These have been provided in Appendix Two. This contains information related to Vector’s forecast ICPs and billed quantities that is not contained in our AMP. This information is confidential and commercially sensitive so should not be publicly disclosed.

Stranding risk

46. The Draft Decision has maintained the same accelerated depreciation profile as DPP3.

47. We strongly support the use of accelerated depreciation to manage stranding risk. This will support the long-term benefit of consumers by supporting an expectation of ex ante FCM.

48. The High Court’s 2022 decision affirmed the use of accelerated depreciation to compensate stranding risk. The High Court stated:

“*Gas pipelines now face a very real risk of network stranding as demand falls away as a result of the government’s policy response to climate change. In a workably competitive market, a falling away of demand in this way would result in lower prices, all else equal, and firms would not expect to recover all their sunk costs. However, these same firms would* *have been compensated ex ante for carrying this risk, which regulated gas pipelines have not been. The long-term benefit of consumers of regulated services will not be served if suppliers of those services receive no ex ante compensation for bearing stranding risk and cannot be confident that stranding risk will be addressed as the need arises. Investment incentives for both gas pipeline services and other services regulated (and potentially regulated) under pt 4 would be undermined in a scenario of this sort, to the detriment of consumers.*"[9]

49. We consider stranding risk has materially heightened since DPP3 and updates to the Commission's depreciation model are warranted.

50. The Draft Decision summarises the key factors relied on by the Commission as the:
    - "*Emergence of tighter-than-expected gas supply – 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.*"[10]

51. We consider this appears to underweight the impact the gas supply shortage is having on the outlook for the gas sector. The evidence since DPP3 suggests there is a greater likelihood of winddown before 2050.

52. For example, Boston Consulting Group's report into New Zealand's energy system described the outlook for New Zealand's gas supply:

    "*New Zealand's upstream gas outlook is now defined by ageing and declining reserves. In the last decade, upstream gas supply has declined 50% from 217 PJ in 2015 to a forecast of 107 PJ in 2025 (see Exhibit 30). Maui, Pohokura and Kupe together supplied 70% of national gas in 2015 (147 PJ), but today their total production has declined by 65% to a forecast of 50 PJ in 2025 – just 47% of total supply based on the Ministry of Business, Innovation and Employment (MBIE) Producer Forecast. The decline in production of these three fields drove the majority of the 90 PJ under delivery in total gas supply in 2024 versus expectation based on 2022 MBIE Producer Forecast. The year 2019 marked a turning point, highlighting the effects of ageing reservoirs nearing end of life despite moderate investment. From 2019 to 2024, Pohokura's annual delivery alone fell 75%. Now, most supply comes from a small set of late-life Taranaki fields, increasing system-wide risk*
    …

    Most of the gas industry's drilling efforts have been development wells. Development well activity since 2021 has been consistently above the average drilling activity (nine wells per

[9] Major Gas Users Group v Commerce Commission [2024] NZHC 959 at 162

[10] At 3.58

year). However, these development efforts haven't delivered expected results. For example, Kupe's 2024 development campaign was unsuccessful: the KS-9 intervention failed to deliver sustainable flow, capping field output and causing both financial losses and underperformance against target flows.

New Zealand's ban on new offshore exploration permits was introduced in 2018, with only a few existing exploration permits proceeding to drilling in subsequent years. Most of these campaigns, including OMV's 2019– 2020 wells, were unsuccessful and subsequently abandoned, with only one minor discovery that was not developed. The reversal of New Zealand's ban on offshore exploration in July 2025 removed a policy constraint, but the investment case for exploration is impacted by demand uncertainty and rising costs. Knowing this, significant focus is needed on disciplined, value-driven development of existing wells. Incremental gas supply is a function of drilling intensity and drilling success; New Zealand needs to concentrate capital on the most productive existing assets and sequence development efforts based on demonstrated results.

Drilling efforts have resulted in disappointing outcomes as ageing reservoirs experience reduced well productivity and pressure. As a result, gas production has repeatedly underperformed MBIE Producer Forecasts by 10–20% each year since 2022, eroding confidence and increasing uncertainty across the sector."[11]

53. The current supply outlook represents an unprecedented level of risk for the gas sector.

54. In addition, the GIFWG's scenario modelling shows that networks could become cashflow negative by 2042. As raised in our submission to the issues paper, the Commission's model assumes a shutdown once the last customer has left the network. However, a rational business would be looking to shut down once it became cashflow negative. The network could become uneconomic well before the assumed 2050 winddown.

55. Accordingly, we strongly recommend the model be updated to recognise a potential winddown date in the early 2040s to maintain ex ante FCM.

56. Frontier's report further explains and recommends:

"*First, we acknowledge the Commission's intent to recognise stranded asset risk while managing short-term price impacts and that achieving the correct balance is not straightforward. However, the assumptions underlying the Commission's earlier scenario weightings no longer reflect the realities of the gas sector. As we highlighted in our prior submission, multiple structural shifts, rapidly declining reserves, rising wholesale gas prices, increasing customer disconnections, and accelerating electrification, have fundamentally altered the likelihood of pipeline networks remaining viable through to 2060. The Commission itself now acknowledges several of these changes. For instance, the*

[11] Boston Consulting Group, *Energy to Grow: Securing New Zealand's Future* (November 2025), section 4.2.1

Commission has recognised that forecast gas supply is falling faster than expected and this tightening supply is impacting on gas prices and use. It is our contention that, in combination, these factors unambiguously increase the probability of earlier network closure than was contemplated at DPP3.

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.*

Third, it is our view that the Commission's decision at DPP3 to apply heavy weighting to a 2060 scenario would almost certainly have been different had the current supply constraints, reserve declines, and heightened decarbonisation momentum been apparent at that time. The updated evidence base now strongly supports the inclusion of an additional earlier-closure scenario, in our view one concluding in 2045, with equal weighting across the three scenarios. This preserves the Commission's objective of balancing prudence, FCM, and long-term customer benefit across a more realistic set of future states. The effect of this approach, as shown in our earlier indicative assessment of the Commission's modelling, is to lower the adjustment factor and increase the extent of accelerated depreciation. This is an outcome that aligns with the heightened risk profile now facing gas networks.

Fourth, 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 profiles.

For these reasons, and consistent with the framework advanced in our first submission, we maintain that the Commission should:

- ***introduce a 2045 scenario*** *alongside the existing 2050 and 2060 scenarios,*
- *apply **equal weighting** across all three scenarios, and*
- ***adjust the depreciation path*** *accordingly to better reflect today's risk environment.*

It is our view that this approach best meets the Part 4 purpose by supporting continued investment, maintaining service quality, preserving FCM, and ensuring a fairer sharing of the cost burden between today's and tomorrow's consumers. It also avoids the asymmetric harm associated with insufficient early action. That is, the irreversible loss of the opportunity to recover efficient costs should the network contract faster than expected. Early action can always be moderated later; late action cannot be corrected."

Accelerated depreciation for new assets

57. The Commission's model treats accelerated depreciation differently for additional assets and existing assets. This appears to be because the IM provides different asset lives for additional assets and existing assets.

58. However, this means the model does not fully depreciate additions by the assumed wind-down year. This is because –
    - The DPP4 model includes existing assets with a reduced life from DPP3. These are further reduced in DPP4.
    - However, the modelling for additions applies the IM 45-year asset life and adjusts the asset life only for the DPP4 accelerated adjustment factor.
    - As a result the asset life for additions is higher than existing assets. This means some residual value for additions remains at the wind-down date.

59. We recommend amending the IM to correct this treatment. To ensure the model completes accelerated depreciation as intended, the asset life for additions need to be set such that it is equal to the years remaining until the wind down year

Depreciation of asset additions

60. The GPB IMs do not wash-up the difference between forecasted asset additions and forecasted depreciation using a 45-year life assumption and actual additions and actual depreciation using actual asset life.

61. This means that any discrepancies between actual and forecast depreciation during the DPP period are never recovered.

62. The greater investment in digital assets makes this issue more significant as GPBs are likely to have a higher proportion of capex on asset additions with shorter actual lives than the 45-year assumption used to determine forecasted depreciation.

63. We recommend the Commission washes up the difference between forecasted and actual depreciation or at least, when forecasting depreciation uses a weighted average asset life that is better reflective of the lives of the assets expected to be commissioned during the period.

The IM treatment of indexation continues to undermine the intent of accelerating depreciation

64. We also note the IM treatment of indexing the RAB to inflation has the effect of backloading cashflows.

65. This undermines the intent of accelerated depreciation to bring cashflows forward and serves to inflate the scale of stranding risk.

66. We recommend the Commission amend the IM to unindex the RAB from inflation to bring cashflows forward in line with the intent of accelerated depreciation.

67. It is not in the long term benefit of consumers that asset cost recovery is more weighted to the backend of an assets life when there will likely be less customers to recover the asset costs from.

Operating expenditure

68. We were pleased to see the Draft Decision recognises Vector's move to an opex based operating model supports the long term benefit of consumers. As described in our 2025 AMP, this will enable Vector to maintain network safety and reliability while minimising exposure to stranding risk. It will also:
    - Enable more targeted, risk based asset maintenance strategies;
    - Support financial capital maintenance in an environment of high uncertainty; and
    - Allow flexibility to adapt to changing market conditions.

69. However, the Draft Decisions approach to the network scale trend factor in the base, step and trend will undermine this approach if left unaddressed.

70. As acknowledged in the Draft Decision, there is a significantly different context from previous resets where all GPBs are expecting declines in ICPs.

71. The Commission has the retained the opex trend factor from DPP3 where ICP and network length profiles are used as the drivers. Both ICPs and network length profiles have an equal weighting of 50% in the opex trend factor. The Commission used a floor of 0% for network length. However, it did not apply a floor for ICP changes on the basis there is likely to be a symmetry between opex and ICP increases or decreases.

72. The Draft Decision acknowledges this means forecast declines in ICPs will result in reduced opex allowances.

73. If this approach is retained in the final decision, this will undermine the long-term benefit of consumers by undermining efficient opex allowances.

74. We do not consider there is likely to be symmetry between ICP increases or decreasing and opex. Customers expect the same quality of supply and safety regardless of the number of connections on the network. The majority of operating costs are fixed or only partially variable. Maintenance costs will not decrease symmetrically with connections nor will costs such as emergency response or regulatory compliance.

75. 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.

76. Frontier's report explains:

"*In considering the regulatory approach for DPP4, we submit that applying a floor of 0% to the output growth factor is both pragmatic and necessary if the Commission continues with the Base Step Trend (BST) methodology. This safeguard reflects the reality that most operating expenditure does not decrease in proportion to the number of disconnected ICPs. The Commission's current approach to ICP declines assumes a symmetry between the costs associated with increasing and decreasing ICPs, yet this assumption does not withstand scrutiny.*

The Commission has not explained why it expects a linear, symmetric relationship between connections and disconnections, nor why opex should decline as connections are lost. In practice, opex does not respond symmetrically to declining connections. While new ICPs can drive incremental costs, such as commissioning, customer onboarding, and possible network augmentation, disconnections do not result in equivalent cost savings.

It is our view there is no compelling justification for the expectation that operating costs will fall in direct proportion to the number of disconnections. Customers rightly expect the same standards of safety and continuity of supply, irrespective of whether the network is serving more or fewer connections. The physical assets of the network remain in place even as customer numbers decline, necessitating continued maintenance, inspection, and compliance activities. These costs are largely fixed or only partially variable, and so the bulk of operating activities, such as public safety, emergency response, leak surveys, statutory compliance, system control, customer service, and incident readiness, must be sustained to uphold network safety and reliability. That is, the operating and maintenance expenses of networks are primarily influenced by the size, complexity, and condition of the assets requiring management, as well as by safety and reliability requirements, rather than by utilisation metrics alone.

While the Commission asserts that GDBs operating in a declining context would be actively seeking cost savings akin to behaviour observed in competitive markets, it is important to *acknowledge that the regulatory framework already provides strong incentives for distributors to pursue efficiencies. Under the current form of incentive regulation, GDBs are continually motivated to minimise their operating costs, as any efficiencies achieved can be retained for a period before being shared with consumers. However, there is a natural and unavoidable floor to these cost reductions, dictated by the need to maintain the service performance standards that customers expect and deserve. Pre-emptively removing anticipated efficiencies from opex allowances is not consistent with the principles underpinning the base step trend approach, nor with the broader philosophy of incentive regulation, which relies on actual outperformance rather than assumed savings. This approach ensures that cost reductions are genuine and sustainable, without compromising safety, reliability, or customer service*."[12]

77. Accordingly, we strongly recommend the Commission also apply a floor of at least 0% for ICPs. Vector's move to an opex based operating model means our opex will increase even though ICPs are declining. Failure to account for this in the base,step and trend creates a real risk that DPP4 does not provide sufficient opex allowances (at a time capex has also been reduced) for appropriate maintenance at the level of consumer demands. This will not support the long term benefit of consumers and is contrary to the Commission's overall approach that acknowledges increased opex and reduced capex is an appropriate response to declining demand in gas networks.

Step changes

78. The Commission did not allow the entirety of Vector's requested step change for SaaS. The Commission allowed the level of step change (as a proportion of base year spend) as in electricity.

79. We appreciated the Commission recognised this was not apparent in the Draft Decision and clarified its approach to us.

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

81. We have provided additional information on our SaaS step change in Appendix One. This shows the significant changes in computer expenses between our RY25 AMP and draft RY26 AMP for electricity.[13] The information contained in Appendix One is confidential and commercially sensitive so should not be publicly disclosed.

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[12] Frontier Economics, *Key issues in Gas DPP4 Draft Decision: Report for Vector* (January 2026) at pages 16-17

[13] We have provided electricity costs as our gas SaaS costs are a cost allocation of shared digital costs.

82. Accordingly, we recommend the gas SaaS step change be a higher proportion of base year spend than was granted for electricity. SaaS costs are now higher than when EDB DPP4 was determined.

Capital expenditure

83. Overall, we support the Commission applying more targeted scrutiny to individual capex categories rather than the broad cap that has been used in previous years. Making greater use of AMP forecasts will support the long-term benefit of consumers by providing a better reflection of the evolving circumstances in the gas sector.

Capital contributions

84. We agree it is appropriate for the Commission to consider GPB capital contributions policies in terms of "*how GPBs assess the costs and benefits of new connections, manage asset stranding risks, and determine when capital contributions are in the long-term interests of consumer*."

85. We agree with the Commission that:

    "*we consider it is important to signal the practices we expect to see from GDBs, that net connection costs reflect a reasonable view of the likely economic life of the connection. Capital contribution requirements should result in an outcome where the net present value of revenues for new customers are expected to exceed their incremental cost, including the incremental value of commissioned asset*."

86. In the electricity sector, the Electricity Authority is currently making significant changes to EDB connection requirements, including capital contributions. We encourage the Commission to highlight any read across from its position on GPB capital contributions to the electricity sector in its discussions with the Electricity Authority.

Decommissioning costs

87. We were pleased to see the Commission has recognised that decommissioning costs is an issue that needs to be addressed, and that, acting in advance of decommissioning occurring can support the long term benefit of consumers.[14]

[14] At F24

88. However, the Draft Decision is not to provide any allowance for decommissioning expenditure on the basis the Commission does not have sufficient information on future decommissioning liabilities, or the likely type or scale of the costs.

89. GIFWG has submitted an expert report from GPA estimating the potential costs of decommissioning using the most efficient theoretical pathway. GPA estimates the quantum of network decommissioning as $123 million, along with $70 million for customer disconnections. We note this a conservative estimate and actual decommissioning costs may be significantly higher.

90. We consider this report should alleviate the Commission's concerns that there is insufficient evidence on the likely type or scale of costs involved in decommissioning and provide support for taking action during DPP4.

91. GPA's report shows the potential scale of network decommissioning costs is significant. Consumer interests are better served by addressing these costs now rather than delaying to recover a more significant portion of costs from a declining customer base. Even a modest and partial solution will alleviate the burden of decommissioning costs in future years.

92. If the Commission cannot act during this DPP reset, we urge it to commence work as soon as possible as part of a separate process. We acknowledge the solution may need to involve policy makers such as MBIE to determine a solution. We would welcome the opportunity to be part of conversations with the Commission and wider government on decommissioning.

93. In our view, it is crucial that steps are taken now to avoid an unmanageable burden on consumers and networks later on when the need for full scale network decommissioning arises.

Innovation

94. The Commission's Draft Decision is not to introduce an innovation allowance for GPBs to pursue renewable gases.

95. We continue to consider that an innovation allowance would support the long-term benefit of consumers by providing greater incentives for EDBs to invest in innovative solutions that could repurpose the network.

96. We agree with the Commission's position that GPBs to "*have a natural incentive to extend the useful life of their networks in order to continue to operate and remain in business and invest where it is economic to do so.*"[15]

[15] At C65

97. However, as highlighted in our expert reports, the current level of in-period demand risk creates a disincentive to investment in innovation. If GPBs continually under recover revenue in-period, they will need to pull back “discretionary” investment such as that on less certain innovations.

98. For completeness, it is worth highlighting GPBs are pursuing work around renewable gases to support the long-term benefit of consumers, such as the GIFWG’s work on renewable gas connection standards intended to support ease of uptake for renewable gas.

Starting price

99. We agree with the Draft Decision to base starting prices on the Commission’s assessment of current and projected profitability, rather than rolling over prices. We agree with the Commission this will better reflect the evolving operating environment of the gas sector than the alternative.