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Reset of the gas default price-quality path 2026: Issues Paper

Vector submission

24 July 2025

1. This is Vector's submission on the Commerce Commission's (Commission) issues paper for the reset of the default price-quality path beginning 2026 (DPP4) for gas pipeline businesses (GPBs) and on the Commission's draft decision on the regulatory period for DPP4.

2. We have submitted an expert report from Frontier Economics as part of our submission on the issues paper.

3. No part of this submission or the expert report is confidential, and we are happy for it to be published on the Commission's website.

4. There remains significant uncertainty around the future of gas networks in New Zealand. Since the last reset, the impact of gas supply constraints has become more evident. We expect to see reduced volumes and connections in DPP4, along with increased disconnections.

5. At the same time, consumers of the gas network still require a safe and reliable network. The regulatory settings need to ensure GPBs can continue to invest (in line with the Part 4 purpose) in the context of declining demand. Preserving an expectation of ex ante FCM remains a key feature in supporting the long-term benefit of consumers.

6. We consider the critical features to support the Part 4 purpose in this reset are:
    - **Ensuring the regulatory settings continue to mitigate stranding risk:** Current gas supply constraints mean this risk has heightened significantly since the last DPP reset. A more aggressive approach to managing stranding risk is warranted.
    - **Ensuring the regulatory settings manage forecast risk:** Extra-ordinary uncertainty in the sector means there is a high probability that volumes or connection growth turn out different than forecast. We consider a revenue cap is needed in the current environment to ensure investment incentives are preserved. We recommend re-openers could be implemented to more equally share risk between GPBs and consumers (alongside a revenue cap) or a hybrid approach such as Jemena's in Australia.
    - **Ensuring opex allowances are sufficient:** In the context of declining demand, it is appropriate for GPBs to increasingly focus on opex solutions (e.g. increased maintenance of existing assets) rather than capex solutions such as asset replacement. Our 2025 AMP reflects a shift to an opex based operating model. To support efficient expenditure, it is critical the allowance setting process reflects this shift. Ensuring appropriate step-changes are included in the price-path is a key issue.

Executive summary

Topic	Vector recommendation
Context for this reset	The future of gas in New Zealand remains extremely uncertain. This uncertainty has significantly increased since the Commission determined DPP3 with the emergence of significant gas supply constraints (and their impact on consumer behaviour). GPBs are forecasting declining connections and gas volumes over DPP4. In our 2025 AMP, Vector forecasts declining connections from 2026 and no new connections from 2029. In the meantime, consumers require a safe and reliable gas supply. We heard in our consumer research that residential gas consumers highly value their gas supply and many businesses do not have a viable alternative energy supply. The maintenance of ex ante FCM remains a key component of supporting the long-term benefit of consumers. We consider this has two elements where: • Existing consumers of the gas network need a safe and reliable supply and, accordingly, efficient investment is needed to ensure this supply; and • Investors in other regulated (and potentially regulated) businesses will be cognisant of the Commission's approach to gas networks. Their willingness to continue to invest in these businesses will be impacted by

	whether ex ante FCM is preserved in the gas network
Forecast risk	If the Commission retains its DPP3 forecasting approach, there is a real risk that volumes and/or connection growth significantly differ from forecast leading to insufficient revenues. This could compromise incentives to invest and therefore impact the long-term benefit of consumers. New Zealand is a small market which runs the risk of major supply side shocks, such as the recent gas reserve constraints and resulting impact on the market. It is materially beyond the ability of the GPB to address this in-period volatility. In terms of traditional forecasting approaches, neither historic trends or future policy settings can be confidently relied on to produce a view of the next five years. We consider consumer behaviour in the current market is largely driven by supply side constraints (e.g. high prices driven by gas supply constraints and retailers not accepting new customers). Further to this, some of our largest gas consumers have 2030 decarbonisation targets, which if successful, will be realised within this DPP period. GPBs are unlikely to have any material influence on consumer behaviour in this context. If left unaddressed this will undermine confidence in the regulatory framework and undermine network investment incentives.

	We recommend the Commission implement a revenue cap. Any historic logic that may have once existed to support a price-cap mechanism (such as promoting greater take up of gas etc) is now absent. If the Commission retains a weighted average price cap (and by implication therefore the need to accurately forecast volumes 4-5 years out), we consider it critical another mechanism to address forecast risk is implemented to preserve incentives to invest. While sub-optimal to a revenue cap, if the Commission decides against implementing a revenue cap we would encourage the Commission to investigate implementing a hybrid mechanism such as that proposed by Jemena in NSW (and accepted by the AER) but maintain that the real solution sits in revisiting the Commission's decision to retain a price cap in a situational context which overwhelmingly points on any objective basis for the need to switch to a revenue cap. We also consider a re-opener to mitigate forecast risk is needed. This could be symmetric (i.e. also triggered by the Commission if volumes/connections are significantly lower than forecast) to ensure equal sharing of risk between consumers and GPBs.
CPRG model	If the Commission uses the DPP3 methodology for its CPRG model (using historical growth rates) it will result in an inappropriately high forecast. We recommend that forecast data, provided by the networks through the RFI process, for both volumes and ICPs (rather than historical

	growth rates) should be used in the CPRG model.
Stranding risk	Stranding risk for GPBs is now greater than when the Commission set DPP3. We recommend the Commission update the assumptions in its asset stranding model to ensure ex ante FCM is maintained (and therefore support the long-term benefit of consumers by preserving incentives to invest). In particular, • The winddown date in the asset stranding model should be brought forward to reflect when the businesses could realistically have negative cashflow. The current environment suggests a winddown date well before 2056. • 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 would become uneconomic well before a winddown in 2050. • Gas Industry Future Working Group (GIFWG) scenario analysis indicates from DPP3 that networks will become cashflow negative by 2042. • Decommissioning would need to begin around 5-years before the network shuts down. Negative cashflow would be further exacerbated by the need to incur decommissioning costs and therefore it is essential that these costs are recognised and started to be funded through the price path commencing in DPP4.

	As prices begin to rise exponentially, price rises may exceed customer willingness to pay in another one or two DPP resets. Accordingly, we recommend the asset stranding model be updated to recognise a potential winddown date in the early 2040s to maintain ex ante FCM. We have also recommended updates to other parameters of the model in our discussion on asset stranding risk. We note the current IM approach of indexing the RAB to inflation undermines the intent of accelerated depreciation bringing cashflows forward.
Decommissioning costs	We consider the long-term benefit of consumers is better supported by addressing decommissioning costs in this reset. This was further highlighted in our consumer engagement where they believed that the networks should be accounting for this already. We acknowledge there is currently a lack of information in the sector about the potential cost of decommissioning. We intend to explore, with GIFWG, quantifying potential decommissioning costs (at least at a high level). Our intention is this research could be ready to submit into the draft decision. We note GIFWG has previously estimated decommissioning costs at 5% of RAB for the purposes of its asset stranding modelling. We consider this is a conservative estimate and actual decommissioning costs could be magnitudes higher. However, it is a useful

	starting point to consider how decommissioning costs should be treated. We strongly recommend the Commission allow for at least some of the costs of decommissioning in this reset. Even a conservative approach that allows for a small amount of decommissioning costs will reduce the amount remaining consumers need to pay in later years and will better support incentives to invest for GPBs. Failing to act now leaves a real risk that – if/when GPBs begin to winddown – there are insufficient customers remaining to cover the costs needed to decommission the network.
Approach to capex allowances	In the current environment past expenditure is not a good predictor of future expenditure needs. Accordingly, we support greater use of AMP forecasts in assessing capex. We consider retaining the DPP3 approach to capex could deliver an efficient level of capex for DPP4.
Approach to opex allowances	We consider the best course of action is to base opex forecasts on GPB AMPs (with appropriate scrutiny). However, the base, step and trend approach could deliver an efficient level of opex if some adjustments are made and providing appropriate step changes are included. Our submission sets out adjustments that are needed, along with step changes to deliver an efficient level of opex.

	Expenditure allowances must manage the opex/capex trade-off. If appropriate opex allowances are not included in the price-path when compared to opex included in AMPs then capex allowances would need to increase above those included in AMPs. Without doing this, suppliers would have insufficient resources to preserve the operational performance of their networks.
Re-openers	Extreme uncertainty is a key context in the gas market and a key feature for the DPP4 reset. It is critical that appropriate uncertainty mechanisms are in place for DPP4. We consider re-openers will be needed to maintain confidence in the regulatory framework. In particular, the following re-openers would be needed: • **A volume/connection re-opener**: managing in-period demand risk is materially outside the control of GPBs in the current environment. We consider a re-opener is needed to preserve investment incentives where volume or connection growth differs significantly from forecast. We recommend this be symmetric (i.e. also triggered by the Commission if the volumes/connections are significantly higher than forecast) to ensure risk is shared evenly between GPBs and consumers. • **Disconnections re-opener**: We consider there is a real risk of an unforeseen step up in disconnections in DPP4 that

	GPBs may otherwise be unable to recover the cost of.
Approach to starting price	We strongly recommend the Commission continue its approach setting starting prices based on its assessment of current and projected profitability under the building blocks model rather than the alternative approach of rolling over DPP3 prices. In line with the Commission's reasoning in DPP3, using the building blocks model will better reflect the evolving circumstances of gas pipeline businesses and better create financial incentives to improve efficiency thereby aligning incentives between GPBs and consumers. We have modelled the impact of rolling over DPP3 prices this would result in a significant shortfall in revenue in DPP4 and therefore compromise incentives to invest.
Innovation	We encourage the Commission to give further consideration to how it can support maintaining optionality for renewable gases. Networks are incentivised to preserve optionality and prolong the useful life of their networks. However, this must be balanced against incentives to avoid investment in the face of heightened stranding risk. We note the potential for GPBs to be cashflow negative by the 2040s. In this context, we consider a dedicated allowance to investigate innovations to preserve optionality would support the long term benefit of consumers.

Length of regulatory period	On balance, we support the 5-year regulatory period in the Commission's draft decision. This is on the basis it may reduce workload (and therefore regulatory costs) for the Commission and GPBs associated with more frequent resets. However, it is critical a longer regulatory period is accompanied by appropriate uncertainty mechanisms to address the significant forecast risk and other unforeseen circumstances that could arise during the period. We consider the key mechanisms needed are: • A revenue cap in order to mitigate forecast risk, or otherwise a hybrid mechanism. Supported by a volume/connection re-opener; and • Other appropriate re-openers such as a disconnection re-opener to manage increased opex resulting from a significant step up in customer disconnections.

Context for the DPP reset

1. Since the last reset, ongoing gas supply constraints (and their impact on prices) have become a significant concern for consumers and the wider economy.

2. The future of gas in New Zealand remains extremely uncertain. This uncertainty has greatly increased since the Commission determined DPP3.

3. As the Commission heard in the technical workshop, GPBs are forecasting declining connections and gas volumes over DPP4. In our 2025 AMP, Vector forecasts no new industrial connections from 2026 or residential connections from 2029.

4. In the meantime, consumers require a safe and reliable gas supply. We heard in our consumer research that residential gas consumers highly value their gas supply and

businesses view it as an essential service with some unable to transition to alternative sources of energy.[1]

5. The maintenance of ex ante FCM remains a key component of supporting the long term benefit of consumers. We consider this has two elements where:

   - Existing consumers of the gas network need a safe and reliable supply and, accordingly, efficient investment is needed to ensure this supply; and
   - Investors in other regulated businesses will be cognisant of the Commission's approach to gas networks. Their willingness to continue to invest in these businesses will be impacted by whether ex ante FCM is preserved in the gas network.

6. We note there is negative sentiment in the market with a high price of gas largely driven by supply constraints.

GPB context

7. It is also worth noting that Vector's gas distribution charges have reduced by over $220 per customer or 30% in real terms since 2013.

8. At the same time, service reliability metrics have improved over the past decade.

9. We consider this demonstrates our gas network has delivered good price and quality outcomes for consumers over the period.

How the gas network fits in the overall proportion of the consumer bill

10. We have undertaken work at a high level to understand what proportion our network charges are on the overall customer bill.

11. In contrast to the electricity sector, there appears to be limited public information on each component of a consumer gas bill.

12. At a very high level, we estimate the gas network portion represents approximately 1/3 of a customer bill on average. This may be substantially lower for large industrials.

13. While these are high level estimates, they provide some context around the impact of network price changes on the overall consumer bill. These figures indicate network charges are not a large proportion of the overall bill.

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[1] Pinstripe Leopard, *What's fair? Qualitative research topline findings of the views of residential and business natural gas customers: prepared for Vector Powerco and FirstGas* (July 2024), page 8

14. We estimate that, for Vector's customers in DPP3, accelerated depreciation resulted in average net price increases of circa:
    - $31.31 p.a. for residential consumers;
    - $78.1 p.a for SMEs; and
    - $505.86 p.a. for Industrial and Commercial.

15. We recognise any price increase in the current economic environment is difficult for consumers to absorb. However, it is important to note these price increases follow a period of reduced prices in real terms and do not represent a large proportion of a customers' overall bill.

16. At the technical workshop, First Gas discussed gas retail margins over the DPP3 regulatory period. Our understanding is First Gas's analysis found gas retail margins had not been squeezed over the period (and margins had actually increased) despite network price increases.

Consumer engagement

17. Vector, Powerco and First Gas commissioned research into sentiment from residential and SME business consumers which has been submitted to this consultation.

18. This research has been submitted to this consultation by the GIFWG.

19. We recognise smaller consumer groups have generally not participated in the DPP regulatory process. Accordingly, we consider this research will deliver valuable insights for the Commission in setting DPP4, along with providing valuable insights for stakeholders more broadly.

Electricity versus gas cost competitiveness

20. The economics of converting gas to electricity is a relevant consideration in terms of the future of the network.

21. At the technical workshop, we mentioned the following reports which demonstrate the cost competitiveness of electricity:
    - EECA's Regional Energy Transition Accelerator (RETA) report for the Auckland Region, which found 229 sites (37% of Auckland RETA sites process heat emissions) have a marginal cost abatement of less than zero. This means they are currently economic to convert to electricity;[2] and
    - The GIC's gas supply and demand study 2024. The low intervention scenario found a 50% reduction in low temperature space heating, 40% reduction in water heating

[2] EECA, *Regional Energy Transition Accelerator (RETA): Auckland Report* (June 2025) Available: https://www.eeca.govt.nz/assets/EECA-Resources/Co-funding/RETA-Auckland-Report.pdf, Page 18

by 2035 for commercial consumers; and a 60% reduction in low temperature space heating and a 40% reduction in water heating by 2035 for residential consumers.[3]

- ReWiring Aotearoa's Electric Homes report, commissioned by EECA, found that a fully electrified home will deliver net savings of $1485 - $4699 including the interest rates associated with banks financing costs for the capex.[4]

22. Our consumer research also discussed consumer views and intentions regarding the future of gas.
    - Some residential consumers were aware of challenges relating to the supply of gas. Some were concerned enough to be discussing transitioning to electricity and others were transitioning due to environmental concerns.
    - The rising cost of gas is a concern for business viability for some medium and larger businesses. These businesses were hearing from retailers that costs would double or treble by their next contract renewal. A few were told by retailers that 3-year contracts could become 3-month ones.
    - Some businesses were investigating transition pathways, some were concerned the cost to transition would be too high and some anticipate transitioning as needed. This depended on the type of business.[5]

Forecast real growth risk – CPRG challenges

23. The Commission uses a Constant Price Revenue Growth (CPRG) model to forecast real growth (i.e. volumes and customers) for the DPP period. This is used in the financial modelling to calculate MAR for the period and the starting price adjustment.

24. If the Commission retains DPP3 regulatory settings, there is a major risk that volumes and/or connection growth significantly differs from forecast leading to insufficient (or inefficiently high) revenues compromising incentives to invest (or excessive profits). Neither outcome is in the long-term benefit of consumers.

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[3] EY, *Gas Supply and Demand Study 2024,* Available: https://www.gasindustry.co.nz/assets/CoverDocument/GasSupplyAndDemand_2024_11_28.pdf, Page 26

[4] ReWiring Aotearoa, *Electric Homes: The energy, economic, and emissions opportunity of electrifying New Zealand's homes and cars* (March 2024) – commissioned by EECA, available: https://www.eeca.govt.nz/assets/Uploads/Electric-Homes-Technical-Report_March-2024.pdf

[5] Pinstripe Leopard, *What's fair? Qualitative research topline findings of the views of residential and business natural gas customers: prepared for Vector Powerco and FirstGas* (July 2024), page 10

25. We strongly recommend the Commission gives further consideration to the impact of applying a weighted average price cap in an environment where CPRG factors are declining.

26. We note that, as volumes and customer numbers decline, deferred revenue must be collected in an environment with lower volumes and customer numbers.

Managing in-period demand risk is materially outside the control of GPBs in the current environment

27. Vector has taken steps to insulate its network (and consumers) from this risk to the extent possible. Vector has:
    - Applied best practice to its approach to forecasting;[6] and
    - Shifted its gas pricing to be largely fixed to mitigate volume risk.

28. Despite a best practice approach to forecasting and the clear overall trend of volume and connection decline, ongoing uncertainty in the gas market means the ability of GPBs to mitigate this risk is limited. This is particularly true of the impact of volume decline from disconnecting customers and where mitigants like fixed pricing fails to address the problem of revenue unable to be recovered which Vector has experienced in DPP3.

Difficulty forecasting in the current environment

29. It is materially beyond the ability of the GPB to address this in-period volatility, both in respect of volume fluctuations and disconnection rates. In terms of traditional forecasting approaches, neither historic trends or future policy settings can be confidently relied on to produce a view of the next five years.

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[6] As discussed at the technical workshop, Vector has strong data and analytics capability supporting the network. We have detailed customer models and, over the years, have undertaken advanced modelling to create a view of what appliances households likely have enabling us to model the impacts of appliance switching over time.

We are a member of the Auckland forecasting network and co-ordinate with peers to align forecasting assumptions, including using Auckland Council's planning to understand housing and business developments; and Stats NZ forecasts to understand growth in population and commercial activities (proxied by GDP).

In addition, we undertake customer research and engagement, along with desktop analysis of macro trends in the energy space.

30. The rapid change in the gas market between DPP3 and DPP4 (i.e. the emergence of supply shortages and resulting market changes) provides evidence of the difficulty in forecasting connection and volumes for the period. The disconnection of a few large users can have a major impact on volumes. We cannot reasonably forecast commercial decisions of individual firms driven by exogenous factors. This is exacerbated by the fact that gas retailers have the primary interface with end users and while retailers may be aware of a consumer's plans to exit or convert to electricity through their discussions on contracting for gas supply, the network companies do not. Historically we have been given very little notice of a consumer exiting or dramatically reducing their consumption. We note the difference between one large user disconnecting and (e.g.) three large users could result in a significant difference in the revenue path.

31. Furthermore, New Zealand is a small market which runs the risk of major supply side shocks that are inherently unpredictable.

32. We commissioned DETA in 2023 to survey our largest commercial and industrial sites on their current and future energy use, including their intentions around decarbonisation (with 83 ultimately interviewed). Based on this research, a conservative estimate on planned projects would see 27% transitioning from gas. An aggressive estimate based on ambition and feasibility would see 88% transitioning from gas. The wide range in estimates highlights difficulty forecasting in the current environment. Since 2023, we have already experienced an 18% decline in industrial gas consumption.

33. It is also worth noting that, as shown in the Issues Paper, connections and demand are both currently tracking significantly below forecasts used to set DPP3.

34. Frontier's report explains:

"*It is our view that this outcome suggests that the form of control is not currently having a material impact on the accuracy of the forecasts. That is, the perceived incentive under a WAPC to forecast below expectation is not being borne out. Instead, it is just becoming increasingly difficult to forecast demand in an uncertain environment. For this reason, we consider that the incentives for forecasting accuracy should not be a determining factor for the choice over the form of price control. Furthermore, it is important to remember that the ability for GDBs to set forecasts is not unbounded. There is strong regulatory oversight on the forecasts such that there is a reasonable likelihood that they end up being unbiased*."[7]

[7] Frontier Economics, *Key Issues for Gas DPP4 reset: Report prepared for Vector* (June 2025) at 3.2.2 on page 18

The drivers of connections and volume growth in the current environment are outside the control of GPBs

35. We consider consumer behaviour in the current market is largely driven by supply side uncertainty (e.g. high wholesale prices driven by gas supply constraints and flow on impacts such as retailers not accepting new customers or limiting long term supply options). GPBs are unlikely to have any material influence on consumer behaviour in this context given the network costs are likely a small proportion of the overall consumer bill.

36. Our consumer research also highlighted differing views on the future of gas and intentions (and ability) to transition to an alternative energy source. Concern about the price of gas (and behaviour) was tied to cost of living pressures more generally. [8]Again, this is something GPBs do not have a material influence over.

37. Some of our largest gas consumers have 2030 decarbonisation targets, which if successful, will be realised within this DPP period. We are aware of progress against some of these targets based on their engagement with our electricity distribution network. For completeness, for the most part businesses have no contractual relationship, obligation or incentive to engage with the network.

38. Although moving to largely fixed pricing can mitigate volume forecast risk, it cannot assist with disconnections.

39. Frontier's report explains:

> *"Putting aside the fact that customers bear the long-term price risk associated with changes in demand, current circumstances suggest that GDBs have very limited means to influence demand. Expecting GDBs to be motivated to drive increased demand was premised on the expectation that they would be driven to encourage connection to a new pipeline running down a street. However, there are now significant external factors that make this an unrealistic prospect, with the more likely outcome that these external factors see more and more customers disconnect from the system for reasons outside the control of GDBs. These external factors (discussed further in Section 4.2.2) include:*
>
> - *Government climate change policy striving for net zero emissions, which in-turn is encouraging customers to electrify*
> - *Rising wholesale gas prices driven by a severe shortage of gas and electricity generation willing to pay high prices for gas during dry winter periods*
> - *Reduced gas supply limiting long-term supply options for gas retailers, with evidence some retailers are declining new connections due to this concern; and*
> - *Rising energy costs generally in New Zealand have been driving large commercial and industrial users out of the market entirely.*

[8] Pinstripe Leopard, *What's fair? Qualitative research topline findings of the views of residential and business natural gas customers: prepared for Vector Powerco and FirstGas* (July 2024), page 10

None of these factors driving reduced demand and disconnection are within the control of GDBs. Therefore, requiring GDBs to manage this within period risk only serves to reduce their ability to fund expenditure required to maintain service performance."[9]

40. This will undermine confidence in the regulatory framework and undermine investment incentives if left unaddressed.

41. Frontier's report explains that:

"*Where there is an expectation that demand will drive the costs of the business a WAPC is likely to be preferred given this can ensure that revenues increase as costs increase. Conversely, if costs are not primarily driven by demand a revenue cap should be preferred. This is because, otherwise, the business might be exposed to windfall gains or losses as demand varies from forecast.*

In particular, given the need for regulation to provide a reasonable expectation of earning at least a normal return on investment (i.e., FCM), where costs are not predominately driven by demand – such as expenditure for replacement assets and maintenance – FCM could be threatened under a WAPC if demand is falling or customers are disconnecting. This is because revenues can fall below the revenue required to meet efficient costs. While tariff structures can mitigate this effect under a WAPC, businesses remain exposed to disconnections. In this case, to preserve profits, a regulated business would have an incentive to inefficiently defer expenditure and so increase the riskiness of the system or degrade overall service performance. This would clearly be a worse outcome for customers that remain connected to the network." [10]

Impact on opex

42. We note if the base, step and trend approach is retained, an incorrect connection growth forecast will also impact opex allowances.

43. This is because the base, step and trend also uses customer numbers to produce the 'trend' to develop the opex allowances.

44. This is discussed in greater detail in our section on opex allowances and in Frontier's expert report.

Approach the Commission should take to address forecast risk

45. We continue to advocate a revenue cap as the best way to address forecast risk. We consider the emergence of supply side constraints and resulting impact on the market since the last IM review are a clear reason to revisit the IMs.

46. We understand the Commission's current view is not to prefer a revenue cap on the basis this allocates too much risk from GPBs to consumers.

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[9] Frontier Economics, *Key Issues for Gas DPP4 reset: Report prepared for Vector* (June 2025), page 17

[10] Ibid, page 15

47. Frontier's report explains a WAPC is no longer appropriate as:

- "*GDBs have very limited influence over future demand given this will be driven predominantly by government policy, environmental concerns, and the wholesale price of gas in an environment of substantially constrained supply.*

- *With falling demand, the GDBs costs will not be driven by demand driven expenditure, so the benefit of using a WAPC to align revenues with increases in demand driven costs is severely diminished, if not lost entirely.*

- *Even with declining demand it is necessary for GDBs to invest to maintain service quality and reliability. With declining demand and reduced revenue, under a WAPC, the ability to fund these investments and maintain profits will be severely challenged.*

- *Rather than encourage efficiency, as posited by the Commission, reducing revenue in this environment as demand falls is more likely to provide an incentive for inefficient deferrals and cost cutting to maintain profits and FCM.*

- *A WAPC does not shield customers from demand risk, it merely does so within the regulatory period. In the long run, customers bear demand risk. Furthermore, under a WAPC, the large price changes that can occur between regulatory periods may serve to encourage faster disconnection due to price shock than if prices change more gradually over time."*[11]

48. A revenue cap is the appropriate regulatory response to the current circumstances. Frontier's report explains:

> *Given a WAPC is no longer appropriate, it is our view that a revenue cap should be applied to GDBs, including Vector. A revenue cap maintains strong incentives for cost efficiency while also ensuring that the businesses have a reasonable expectation that they can fund the replacement and service performance projects that are required through the regulatory period.*
> *Importantly, even under a revenue cap, Vector and other GDBs will retain an incentive to preserve demand where possible. This is because maintaining demand helps avoid or delay the 'death spiral' that could result from further disconnections and declining usage, thereby reducing the risk of asset stranding."*[12]

49. We note that a revenue cap is already the form of control for the gas transmission business (GTB) with the key justification being forecast risk.

50. The Commission in its 2013 reasons paper stated:

"*Because we are not able to forecast these values reasonably accurately, allowed revenues may be significantly higher or lower under a weighted average price cap than required by the business. By contrast,*

[11] Ibid, page 18

[12] Ibid

the application of a revenue cap means that each supplier's revenues will reflect costs that are relatively straightforward to predict."[13]

51. The Commission reaffirmed this for the GTB in the 2016 IM review stating:

"*we consider that gas transmission demand is difficult to forecast and that transmission businesses have little ability to influence demand, and so keeping a revenue cap is in the long-term interests of consumers by ensuring suppliers are more likely to be incentivised to invest efficiently compared to alternatives (consistent with s 52A(1)(a) and (b))."*[14]

52. This reasoning equally applies to GDBs in the current environment.

Another mechanism is needed if the Commission doesn't implement a revenue cap

53. If the Commission retains a weighted average price cap, we consider it critical another mechanism to address forecast risk is implemented to preserve incentives to invest.

54. We support the Commission further investigating implementing a hybrid approach between the weighted average price cap and revenue cap, such as that proposed by Jemena in NSW (and accepted by the AER) through its 'hybrid tariff variation' mechanism. This would have the benefit of sharing risk more equally between consumers and GPBs.

55. We note Jemena engaged with its consumers on the hybrid tariff variation mechanism through its Tariff Forum including on what constitutes fair sharing of risk. These consumers ultimately supported the hybrid mechanism.[15]

56. The AER's explained that:

"*We note JGN's hybrid tariff variation mechanism was subject to significant stakeholder engagement during the design phase and attracted the support from many of those stakeholders because it shares volume risk between JGN and its customers. The hybrid design also mitigates negative aspects of revenue cap regulation, such as year-on-year tariff volatility. While the hybrid design does not entirely avoid*

[13] Commerce Commission, *Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services* (28 February 2013) Attachment F, at F9

[14] Commerce Commission, *Input methodologies review draft decisions – Topic paper 1: Form of control and RAB indexation for GDBs, GPBs and Transpower* (16 June 2016) at 148

[15] AER, *Draft Decision: Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030)* (November 2024) available:https://www.aer.gov.au/system/files/2024-11/AER%20-%20Draft%20decision%20-%20JGN%20access%20arrangement%202025%E2%80%9330%20-%20Overview%20-%20November%202024.pdf, page 19

incentivising JGN to grow the volume of gas carried by its network, it weakens that incentive. We consider this better aligns with the updated NGO than JGN's existing weighted average price cap."[16]

57. In line with the AER decision, we consider that, failing a switch to revenue cap, implementing a hybrid mechanism in the DPP would better support the long-term benefit of consumers:
    - It would better preserve investment incentives by mitigating the revenue impacts of differences between forecast and actuals; and
    - It weakens the incentive to grow new connections consistent with New Zealand's net zero target (which the Commission may take into account under s5ZN of the Climate Change Response Act 2002); while
    - Mitigating volatility in prices that could be associated with a full revenue cap.

Potential design of hybrid approach for the DPP

58. We understand Jemena's hybrid tariff variation mechanism involves the application of a weighted average price cap where quantities are within 5% of the quantities used to set its tariffs. If they are 5% higher or lower than target, the resulting revenue over/under recovery is shared between Jemena and its consumers. 50% of the over/under recovery is retained by Jemena and 50% is passed on to consumers through higher/lower prices.

59. We consider a similar mechanism could be implemented as part of the DPP4 determination of price with some tailoring for the New Zealand context.

Re-openers

60. We also consider re-openers to mitigate forecast risk should be implemented. This could be symmetric (i.e. also triggered by the Commission if volumes/connections are significantly lower than forecast) to ensure equal sharing of risk between consumers and GPBs.

61. We consider re-openers should be included regardless of the form of control.

62. This is discussed in greater detail from paragraph 147.

63. Frontier's expert report provides further discussion about how these approaches would better support the long term benefit of consumers.

CPRG modelling

[16] Ibid at 32

64. We have updated the DPP3 CPRG model and Concept Consulting model for the DPP4 period and observe the following issues if the same methodology was applied to DPP4.

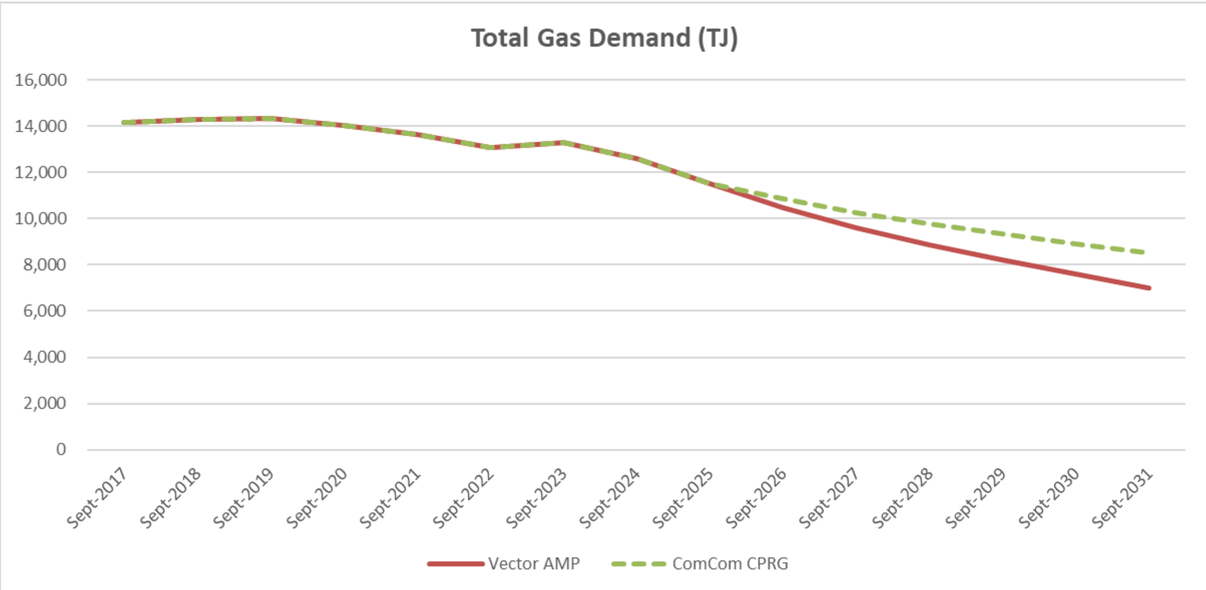
65. The Commission's CPRG model is based on a combination of forecast volumes and customers (ICPs) where:
    - The volume growth forecast (variable growth) is calculated as the average of: (i) the historical growth rate in billed kWh (50%) and (ii) the Concept Consulting growth forecast (50%); and
    - The customer (ICP) growth forecast (fixed growth) calculated only using the growth rate in number of customers (ICPs).
    - The CPRG is a combined growth forecast calculated as the weighted average of the variable and fixed growth forecasts above. The weights are based on the variable vs fixed revenue composition in the base year Information Disclosures (2025 for DPP4).

66. If **historical growth rate**s (2022-2025 for DPP4) are included in the CPRG calculation, the Commission CPRG variable and fixed growth forecast ends up being higher than Vector's or Concept Consulting's forecast. The historical figures show an increase, especially in the post covid years, but the forecast is for declining volumes and ICPs over the DPP4 period due to gas supply, gas cost and climate related policies adopted by consumers as discussed during the asset stranding model workshop on the 15 July 2025.

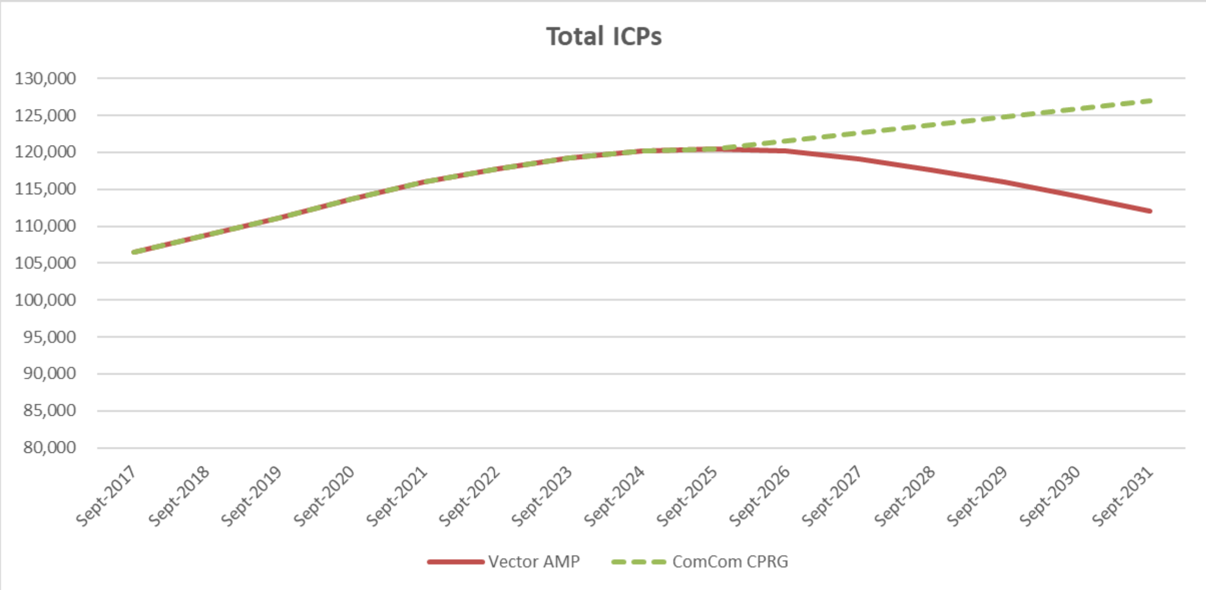
67. The DPP3 methodology of using historical data will not be appropriate in the current environment (DPP4 period). We recommend forecast data for both volumes and ICPs should be used in the CPRG model.

68. The graphs below show the impact of retaining the DPP3 methodology for CPRG modelling.

Actual and forecast gas demand



Actual and forecast ICPs



Stranding risk

69. We appreciated the opportunity to present and hear from other stakeholders at the technical workshop.

70. As discussed at the technical workshop, Vector's 2025 AMP forecasts show:
    - Declining connections and volumes, with no new industrial connections from 2026 and no new connections from 2029. We note actual trends in terms of connections have significantly worsened since the AMP was published; and
    - Increasing disconnections.

71. The key change since the last reset is emergence of significant supply issues and resulting very high wholesale costs that have worsened the outlook for gas.

72. EY's 2024 report for the GIC sets out the current market context:

> "*New Zealand's upstream gas sector has experienced supply headwinds over the last year. The sector continues to be challenged on three main fronts, lower than expected new supply outcomes from drilling campaigns, regulatory and policy decisions around exploration and decommissioning securities, and the ability to raise capital for fossil fuel extraction. On the downstream side, large consumers have a medium-term focus on reducing or eliminating their use of fossil fuels and electrifying their transportation and low-temperature heat applications. Although a reduction in natural gas demand is expected in the mid- to long-*

term, there has not been a material reduction in total demand in the recent past (excluding industrial exits and closures)."[17]

73. MBIE's most recent gas reserves data highlights that New Zealand's gas supply is reducing more rapidly than previously forecast where: "*Previous forecasts had annual gas production falling below 100 PJ by 2029, but due to revised production forecasts we now expect to reach this level by 2026.*"[18]

74. Frontier's report notes:

"*Since 2022, gas producers have been unable to find the gas resources they expected to find with high profile drilling projects coming up empty-handed.*[19] *Such expensive failures only serve to discourage further drilling and exploration activity. Furthermore, the ban on offshore oil and gas exploration has seen tier 1 producers exit the New Zealand market; meaning that expertise in finding gas has also left the market making the prospect of locating new reserves more challenging.*

The result of the failure to find the amount of gas that was expected means that gas production and reserves have fallen well below historical levels, and levels that were forecast only a few short years ago… Based on this change in circumstances, the most recent supply and demand forecast undertaken for the GIC forecasts anticipate that there is insufficient supply to meet requirements even in 2025 without demand response. It further predicts that gas price and supply constraints will drive supply shortfalls and industrial and commercial closures by 2030…While much of the closure may come from Methanex leaving New Zealand, and this would serve to free up some supply, it also removes the largest buyer of gas in New Zealand…

Should the wholesale price of gas continue to increase over time – which is a reasonable prospect without material additional gas supply being found – electrification and disconnection becomes increasingly attractive. This is particularly the case for residential customers and some commercial customers where the cost of switching to electricity is much lower than for certain industrial customers. Forecasts prepared for the GIC suggest that over the short term, under certain assumptions, residential demand for gas for space heating will reduce by up to 60% over the short term, and up to 95% over the longer term.

Consistent with the forecasts prepared for the GIC, Vector is also now forecasting the number of new gas connections to decline at an accelerated rate, with no new connections from 2029. Conversely, disconnections are forecast to continue to increase over time."[20]

75. The impact of New Zealand's constrained gas supply has received significant media coverage. For example, see:

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[17] EY *Gas Supply and Demand Study 2024,* page 7

[18] MBIE, *Gas supply reducing faster and sooner than previously forecast* (June 2025), available: https://www.mbie.govt.nz/about/news/gas-supply-reducing-faster-and-sooner-than-previously-forecast

[19] See: https://www.rnz.co.nz/news/business/517508/attempts-to-get-more-gas-from-kupe-field-fail

[20] Frontier Economics, *Key Issues for Gas DPP4 reset: Report prepared for Vector* (June 2025), page 26 - 30

- NZ Herald, "Genesis owned Frank Energy exits gas market, focusses on electricity";[21]
- BusinessDesk, "NZ's sole aluminium recycling foundry may close because of gas shortage"[22]
- EnergyNews, "Govt tries again to secure gas for agencies"[23]

Updates are needed to the asset stranding model

76. Stranding risk for GPBs is now greater than when the Commission set DPP3. We recommend the Commission update the assumptions in its asset stranding model to ensure ex ante FCM is maintained. In particular,
    - The winddown date in the asset stranding model should be brought forward. The current environment suggests a winddown date well before 2056.
    - The Commission's model assumes a shutdown once the last customer has left the network. However, a reasonable business would be looking to shut down once it became cashflow negative.
    - The network would become uneconomic well before a winddown of 2050. GIFWG analysis indicates that the network will become cashflow negative by 2042.
    - Decommissioning would need to begin around 5-years before the network shuts down. Negative cashflow would be further exacerbated by the need to incur decommissioning costs.
    - As prices begin to rise exponentially, price rises may exceed customer willingness to pay in another one or two DPP resets.

77. Accordingly, we recommend the asset stranding model be updated to target a winddown date in the early 2040s to maintain ex ante FCM and therefore preserve incentives to invest.

78. Frontier's expert report provides further commentary on addressing stranding risk and concludes:

    "*Our review of current and forecast conditions for the gas market in New Zealand suggest to us that there is a plausible scenario in which gas networks are decommissioned earlier than 2050. Among other things, this is due to the risk of near term shortages of gas supply, the uncertainty about sources of new gas supply in the long-term, the potential for increasing wholesale gas prices, and the impact that these have on decisions by customers and by policy makers about the continued use of gas.*

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[21] Available: https://www.nzherald.co.nz/business/genesis-owned-frank-energy-exits-gas-market-focuses-on-electricity/RYQCYEHWNNCLDIO244FXN64KDQ/

[22] Available: https://businessdesk.co.nz/article/energy/nzs-sole-aluminium-recycling-foundry-may-close-because-of-gas-shortage

[23] Available: https://www.energynews.co.nz/news/gas-supply/815966/govt-tries-again-secure-gas-agencies

The earliest date of decommissioning considered by the Commission in assessing accelerated depreciation for DPP3 was 2050. Given the worsening outlook for the gas market in New Zealand suggests that there is a plausible case for decommissioning of the gas networks before 2050, our view is that the Commission should consider a new scenario with earlier decommissioning of the gas network for DDP4. Given that the existing scenarios from DPP3, which see the gas networks decommissioned in 2050 and 2060 also remain plausible, our view is that the Commission should consider an additional scenario for DPP4, with decommissioning of the gas networks occurring by 2045, and that each of the three resulting scenarios should be given equal weight.

We think that this modification of the Commission's approach for DPP4 would be consistent with the broad approach to accelerated depreciation that can be observed in other jurisdictions. In particular, the extent of action of accelerated depreciation varies depending on the prospects for the gas sector in that jurisdiction. ***Given that the prospects for the gas sector in New Zealand seem more challenged that in many other jurisdictions, it is appropriate for New Zealand to consider stronger action on accelerated depreciation****. Also, where new information becomes available, approaches to accelerated depreciation can change from one regulatory period to the next*."[24] [emphasis added]

Other updates to the asset stranding model

79. We also recommend updating the following parameters of the asset stranding model:
    - **Stranding Year** – Stranding year options were 2050 and 2060 in the DPP3 model. These years should be moved forward due to the increased risk arising from gas supply constraints (etc). For example, move to 2040 and 2050
    - **Number of ramp-up years**: The Commission's model has a MAR ramp up period selection option from 4 years to 14 years. For Vector, ICPs and volumes are now declining not increasing. Therefore, the number of ramp-up years will be zero. The model needs to be updated to accommodate this factor.
    - **Curve on MAR ramp-down**: The CPRG gets applied only during the DPP3 period and nowhere else. Meanwhile, the 'curve on ramp down' effectively does not apply until the first year of MAR ramp down. Hence, the 'curve on ramp down' seems to take the place of CPRG after the DPP period. Therefore:
        - The 'curve on ramp down' should be allowed to go negative when volumes are declining (i.e. CPRG rates are negative post the DPP period).
        - The 'curve on ramp down' should also be applied in the intervening years between the end of the DPP period and the start of the ramp down (currently, 0% is applied during these years).

- **Expected MAR in Stranding Year (% of 2023 MAR)**: The 20% used for DPP3 is too high. The final MAR should be set to zero.
- **Alternative X factor**: The real price increases are smoothed over the DPP period, even if the real starting price adjustment without smoothing is less than a certain threshold. The smoothing should only apply when the real SPA is more than the cap / threshold (10% in DPP3).

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[24] Frontier Economics, *Key Issues for Gas DPP4 reset: Report prepared for Vector* (June 2025), page 29

Consumer views

80. Our consumer research considered fairness in terms of front-loaded versus flat recovery in the context of stranding risk. Key points included:

- Residential consumers were more likely to consider front loaded recovery as fair when attached to a positive outcome (e.g. biogas) rather than a negative one (e.g. decommissioning). Consumers felt this should be accounted for by the network already;
- Younger customers (under 50) were more inclined to see a front-loaded cost recovery as fair whereas older customers were more inclined to see flat recovery as fair; and
- Business consumers were less unanimous in their views. Some smaller businesses were 'ok' if a small amount added to their monthly bill (e.g. 10-15%) if there's a benefit (e.g. continued supply), other businesses were inclined to say that costs are high enough already and that nothing is fair. [25]

81. We understand the concern raised by MGUG and others at the workshop that bringing cost recovery forward could create a tipping point where it results in consumers leaving the network due to price rises (i.e. causing stranding).

82. While no price rise should be taken lightly, particularly in the current environment where viability is a concern for many businesses, accelerated depreciation is a comparatively small proportion of the overall customer bill. We consider it is unlikely be a major driver of demand reduction compared to gas supply uncertainty, high wholesale prices and flow on effects such as retailers not accepting new customers.

83. In line with the Commission's original decision to implement accelerated depreciation, there are two major risks to consumers if stranding risk is not addressed where:
    - Consumers unable to disconnect from the network are left with unmanageable price increases as cost recovery is spread over a thinner base; and
    - Networks are unable to recover the cost of their assets thereby breaching the principle of ex ante FCM. This would result in significant consumer harm where:
        - The network winds down before it is optimal to do so and where consumers still have demand for the service, including consumers who currently have no viable alternative to natural gas; and
        - Investment in other regulated industries is compromised with investors less willing to accept a lower return with a higher risk of not recovering the cost of their investment. This could have significant negative implications in the wider NZ economy.

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[25] Pinstripe Leopard, *What's fair? Qualitative research topline findings of the views of residential and business natural gas customers: prepared for Vector Powerco and FirstGas* (July 2024), page 13

84. We consider these remain a greater risk to consumers, particularly given the likely major drivers of consumer disconnections.

85. As explained in Frontier's report:

"*Stranded asset risk is an aspect where there are asymmetric consequences from a failure to act sufficiently early. That is, if early action is not taken there will simply become a point where it is no longer possible to recover all the capital invested in the network. Therefore, it is prudent for there to be a bias towards earlier recovery, noting adjustments to extend asset lives can be made at a later date should new information reveal a longer asset life is more likely. The primary constraint on how much recovery is advanced is customer willingness-to-pay. That is, if prices were to rise too high this may exacerbate the stranding risk. Some important factors to bear in mind in this context however are:*

- *It is better to bring forward cost recovery while more customers remain connected to the network given this reduces the cost burden on individual customers*
- *While advancing prices now should lead to a more stable price path over time by minimising the extent that prices need to rise in later years when demand falls further*
- *At current rates, accelerated depreciation is a relatively low contributor to price increases, and*
- *There is no evidence that customer willingness-to-pay has, on average, been exceeded yet, recognising that, for residential customers at least, prices are still below peaks that occurred in 2007*."[26]

86. It is worth noting that accelerated depreciation is NPV neutral, so raises no concern about excessive profits. It is the 'no regrets' option compared to risking the maintenance of ex ante FCM.

Maintaining ex ante FCM remains critical to support the long-term benefit of consumers

87. Since the last DPP reset, the High Court affirmed the role of maintaining ex ante FCM to support the long-term benefit to consumers in MGUG's merits appeal against the Commission's decision to introduce accelerated depreciation.

88. The High Court found:

"*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.***"[27] Emphasis added

[26] Frontier Economics, *Key Issues for Gas DPP4 reset: Report prepared for Vector* (June 2025), at page 32

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

89. The High Court also discussed why sunk assets (i.e. not just new assets) should be recovered to support the long term benefit of consumers:

> "*[applying accelerated depreciation only to new assets] would provide investors with an expectation of receiving a return of and on new investments required to maintain safe and effective service delivery, provided the time profile of demand turned out to be consistent with expectations. However, as discussed earlier, in a workably competitive market suppliers would be compensated ex ante for bearing stranding risk; historically for sunk investments and in the current price path for new investments. Neither occurs under the existing regulatory settings, with or without the amended input methodologies, and the risk of network stranding is now significant and affects both existing and new assets, even allowing for the accelerated depreciation of new assets.*
>
> *With a fixed depreciation profile, suppliers would bear the remaining network stranding risk. With no compensation to cover the cost of bearing this risk on new assets, the risk is asymmetric and a rational investor would likely be wary of making those investments unless they were very confident of demand forecasts. While this option is preferable to leaving the input methodologies settings unchanged, it still puts at risk the substantial ongoing investments required to maintain gas pipeline services as required in the years ahead. Accordingly, we are not satisfied that this option would be materially better than the Commission's 2022 Input Methodologies Decision*."[28]

90. The High Court further discussed the risks to consumers if ex ante FCM is not maintained:

> "*More broadly, the failure to make good on regulatory expectations could undermine confidence in the regulatory system and investment incentives for suppliers of other services regulated and potentially regulated under pt 4.* ***As discussed earlier, the relevant group of consumers is consumers of all services regulated under pt 4****. Furthermore, as the Court found in Wellington International Airport, it is open to us, but we are not required, to consider the interests of consumers of services potentially regulated under pt 4.* ***Electricity lines services have not received any ex ante compensation to carry network stranding risk and have made investments to date based on an expectation that network stranding risk would be addressed if and when required.***"[29] Emphasis added

91. As discussed in the High Court in that case, the Commission must consider the long term benefit of consumers in all markets regulated (and potentially regulated) under Part 4. If the Commission were to depart from providing ex ante FCM for GPBs, the interests of these consumers would clearly be compromised given it could significantly reduce the willingness of investors to invest in any market subject to Part 4 regulation.

RAB indexation

92. Along with updates to the model to target an earlier winddown date, we continue to advocate the Commission un-index the RAB from inflation. Retaining the current indexed approach undermines the purpose of accelerated depreciation by inflating the

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[28] Ibid at 210

[29] Ibid at 215

scale of stranding risk. As can be seen in DPP3 the Commission assumed a forecasted revaluation rate of 2% in its asset stranding model, however outturn inflation was higher. This results in existing assets at the start of the DPP not achieving the expected written down value at the end of the period as the outturn revaluation rate has eroded the expected write down impact from the acceleration.

93. Furthermore, arguments in favour of revaluing the asset base such as back-ending cashflows for when assets need replacing are no longer relevant in a wind-down scenario.

Expenditure allowances

94. Our 2025 AMP details Vector's shift from a capex to opex based operating model:

> "*Our updated modelling sees new connections stopping in FY29 and an increase in disconnections, resulting in a decline in net connections to the network in FY26, and the overall gas volume continuing to decline, but at a faster rate. This modelling of negative growth increases the stranding risk of the gas network which will impact customer's and Vector's gas assets. We therefore must take prudent steps to optimise our asset management strategies to maintain network safety and reliability, while reducing asset stranding risk.*
>
> *One of the ways we're doing this is by reducing capital expenditure on asset replacements (which is recovered over the life of the asset) and replacing this with increased operational expenditure on maintenance (which is recovered during a single financial year).*
>
> *There are other benefits of this approach, which are that it:*
>
> *• Enables more targeted, risk-based maintenance strategies;*
>
> *• Helps financial capital management in an environment of high uncertainty; and*
>
> *• Allows flexibility to adapt to changing market conditions.*
>
> *In making this switch from a replacement to maintain and repair strategy, we've had to consider several significant factors.*
>
> *One is, that the risk of asset failure is mitigated rather than removed, since assets are repaired rather than replaced. Our change in asset management strategy addresses known vulnerabilities that may result from the change, and increases the frequency of leak detection surveys, to continue to maintain a safe and reliable network.*
>
> *Another factor is that the technology which enables increased maintenance and inspection, specifically the introduction of a new camera-based inspection technique, needs to be managed in a staged approach where operator training, and detection accuracy can be validated and then rolled out more widely. If the camera technology proves ineffective or unreliable, we may need to revert to full replacement strategies, incurring cost and time delays.*
>
> *This approach carries the risk that regulatory allowances may be insufficient to ensure success of our asset management strategy. The Commerce Commission's methodology for determining operating expenditure allowances is primarily based on historical spending levels. Should this calculation method be applied, our analysis indicates that there would be a shortfall in the DPP4 operating expenditure allowance compared to our AMP forecast. It is crucial for the Commission's allowance setting process to recognise this and adjust the methodology by incorporating the most recent AMP forecasts. Setting operating*

expenditure allowances too low, coupled with significantly reduced incentives to invest in capital assets due to prevailing uncertainties, could result in a stranded asset risk."[30]

Managing the opex / capex trade-off

95. As discussed above, in the context of declining demand, an appropriate response by GPBs is to incur more opex (e.g. on maintenance) rather than capex (e.g. replacements).

96. We consider the critical issue in terms of setting expenditure allowances is delivering an appropriate level of opex.

97. Frontier's expert report explains:

"*The expected decline in net connections to the gas network and associated fall in overall gas volumes brings in to question the remaining life of the gas network in New Zealand. This uncertainty makes asset management strategies more complex, with the need for GDBs to adapt to maintain network safety and reliability, while managing asset stranding risk.*

Robust asset management systems monitor, maintain and replace assets using a risk-based lifecycle decision framework. When assessing capital investment options, the aim is to optimise lifecycle (capital and operating) costs while continuing to operate the network safely and effectively. Normally these decisions are made under the expectation of a stable network.

In the current circumstances an economically rational approach is to:

- *reduce capex on asset replacements (where these costs are recovered over the life of the asset); and*
- *increase opex on maintenance (which is recovered during a single year).*

Increasing maintenance opex can be more expensive over the long term, however it provides flexibility to adapt to future market conditions and makes economic sense if the network has a shorter remaining life.2 In other words, choosing opex over capex can be a prudent investment to achieve the lowest sustainable cost of delivering pipeline services in an environment of uncertainty regarding the future life of the assets."[31]

Capex

98. The issues paper seeks feedback on the Commission's proposed approach to confirm proposed expenditure is consistent with proposed volumes and connections; and that GPBs are considering long term risk of recovering investments when expanding by:

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[30] Vector, *Gas Distribution Asset Management Plan 2025 - 2035*, available: https://blob-static.vector.co.nz/blob/vector/media/vector-2025/04-june_gas-distribution-2025-amp-v0-6-2_updated-250625.pdf, page 5

[31] Frontier Economics, *Key Issues for Gas DPP4 reset: Report prepared for Vector* (June 2025), at 2.4

- Applying scrutiny to all forecast expenditure that is at or above historical averages, or a lower threshold where a decline is anticipated; and
- applying targeted scrutiny to any proposed growth categories (consumer connection and system growth) to ensure the businesses have a strong evidence base for any forecast expenditure.

99. We agree this approach is reasonable. We are supportive of all moves that make greater use of GPB AMPs and the most up-to-date information as, in the current environment, historic expenditure is not a good predictor of the future.

100. Overall, we consider using the same capex methodology as DPP3 (i.e. setting capex based on the lower of supplier forecast or the Commission's capex gate based on historic spend over the past five years) will be able to deliver an efficient level of capex. Any one-off change could be addressed through the capex adjustments section of the model.

Capital contributions

101. The Commission notes it will review GPB capital contributions in setting capex allowances and that:

> "*Given the more conservative outlook for new connections, and risk of asset stranding, we wish to understand stakeholder views on the appropriateness of GPBs' connection capex forecasts and approach to capital contributions. A simple approach would be to not allow any connection capex, forcing new connections to be funded upfront. Some level of connection capex could be justified for example by term commitment to remain connected to the network. The key will be that there is clear justification and evidence to support connection capex*."[32]

102. Vector's policy is to charge 100% of new connections to the gas network upfront through a capital contribution and, accordingly, forecast no system growth expenditure in the upcoming regulatory period.

103. We consider this policy is in the best interest of consumers by reducing RAB growth and therefore mitigates stranding risk.

Opex

104. As discussed above (and in our 2025 AMP), Vector is moving to an opex based operating model to better manage the network in the context of declining demand.

[32] Commerce Commission, *Gas DPP reset 2026: Issues paper* (June 2025), at 3.22

105. Ensuring the regulatory framework delivers an efficient level of opex should be a key consideration for the reset.

106. We consider the best course of action would be basing opex forecasts on GPB AMPs (with appropriate scrutiny).

107. The base, step and trend approach will not deliver a sufficient level of opex for DPP4 without some adjustments and, most critically, unless appropriate step changes are granted.

108. If the base, step and trend is maintained, the following issues will need to be addressed:
- The trend factor is tied to the number of consumers resulting in a negative trend factor for DPP4;
- The shift to an opex based operating model necessitates a number of step changes; and
- The opex gates will need to reflect this step up in opex.

109. If these factors are not addressed, Vector would face an opex shortfall of $16 million over DPP4.

110. If the DPP4 opex allowances are insufficient, capex spend would need to increase.

111. Frontier's report also concludes that continued application of the BST poses challenges in the current context of network decline and uncertainty. Frontier's report sets out how the Commission should provide appropriate flexibility if the Commission retains the BST.

The trend factor is tied to number of consumers

112. A concern is the approach to the trend factor which includes a 'number of consumers' factor and a 'network length' factor.

113. The 'number of consumers' factor is driven by forecast consumer numbers (ICPs). The 'network length' factor is partially driven by the forecast consumer numbers.

114. Consumer numbers are expected to decline over the DPP4 period. This will result in a lower trend factor resulting in a lower opex allowance in real terms over DPP4 relative to the base year. This is a perverse outcome given an appropriate response to declining volumes and connections is for GPBs to increase opex (e.g. on maintenance rather than asset replacement).

115. While the decline in opex allowances driven by the "number of consumers" factor could be small and there is likely little or no change in network length these impacts still need due consideration by the Commission when setting opex allowances.

116. The key component in setting an appropriate opex allowance is ensuring appropriate step changes are provided for that supports the move from a capex to an opex based operating model.

Step changes

117. As discussed above, Vector is moving to an opex based operating model for DPP4. This will necessitate a step up in opex.

118. We consider this is in the long-term benefit of consumers. It reflects an asset management strategy designed to minimise stranding risk while maintaining reliability and safety.

119. The following step changes will be needed for DPP4 to deliver an efficient opex allowance:

    - **Subcomponent replacements**: Following the development of the Condition Based Asset Risk Management (CBARM) model, Vector has transitioned from a traditional approach of full asset replacement to a data-driven, condition-based strategy focused on targeted intervention of asset subcomponents, without full replacement. This reflects a whole-of-life cycle management, where the need for asset replacement is assessed not solely on age or asset type, but on actual condition, risk exposure, and operational context.

    - **Increasing corrective maintenance and predictive maintenance to reduce capex**: This reflects a targeted inspection and corrective replacement of pre-85 pipelines, along with a strategic shift in the management of valves.

    - **Non-network cost increases in line with those granted for EDB DPP4**: System operations and network support costs and business support costs have increased $1.4m per annum in FY26$ terms, largely driven by increased investments in cyber security, cloud and data strategy and digitisation costs.

120. We have not provided further details or costs associated for these step changes as part of this submission as we would expect the Commission to follow a similar process to what it adopted in determining step changes for the recent electricity DPP reset

121. We therefore recommend the Commission issue a s54ZD request for information on proposed step changes in line with the approach it took during the EDB DPP4 reset.

Opex gates

122. In DPP3, the Commission limited opex increases based on historic expenditure. If applied in DPP4, this approach would unduly limit opex allowances due to our shift to an opex based operating model resulting in a step up in opex and reduced capex.

123. We recommend the Commission instead use AMP forecasts with appropriate scrutiny.

Consistency with EDB DPP4

124. Opex and capex inflators require an uplift similar to the Electricity DPP4 reset. This could be done on the same basis as electricity if industry specific inflation data is unavailable. However, this approach would still miss categories like traffic management which has increased significantly in Auckland.

Disconnection costs

125. Our 2025 AMP forecasts a step up in consumer disconnections.

126. As discussed above, GPBs are not able to materially influence nor forecast with confidence the key drivers for increased disconnections (such as gas supply shortages and resulting higher wholesale prices). Accordingly, we consider a real risk remains that disconnections turn out significantly different than forecast.

127. Our customer research discussed customer perceptions of fairness in terms of disconnection costs. This found:

- Residential consumers felt if it was the customer's choice to disconnect, they should pay the full cost to the meter. If the network was shutting down for economic reasons this should be handled by the network.
- Small business customers were similar to residential while some of the medium/larger businesses felt they were priced out rather than leaving the network and therefore should not cover the costs; and
- A few larger businesses felt if they had paid for the connection they would logically pay the entire removal/disconnection from their property.

128. Vector's 2025 AMP proposes an increase to the disconnections charge for residential and small commercial customers from $750 to $2,500, which is a full cost recovery. This approach aligns with the current charges for large industrial, steel service and Housing NZ disconnections which are all full cost recovery.

129. This is built into the opex forecasts in our AMP. We consider this best supports the long-term benefit to consumers by avoiding cross-subsidisation and therefore keeping network costs lower than they otherwise would be. We understand and empathise with customer perspectives that only disconnection up to the meter should be covered. However, in the face of a significant increase in disconnections, the burden on existing customers could be significant if cross-subsidisation continues.

130. In NZ, a 'permanent' disconnection can be performed at the boundary ($2,500) or have the meter replaced, at a significant lower cost. Vector's assumption is that the $2,500 charge for a permanent disconnection will be at the boundary and paid for by the retailer.

131. There is a risk that more disconnections are completed by removing the meter only leaving the service pipes live with gas inside private property.

132. This scenario would incur additional expenses for inspecting and maintaining the remaining and increasing inactive pipes and, in the future, conducting more health and

safety disconnections, which has not been fully allowed for in the 2025 AMP or DPP4 opex provisions. Once a critical number of customers have disconnected their meter in a neighbourhood, Vector may have to permanently disconnect that area of the network for safety reasons.

133. We consider a re-opener to cover potential opex associated with disconnections (whether standard disconnections or expenditure required to keep the network safe in the face of customers leaving the network by removing the meter) could mitigate this risk. This would preserve investment incentives in the face of unforeseen opex related to disconnections while not requiring any additional cost recovery from consumers if this does not eventuate.

Decommissioning costs

134. The issues paper notes the Commission's view that decommissioning costs are likely out of scope for this reset and that:

> "*the main barrier to considering the issue within the timeframe for the DPP4 reset is the high degree of uncertainty over the need, nature and quantum of any net costs associated with eventual decommissioning, and the novel nature of mechanisms submitters have proposed to address the issue.*
>
> *However, we acknowledge that early action to address this issue may provide the greatest benefit for consumers…*"[33]

135. We consider the long-term benefit of consumers is better supported by addressing decommissioning costs in this reset.

136. Failing to provision decommissioning costs this reset would have the following negative impacts for consumers –
    - Higher prices for remaining consumers on the network if/when the need for decommissioning becomes apparent in later years;
    - The risk that GPBs become cashflow negative and need to winddown with insufficient consumers remaining to pay the costs of decommissioning; and
    - Potential breach of the ex ante FCM principle where cost recovery is compromised by the injection of decommissioning costs in later years that cannot be recovered (this is discussed in further detail in the section on stranding risk).

137. Our customer research discussed how decommissioning costs should be provisioned. We heard from customers that they were not willing to pay additional costs for

[33] Commerce Commission, *Gas DPP reset 2026: Issues paper* (June 2025), at 2.35

decommissioning based on the assumption that GPBs would/should have provisioned for decommissioning already.[34]

138. This customer view is consistent with our understanding of GAAP requirements for decommissioning. Under GAAP, businesses must include capitalise decommissioning costs where they are aware they are under an obligation to incur decommissioning costs.

139. Historically, it has been assumed GPBs will continue in perpetuity. This assumption no longer holds.

140. We acknowledge there is currently a lack of information in the sector about the potential cost of decommissioning. We intend to explore potentially quantifying decommissioning costs through GIFWG (at least at a high level). Our intention is this research could be ready to submit into the draft decision.

141. We note GIFWG has previously estimated decommissioning costs at 5% of RAB for the purposes of its asset stranding modelling.[35] This was an approximate estimate and we expect actual decommissioning costs are likely to be higher. However, it is a useful starting point to consider how decommissioning costs should be treated.

142. We strongly recommend the Commission allow for at least some of the costs of decommissioning in this reset. Even a conservative approach that allows for a small amount of decommissioning costs will reduce the amount remaining consumers need to pay in later years and will better support incentives to invest for GPBs.

143. Failing to act now leaves a real risk that – if/when GPBs begin to winddown – there are insufficient customers remaining to cover the costs needed to decommission the network.

144. Frontier's report further explains:

> "*With respect to the timing on recovering decommissioning costs, our view is that there is less risk from taking action now to recover decommissioning costs (recognising that such action may turn out to be unnecessary) than there is from failing to take action now to recover decommissioning costs (when such may turn out to be necessary). This is because:*
> *•It is gas customers that benefit from the use of the gas network and so it should be gas customers that pay for the full costs of the gas network, including decommissioning costs.*
> *•If action on decommissioning costs is taken early, and proves to be unnecessary, any contributions can be returned to customers.*

[34] Pinstripe Leopard, *What's fair? Qualitative research topline findings of the views of residential and business natural gas customers: prepared for Vector Powerco and FirstGas* (July 2024), page 13

[35] NZ Gas Infrastructure Future, *Gas Transition Analysis Paper* (June 2023) at A.6

•*If action on decommissioning costs is delayed, and decommissioning costs cannot be recovered in fully from customers, there is no prospect of future recovery of these costs from customers.*"[36]

145. We note our customer research found a key concern for customers, in terms of decommissioning, is that they receive sufficient notice. For residential consumers, 5-years notice was the most frequently mentioned timeframe (with a range of 12 months – 10 years mentioned) to allow time for the transition. Business consumers expected the notice period to be around 3-5 years as a minimum for their own business planning.

146. Our consumer research also revealed residential consumers had a sense that 'someone' would need to help vulnerable people pay for costs associated with decommissioning whereas business consumers did not expect compensation. Some businesses were actively looking to future proof their businesses (e.g. switching to appliances that run on LPG) and some larger businesses felt they would be forced to close before decommissioning ever happens.[37]

147. We consider consumer views around the need for adequate notice on decommissioning and views around support for vulnerable consumers suggests a broader conversation around decommissioning is needed between GPBs, the Commerce Commission, government and consumers to ensure consumer needs are met.

Mechanism for potential recovery of decommissioning costs

148. The issues paper noted the novel nature of mechanisms proposed to address decommissioning costs as one of the barriers to considering the issue in the DPP4 reset timeframe.

149. We encourage the Commission to consider the mechanism proposed in Frontier's report where:

> "*In our view, a sensible approach for recovery of decommissioning costs from customers over time is through a dedicated 'decommissioning liabilities fund', which would replicate the way that these costs would be recovered by a business in a workable competitive market.*
>
> *We think that a decommissioning liabilities fund could operate as follows:*

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[36] Frontier Economics, *Key Issues for Gas DPP4 reset: Report prepared for Vector* (June 2025), page 36

[37] Pinstripe Leopard, "What's fair? Qualitative research topline findings of the views of residential and business natural gas customers: prepared for Vector, Powerco and FirstGas" (July 2025), Page 15

1. Initial decommissioning cost estimation: At the beginning of each regulatory period, the Commission would estimate the projected decommissioning costs ("target fund amount") for the assets, including decommissioning costs both prior to and after the end of the asset's economic life. The Commission would also estimate the remaining economic life of the gas assets – which would align with the Commission's asset stranding model.

2. Recovering the target fund amount over time: Once the Commission has determined the target fund amount and the number of remaining years over which to recover it, a series of annual payments would be calculated to provide cashflows that are equal in net present value terms to the target fund amount.

3. Revenue allowance: The Commission would then provide this set of annual payments to GDBs through the revenue allowance. The Commission would assume that the GDBs will invest the annual payments, to earn an appropriate return (equal to the discount rate assumed by the Commission when calculating the annual payments) such that, in expectation, the total accumulated funds at the time of decommissioning equals the target fund amount.

4. Track the growth in the decommissioning liabilities fund over time: The Commission would maintain a running balance of the decommissioning liabilities fund over time. This would allow the Commission to assess whether the annual payments should be adjusted up or down in subsequent regulatory periods such that the target fund amount is collected by the time decommissioning occurs.

5. Periodic reassessment: This process would be repeated during each regulatory reset. The Commission would re-forecast the target fund amount, given the uncertain nature of decommissioning costs. The Commission would also reassess the estimated remaining economic life of the assets and calculate the outstanding amount needed for recovery over the remaining life of the assets i.e., revised target fund amount minus accumulated annual payments. In the event that the Commission has provided for collection of more funds than required, or if decommissioning is no longer required, the excess funds would be returned to customers."[38]

Re-openers

150. Significant uncertainty is a key context in the gas market and a key feature for the DPP4 reset. It is critical that appropriate uncertainty mechanisms are in place for DPP4.

151. The emergence of gas supply uncertainty (and its impact on the market) suggests the uncertainty provisions in the IMs should be revisited as part of the reset.

152. We consider the following re-openers are needed to ensure the regulatory framework maintains incentives to invest:

- **A volume/connection re-opener**: managing in-period demand risk is materially outside the control of GDBs in the current environment. We consider a re-opener is needed to preserve investment incentives where volume or connection growth

[38] Frontier Economics, *Key Issues for Gas DPP4 reset: Report prepared for Vector* (June 2025), page 38

differs significantly from forecast. We recommend this be symmetric (i.e. also triggered by the Commission if the volumes/connections are significantly higher than forecast) to ensure risk is shared evenly between GPBs and consumers.

- **Disconnections re-opener**: We consider there is a real risk of an unforeseen step up in disconnections in DPP4 that GDBs may be unable to recover the cost of.

153. Frontier's report states:

> "*An additional option to manage demand risk that has previously been put to the Commerce Commission is to apply a demand reopener if actual demand turns out to be below or above the underlying forecast by a pre-specified margin, such as 10%.21 The Commission rejected this option based on its view that GDBs are best placed to manage within-period demand risk and so should bear this risk. It also indicated it would not be in the long-term benefit of consumers to shift some downside risk to consumers while GBDs would benefit if they were to outperform the forecasts.*
>
> *It is our view that the reasons given by the Commission for rejecting reopeners are misguided. It is our view that reopeners would lead to better outcomes than the status quo given the inability for GDBs to efficiently manage and respond to within period demand risk.*"[39]

Approach to starting price

154. We strongly recommend the Commission continue its approach setting starting prices based on its assessment of current and projected profitability under the building blocks model rather than the alternative approach of rolling over DPP3 prices.

155. In line with the Commission's reasoning in DPP3, using the building blocks model will better reflect the evolving circumstances of gas pipeline businesses and better create financial incentives to improve efficiency thereby aligning incentives between GPBs and consumers.

156. We have modelled the impact of rolling over DPP3 prices rather than using the building blocks model. This would result in a significant shortfall in revenue in DPP4 (made worse by declining real revenue growth factors i.e. customers and volumes).

157. In our view, rolling over DPP3 prices would compromise the Part 4 purpose by leading to a shortfall in revenue and therefore hindering incentives to invest.

Innovation

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[39] Frontier Economics, *Key Issues for Gas DPP4 reset: Report prepared for Vector* (June 2025), page 19

158. We note the Commission's statement that: "*we support the businesses maintaining optionality for renewable gases, our early view is that we do not consider a dedicated allowance is required to incentivise suppliers to prolong the useful life of their networks.*"[40]

159. We encourage the Commission to give further consideration to how it can support maintaining optionality for renewable gases. Networks are incentivised to preserve optionality and prolong the useful life of their networks. However, this must be balanced against incentives to avoid investment in the face of heightened stranding risk. We note the potential for GPBs to be cashflow negative by the 2040s. In this context, we consider a dedicated allowance to investigate innovations to preserve optionality would support the long term benefit of consumers.

160. We note our consumer research considered consumer feelings towards biogas. Residential consumers were generally positive towards biogas although there was concern the logistics would cost more. Business consumers had questions around economic viability, timing and logistics.

161. We also note residential consumers were more likely to consider front loaded recovery 'fair' where tied to a positive outcome (e.g. biogas rather than decommissioning), although business consumers were more focussed on the cost of gas.

162. In our view, an innovation allowance for GPBs could be designed in line with the innovation funding available in the EDB sector. This would ensure GPBs only received funding if their application to the Commission established the research would support the long term benefit of consumers.

163. An innovation allowance could also cover projects that may further increase the economic efficiency of gas pipeline companies during a winddown.

164. Vector is currently working with GIFWG to investigate incentives for renewable gases.

Regulatory period

165. On balance, we agree with the draft decision to apply a regulatory period of 5 years.

166. The current environment is uncertain and potentially subject to rapid change. This would support a shorter regulatory period to better address any events that arise.

167. On the other hand, there is a benefit to the regulatory certainty provided by a five-year period and, from a practical perspective, a shorter period imposes a greater workload

[40] *Gas DPP reset 2026: Issues paper* (June 2025), at 3.30

burden on both GPBs and the Commission implementing more frequent resets. Accordingly, the five-year period may reduce compliance costs.

168. We consider the five-year period is likely the best option. However, the longer period should be supported by ensuring appropriate uncertainty mechanisms are implemented in case of any unforeseen changes in the sector. We consider the greatest risk is a significant escalation of volume or connection decline compared to forecast. We strongly recommend the Commission move to a revenue cap to address this risk, along with re-openers and/or a hybrid mechanism.