19 July 2023

Charlotte Reed
Input Methodologies Manager,
Infrastructure Regulation
Commerce Commission
P O Box 2351
Wellington

Via email: im.review@comcom.govt.nz

Dear Charlotte

Re: Report on the IM Review 2023 Part 4 Input Methodologies Review 2023 – Draft decision

1. This submission is on the Commission's Draft decisions on Part 4 Input Methodologies Review 2023 dated 14 June 2023 (in this submission "the Paper").

2. Our submission is focused on decisions related to Gas Pipeline Businesses (GPBs) including Gas Transmission Business (GTB) and Gas Distribution Businesses (GDBs).

3. Our members have been consulted in making this submission but it does not necessarily represent all the views of any of them and some members may make separate submissions.

4. We reference legal proceedings and briefs in relation to the Merit review of the 2022 gas IM amendments. We have no concern about disclosure of any of the relevant documents, including submissions and statements of claim to the High Court, but as a matter of courtesy to the court they should remain confidential to the parties involved in the proceedings until after 16 October this year. If anyone seeks access to them, we are likely to approve it.

Yours sincerely

[redacted]

Len Houwers
Secretariat for the Major Gas Users Group Incorporated

Summary

5. On a prima facie basis, MGUG variously supports or does not express a view on the following decisions and reasoning applied:
    a. **Decision AV16** to amend depreciation rules to avoid overcompensating suppliers and limit their ability to extract excessive profits.
    b. **Decision CCO2** WACC Percentile – apply mid-point WACC (50th percentile).
    c. **Decision CC05** Cost of Debt in WACC estimates to allow for a four-year regulatory period.
    d. **Decision CC07** Change TAMRP estimate for GPBs to 7.0%
    e. **Decision SP07** recoverable costs – GTBs
    f. **Pre-review reconsideration of price-quality path IM decisions RP01.7, RP02.7 and P05.7** – requiring supplier which nominates reopener event to provide sufficient information to enable the Commission to assess whether a reopener event has occurred and whether a price-quality path should be amended.

6. MGUG does not further comment on those matters because it is not confident that it fully understands all the reasoning or their materiality in application. Without the insights of accountants who work for suppliers and therefore alive to the implications we could be unaware of issues of significance. We therefore have to rely on the Commission to protect the interests of consumer in these respects.

7. MGUG opposes the following decisions
    a. **Decision CC07** – maintaining asset beta uplift of 0.05 for GPBs relative to asset beta for EDBs.
    b. **Decision AV17** – we oppose keeping accelerated depreciation (asset life adjustment mechanisms) for sunk assets introduced in the 2022 amendment.

8. MGUG anticipates a law change to the definition of gas pipeline services in the next parliamentary term. Together with real progress towards pipeline repurposing and political acceptance for lower carbon gases, MGUG considers that estimates of economic stranding risk should materially reduce. If it is appropriate for stranding risk to be transferred to consumers by accelerated depreciation (which MGUG rejects) measures to recover investment revenue early need to be recalibrated to reflect progress in the real world.

9. The case against the transfer of stranding risk to consumers is even stronger now, than last year. Events and information make it more obvious that it is premature to begin compensation in advance of a speculated material decline in demand for the suppliers' services based on expectations of government constraints.

10. In particular the Commission is not bound to require consumers to provide incentives for gas pipeline asset investments toward a hypothetical future where suppliers will lose demand, as if they will be confined to the transport of natural gas. It is almost irrelevant that the current law arguably confines the Part 4 regulation to natural gas facilities. That does not prevent the

Commission (or the accountants of the suppliers) from considering the likely value of the assets in any use, or to any buyer, at the end of the projected natural gas use, when thinking about incentives.

11. Anticipation of an early end to natural gas use unavoidably anticipates substantial changes in law and regulation, among other things, to compel the demand reduction the draft determination expects. Current law does not contain mechanisms that will result in that lost demand. If it is competent for the Commission, in foreseeing the future, to anticipate law that will decree reductions in natural gas demand, it is equally open to the Commission to take account of the likely changes in technology and resource availability, and law, that will accompany replacement of fossil fuels with 'green' equivalents. MGUG argues that it is not only permissible, it is incumbent on the Commission to take a real-world view.

12. We are advised that among the grounds for judicial review is making decisions based on a mistaken view of the law. If the narrow statutory definition of natural gas is a reason for the Commission's apparent omission to give appropriate weight to a material factor affecting both the degree and timing of impact of a proposed phase down of natural gas (including the likelihood and value of transport services for green alternatives) that would be a mistaken view of the law. If the law permits the Commission to take into account speculation about adverse changes to demand for services, it permits and probably requires it to take into account the real world factors that are equally or perhaps more likely to add to demand for other services the assets can provide.

13. We explain the AER approach as an example of how to improve the methodology for asset stranding risk assessment. We urge the Commission to apply the AER methodology to improve and update the asset stranding risk model.

Previous objections not addressed

14. Appendix 1 traverses MGUG's arguments and reasoning across the history of the 2022 gas IM amendment and the various papers related to that and this current review. These address matters related to; natural gas demand risk, GPB risk profiles and revenue risk, policy risk, modelling probabilistic outcomes, New Zealand case law, competitive market outcomes, whether regulated suppliers face asymmetric risk, and understanding of ex-ante FCM principle. Reviewing the arguments and reasonings supplied in previous submissions we consider that these remain material to consideration for reversing the 2022 gas IM settings.

15. We've updated some of the factual evidence in the Appendix to reflect two further years of information. However, time constraint on the submission deadline has meant that we weren't able to fully update all of our evidence. However, our view is that further update wouldn't have altered the narrative associated with the points that they were expressing. We'd be happy to update further if this assists the Commission in reaching its final decision.

Decision CC07 – Asset Beta uplift for gas

16. The draft determination assumes that the asset beta uplift for GPBs continues to be justified. The CEPA review of cost of capital contains no follow up on the topic in spite of having raised and discussed this in their 29 November 2022 -Review of Cost of Capital 2022/2023. CEPA notes our submission on the WACC percentile but not our reasons for considering the asset beta uplift for GPBs to be unjustified.

Beta uplift for gas not warranted

17. The current asset beta uplift for GPBs relative to EDBs and Transpower is 0.05 as reflected in the 2016 IM review final decision[1]. The 2016 final decision changed the draft decision which argued against any uplift[2]. The arguments for, and against uplift, appear to have been finely balanced and ultimately relied on a judgement call to provide for some uplift while winding it back from its 2010 setting.

18. If the same arguments for and against an uplift apply, the Commission needs to explain how it comes down on one side or the other. The CEPA empirical evidence, which includes statistical confidence bounds, indicates that gas asset betas are indistinguishable from electricity sub samples[3].

19. We also note that the evidence of Vector's asset beta[4] relative to the average of comparator firms is lower by more than the current gas uplift (0.05). i.e. there may already be an upward bias on asset beta for New Zealand firms.

20. The current evidence provided in the CEPA report doesn't justify asset beta uplift for GPBs. It combines the already weak case for the current uplift decided in 2016, with the two other pieces of information from CEPA's work showing that no uplift is needed (i.e., high degree of confidence interval overlap, and Vector's asset beta being considerably lower than the recommended energy asset beta).

21. Removing the gas asset beta uplift better meets the purpose of Part 4, particularly S52A(1)(d)[5].

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[1] Commerce Commission "Input methodologies review decisions: Topic paper 4: Cost of capital issues" (20 December 2016), para 339-457

[2] Commerce Commission "Input methodologies review draft decisions: Topic paper 4: Cost of capital issues" June 2016), para 330

[3] CEPA – p16 commentary, including Figure 2.3. We would expect a statistical test on whether the mean outcomes are the same (null hypothesis) would show that there is no evidence against this.

[4] CEPA – 29 November 2022 *Review of Cost of Capital 2022/2023 New Zealand Commerce Commission* Appendix B, p56

[5] Specifically, S52A(1)(d) – limiting supplier ability to extract excessive profits

Decision AV17 – Asset Life Adjustment

22. MGUG's opposition and reasoning to the Commission's decision to accelerate depreciation for sunk assets in the RAB as a response to perceived economic stranding risk has been documented in all our previous submissions dating back to August 2021. The points and evidence made in those submissions continue to apply for this review. For convenience we've collated them in Appendix 1

23. The main arguments for preserving the acceleration of depreciation to transfer stranding risk to consumers appear in *Financing and incentivising efficient expenditure during the energy transition topic paper* (topic 3d).

24. We address the problem definition reasoning, but also refer the Commission to the Appendix for more detail.

Problem Definition

25. The essential premises for preferring the current IM settings for gas are discussed in para 3.176 -3.199 of the *Financing and incentivising efficient expenditure during the energy transition topic paper*.

26. Para 3.176

    The long-term benefit of consumers is promoted by ensuring GPB networks continue to provide a safe and reliable supply of natural gas until they are no longer needed. This means GPBs require incentives to invest and innovate in line with s 52A(1)(a).

27. In response:

    a. Any incentive need should apply only to the new investment pertaining to long term safety and reliability. There is no 'incentive' achieved by extending it across sunk assets, or the parts of the RAB that have nothing to do with longevity and reliability of long term supply.

    b. It is not necessary or proven that incentives to innovate are needed, or desired by consumers, if it is true that there is a looming sunset with stranding of their own gas related assets

    c. There is no evidence that incentives for reliability are not already sufficiently strong to ensure that consumers will continue to benefit from reliable and secure supply of gas pipeline services

        i. Quality standards inherent under Price Quality regulation penalise suppliers for failures in reliability and security.

        ii. Petroleum pipeline regulation under the HSWA prescribe design, maintenance and operation standards to ensure that asset integrity and its management is integral to pipeline ownership. Proven breaches lead to substantial fines and reputational damage.

iii. Social license to operate is integral to managing company reputation risk. The prudent operator standard is non-negotiable for companies with such deep and wide ties to consumers in New Zealand.

d. GPB asset management programs (AMPs) provide sufficient transparency on asset risks and measures that support minimum integrity levels. These provide public visibility on the inspection, maintenance, and CAPEX programs of asset operators. The Commission and others are able to conclude by inspection that GPBs are managing their expenditure programs to maintain asset standards in the face of stranding risk assessment (which may be markedly different than what the Commission might assume it to be).

e. Even, if the Commission remains concerned that more incentive might be needed, the Determination should not reflect that untested assumption without ascertaining the value consumers would place on the alleged gains in reliability and longevity in supply, weighed against additional front end loaded prices.

28. Para 3.177

The risk of 'asset stranding' is a problem if it results in deferral of otherwise efficient investment or in underinvestment. This can happen where there is an expectation of losses from investment due to asset stranding risk despite there being sufficient willingness to pay from consumers (before the investment is made) to support normal returns. The magnitude of risk for GPBs depends on the long-term outlook for gas pipelines, but also depends on how we regulate GPBs and specifically how we address stranding risk through the IMs. 'Asset stranding' occurs when the returns a firm makes on an investment are less than necessary to compensate for the initial investment cost. For example, this could occur if an asset is permanently underutilised or shut down early.

29. The para 3.177 statement is purely theoretical. It is an attempt to lay the ground work for a problem definition that the regulator feels obliged to address. The key phrase is "*if it results*.." It also implies an expectation for compensation that remains a point of contention.

30. Para 3.178 and 3.179 assume an interpretation of ex-ante FCM principle which seems to give "ex ante" no material meaning. It is also a use of the principle that makes outcomes inconsistent with the outcomes in competitive markets:

a. Transferring stranding risks and losses to avoid write offs and write downs in asset valuation is not a workably competitive market outcome. In workably competitive markets, suppliers, not consumers absorb economic losses.

b. It assumes a regulatory compact or bargain, even while this is denied by the Commission. There might be a line between *return guarantee*, and *expectation of a return* but the Determinations in practice show no distinction. By allowing shortened asset lives for sunk investments the concept of ex-ante has lost its essential meaning. We expect that the Merit review will address this point to provide a clear legal interpretation.

c. The draft Determination will be grounds for greater supplier expectation that settings will be adjusted to keep suppliers whole in their investment decision after they've already been made. The draft, by not setting any boundary on the FCM concept creates a moral hazard opportunity for suppliers. This is not efficient since suppliers will assign a lower risk to their investments and have incentives to overcapitalise expenditure because of the ability to transfer risk to consumers.

31. Para 3.181.2 reasserts a claim that is not backed by any evidence:

The risk is asymmetric because GPBs profits are constrained on the upside, but not the downside. The commitment to keep assets in the RAB should be sufficient to provide GPBs with an opportunity to recover the cost of their investment including a normal return. But if operations cease prior to full recovery of the RAB, or consumers are not willing to pay the required charges, then GPBs may be unable to recover the cost of their investment and may make less than normal profits.

32. In response:

a. GPB profits being constrained on the upside is only partially true. GPBs are incentivised to earn above normal profits within a regulatory period. Equally their expectation is that they can earn normal profit over the long term. This is no different to the expectations of firms operating in a competitive market place. It is the definition of a competitive market that on average forms may only expect to earn "normal" returns. Expected returns are capped as much in a competitive market place as it is by regulation for monopolies. It is an essential design feature of monopoly price regulation to constrain prices to mimic competitive market outcomes.

b. Making "less than normal profits" is a risk equally faced by firms in a competitive market. There should be nothing unusual that this may also be an outcome for regulated suppliers.

c. If it is the intention that regulated suppliers should always expect the odds to be weighted towards achieving a normal return than this reduced risk of loss should be reflected in their WACC. Equity betas are no longer relevant and WACC is essentially equivalent to a bond valuation. Since this is not the case under the WACC setting methodology, this supports that risk premiums compensate for downside exposure.

33. Para 3.182

In the case of GPBs there are risks of economic network stranding as a result of changes in climate change policies or consumer preferences. For example:

3.182.1 the risk that future governments close or place restrictions on gas pipeline usage which would limit which consumers have access to gas pipelines;

3.182.2 that in the future the cost of alternative fuels declines relative to delivered natural gas, which essentially caps individual consumers' willingness to pay for natural gas;

3.182.3 that consumers place less value on gas because of environmental or other concerns relating to climate change; or

3.182.4 that consumers anticipate potential network wind-down and when they need to replace existing assets with new assets, choose energy alternatives that do not use natural gas and/or are not dependent on gas pipelines to avoid the risk that their own investments may become stranded.

34. In response:

    a. There is no evidence that there is any political consensus on the future of gas or use of gas pipelines, or indeed a strong preference to close or place restrictions on gas pipeline services. The Commission is confusing a possible outcome with a probable outcome. The broad range of competing outcomes from various studies and agencies is shown in Appendix 2. These illustrate the lack of consensus on the future of gas and gas networks. However, we would refer to the IEA October 2022 World Energy Outlook commenting on electrification of the energy system,section that seems relevant for New Zealand

       Where it has been built, in many cases the gas network provides a larger and more flexible energy delivery mechanism than the electricity network

    b. Consumer willingness to pay for natural gas isn't the same as consumer willingness to pay for gas pipeline services. This is because gas pipelines can be repurposed to carry a blend of various gases (hydrogen, natural gas, biomethane, biogas). Consumers pay GPB for gas pipeline services. If there is a demand for these services, the nature of the gas that is being transported is irrelevant.

    c. This is the same argument as espoused in b, and has the same response.

    d. That consumers make fuel choices that are different from gas, is a feature of the current market. What is also evident is that more consumers are choosing to connect than disconnect. Both the real data on active connections and the GDB growth projections make clear that, at least within the planning horizons of GPB AMP's connection growth is still expected[6].

35. Para 3.183

While the prospect of asset-related costs not being recovered may not be imminent (ie, under-recoveries are unlikely to occur in the current regulatory period or the next), it is the uncompensated risk that under-recoveries may eventuate in the future that can signal a potential economic stranding event and threaten current investment incentives.

36. In response:

    a. If it's not imminent over the next 9 years, and suppliers are agreeing with this through their AMPs and asset strategies, why is there a need for the regulator to respond at all?

[6] GasNet is an exception. It is also the smallest GDB. In aggregate demand for GDB services continues to grow.

b. If it's not imminent (expected) in the next 9 years, why would it be considered imminent at some further point into the future when the nature of complex systems is that the future is inherently uncertain?

c. Uncertainty increases with distance into the future. More so for complex adaptive systems like the economy and energy systems. The question isn't whether the future is uncertain, it always is. Rather it is whether we can know enough to risk making bold moves now that we would regret making later.

d. There are better timing options that give flexible opportunities to adapt should the signals become stronger. Existing regulatory tools include out of cycle AMP amendments, CPP applications, and price reopening events. These can work well in conjunction with supplier AMPs (annually updated) to give sufficient warning and time to respond, without locking in settings for 7 years.

37. Para 3.184

If economic network stranding risk is material, it needs to be addressed to provide for ex-ante FCM. Stranding risk may be partly systematic, given the relatively low penetration of gas infrastructure in New Zealand. To this extent, it is one of many factors we have recognised in calculating the asset beta of the WACC. However, the gas sector faces specific non-systematic risks (such as those listed in paragraph 3.182 relating to decarbonisation which are not accounted for in the parameters that determine the WACC.

38. In response:

a. "If economic network stranding risk is material" – the evidence to date has failed to show that on balance of probable outcomes, that network stranding risk is material.

b. Ex-ante FCM assurance is a concept that isn't generally understood to apply to sunk assets, particularly where the regulatory regime seeks to create outcomes that are consistent with the workings of a competitive market.

c. Decarbonisation doesn't conflate with reduction in gas pipeline services.

39. Para 3.185

Non-systematic risk of stranding needs to be specifically addressed. Ex-ante FCM can be supported through measures that bring forward cash flows in a way that would be NPV neutral if stranding did not occur (meaning consumers continue to bear most of the risk) or compensated for through an ex-ante risk premium which consumers pay (meaning suppliers are paid for bearing the risk – or more risk – going forward)

40. In response:

a. This puts the position as neutral on the supplier (NPV=0), but not the consumer. We explain this later in this submission. For consumers raising prices now almost certainly creates a consumer deficit because of higher consumer discount rates. The trade-off between higher prices now for a nebulous promise that suppliers might continue to invest in keeping their service available for some distant future isn't quantified. That it serves the long term benefit of consumers seems a belief, not a fact.

b. The assumption that the regulator can adjust settings later to create an NPV = 0 outcome assumes that suppliers have an obligation to keep their assets available for natural gas. What would the regulator's response be if suppliers decided that gas other than natural gas is more profitable to transport? Technically suppliers have created an economic loss for the value of their assets (NPV<0), but in reality they have simply repurposed them to provide the same service, but for a different gas earning them economic rents on their investment.

c. We have no opposition to shorter lifespans for new assets, but this can't be through a blanket approval. We would expect suppliers to apply for and justify shorter economic lives for investments yet to be made, and justify why that is more efficient than opting for OPEX, or less durable CAPEX alternatives.

d. We see no argument for an ex-ante risk premium. This falls into the same camp as ex-post compensation for investment bets that don't pay off.

41. Para 3.187

Changing asset lives or depreciation method does not lead to excessive profit (ie, it is NPV neutral) because it changes the timing but not the total real value of revenue received by GPBs. Suppliers continue to bear the residual stranding risk, if the risk mitigation is insufficient.

42. In response:

a. The response is the same as noted against para 3.185. There is no obligation on suppliers to operate their assets exclusively for carriage of natural gas in the future. This creates an opportunity for them to achieve an outcome where NPV>0.

b. As we detail later, even if "consumers" are treated as some amorphous collective where future consumers are the same as current consumers, the collective value of time for consumers is still higher than for suppliers. The consumer position is that accelerating revenues for GPBs is NPV negative for them. The corollary is that consumer willingness to pay for reliability is less than what it the regulator is allowing suppliers to charge them.

43. Para 3.181

Under current IMs we do not have provisions that allow for ex-ante compensation at the time of a price-quality path reset and suppliers have not received ex-ante compensation in the past for non-systematic asset stranding risk.

44. In response:

a. Para 3.181 is disputed by the facts

b. The statement that the regulator doesn't have a provision for allowing ex-ante compensation at the time of a price-quality reset appears at odds with the decision to amend the gas IM out of cycle in 2022 as part of the price quality path reset. We understand that this might not be preferred practice, but neither has the bar for allowing it, been set particularly high by the Commission's precedent. The option seems available, and arguably is a solution for a better adaption strategy that recognises the value of delay when uncertainty is high.

c. "*suppliers have not received ex-ante compensation in the past for non-systematic asset stranding risk*". What is the value of this statement? Has it been warranted in the past, but not granted? If so, why would it be warranted now? If it has never been warranted, why raise it?

45. Para 3.189 – 3.192 acknowledges risk of price shock to consumers and argues that these are by "price smoothing" mechanisms by allocating increases over multiple years and "adjusting alternative rate of change"

46. As we show further below, consumer price impacts are not even, and the distributional impacts aren't controlled for other consumer welfare outcomes. The reality is that no one can control or even anticipate what the consumer experience will be. Price shocks are being experienced now after just one year into the DPP3 period. The current settings anticipate even larger increases to occur over the next 5 years.

47. Para 3.197 appears to justify this as equitable:

While we acknowledge that changes to asset lives that affect depreciation have varied impacts on individual consumers, such changes reduce the likelihood of asset stranding occurring in the first place. This means that consumers pay more cost-reflective (and in turn more equitable) charges over time which mitigates the risk of consumer price shocks in future regulatory periods.

48. Our response to that is that the statement "*reduce the likelihood of asset stranding occurring in the first place*" is not something that has been demonstrated. There was no attempt to assign likelihood to any outcome in the modelling of asset stranding risk. There was also no factual assessment against the counterfactual that has been promoted to claim net consumer benefits.

49. This is further reinforced by the fact that there is no obligation on suppliers to make the assets available for future demand. This loop hole is demonstrated in our response to para 3.187.

50. Para 3.193 *Other stakeholder concerns*: The list of other concerns is one that we are familiar with, having raised them. These centred mainly around the purpose statement where we argued that the regulatory regime was designed to promote outcomes that are consistent with outcomes produced in competitive markets.

51. The Commission's response to that challenge (3.195) is:

Where appropriate, we can draw relevant insights from workably competitive markets. However, our task under the Part 4 purpose is to promote the specific competitive outcomes under s 52A(1)(a)-(d) in the market for the regulated service.

52. The suggestion is that S52 *to promote outcomes that are consistent with outcomes produced in competitive markets* is trumped by s 52A(1)(a)-(d), because of the qualifier "*such that*". This seems debatable. We understand that if both can be achieved, that is what should be pursued, not one or more of the sub-paragraph objectives at the expense of others, and at the expense of the required consistency with competitive market outcomes. Hopefully the merit review will cast further light on this.

53. We submit that the primary duty is to promote outcomes consistent with competitive markets, making sure that they include those in paragraphs (a) to (d). That makes sense of both elements, and sees the sub-paragraphs as necessary elements or conditions, but as particular instances of outcomes generally found in competitive markets.

54. The remaining paragraphs (3.198 – 3.199) summarise all of the arguments for not altering the settings (3.200). We've laid out why the line of reasoning and assumptions don't seem persuasive.

Gas pipeline services should no longer be linked to exclusivity to transport natural gas

55. The Commission discusses anticipated premature decline in natural gas demand as the justification for a transfer of stranding risk to consumers. Natural gas demand is not a sound proxy for demand for gas pipeline services. It seems that the Commission feels it cannot consider the prospects of gas pipeline assets being used to carry more than natural gas.

> ***The Act's definition of natural gas limits the extent to which we can support the optionality of alternative gases****. The service we regulate is the conveyance of 'natural gas' by pipeline (s 55A), but 'natural gas' is not a defined term under the Act. Our view is that neither biogas nor hydrogen can be considered 'natural gas' under the Act, while a blend of biogas or hydrogen with natural gas where natural gas is the most significant component could be considered 'natural gas'. However, we consider that if the blend requires a change in appliances that use natural gas it would not be natural gas*[7]*.*

56. In tandem, the Commission adopted natural gas demand as a proxy for supplier revenue, and simplified this further by assuming that gas demand risk would affect each GPB equally. These greatly oversimplified the issues and risks facing GPBs as we have pointed out in our other submissions and detailed in Appendix 1.

57. The draft Determination proceeds on an assumed need to act on speculative outcomes 25-30 years into the future. The Commission has acknowledged that any mandatory fall in natural gas demand was unlikely to affect GPBs over the next two regulatory periods (to 2031). The two outcomes modelled for the 2022 amendments projected for asset stranding in 2050, or in 2060.

58. Though there has been Commission comment about residual value from repurposing gas pipelines that would reduce economic stranding risk, the modelling did not take repurposing into account to adjust residual values for new economic lives. There are scenarios in which the

[7] Ibid- para 3:30

repurposed assets remain economically viable and carry more value than assumed residual RAB values at point of natural gas induced stranding.

59. We submit that the asset stranding risk must be assessed without confining gas pipeline services to natural gas.

Likelihood of change in the Act's definition of gas pipeline services.

60. Though MGUG understands that the Commission is not constrained by the restrictive wording of the Act in drawing conclusions from scenarios of the future, it is pertinent to note that the Commission has actual knowledge of the likelihood that the law will not have that constraint in the periods of those scenarios. In earlier submissions we have observed that the drafting of the Act had anticipated that the definition of regulated industries could change over time (Appendix 1)

61. We took our concerns about the narrow definition to MBIE in November 2022. In follow up (Jan 2023), MBIE agreed that the Act in its current wording might not be fit for purpose and needed updating. They proposed to draft a change to the definition of gas pipeline services to include the emergence of natural gas blends or alternative gases. This was to be done through the omnibus Regulatory Systems Amendment Bill (No 4). They expected to "future proof" the regime so that further gases could be added by Order in Council. It required the Minister's consent, but plainly it lost legislative priority. MBIE anticipate picking it up after the election[8].

62. MBIE have assured us that the Commission are fully briefed on this initiative. This, in our view, is not a material change to key information informing stranding risk, because the definition should never have affected scenario planning. However, on the reasoning previously applied it should affect the scope of the Commission's modelling.

63. To labour the point, it is distortionary to argue for action based on an *expectation* of what natural gas demand *might do* in 20-30 years-time, and not include an expectation that the Act itself would also have evolved by then.

64. The initiatives towards repurposing gas systems for renewable gases has political support from the Minister. She addressed the GasNZ 2022 conference in November 2022 outlining the government's vision for renewable gas as part of the long- term energy future for NZ[9].

65. The Commission knows that the industry is fully engaged in preparing for gas pipelines to transport other gases. There is currently a working group (established September 2022) drafting updates for NZS5442 (specification for reticulated natural gas) to accommodate gas blending and biomethane in regulated pipelines[10]. The updated NZ standard is targeted to be in place for biomethane by the end of 2023, and for blending hydrogen by the end of 2024. The target dates are aligned with *actual* programs to physically blend gases in natural gas pipelines.

66. If the Financial Model developed for the 2022 amendment has not been updated, it should be. It is now misleading. The draft Determination should not be completed without circulation of

[8] Email MGUG / MBIE 7 July 2023 confirming the status of amendment bill.
[9] https://gasnz.org.nz/news/minister-supports-renewable-gas-future-at-gasnz-conference
[10] The technical committee is chaired by GasNZ, and includes various industry stakeholder representatives

modelling showing a wider range of scenarios, to reflect real world uncertainty about international policy and agreements as well as local developments. In Appendix 2 there is a range of materials from public sources that show political and agency irresolution.

67. The Commission should consider adopting the approach and methodology that the Australian Energy Regulator (AER) took in assessing the same risk in Australia. We describe this next.

AER Business Case

68. The AER in the context of similar supplier concerns to economic stranding of gas network assets released an information paper in November 2021, *Regulating gas pipelines under uncertainty.* This traversed many of the issues that concerned the Commission. A key distinction between the Commission and the AER is in deciding responsibility for demonstrating the stranding risk. In New Zealand, it appears that the Commission considered itself responsible to mitigate uncertainty in the future for suppliers, but to exacerbate them for consumers. While also bringing forward demand suppression, with both costs and signals of an intention to load even more cost onto a declining consumer base, with an open-ended assurance of comfort for suppliers. In effect the Commission has become the advocate for the supplier position, and taken on all the justification of the case for shifting stranding risk.

69. In Australia, the regulated suppliers were told to do their own justifying, leaving the regulator to be persuaded:

AER's expectation[11]:

To demonstrate stranded asset risk, ***we expect regulated businesses*** *to provide plausible future energy scenarios that covers a spectrum of outlooks from the most pessimistic to the most optimistic for their networks, and to estimate the likelihood (probability) of each scenario. We expect regulated businesses to demonstrate the magnitude of stranded asset risk and possible divestment and investment plans under each scenario. In particular, to demonstrate the materiality of stranded asset risk and the justification for early regulatory intervention, we expect a regulated business to provide compelling evidence to identify:*

- *the factors that influence the estimates of expected economic lives, such as applicable government policies, evidence of their customers' sentiments in switching away from gas, developments in competing technology etc*
- *those assets that may be repurposed for transporting hydrogen and those that cannot be*
- *those assets whose economic lives may need to be adjusted to reflect the potential decline in long-term demand*
- *the value of stranded assets under the different forecasting scenarios*
- *the costs that may be avoided or incurred in the different forecasting scenarios*
- *the level of customer support for the business's proposed action to manage the risk and the quality of that customer engagement*
- *analysis of the price impact for the business's proposed action*.

[11] AER, Nov 2021 Regulating gas pipelines under uncertainty – p45

The rigour of this approach; considering a range of outcomes; assigning probabilities; a list of actions the suppliers would take; and materiality (i.e. revenue impacts), is in our view better practice.

70. A model developed this way can be routinely updated to reflect the latest information to shift outcome probabilities. In a New Zealand context, this means reassessing supply and demand risks for natural gas, policy likelihoods, progress on repurposing, assessment of supplier behaviour and signalled intentions, and particularly that ***the Commission need not be bound by a definition of pipeline services tied to only transport of natural gas***.

71. Furthermore, the AER also understood that a blanket approach to all regulated pipelines would not be appropriate:

    *We recognised that a broad base approach may not necessarily be in the long-term interests of consumers as **gas networks face varying levels of asset stranding and operate in different environments**. As such, we would assess the depreciation path proposed by regulated businesses on a case-by-case basis, with reference to the evidence submitted by the businesses[12].*

    MGUG has made the same point in a number of our submissions in drawing distinctions between GTP vs GDBs and between GDBs. This point is further illustrated in Figure 2 where GasNet is forecasting a decline in connections vs the growth in connections in all other GDBs. It's not novel for the Commission to prescribe different setting to different regulated businesses because of different risk profiles.

72. The AER also drew a stronger distinction between Australian emission targets and impacts on gas network assets to describe how it might deal with gas assets differently:

    AER's expectation[13]:

    We would expect regulated businesses to provide compelling evidence to justify the asset lives that they have proposed.

    *Notwithstanding the 2050 net zero emissions targets adopted by State and Territory governments, this does not necessarily mean the gas networks must be decommissioned or retired completely at that time. There is a possibility that hydrogen or bio-methane can be used as reticulated gas in the future. There is also a possibility that natural gas may continue to be used by specific customers (for example, industrial users who must use natural gas as a chemical feedstock), such that gas networks may continue to operate beyond 2050 at a smaller scale or in specific regions. **Therefore, in our view, assuming 2050 as the cap for the expected economic lives of pipeline assets without reasonable evidence or analysis would be inappropriate**.*

    As regulated businesses may face different levels of stranded asset risk, we may consider a departure from our typical approach of assuming uniform standard asset life for a specific class of assets (based on technical life). We may allow the same class of assets to have

[12] Ibid – p45
[13] Ibid – p46

different assumed asset lives (depending on the economic stranding risk the relevant business faces) among regulated businesses.

The AER's description of the possible landscape under national emission targets apply equally in New Zealand where the options between natural gas and low carbon gas aren't binary.

73. Lastly the AER had an expectation that suppliers should consult closely with its customers:

AER's expectation[14]:

Regulated businesses, consumers and regulators may have differing perspectives on how quickly network investments can or should be depreciated. ***Consumer views are vital in determining what depreciation adjustments would be in the long-term interests of consumers under the circumstances****. Consumer views are also important to us in understanding their expectations of future energy needs and the particular challenges that captive customers may face in this energy transition. Such information will enable us to determine what regulatory approaches would be efficient and prudent.*

*We expect that, in proposing any variation to the existing depreciation schedules****, regulated businesses would actively and meaningfully engage with their customers on the range of available options and reflect customers' feedback in their proposals.*** *We consider that good consultation will involve a range of scenarios being put to consumers with respect to demand forecasts, expenditure and any stranding mitigation measures, together with the price impacts of those scenarios.*

In other words, the AER provides for something that is lacking in the Commission's assessment, consumer buy in.

74. The AER's approach strongly contrasts with the Commission's. In Australia, suppliers are tasked with convincing the regulator and consumers that altering the depreciation settings is in the long-term interest of consumers. In New Zealand, the Commission has taken on the responsibility for the evidence to justify and defend its case to both suppliers and consumers for accelerated depreciation on the entire RAB.

75. The approach in the draft Determination , also seems at odds with New Zealand precedent. In a consultation paper produced by Ofgem in 2012 on real options and investment decision making[15] the authors referenced New Zealand as an example of where the regulator took a probabilistic framework to developing market scenarios (in the context of Grid Investment Test). The evaluation tools did not just consider expected NPV analysis, but also real options analysis.

Either standard net present value analysis or real options analysis must be applied in assessing the expected net market benefit of a proposed investment or alternative project*.*

[14] Ibid – p47

[15] Ofgem – 19 March 2012 *Real Options and Investment Decision Making* – Appendix 2 Regulatory Precedent (New Zealand)
https://www.ofgem.gov.uk/sites/default/files/docs/2012/03/real_options_investment_decision_making.pdf

The type of analysis to be used in applying the grid investment test to a particular grid investment must be whichever of standard net present value analysis or real options analysis is more appropriate ***having regard to the likelihood of occurrence of any real options during the economic life of the proposed investment or alternative project***[16]

76. This example was within the context of assessing *new* investment being undertaken by a supplier, but it can equally translate to the current situation with the gas IM. The further idea in this approach is the concept of real option analysis as a complementary tool to improve decision making. Conceptually, the decision by the Commission to allow accelerated depreciation is equivalent to the Commission providing (a free) put option to suppliers which they have subsequently exercised. The fact that it was immediately exercised means that suppliers considered the put to have been "in the money". The question is whether consumers have also benefited from this.

Supplier Put Option

77. The standard definition of a put option is something that gives the holder the right (but not obligation) to sell a number of assets within a specific period of time at a certain price. This contrasts with a call option where the holder has the right (but not obligation) to buy a number of assets within a specific period of time at a certain price. This applies traditionally to financial products but the terminology translates readily to real option valuation.

78. The IM amendment last year and the draft Determination simply allowed suppliers (but did not mandate that they should) to apply accelerated depreciation to their RAB, it has conferred an option right on suppliers. In this case a put option (right but not obligation to sell higher prices to consumers now). Unsurprisingly given that a dollar today is worth more than a dollar tomorrow, all suppliers have exercised their option. This is without any clarity as to the value of the long-term interest of consumers.

79. In the context of the gas IM, the asset on which the option is being placed is simply the service being provided by the pipeline. The Commission contends that this means a safe and reliable supply of natural gas while it is still being used widely as energy sources for homes[17].

80. The Commission's financial analysis in 2022 focused on the value that accelerating depreciation created for suppliers, but it didn't attempt to quantify the benefit to consumers. The Commission defended its decision on the basis that accelerating depreciation was still within the context of preserving ex ante FCM (ie NPV=0) for suppliers. Higher prices to consumers now would mean lower prices later. Implied in this, is that consumers would also not be worse off in the long term.

81. However, in attempting to speak on behalf of consumers without actually asking them what value they would place on reliable supply the Commission can't convincedly argue that these

[16] See: New Zealand Electricity Commission (2005) Schedule F4 – Grid Investment Test, Article 14

[17] Commerce Commission –14 June 2023 *Context and summary of Draft decisions Part 4 Input Methodologies Review 2023* – para 4.3 p21. NB It is unclear why the Commission should single out homes (residential sector) as the key beneficiary of its decision, but we assume that it also meant to include the wider market, including commercial and industrial sectors

measures serve the long- term interest of consumers either. Firstly, because this decision doesn't guarantee that suppliers won't have an outcome where NPV>0 (as explained previously), and also that this will never be NPV neutral for consumers (it's negative). Secondly it depends on how "benefit" is defined (welfare or surplus). Based on a consumer surplus argument, the answer is that there is none (a consumer deficit is more likely). If the consideration is for consumer welfare than these include measures such as;

a. Enhanced Competition/ Lower prices

b. Consumer protection/ Quality/ Safety

c. Market efficiency

d. Innovation and technology advancements

e. Stability and consumer confidence

f. Social welfare

82. Based on our understanding of how the Commission has applied various tests to its decisions our assumption is that Part 4 is concerned with the broader concept of consumer welfare[18]. We expand on that further below.

Outcomes so far from 2022 IM amendment.

83. We have mentioned the new information that should result in a recalculation of stranding risk through an improved modelling approach. A further reason for recalibrating is to review whether the settings are influencing supplier behaviour and consumer outcomes in a way that the Commission broadly expected them to

84. While it is only 9 months into DPP3 there is sufficient evidence to question whether the settings are likely to benefit consumers.

85. The Commission considers that accelerated depreciation is for the long- term benefit of consumers. More specifically the consumer benefit was in maintaining incentives for suppliers to invest to maintain reliability and safety in network and that the settings would make investment "efficient"[19]. The decision was also "considered NPV neutral for GPBs so that this would satisfy Part 4 52A(1)(d) (suppliers limited in their ability to extract excessive profits).

[18] Consumer welfare encompasses not only the monetary value consumers derive from their purchases but also non-monetary aspects such as the quality of products, safety, health, environmental impact, and other subjective factors that affect consumer well-being. Consumer surplus, on the other hand, is a more specific economic concept that focuses on the difference between what consumers are willing to pay for a product or service and what they actually have to pay.

[19] We are unsure what efficient" refers to. We assume that all investment decisions are efficient **ex-ante**.

Distributional impact on consumers were framed as being moderate[20]. None of those claims seem likely to be met.

86. The experience so far suggests:

a. Suppliers have *reduced* their investment intentions in reliability and safety CAPEX.

b. Connection growth in all GDBs is continuing at their historical rate. It's not evident that consumers have lost faith in the long-term future of gas.

c. Some suppliers have switched their pricing structures to households to transfer more of their revenue risks to them (further underscoring why revenue, not gas demand is what should drive the Commission's analysis).

d. While the implication is that suppliers are being kept whole at NPV =0 over the lifetime of the assets, it is questionable that the outcome is the same for consumers.

e. The ability of suppliers to recover their revenue streams early, could enable higher entry barriers to competition later.

Supplier CAPEX investment in reliability has decreased

87. Supplier investment intentions having decreased after the decision to transfer supplier risk of stranded assets were described in our earlier submission[21] , and restated in Appendix 1. While this doesn't necessarily disprove the counterfactual that suppliers would have altered their investment plans even more if the risk transfer hadn't been enabled, the outcome should trigger serious re-evaluation. . Relative plausibility suggests that suppliers are simply using the extra cash to boost their balance sheets while using the time option to delay growth expenditure.

Consumer demand for gas transport services continues to grow

88. Consumer behaviour shows continued confidence in gas. Connected and active gas connections continue to increase at the same rate since before the Climate Change Commission's advice (Figure 1).

89. GDBs continue to forecast growth[22] in connections via their Asset Management Plans (Figure 2).

90. Gas Transition Pathways assessments demonstrate the viability of gas as an energy choice, even as emissions reduce[23].

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[20] Ibid – para X6 –medium annual household gas bill would increase by around $48 per year for each of the four years of DPP3.

[21] MGUG 10 Feb 23 https://comcom.govt.nz/__data/assets/pdf_file/0022/308380/Major-Gas-Users-Group-MGUG-Submission-on-IM-Review-Options-to-maintain-investment-incentives-in-the-context-of-declining-demand-paper-9-February-2023.pdf para 72 - 87

[22] GasNet – the smallest network projects a cumulative loss of 112 connections (approximately 1%)

[23] Refer recent work by BEC, Castalia, and GIC. These include a variety of technically feasible policy choices including CCUS for natural gas, biomethane, and hydrogen

91. Despite recent headlines[24] the physical supply of gas in terms of remaining life of reserves has barely altered since 2012 (Figure 3). Natural gas demand will be determined by policy and economics, not resource potential.

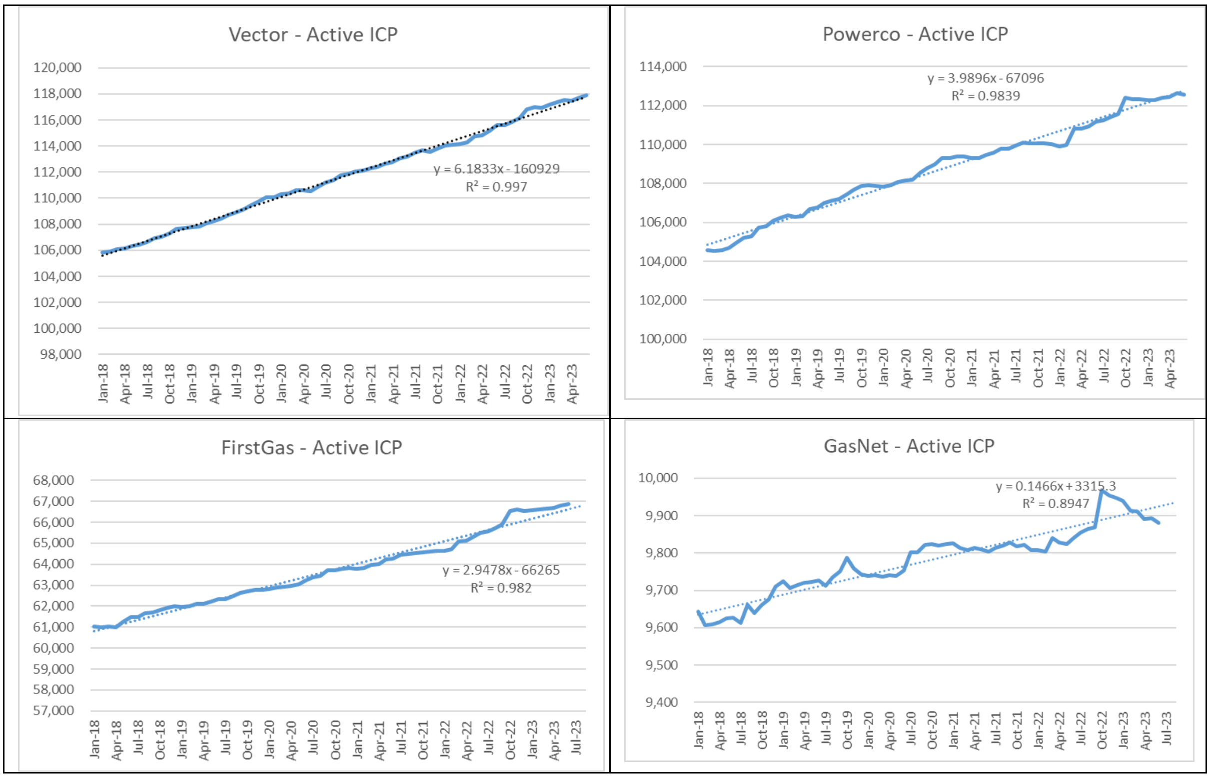

Figure 1: Active ICP growth - Jan 2018 - June 2023[25]

[24] https://www.energynews.co.nz/news/oil-and-gas/142252/gas-reserves-drop-record-low

[25] Source: Gas Industry https://weblink.blob.core.windows.net/$web/RegistryStats.xlsx

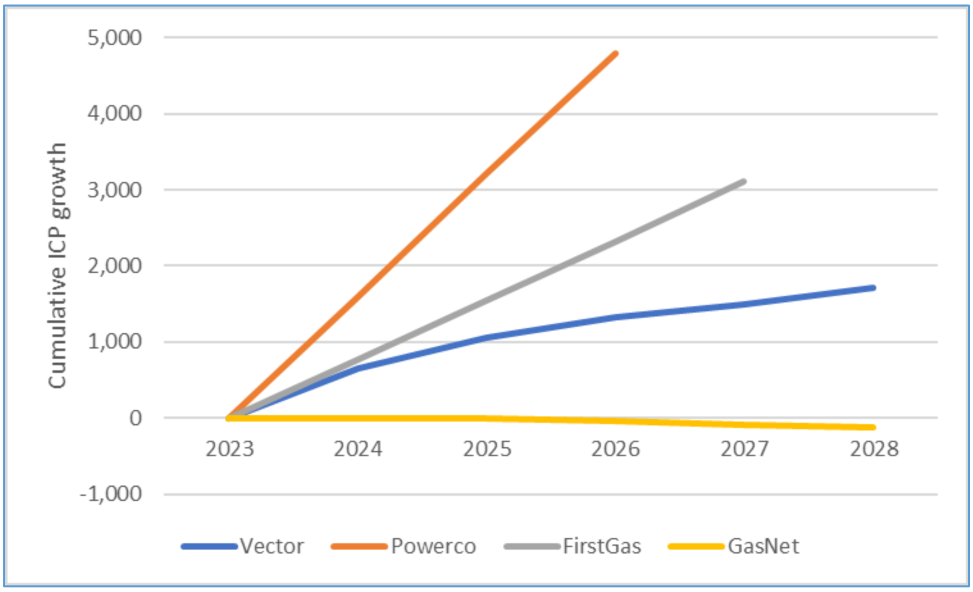

Figure 2: Forecast connection growth – from 2023[26]

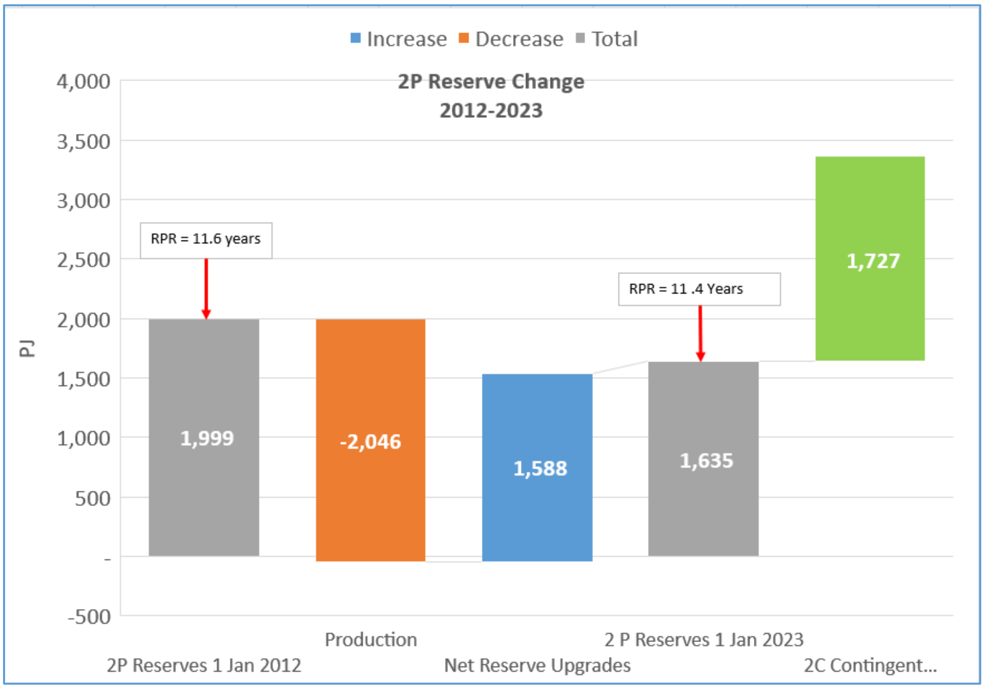

Figure 3: Gas Supply - Reserves to Production Ratio[27]

Supplier put option has a negative NPV on consumers

92. These outcomes of the 2022 Amendment are reflected in the experience of our members. Individual price increases for gas pipeline services for the first two years of DPP3 range from -

[26] Data Source: Supplier AMPs – Schedule 12c. Note that only a five- year forecast is required. CAPEX for connection growth expenditure over 10 years is also a feature of these plans
[27] Source: MBIE reserves and production data

7% to +69%. Collectively our four members are facing a 43% increase ($14 million) in gas transport costs since the start of DPP3. $10 million will be added to transport next year on top of a $4 million increase for this year.

93. Any conclusion that the accelerated depreciation measures are NPV neutral for suppliers, there is an implication that consumers are equally held "whole" – i.e. nobody wins, nobody loses. NPV assumes a discount rate, but the discount rate for suppliers is not the same as for consumers. A large number of studies show that discount rates for households and individuals vary considerably are of the order of 20%[28] with a meta-analysis of experimental evidence of a mean annual discount rate of 33%[29].

94. Interestingly, the lower the income class, the higher the individual discount rate (up to 89% for lowest income households)[30]. This becomes relevant when we consider what the early price increases have been for households as a result of the amendment in 2022 to permit accelerated depreciation and how this has flowed through to households.

95. For other consumers, including commercial and industry, standard discount rates will depend on the industry. Our members for example, range 10-20%.

96. The implication is that suppliers' willingness to raise prices now for lower prices later is unlikely to reach consumer thresholds for value. More so, because of the signal that revenues will be accelerated for at least 6 years to address "stranding risk", though the Commission considers it unlikely that demand for gas pipeline services will decline until a further 3 years after that.The implication is that suppliers' willingness to raise prices now for lower prices later is unlikely to reach consumer thresholds for value. More so, because the Commission has signalled that it proposes to accelerate revenues (raise prices to consumers) for at least 6 years to address "stranding risk", even while they consider it unlikely that demand for gas pipeline services will decline for a further 3 years after that.

97. October 2022 was the first opportunity that GPBs had to accelerate depreciation and this is reflected in higher prices to consumers. The results have been revealing in the price history trends of all suppliers.

98. Figure 4 and Figure 5 show the price trends for gas transmission under a revenue cap since the start of DPP2. MPOC pricing, because of tariff structure has a consistent increase for all consumers. VTC pricing, because of fixed capacity booking is dependent on the mix of booked capacity vs total annual throughput. In this case we have used an example of a small industrial user in the Auckland price zone to illustrate the trend.

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[28] National Bureau of Economic Research - Richard G. Newell, Juha V. Siikamaki 2015 *INDIVIDUAL TIME PREFERENCES AND ENERGY EFFICIENCY – Figure A1* http://www.nber.org/papers/w20969

[29] Experimental Economics (2022) 25:318–358 https://doi.org/10.1007/s10683-021-09716-9 Matousek, J. Havranek T., Irsova Z *Individual discount rates: a meta-analysis of experimental Evidence*

[30] The Bell Journal of Economics, Vol. 10, No. 1 (Spring, 1979), pp. 33-54 Hausman, J. *Individual Discount Rates and the Purchase and Utilization of Energy-Using Durables* Table 8 https://www.jstor.org/stable/3003318

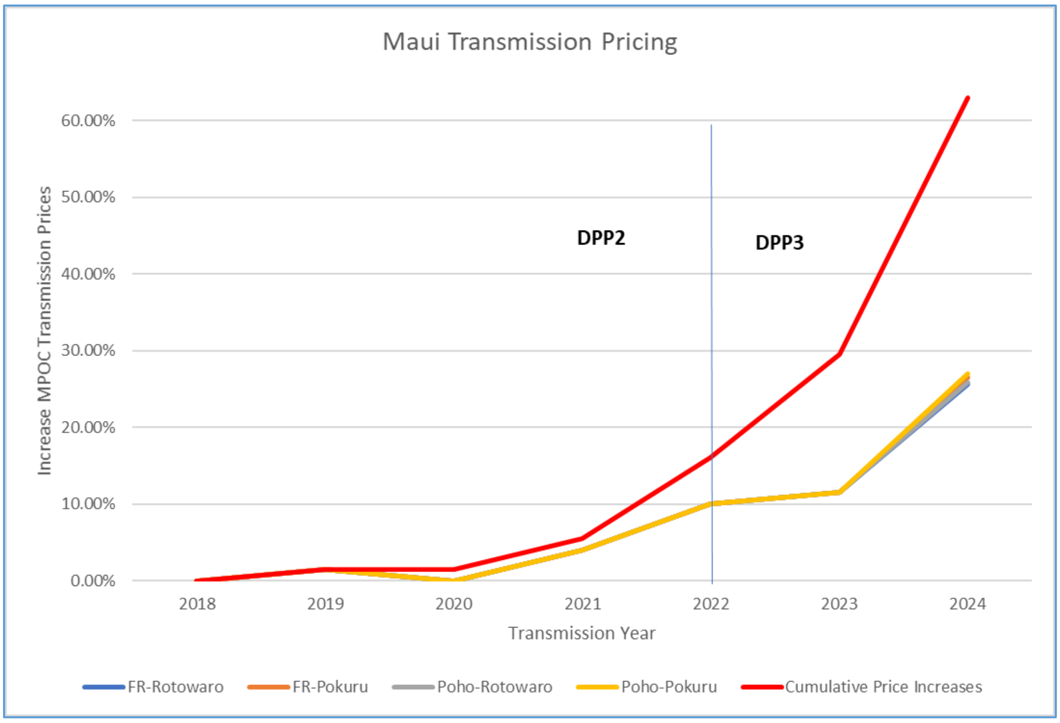

Figure 4: MPOC Transmission Pricing Changes since DPP2 (2024 = provisional)[31]

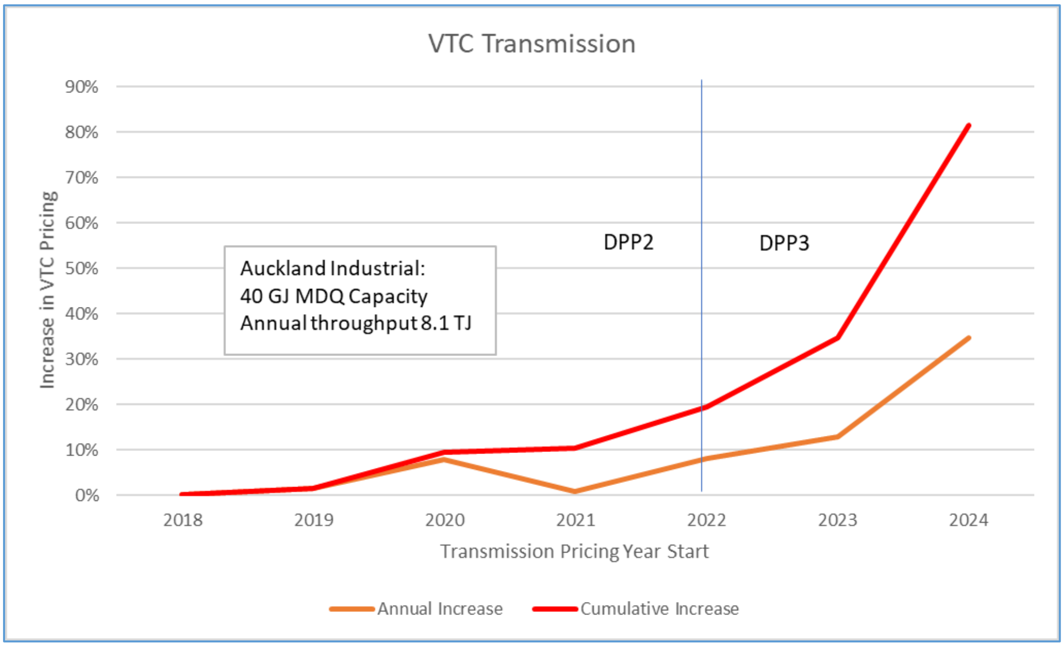

Figure 5: VTC Transmission Price changes since DPP2 (2023 = provisional)

Distributional impact differs also across households.

99. The analysis for increases on households for distribution charges is more limited since pricing for the coming gas year are still to be published. However, it seems transaprent that price

[31] Source: Published tariffs

impacts are not "smoothed" and some households have already experienced significant price shocks.

100. While prices to all load groups increased markedly from 1 Oct 2022, the impact is uneven across different customer groups (Figure 6 - Figure 9)[32]. The steepest increase has been for low user households in the Vector distribution system. Their price experience is of 38% increase in one year. These customers are now paying 53% more than at the start of DPP2 in 2017. This shift is largely through Vector's pricing structure shifting to generate a greater portion of their revenue from fixed charges. Household fixed connection fees have increased 68% from 41c/day to 68.8 c/day ($100 per year increase).

101. Long term consumer benefit in economics is also generally linked to the concept of social welfare, or more narrowly to consumer surplus. Ofgem, the UK's energy regulator, for example links its decisions to annual consumer impact reports (CIR)[33]. These discuss the expected benefits of their regulatory decisions in money terms, as well as the wider benefits that are more challenging to measure financially but just as important. For example, the impact on consumers in vulnerable situations. It is difficult to see how significant GDB price increases now in return for a future "maybe" promise of lower prices could be welcomed by vulnerable consumers here. A recent MBIE study[34] showed that 110,000 households were unable to afford to heat their homes. Notably the MBIE reported up to 30 June 2022 (before the significant price increases demonstrated in Figure 6 - Figure 9 had taken effect).

102. The future "maybe" promise of lower prices relies on expectations that the incentives of current prices higher than the cost of current services will induce suppliers to invest in assets they would otherwise have not invested in, that will last long enough to maintain reliable natural gas supplies for 30 more years. At the same time as suppliers and consumers are being told by the Climate Change Commission and political leaders that if they are to avoid the worst impacts of climate change, fossil fuel use must phase out long before then. They were told only a couple of years ago, that there should be no new domestic connections after 2025.

103. We think it is surreal to base alleged consumer benefit on making lay by payments for delivery several decades out, when the supplier is under no obligation to continue to provide, and there is plenty of commentary telling consumers they will not even want the supply by then. Compounding this, they are making the lay-by payments to relieve the owners of the assets from putative losses on assets they bought years ago, at a time when stranding was always a risk because of reserve/supply inadequacy, and climate change regulatory stranding was in nobodies' mind.

104. Consumers might conceivably understand a need to assure suppliers that they will get their money back earlier on new assets when stranding is a live risk, otherwise they will not make the investment. But there is absolutely no evidence of improved consumer welfare outcomes in transferring the owner risk on sunk assets.

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[32] Source: Published tariffs from respective distributors
[33] https://www.ofgem.gov.uk/publications/impact-assessment-guidance
[34] https://erm.createsend1.com/t/r-e-ttiiolk-l-t/

105. Consumer welfare loss experiences are real. If the Commission had adopted the AER approach where suppliers had to *actively and meaningfully engage with their customers on the range of available options and reflect customers' feedback in their proposals* we might have a better appreciation if there is an expected trade-off between short term pain and long term gain

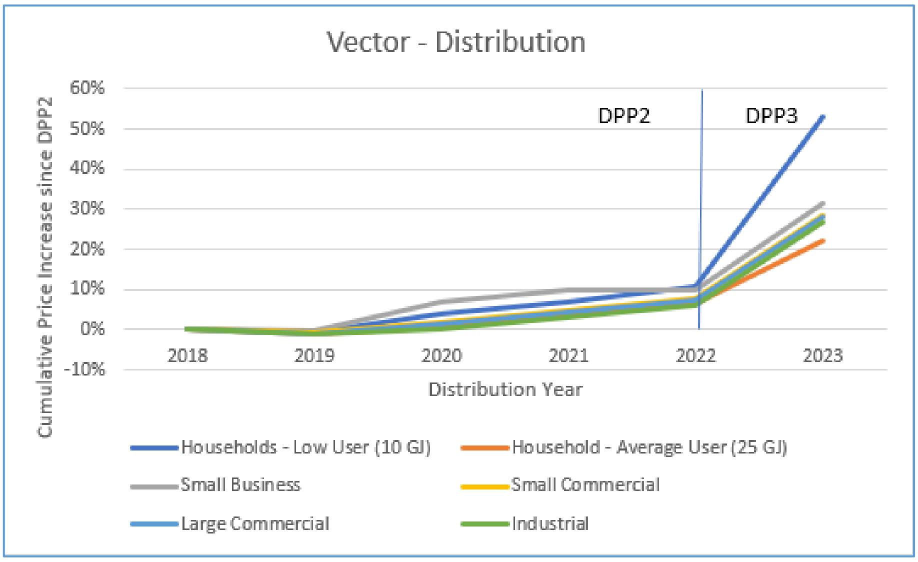

Figure 6: Vector Price increases since DPP2

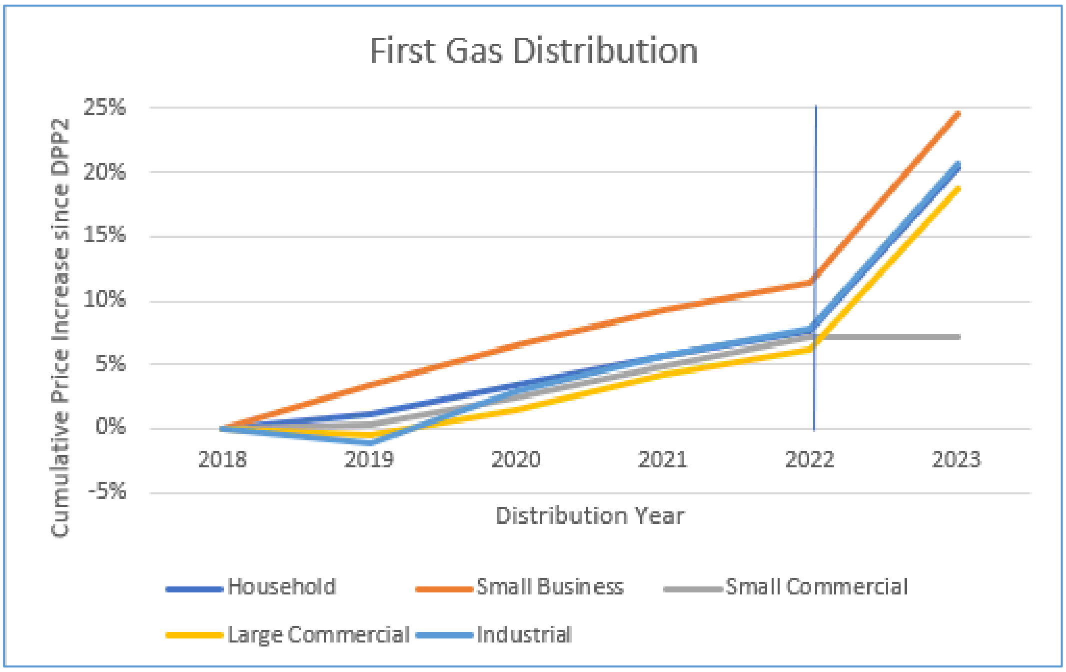

Figure 7: First Gas Distribution Price Increases since DPP2

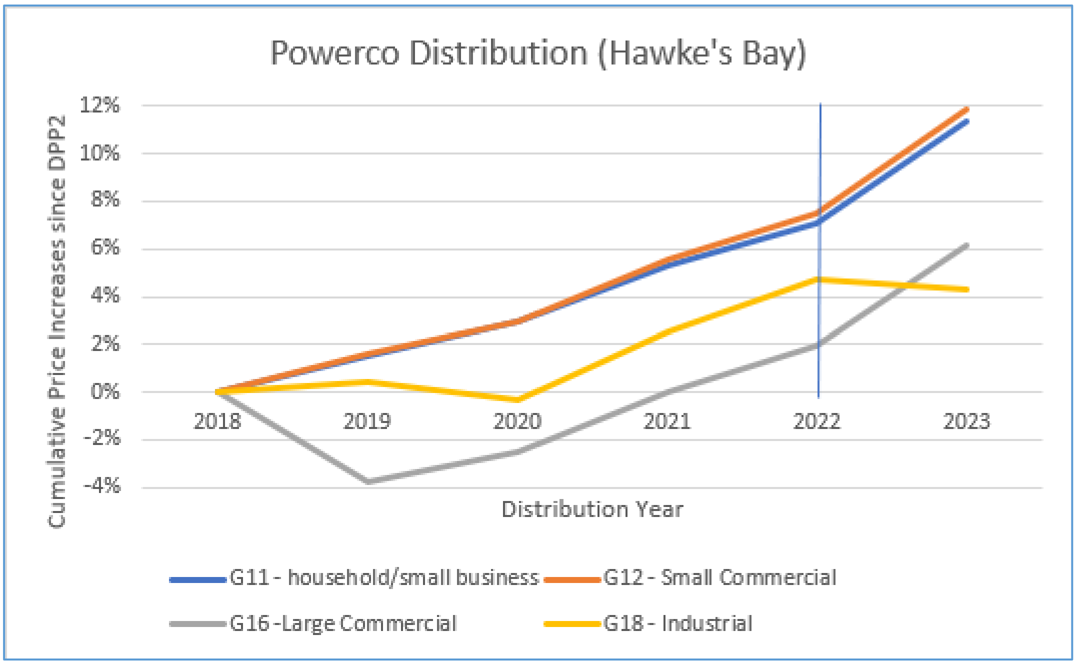

Figure 8: Powerco Distribution Price Increases since DPP2

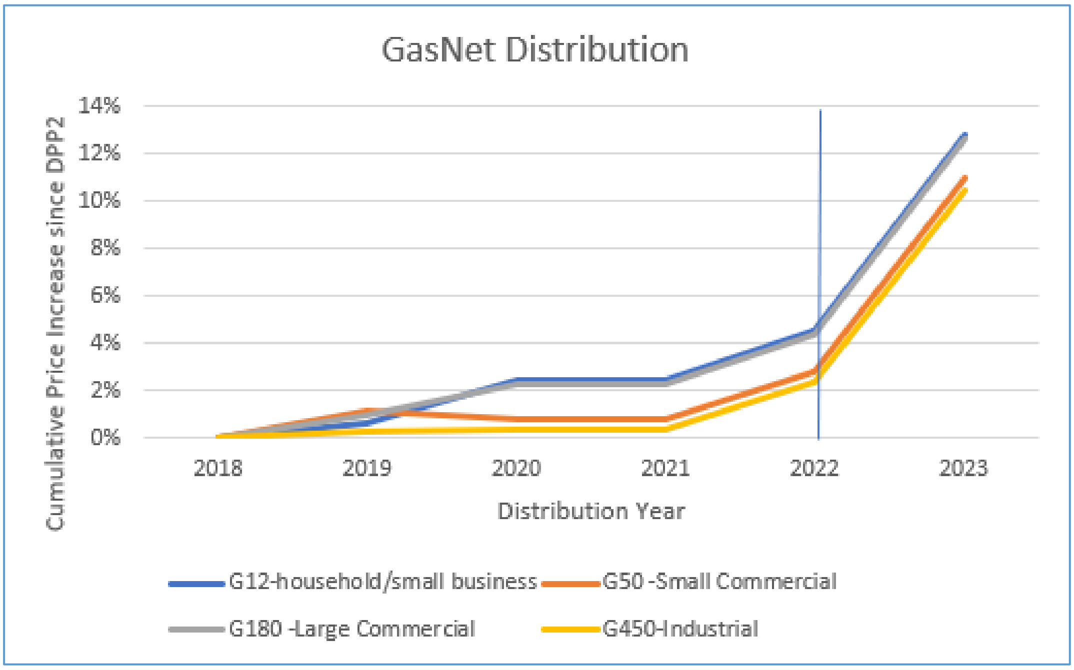

Figure 9: GasNet Price Increases since DPP2

Lower prices later increase entry barriers

106. The draft Determination's implicit interpretation of the ex-ante FCM assurance[35] extends it to sunk assets. We consider that to be unlawful because of the inconsistency with competitive market outcomes. The scheduled Merit review outcome will hopefully help resolve this. Regardless, under the current settings GPBs are able to raise their prices to recover more of their investment earlier. The implied bargain is that they are expected to have lower prices later. We have argued that this is not necessarily an outcome that is NPV neutral for consumers because their time value on money is higher than suppliers (neither does it guarantee that suppliers can't engineer outcomes where NPV>0). From a consumer perspective, they are paying more for services than they would otherwise prefer. Consumer surplus is negative (aside from other welfare losses).

107. A further consumer detriment is created by the future ability of suppliers to charge lower prices later.

108. In competitive markets, new entrants can come in and compete at a lower price point (or better value). An incumbent would then have to consider its service offering to enhance value, or lower its price to retain market share. This can occur in such a way that the incumbent has to forego its ex-ante FCM expectation of a normal return.

109. Currently GPBs are regulated because they are considered monopolies. This need not always continue to be the case. Technology/ innovation/ social change etc could well create a future where GPBs are no longer natural monopolies. This will be good for consumers if GPBs are forced to compete for services. Consumers will expect to pay lower prices and/or receive enhanced services. However, under the current settings, consumers are paying for monopoly suppliers to compete at a lower price level to block competition that might benefit them.

110. We note that the same risk applies to consumers in other regulated industries including EDBs. This is also why we would urge the Commission to question EDB submission motives that argue for supplier flexibility in choosing depreciation regimes that look to recover investment early.

Conclusion on Decision to not alter 2022 gas IM amendment

111. In its final decision paper for DPP3 and gas IM amendments the Commission noted[36]

> *We have made this decision based on the information available to us, but we may in future need to refine our assessment of economic asset lives in subsequent resets if new and materially changed information becomes available*.

112. The foregoing sections explain the material changes. The Commission shouldn't assume that gas pipeline services should be considered only in the context of transport of natural gas. It would be inconsistent to assume that natural gas demand might change in the future and not consider

[35] We accept that the Commission argues that this is not a guarantee. However the Commission has created an outcome here that is not consistent with outcomes with workably competitive markets.

[36] Commerce Commission – 31 May 2022 *Default price-quality paths for gas pipeline businesses from 1 October 2022 Final Reasons Paper* – para 6.15.2 p93

it likely that the legislation will have adapted to redefine the definition of gas pipeline services. If outcomes in 2050 and 2060 are being modelled these should reflect the different scenarios and probabilities, including that gas pipeline services are repurposed to transport low carbon gases that are not natural gas.

113. We prefer the AER approach that requires suppliers, not the regulator to justify depreciation measures. Their methodology is also better at capturing and demonstrating uncertainty and sensitivities.

114. The Commission should also consider what value consumers place on reliable supply, their investment time horizons/ discount rates, and likelihood of supplier underinvestment occurring in the context of existing incentives.

115. Furthermore, the evidence of the current settings suggest that consumer welfare has a wider consideration than just an assurance of reliable supply. The trade-offs between higher prices now and long-term consumer benefits have yet to be considered.

116. The Commission has other tools at its disposal to adapt to actual changes in the environment. The 2022 gas IM amendment is a blunt instrument with potential for many unintended consequences to be generated, some of which are already becoming apparent. The value of timing flexibility should be integral to assessment of alternatives. Price reopeners, CPPs, and IM reopeners as part of a DPP reset are all better options for dealing with emergent risks.

Materially Better Outcome Solution to Actual Risk Event

117. The Commission's central premise for its 2022 Gas IM amendment references uncertainty:

Natural gas use is expected to decline in the long-term but there is significant uncertainty about the pace of change and extent of decline, and the potential impact on GPBs. This has potential implications for how best to address asset stranding risk in order to promote the Part 4 purpose[37]*.*

118. The two sentences are a non-sequitur. There is no necessary connection between an uncertainty and a need to "address" stranding risk. The statement seems to imply that an uncertainty should generate a bold response for action now, when that willingness and the action now may itself accelerate the demand decline.

119. Uncertainty increases with distance into the future. The question isn't whether the future is uncertain, it always is. Rather it is whether we can know enough to risk making bold moves now that we would regret making later.

120. Accelerating depreciation for an event that has not occurred, or is considered only probabilistically likely at some distant point in the future is costly decision. It reduces current consumer options with an argument that it might increase their choices in the distant future . Alternative mechanisms exist:

[37] Part 4 IM Review 2023 Draft Decision Financing and Incentivising Efficient Expenditure - Para 3.168

a. Review gas IM settings as part of setting DPP4, or subsequent price quality resets[38]

b. Reopener provisions within Gas IMs

121. The Commission has already set a precedent in DPP3 to bring forward amendments to IMs if it considers it necessary to do so. The Commission acknowledged that prospect of asset-related costs not being recovered may not be imminent and under-recoveries are unlikely to occur in DPP3 or DPP4[39]. This is consistent with current supplier AMPs and continued connection growth (Figure 1, Figure 2)

122. The Gas IMs have provision for reopeners within a DPP[40]. Reopener events include catastrophic events, change events, risk event, and resilience or asset relocation event. These could cover most Commission concerns about underinvestment in maintaining safe and reliable assets. But the main incentives for maintaining safe and reliable assets are already in the quality requirements of the regime, and in safety regulation, as well as being in the suppliers' long-term interest.

123. The regime prescribes that most resilience type expenditure should occur as part of a regulated supplier's ordinary asset replacement and renewal programme of work. These are identified in supplier AMPs along with their statements that asset policies support reliability and safety of their network. If AMPs produced in good faith but suppliers underinvest in reliability and safety of their networks (have opted for OPEX rather than CAPEX solutions) and this then leads to imminent failure, then the supplier can approach the Commission for a resilience type expenditure reopener. A supplier might argue for a risk event instead.

124. MGUG considers that flexibly adapting to real changes in circumstances as they emerge is a better way to promote the long- term benefit of consumers. It puts the onus on suppliers to justify real expenditure plans (as opposed to a hypothetical distant future). They will have to show how these meet the quality standards as well as other regulatory requirements (including HSE regulation for operation of petroleum pipelines). If suppliers don't wish to commit CAPEX to asset renewal and replacement because they don't consider that they will earn a normal return on the investment they will need to explain and justify this to the Commission.

125. Note that if the Commission doesn't consider that current reopener events can cover this situation, it can look to create one. The issue here is that the ability to adapt should maximise the time value (option) of delay.

[38] Commission - *Default price-quality paths for gas pipeline businesses from 1 October 2022 Final Reasons Paper* Para 3.35
[39] Ibid para 6.12
[40] Subpart 5

Appendix 1 – Evidence and Reasoning that continue to apply

The tight timeline for this submission did not allow us sufficient time to update all of our factual information to capture the data since these were first demonstrated. However, we are confident that it doesn't alter the overall picture of what the data was conveying. We'd be happy to follow up later if the Commission thinks this is necessary.

30/8/21- MGUG - GPB DPP3 Reset – Process and Issues Paper

Gas future has always been considered uncertain. This is the first instance where MGUG pointed out that uncertainty always increases with distance into the future and that other information is helpful in determining how real the threat is considered to be to affected parties:

Para 11 – GPBs, "BAU with caution"

While the medium to long-term future of gas consumption is uncertain, we don't consider that the pathway for gas in the next regulatory period has uncertainties that are materially different to the previous regulatory period. In particular we note that GPBs are already factoring in the current policy uncertainty environment in their own forecasts. While Powerco has yet to release their 2021 Asset Management Plan (AMP) update, Vector and GasNet have their AMP publicly available, and we are aware of First Gas's update through a webinar First Gas held on 14 June 2021. In particular we would note:

a. Vector's updated AMP shows a reduced growth forecast for new connections to FY31[41].

b. GasNet's updated AMP indicates that gas connection growth will continue[42].

c. First Gas presented their consumer connections forecasts to FY31 showing growth[43].

Para 13 – GPBs using asset policies to manage risk

GPBs CAPEX and OPEX programs acknowledge future uncertainty including:

a. Vector has updated its capital contribution policy to require consumers connecting to its gas network to contribute 100% of the cost of doing so[44].

b. First Gas have adjusted their compressor replacement strategy delivery plan from 2020 to 2021 to acknowledge uncertainty over future needs[45].

c. We would expect that prudent asset management would balance CAPEX/ OPEX trade-offs. For example, if GDBs anticipate asset stranding risk they would budget higher OPEX to maintain assets rather than replace them, while still retaining the option to replace them later.

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[41] Vector – Gas Distribution AMP Update 2021 – figure 5.1. While rate of growth is reduced, Vector are still forecasting growth in connections.
[42] GasNet AMP 2021-31, Section 7.3 System Growth
[43] First Gas AMP and Business update – 14 June 2021
[44] https://www.vector.co.nz/news/gas-distribution-2021-capital-contributions-poli
[45] First Gas AMP and Business update – 14 June 2021

Para 14 – GPBs creating repurposing option to preserve pipeline economic value

The evidence therefore suggests that within the timeframe of DPP3, these GPBs have all taken into account the advice of the CCC, as well as other developments surrounding the future of the gas network system. In First Gas's case their working assumption in which they are investing resources, is repurposing the system, not wind down. Furthermore, the wider factors around the gas market, particularly supply restrictions created out of Government policy, and wind down of domestic gas supplies have existed since 2018. This is not new information, and gas market participants have worked with this environment and are able to project this forward in their planning.

Para 15 – CCC advice doesn't contemplate complete phase out for natural gas

We also note that even the CCC's most extreme interventionist advice on gas suggested only bans on new connections, not a complete stop and dismantling of the gas system. The CCC advice assumes that natural gas will continue to be part of New Zealand's energy system to well beyond 2040.

Para 16 – Government position on gas also shifting to accepting its role in the energy landscape

We further note a shift in the Government's attitude to gas in the last eight months. There is a greater appreciation that gas has an important role to play in the energy transition implying an acceptance that gas has a longer-term future in New Zealand. [46]

13/9/21 - MGUG - GPB DPP3 Reset –Process and Issues Paper- Cross Submission

MGUG cross submission expanded on the theme that the evidence didn't support the need to change settings because of a perceived threat that might materialise 20-30 years into the future. MGUG supported the measure of a 4-year regulatory period for DPP3 as this allowed for better information on policy settings to emerge.

This submission also raised that individual GPB risk profiles in the face of possible stranding risk were different, and that the problem statement should be about sustainable revenue for GPBs, not whether natural gas demand would decline.

Para 24-31 Outline the different business drivers of GPBs

24. First Gas is involved in gas transmission, whereas Powerco, and Vector, only own gas distribution networks. Vector and Powerco also own electricity distribution networks, First Gas only operates gas distribution.

25. While there may seem to be an argument for a common risk on what will happen with gas supply and potential regulations affecting gas demand, the impacts and responses will manifest themselves differently across time and sectors. For example, mass market connections are more resilient to cost increases, particularly relative to electricity. Gas for hard to abate industries (high temperature process heat, feedstock) are likely to persist longer than for places where fuel switching is an easier economic choice

[46] Minister Woods – letter to the GIC 18 December 2020 indicated that gas will continue to be important to support the Government's energy transition plans.

28. The most obvious difference between GTB and GDB is in market/ customer segmentation and volume. GPBs have structured their business models based on these distinctions.

29. The distribution market serves mass market connections (residential, small commercial), as well as a range of small to larg(ish) commercial and industrial connections defined by their meter size but generally below 200 scm/hr (typically 10-50 TJ p.a. range for larger users). The total number of connections served by GDBs is around 307,000[47]. The total gas volume in the distribution market is around 33 PJ pa (23%) of the total New Zealand gas demand of 143 PJ in 2022 calendar year (Figure 10*)*.

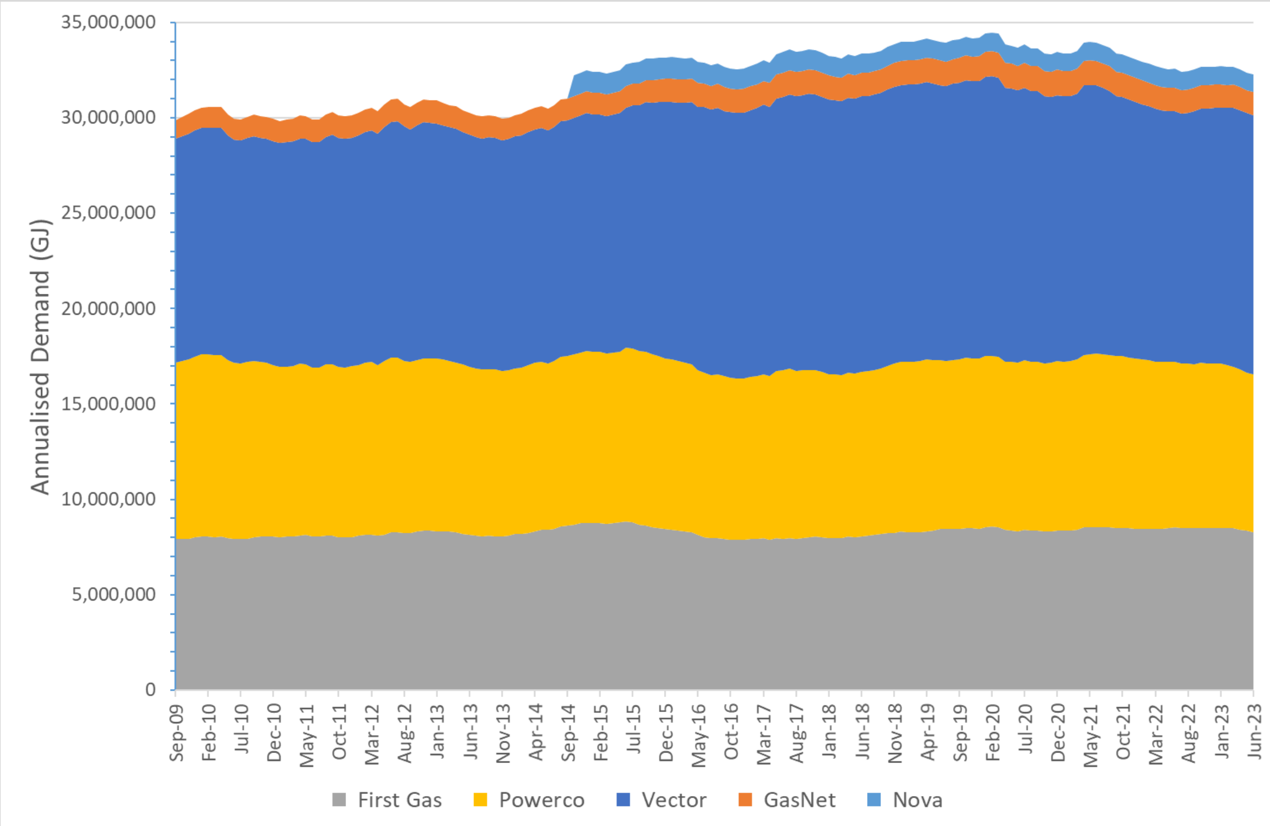

Figure 10: Annualised Demand- Gas Networks[48]

30. The transmission pipeline serves about 126 delivery connections which includes the distribution network gates as well as directly connecting around 37 larger users[49]. The transmission system transported about 170 PJ in 2020 (Figure 11).[50]

[47] Source: Information Disclosures

[48] Source: Gas Reconciliation Data. Note that private network Nova only publically reported since October 2013 so annualized data starts October 2014. They are included here, only to characterize the overall network sector.

[49] Although a number of these would be classed as relatively small demand now.

[50] 5 PJ of gas demand was own use and losses at production stations and around 8 PJ is transported outside of the regulated transmission lines at Kapuni and to Methanex.

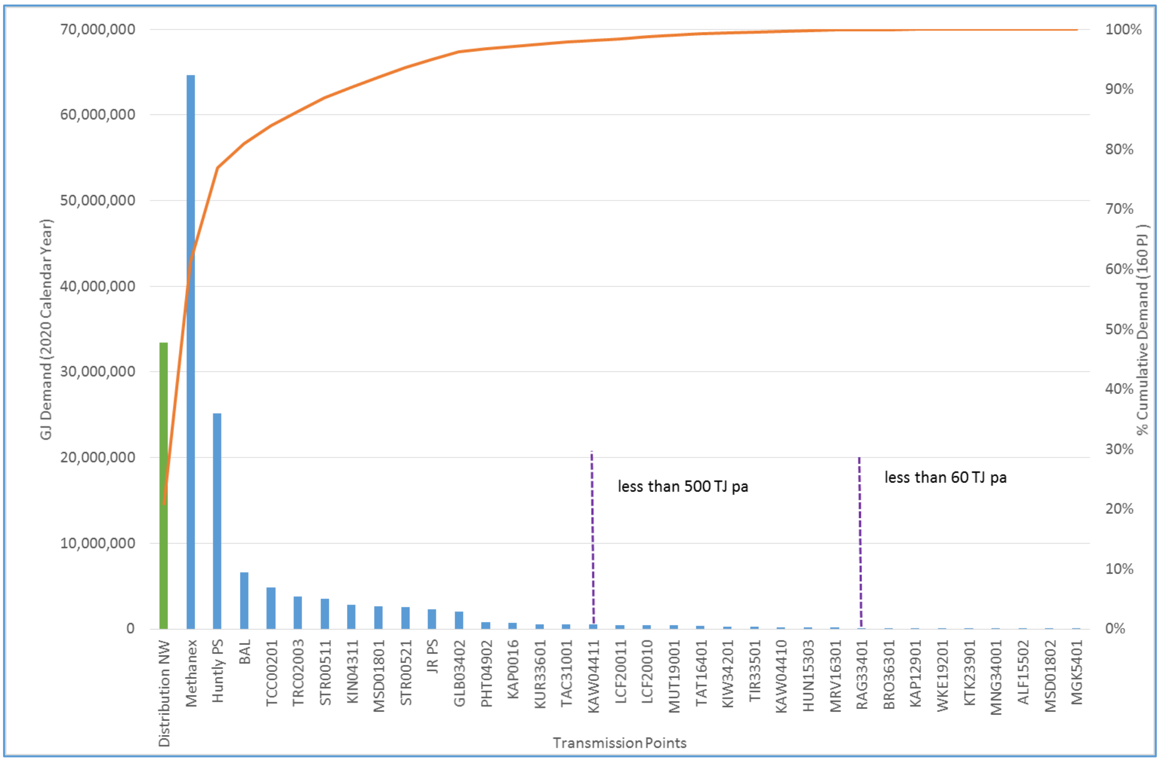

Figure 11: Gas Transmission volume[51]

31. While there are four gas distribution businesses, their structure in terms of customer type (mass market, small commercial, large commercial, industrial, non-standard) is very similar[52] with 96%-99% of connections being mass market customers (Figure 12)

[51] Source: Oatis

[52] There are some differences in how different networks split their customer type. Generally there is close agreement on what constitutes a mass market customer. The other categories vary and the split between industrial/ large commercial/ Non-standard can depend on how meter size is split and whether a large customer should be treated as non-standard.

Figure 12: GDB - Connection Split[53]

Para 33-50: CCC advice needed to be seen in the context of the legislation

33. Considerable weight is placed by GPB advisors on what the CCC advice[54] is in relation to gas demand in the analysis used by Vector/ First Gas/Powerco. In this regard the GPB's overseas based consultants do not appear to have been fully briefed on what constituted advice to Government vs the CCC work to demonstrate that their advice had a reasonable factual basis.

34. This is a subtle but fundamentally important distinction to make. The core of the CCC work is to develop overall emission budgets. Despite a commonly held misconception, the Commission ultimately does not prescribe individual emission pathways.

35. A key point is that the CCC has not determined what a gas demand pathway will look like. **Nor has it advised the Minister on any specific policies for gas**. Rather it acknowledges that in absence of specific supplementary policies targeting gas use (which it is not recommending) gas demand can only be *influenced* by market settings.

36. It follows that views on future gas demand can only be informed by views on how the energy market will allocate gas in the energy mix, not by central government directive or wish.

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[53] Source – Information Disclosure

[54] Climate Change Commission, 31 March 2021, *Inaia tonu nei; a low emissions future for Aotearoa- Advice to the New Zealand Government on its first three emissions budget and direction for its emissions reduction plan 2022-2025*

Despite the length of the document and accompanying evidence, the CCC report provides specific advice ***only*** **in relation to the following matters**[55]:

a) The recommended quantity of emissions permitted in each emissions budget period.
b) The proportions of an emissions budget that will be met by domestic emissions reductions and domestic removals, and the amount by which emissions of each greenhouse gas should be reduced to meet emissions budgets and targets.
c) The appropriate limit on offshore mitigation that may be used to meet an emissions budget, and an explanation of the circumstances that justify the use of offshore mitigation.
d) The rules that will apply for measuring progress towards meeting emissions budgets and the 2050 target.
e) How the emissions budgets, and ultimately the 2050 target, may realistically be met, including by pricing and policy methods.
f) The direction of policy required in the emissions reduction plan for that emissions budget period.

38. With respect to the advice, there is no mention of gas in items a-d above[56]. Emissions from gas are considered part of the aggregate quantities of net long lived greenhouse gases (primarily carbon dioxide). Although there is a reasonable assumption that reduction in gas demand might play a role, it is not quantified, and the CCC is largely indifferent on how those targets should be met by different sectors and fuel types. This is consistent with the objectives for the role established for the CCC under the Climate Change Response Act (CRA)[57].

39. Parts a-d specify the net outcomes and how they should be measured, but there is an assumption of wide flexibility on how those outcomes are achieved. There are no statutory targets proposed on the gas sector.

40. Item e addresses Section 5ZC of the CCRA where the CCC has to *demonstrate* how the (2050) target may be realistically met. To do so, the CCC develops models for possible futures. Plausibility of pathways are heavily caveated on underlying assumptions in the modelling work that may or may not be realised. Gas is still not specifically mentioned, but is included as part of a sector (Energy, Industry, and Buildings). This is summarised in a *demonstration* pathway[58] (our emphasis added) that combines scenarios with "principles and judgement"[59]

41. Importantly for this discussion, **the pathway is not a forecast or even a prediction**. This point was made clearer following a CCC response to a question on economic modelling work used by the CCC[60].

> *"CGE modelling is used internationally to provide insights on the impact of emissions reduction pathways on the economy. CGE models, including C-PLAN, can provide*

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[55] Ibid – Table 3.1, p40. Note we have omitted two other pieces of advice requested separately by the Minister that relate to biogenic methane reduction and New Zealand's Nationally Determined Contributions (NDC)
[56] Ibid – Chapter 5 deals with items a, b, c in various tables and figures, item d is covered in Chapter 10
[57] Climate Change Response Act 2002 – 5Q
[58] Demonstration pathway is to 2035
[59] Ibid – figure 7.1
[60] Personal correspondence with CCC seeking clarification on how to interpret their modelling work

insights on the impacts of potential future scenarios, ***but are not usually used to predict or forecast the future.***

The ranges we provide in our analysis are for the range of scenarios that we have modelled as opposed to probability ranges*, and the sensitivity analysis we carried out was focussed on understanding the impacts of varying key variables within the model.*

It is not possible to validate CGE models in the way you suggest ***as they are not forecast models"***

Communications & Engagement Team (12/7/21)

42. This commentary related to questions on the C-Plan (impact on national economy and industries). The C-plan however is linked to the CCC's ENZ model. ENZ is a spreadsheet based model that attempts to find an internally consistent pathway for various sectors and subsectors based on technical and economic assumptions. Its output feeds into C-Plan as an input. For gas the ENZ model includes assumptions about gas reserves, regional pricing and network costs and LNG price. These are set exogenously (i.e. fixed outside of the model).

43. The ENZ model sets further *exogenous* assumptions about technology, fuel prices, switching options, years to transition, Opex, Capex, building stock, gas phase out profiles, new generation build schedules, and so forth. As far as is visible from the public information on the modelling work, the model outputs are deterministic, not stochastic. Limited sensitivities around some assumptions have used an equally deterministic approach but correlations between any of these doesn't appear to feature in the modelling work[61].

44. The ENZ model does not include green or blended gasses as an option to use in technology selection. This is deliberate. The CCC acknowledges that gas infrastructure might be retained beyond 2050 to support "green gas" deployment. However in its advice, it only allows itself to consider technologies that are "*technically and economically achievable in light of uncertainty*". Because New Zealand hasn't yet demonstrated green gas technology in its domestic setting, it is not included as an option in a demonstration pathway. Should First Gas say, accelerate its proof of concept of blended gas before its current proposed 2030 timeframe, it could be considered as an option in the next CCC report. The obvious corollary to that statement is **that rather than accelerate revenue recovery, the stranding risk is better controlled and mitigated by accelerating proof of concept work on hydrogen blending in pipelines**.

45. This is not a criticism of the modelling work undertaken by the CCC. The CCC needed an objective demonstration that its advice was based on more than just an opinion. The unspoken reality is that energy policy, social policy, and climate policy operate in a complex adaptive system that is inherently unpredictable with any degree of accuracy. As noted above, the CCC has not attempted to predict, and by extension can't even put a plausibility range around the pathway that might reflect actual outcomes. The only clear objective is net zero (long lived gases) to be reached by 2050.

[61] The CCC was only prepared to release the ENZ model input assumptions citing private commercial reasons for not disclosing the full model.

46. As alluded to above, the CCC takes an evolving approach to its advice to adjust emission budgets over time. It acknowledges that this could be altered according to various developments including technology. Target reviews are triggered under Section 5ZE, which in principle can be at any time through changes in the underlying assumptions the CCC has to have regard for (Section 5ZC). As a minimum the CCC is proposing its next review and advice to occur in December 2024, followed by December 2029, and then December 2034[62].

47. The key point in this is that in the next review (December 2024) depending, amongst other matters, technology progress, and emissions data will shape the advice in their next report, leading to a possibly different set of beliefs, including for gas.

48. With respect to gas in the current report, the CCC outlines policy advice to the Minister in Chapter 15, and only proposes a direct intervention on fossil fuel use in boilers[63]. Even then it's not clear what that timetable encompasses, or the means to achieve it.

49. Ultimately the CCC acknowledges that within the energy, industry, and building sectors, *the New Zealand Emissions Trading Schemes (ETS) influences the choices and investment commercial actors make, and that this will continue to drive action and reduce emissions, particularly as emission prices increase*[64].

50. This seems sensible and reflects how the real world operates. Nevertheless, an emission price will only have an indirect effect on fuel choice since it is emissions that are penalised, not the energy itself. Technology progress, not included in the CCC advice, cannot be discounted as providing a solution to fossil fuel emissions.

Para 51 – Gas Uncertainty is not a new feature of the gas market. Hence why should events that might play out over 20-30 years be more critical than what regularly shows up as demand decline 5 years into the future?

51. A further perspective to lend to stranding risk, is to ask whether the lack of certainty on gas supply future is very different than what the industry has worked with in the past. *Figure 13* shows the forward gas supply curves based on data published annually by MBIE. The notable pattern is one of precipitous declines in gas supply (and therefore demand) happening five years into the future.

[62] Ibid – Figure 3.1, p37
[63] Ibid – p275 "Set a timetable to phase out fossil fuel use in existing boilers"
[64] Ibid – p276

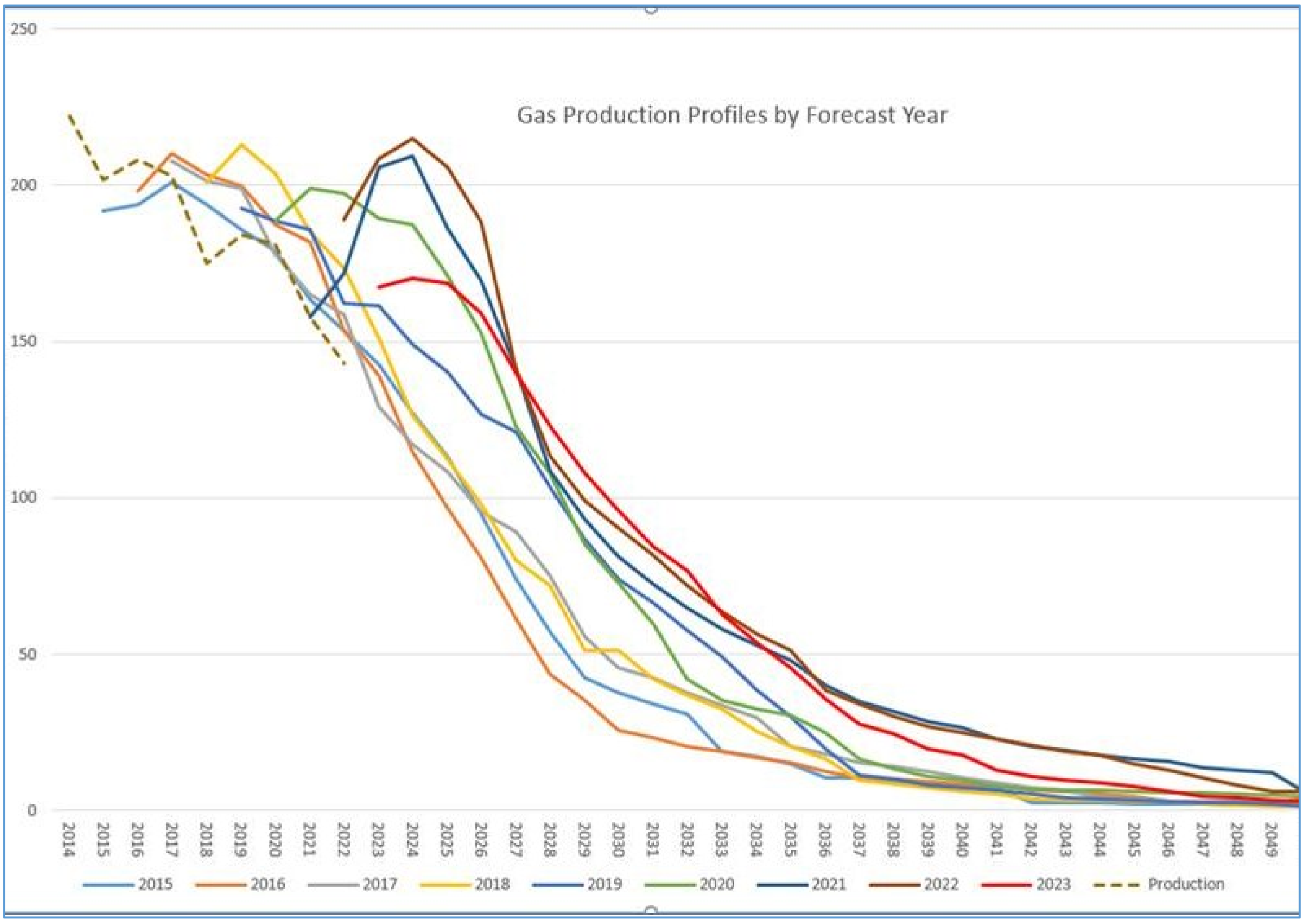

Figure 13: Reserve Forecast Production Profile

52. New Zealand doesn't import gas so this represents New Zealand's forward supply curve for gas reserves. While there is a broader resource category, of contingent resources that is not included in this graph, there is only an assumption that contingent resources will be developed into reserves by the upstream.

53. It should also be noted that 2P reserves themselves are not certain either, having only a 50% probability that the quantities are at least the amount reported. Yet despite the lack of certainty on resource quantities and ability to deliver them to market, coupled with lack of alternative supply from imports, GPBs continued to invest in their infrastructure over normal long term investment timeframes.

54. According to the latest reserves/ contingent resource reporting, New Zealand's 2C contingent gas sits at 2,977 PJ. This is higher than the 1,876 PJ reported in 2018, ahead of the Government announcement on the exploration ban demonstrating that current permits continue to be developed and supply can continue to be available.

55. The greater risk to pipeline asset stranding continues to be in domestic gas supply, since there are no policies to ban gas use. But if this didn't warrant shortening asset lives before, it shouldn't be warranted now.

Para 56 –70: Revenue uncertainty, not demand uncertainty is the relevant metric

56. While physical demand may be presented as a proxy for revenue, the reality for GPBs is that these are not proportional. The real concern from GPBs should be in their ability to recover sufficient revenue to recover the cost of their investment. It is surprising therefore that they didn't instruct their consultants to analyse their revenue risk, rather than their gas demand risk.

57. As the following figures demonstrate, the relationship between demand and revenue for different customer is not proportional to overall demand.

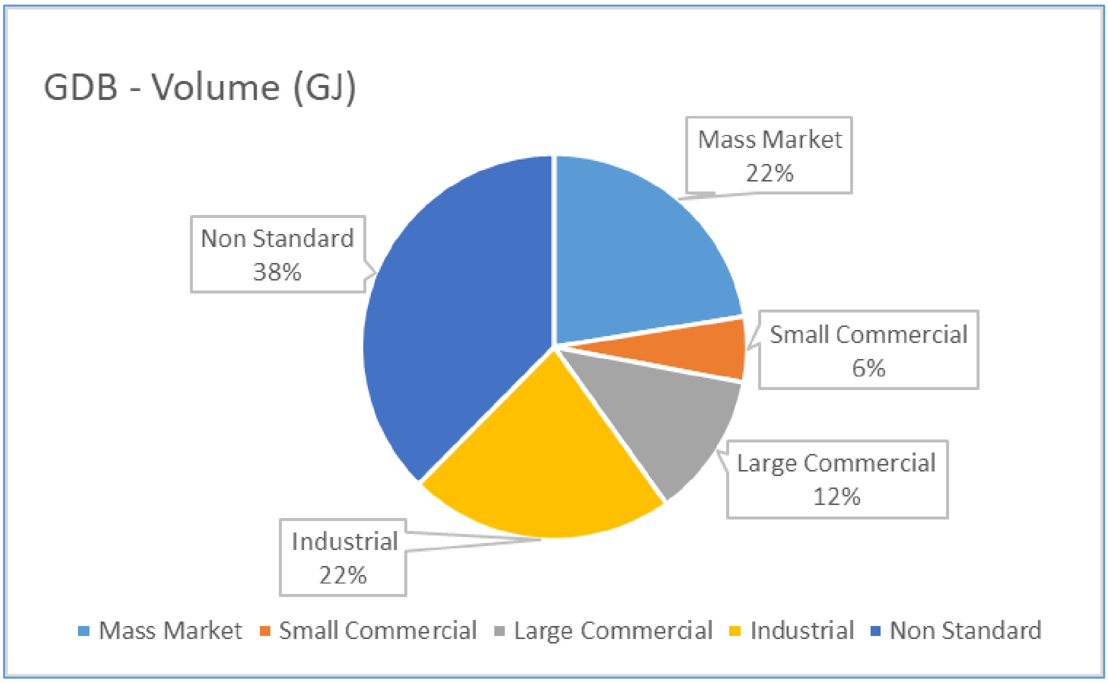

Figure 14: GDB Volume Split[65]

[65] Source GDB Information Disclosure Schedule 8 - 2022

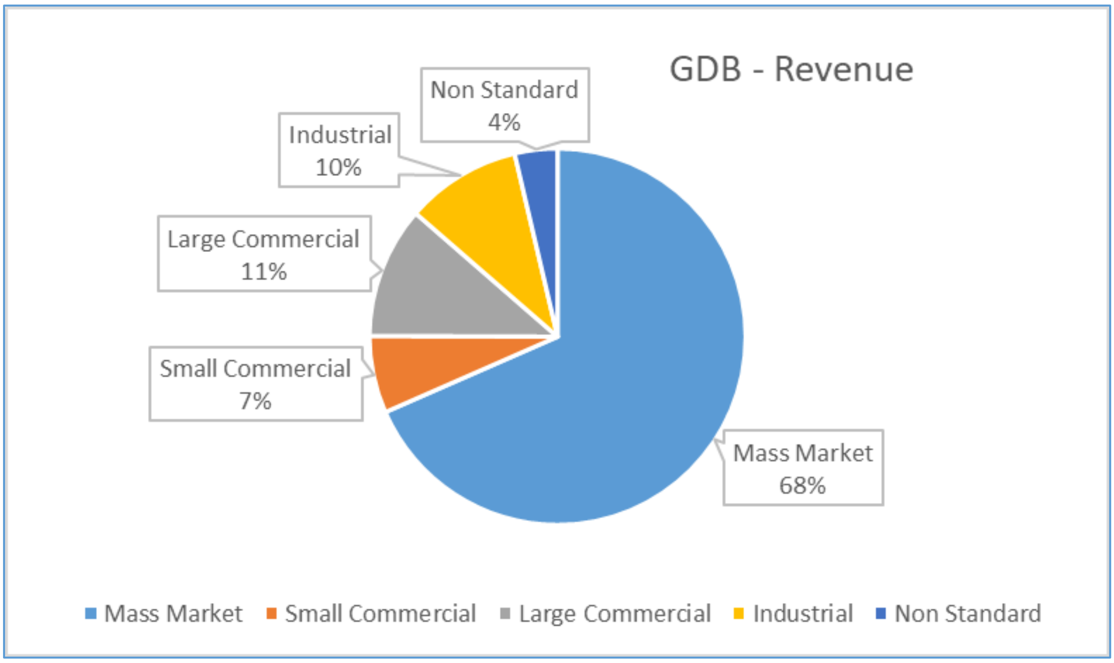

Figure 15: GDB Revenue Split[66]

58. The revenue makeup between different GDBs is also reasonably consistent with between 2/3 to ¾ of the revenue coming from just 23% of the gas volume

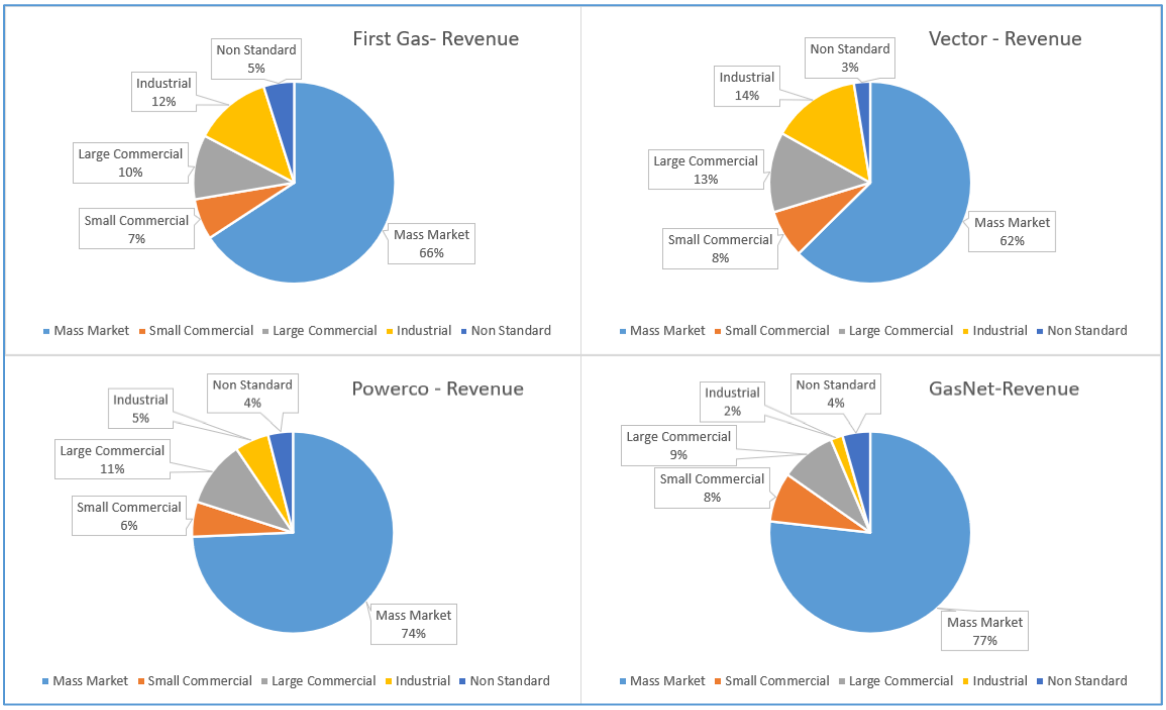

Figure 16: Revenue Split (2022)

[66] Source GDB Information Disclosure Schedule 8 - 2022

59. To give some perspective on why this is so, *Figure 17* gives the weighted average pricing by customer type. Residential and other mass market connections on average pay 17 times as much for their gas connection as a non-standard user.

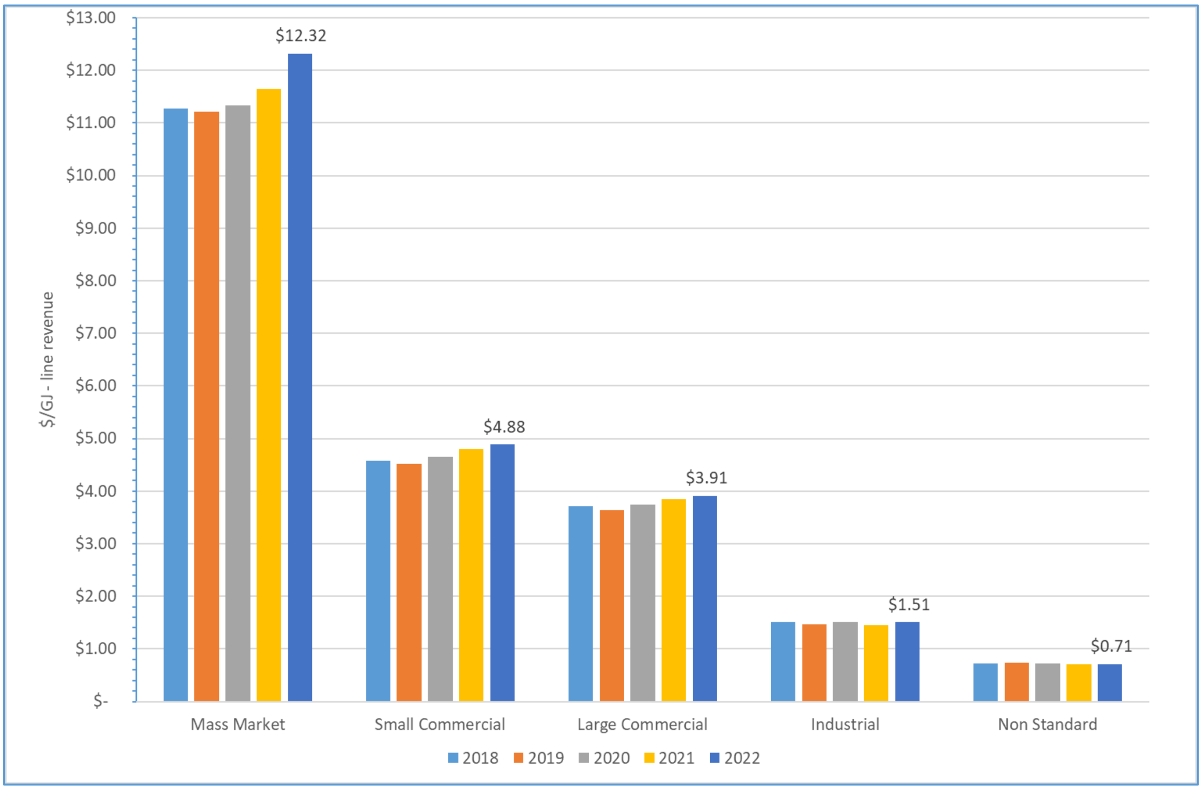

Figure 17: Consumer contribution - Networks

60. We haven't attempted to distinguish this further as there are also elements of fixed vs variable pricing to consider in these number. Typically GDBs insulate themselves further from demand volatility by recovering between 42% (Powerco) and 49% (First Gas) from fixed charges to connections.

61. The mass market represents about 7.7 PJ pa of total demand. While the government may yet ban new gas connections[67]there is no expectation that residential gas connections will disappear, even beyond 2050. Consequently, so long as there is gas available, so will the disproportionate transport revenue being created out of this demand.

GTB Revenue vs Demand

62. GTB revenue sources and risk are harder to unwind from public information given that two separate pipeline codes operate with different pricing regimes. MPOC has price discrimination based on a volume distance component as well as a volume component. The VTC uses annual capacity fees as well as throughput fees, and has non-standard agreements. Customer types, other than Standard

[67] This would be inconsistent if the Government also considered that green gases should have a role in New Zealand's energy mix.

vs non-standards are also not easily separated. It is further complicated by a pricing system based on nominations on MPOC that includes bi-directional flow on the Frankley Rd System[68].

63. Total line charge for the year ended 30 September 2020 was $132.5 million.[69]Of this amount $79.3 million (60%) represented fixed capacity charges on the Vector System and an average revenue of $0.24/GJ on the Maui system and $0.51/GJ on the Vector system[70]

64. The overall picture for GTB revenue does show a similar pattern to gas distribution where larger users pay proportionally less than smaller consumers. We didn't have sufficient time and resources to analyse this in greater detail but can offer an example. The biggest single customer, Methanex received 64.6 PJ of gas in 2020 calendar year. Assuming the source of that gas as being a mix of Pohokura, Maui, and Mangahewa, the total transmission revenue from Methanex is estimated at around $6 million. We estimate that this represented less than 5% of total transmission revenue, despite Methanex demand being approximately 40% of the total volume.

65. Given that Methanex has generally acted as the demand response in the gas market it would be expected that reduction in supply would effect Methanex first, and although this might be dramatic in volume terms, the impact on revenue is an order of magnitude less. Conversely, because Methanex has idle capacity, should demand drop off on other parts of the system (e.g. gas baseload generation), it can be expected to recover the lost volume.

66. A more complete illustration of the revenue approach for GTB is provided in *Figure 18*[71]. This graphic was presented at an industry forum in 2019 as part of the work-stream on GTAC development (the access code meant to replace the VTC and MPOC). This showed how revenue would be allocated to the different zones on the pipeline. It excludes revenue and volume from non-standard pricing contracts[72].

[68] Nominations get charged in both directions. Physical flows will differ from the nominations on this part of the system.
[69] Information Disclosure Schedule 8
[70] Indicative numbers. $0.24/GJ is based on $37.3 million of revenue from MPOC and 154.7 PJ of approved nominations. $0.51/GJ reflects $94.0 million of revenue and 184 PJ of reserved capacity
[71] With permission from First Gas
[72] Approximately 25% of the demand and 24% of the revenue.

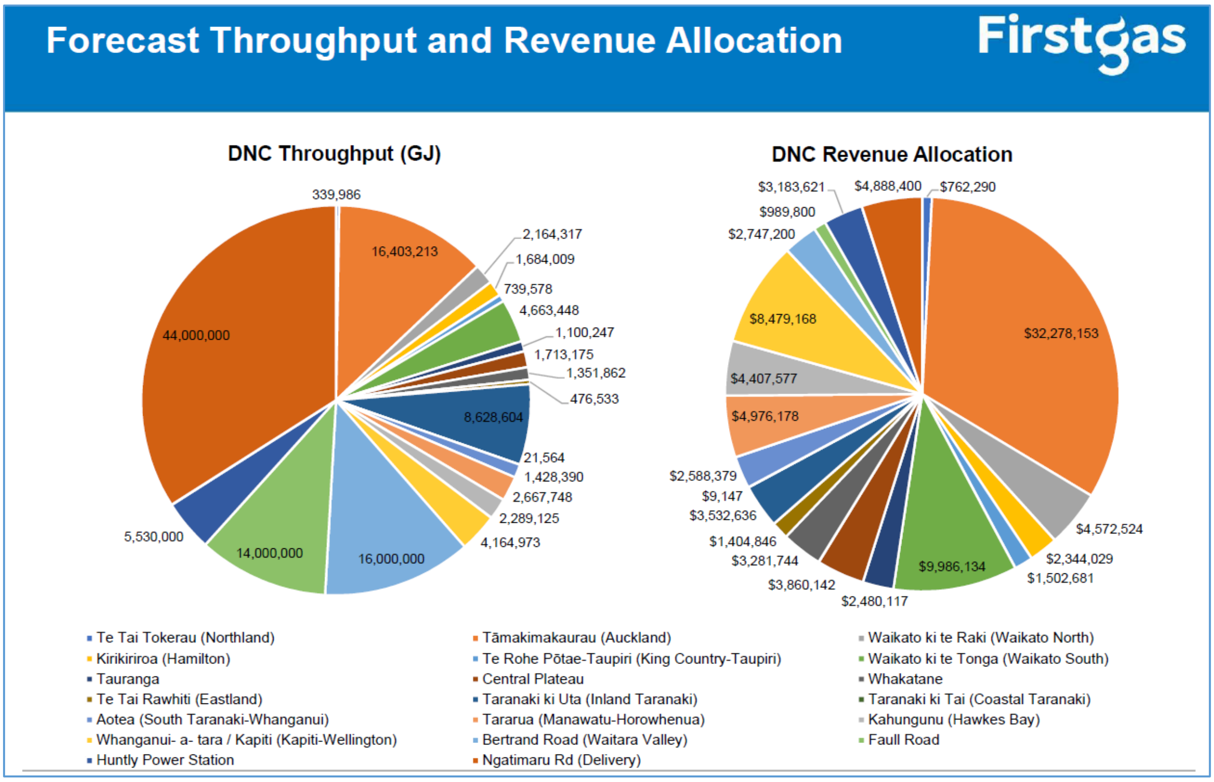

Figure 18: Illustrative connection between revenue and demand for GTB

69. This illustrates for example that Methanex although 57% of the demand, contributes only 9% to revenue. The Auckland zone (principally Vector network) was 13% of the demand, but provides 33% of the revenue.

70. A further point is that many of the larger users on the system are in hard to abate industries (Methanex, Ballance, Evoniks, Steel), high temperature process heat (pulp and paper, dairy companies) or deliver electricity supply security through thermal peaking plants (Contact, Nova). These industries have high capital investments in often integrated facilities and will take some time to transition. Gas is likely to be a preferred option for some time for them.

Para 69-73 ; Argument that it lowers price shocks to individual consumers to do this at maximum demand than logically the Commission should anticipate when the market stops growing

69. A key point made by the GPB advisors is that it is better to act now to raise prices over a larger base of demand than it is to attempt to raise the same revenue over a smaller base later.

70. Yet, inspection of the GDBs own forecasts (at least over the next 5-years) within their AMPs (released since the CCC advice[73]), reveal expectations of continued growth in connections and demand (*Figure 19*).

[73] Note that FG hasn't released its 2021 AMP, so figures to 2025 reflect 2020 AMP update.

71. The message in this, is that GDBs have taken a view, despite the CCC report that, at least as far as networks are concerned, there is cautious optimism in the outlook for the future. GDBs have made some adaptions to their plans to secure their futures, including looking at capital contribution policies for new connections (Vector) and adjusting the connection growth based on updated policies.

72. We think this is sensible. But, more importantly, it suggests that the GDBs have assessed their stranding risk response within the current price path settings on capital recovery

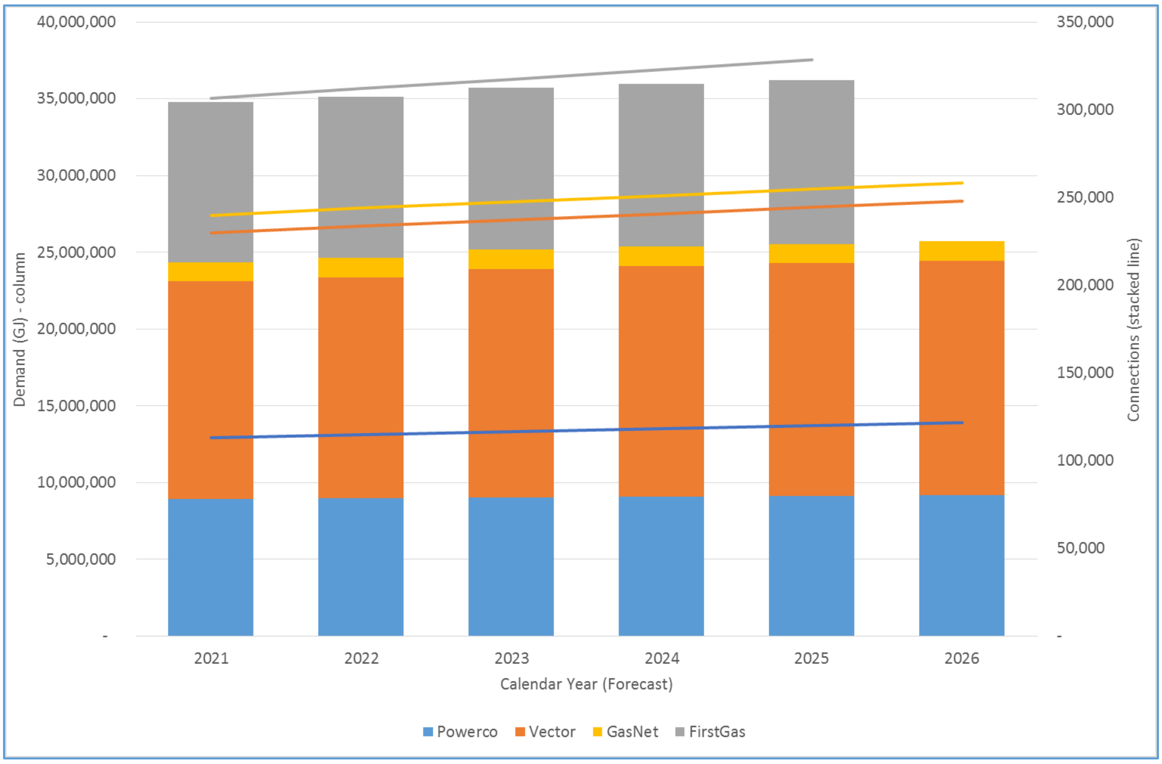

Figure 19: AMP Gas demand and connection forecast[74]

What about the GTB forecast?

73. Other than growth in the network sector supplied by GTB, the prospects for further growth in gas transmission are effectively determined by gas supply, and how that is picked up by Methanex's idle capacity. While it may be expected that some key demand will diminish with time, particularly for gas fired baseload generation (TCC, and Huntly), any loss of volume looks likely to shift to Methanex' idle capacity.

[74] Note First Gas had yet to post their most recent AMP on their website

74. While we demonstrate that the impact on revenue with Methanex is disproportionate to the volume, First Gas does have flexibility to adjust their pricing methodology to compensate.[75] In other words, Methanex may pick up some share of that lost revenue.

14/03/22 - MGUG - GPB IM Review and DPP3 Reset - Submission on Draft Advice

This submission addressed the draft advice and challenged key assumptions

Para 59 – whether the definition of gas pipeline services limiting it to transport of natural gas should be considered as immutable. MGUG noted that Part 4 was able to be adjusted to meet new circumstances and definitions of regulated sector and services and that it's foreseeable that the Commission would be able to consider an updated definition of gas pipeline services.

59. We agree that the s55A of the Act exposes a grey area in the meaning of "*gas pipeline services*" as they apply to S52A. It is not difficult to imagine why legal drafting at the time might not have anticipated other gases becoming more relevant as substitutes for natural gas while relying on the same monopoly infrastructure service. We haven't sought expert legal opinion to test the Commission's interpretation but we do think there is an open legal argument to challenge it. If Part 4 was set up to regulate the price and quality of goods or services in markets where there is little or no competition and little or no likelihood of a substantial increase in competition (S52), and S52A covers such markets referred to in S52, and 52B(3)(c) includes "gas pipelines" then ultimately the final interpretation should still fall back to the intent of Part 4 to address a specific competition issue (gas pipeline services). S52G provides the opener to do this

Para 13 – MGUG noted that it wasn't self evident that GPBs in the absence of further investment incentives wouldn't invest in maintaining the reliability and safety of their networks

13. We would dispute a number of other assertions in the above statement. This includes the implication that GPBs currently have no other incentives to invest in safe and reliable assets. Under both PQ regulations and Petroleum regulations GPBs have *a statutory obligation* for maintaining asset reliability and safety. There are significant penalties (i.e. incentives), including reputational damage and financial for breaches in performance standards. Underinvesting to maintain safety and reliability of assets isn't an option for GPBs.

Para 16 –17: reintroduced the argument that revenue, not gas demand is the central question assessing stranding risk

16. The other "*compelling reason*" offered is, a "*material risk of accelerated decline in the use of gas pipelines for conveying natural gas exposing GDBs to economic risk stranding*" based on "*our expectations are that natural gas demand will still fall in the medium to long term*". While it implies a

[75] Similar adjustment was made in 2016 after Southdown and Otahuhu B closed. Vector (at that time owner) spread the lost revenue burden over network parts that shouldn't have been affected by this in their cost allocation methods.

causal relationship (fall in demand leads to economic stranding) it overlooks the relationship between gas volume and pipeline revenue. We explained this extensively in our cross submission in the Process and Issues paper. We deal with this point again further on in our submission, but in summary we believe that the Commission hasn't considered how demand will decline through different consumer segments, and how pipeline revenue might decline with it. Our examination of the evidence from GPBs asset management programs, various information disclosures, and our understanding of the NZ gas market would show that revenue impacts for a gas transition pathway are manageable without needing to decide to accelerate revenue in DPP3.

17. We also note that falling demand for natural gas doesn't necessarily mean falling demand for gas pipeline services, including for blended gas.

Para 19- questioned the lack of the factual against the counterfactual to assess stranding risk as well as questioning the modelling approach

19. The substance of the argument seems to have been covered in the DPP paper from paragraph 6.65. The analysis appears to largely rest on the conclusions drawn from the financial model[76] developed by the Commission. Despite extensive searching through both the model and the DPP paper chapter we cannot find the answer to the straightforward question – "**how does the factual compare to the counterfactual in terms of consumer impacts to enable a judgment to be made on whether acting now is in the best long term interest of the consumers?"**

20. We accept that the future is uncertain as the Commission repeats often, but we think that the Commission should have at least attempted to quantify the difference between the factual and counterfactual for consumers. The financial model only shows the difference between its factual of acting now versus a different counterfactual ***of never acting at all.*** In other words the modelling work itself has shifted the argument away from the merits of acting in DPP3 versus acting in DPP4, to whether it is justified to act in DPP3.

21. We have a number of other criticisms on the model itself which we deal with further in this submission, but given that the model provides the only quantified foundation for arguing that there are compelling reasons to act now, we looked at what the model could show us to answer the question "*what happens to consumer outcomes (benefits and detriments) if the Commission waited until DPP4 to accelerate depreciation*?"

22. Unfortunately the model isn't designed to answer this question without extensive reprogramming and reconfiguration of all the supporting inputs. The Commission's modellers also couldn't adapt the model to answer that question in time for this submission[77]. We think that this question needs an answer given that what the Commission proposes for DPP3 will be significant price

[76] Gas DPP3 draft – Asset Stranding model – 10 February 2022 xlsm

[77] MGUG requested that the Commission add further functionality to answer that question on 4 March. The reply received 10 March indicated that this wasn't possible. "*Our modellers have looked at an approach for modelling delaying changes to DPP4. They do not think they can come up with a solution within the submission period*."

shocks for consumers. Modelling should look to illustrate what the trade-off of is between a speculative price shock later versus a certain price shock now[78].

23. While we propose that the Commission should run its model starting in DPP4 (2026) and then compares the outcomes on (CPI) X and adjustment factors with what it has calculated for DPP3, we question whether that would provide any clear signal. The Commission has already provided a sensitivity range from 2040 -2070 for stranding with a reference case of 2050. Whether the case is run 17-47 years into the future or 13-43 years into the future hardly matters in terms of the degree of likely overlap in outcomes. In other words we don't believe that delaying further action by 4 years will have any detrimental impact on the long term interests of consumers, while imposing price shocks now will not only impact consumers now with 100% certainty, but also create the outcome the Commission is hoping to avoid.

24. We would note that the Commission has accepted the GDB's own connection and volume growth forecasts to 2028. So our argument is that any possible price shocks in 2026 from the normal IM review would be applied to a *larger* base of customers than in 2022. This deals directly to the Commission's statement that it is better to provide a price shock now in order to manage "*unmanageable consumer price shocks in future regulatory periods*".

> ***Our intent is to avoid unreasonable price shocks to consumers***
>
> *By mostly addressing the increased stranding risk through real price increases in DPP3, we also mitigate the risk of unmanageable consumer price shocks in future regulatory periods. This provides some head room if other BBM cost components (such as the return on capital) were to increase in future regulatory periods.*

DPP paper – para 6.116

25. While this statement seems to also cover "*other BBM cost components*", the Commission has also declared that price shocks can be spread over more than one regulatory period to mitigate their impacts.

> *A key assumption in our long-term financial model is the MAR profile. This is the revenue which we assume is effectively available as an 'envelope' to accommodate cost recovery, including accelerated depreciation. In profiling the MAR we allow six years of constant real annual increases, then a constant real MAR to 2029, followed by a ramp down.* ***Our MAR profiling assumption for the first six years reflects our intent to address most but not all the assumed stranding risk in the four years of DPP3. We consider this provides GPBs with an opportunity to maintain ex-ante FCM while softening the effect of revenue increases on consumers by spreading the transition over an additional two years.***

DPP paper – para 4.33

26. It appears from the above statement that the Commission is arguing that all possible price shocks are better spread across a number of regulatory periods. However, neither changes in other BBM components, *nor whether it would still be necessary to accelerate depreciation* through the normal IM review are known. If accelerating depreciation is not an outcome of the normal IM review,

[78] Including whether any difference is clear within uncertain projections and whether the difference is material.

the Commission will have acted prematurely in DPP3 and created lasting consumer detriment without benefits. Should the IM review actually determine that price shocks of other BMM components need to occur on top of accelerated depreciation the Commission still has the same option to spread the shock over a longer period.

27. Fundamentally the price shocks can be better managed by future consumers than current consumers.

Para 40 –52 highlight lack of political consensus on energy policy and climate policy interaction and that the issue of natural gas and gas pipeline services wasn't settled with high likelihood that policy hostility to gas wasn't a given. The risk was that the Commission was acting ahead of policy.

40. The CCC advice also needs to be observed through the lens of political economy and the limits based on its findings.

41. While the climate policy objective of the CCRA, and the ETS policy enabler, have multi-partisan political support, energy policy ideas to achieve climate policy objectives do not. It appears that Labour, and its political ally, the Greens, have a stronger ideological affinity for energy policies that look to shift energy towards renewables and would be sympathetic to the CCC advice on bans and renewable energy targets. The centre right parties (National/ Act) however see supplementary measures as only necessary for addressing supplementary issues, leaving the ETS to work on incentivising carbon reductions. This climate policy approach is closer to what NZIER in its most recent insight into addressing climate change challenges would promote as "tight targets, flexible (loose) approaches framework"[79].

42. There are at least 9 election cycles between 2023 and 2050 where energy policy shifts around climate measures are likely to occur. These will shift not just based on political ideology, but also on economic and social factors, and technology progress. Technologies with no commercial proof in New Zealand was something explicitly excluded from the CCC advice, including its modelling work. History however would show that we substantially underestimate the rate of technological progress and cost (e.g. solar photovoltaics, wind power, battery storage, IT processing power, digital platforms etc.)[80]. Technologies considered as unproven (e.g. methane pyrolysis), or expensive (such as green hydrogen) are likely to appear faster and be cheaper quicker than current predictions anticipate.

43. The current government is also prepared to challenge CCC advice and assumptions. The most recent example, is the Forestry Minister announcing a U-turn on exotic forest planting where exotic planting is proposed to be excluded from the current ETS[81]. The other is around the idea that gas connections should be banned by 2025.

[79] NZIER Insight 100-2022 "*Fast forwarding technology to address climate change*" https://nzier.org.nz/publication/fast-forwarding-technology-to-address-climate-change
[80] Azhar A. (2021) "*The Exponential Age: How Accelerating Technology is Transforming Business, Politics and Society*" - ISBN: 9781847942906
[81] Business Desk – 3 March "*Govt backs down on permanent exotic forests in ETS*"

44. The Commission mentions connection bans as an example of a possible policy outcome accelerating decline in gas demand. We think the debate about banning new gas connections has moved on since being floated as an idea. One reason is that banning could lead to the perverse outcome of higher emission. We pointed this out in our submission on the ERP. Direct use of gas in households has 20% to 42% of the carbon footprint of delivering the same energy via electricity generated from gas or coal[82] (*Figure 20*)

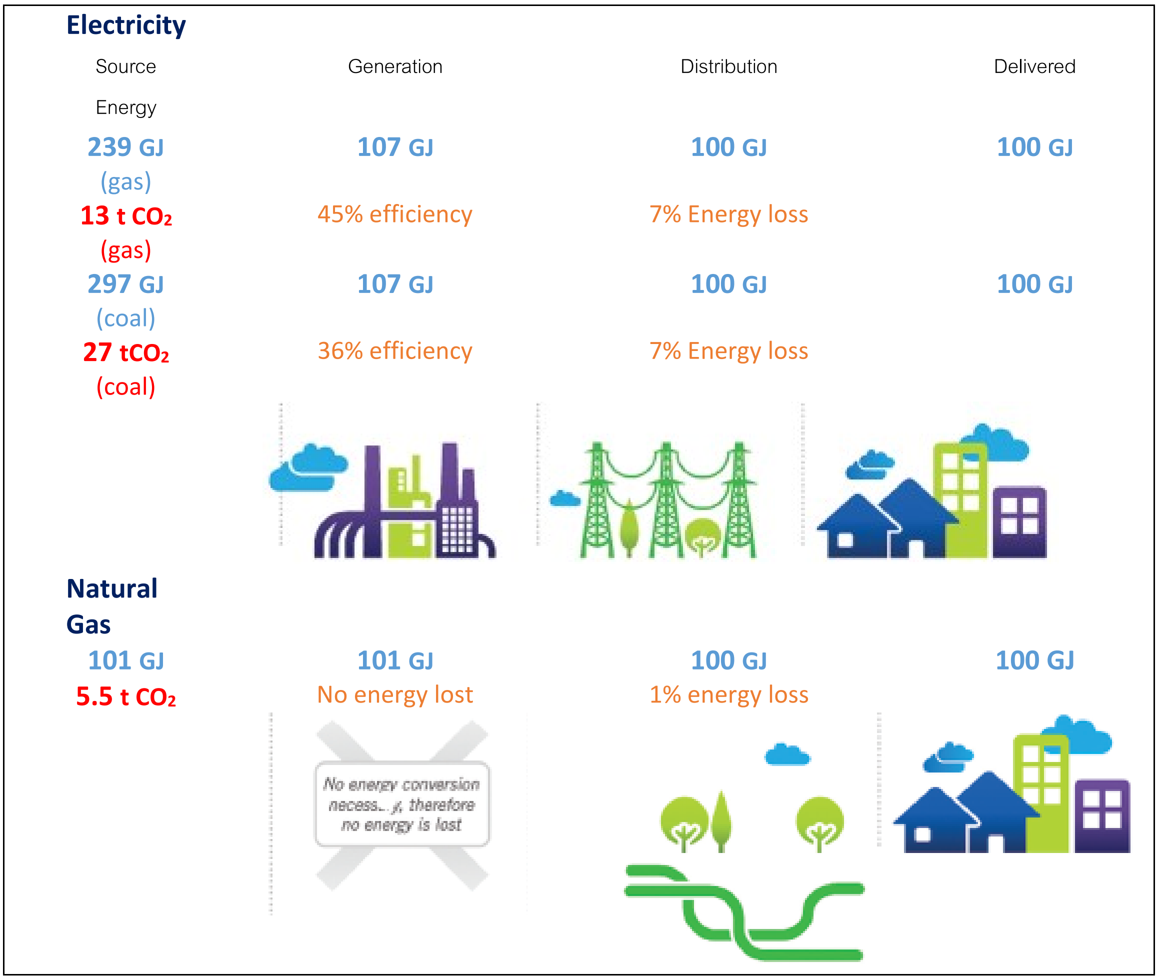

Figure 20: Fuel Cycle Comparison - Consumer Energy

[82] Unless we achieve 100% renewable electricity generation in New Zealand. There are numerous reasons why a 100% renewable electricity generation target creates suboptimal outcomes – ranging from poor capital deployment (overbuild) and increased electricity price volatility. Both the CCC and the Minister have framed the 100% renewable electricity generation as an "aspirational" target, accepting that fossil fired generation will continue as the marginal generators.

46. Retaining gas connections is also seen as necessary for preserving options to repurpose towards lower carbon gases[83]. The Minister made a statement at the BusinessNZ Energy Council webinar on 10 March 2022 supporting gas[84].

> *The Government wants to work with industry around developing and enabling biogas and green hydrogen as potential replacements for natural gas.*
>
> *She says introducing these new fuels could over time reduce emissions and retain a diverse fuel mix, and using existing gas pipelines could limit costs rises and offset transmission investment requirements.*

47. The CCRA legislation doesn't require that carbon reductions all be achieved domestically either. The Act requires that by 2050 "*net accounting emissions* of greenhouse gases in a calendar year, other than biogenic methane, are zero by the calendar year beginning on 1 January 2050 and for each subsequent calendar year". The "*accounting*" term is important since this allows both domestic contributions *and* international carbon offsets.[85] The least cost approach would assume that net zero New Zealand can still mean positive, domestic based carbon emissions in 2050.

48. There are further compelling strategic reasons for natural gas as a domestic primary energy resource remaining an option in our energy system to add to domestic economic resilience, and energy security, a fact highlighted by geo political events in progress.

> *Woods says the Government recognises that energy supply and affordability are important, both throughout the transition, and right now as Ukraine defends itself against Russia.*
>
> *"These are not nice-to-haves – they're non-negotiables," she says*
>
> Source: BusinessNZ Energy Council webinar on 10 March 2022

49. As we pointed out in our submission to MfE on ERP, domestic gas has reduced dependence on imported energy from about 45% to 25%[86].

[83] Note that lower carbon gases would include blending zero carbon gases with natural gas.
[84] https://www.energynews.co.nz/news/electricity/116667/woods-welcomes-industry-dry-year-solutions-work
[85] For the period 2023-2035 (first three carbon budgets) New Zealand has to rely on international offsets to meet its climate obligations under the Paris Accord.
[86] Note this doesn't include associated liquids that net off against oil imports.

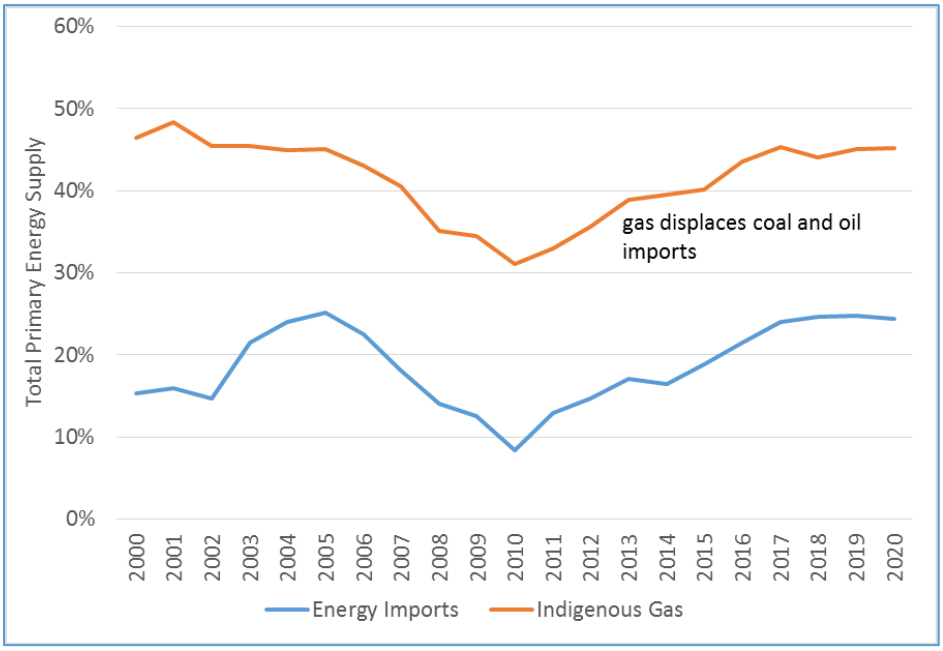

Figure 21: Indigenous gas contribution to energy independence and carbon minimisation[87]

50. The national energy strategy process to be started this year (and finished in 2024) should provide a better steer on the direction of energy policies that might be relied on by the Commission in the normal IM review process. We expect the national energy strategy to be developed by 2024 will consider the wider contributions of New Zealand's gas endowment as necessary to meet economic, social, and environmental objectives.

51. This collective interpretation of the *actual* current policy settings makes assumptions about what energy policies *could be*, and their durability, highly uncertain. While the future will remain uncertain, by 2026 we will have more certainty on energy policy direction to provide a more robust decision framework for re-setting IMs for gas without losing the opportunity to address the most pessimistic outlook for gas transport in New Zealand.

Commission Acting Ahead of Policy

52. There is no formulated energy policy on decreasing gas consumption. The Commission's proposed measures would be acting ahead of government policy. We consider this sets a poor precedent for future decision making.

Para 53- 58 Reiterated the central issue of sustainable pipeline service revenue, rather than natural gas demand

Confusing Policy Impacts on demand with impact on revenue

53. We have covered the point on separating gas volume trajectory with pipeline revenue trajectory extensively in our cross submission[88]. We haven't seen this important distinction carried

[87] Source: MBIE - Energy In New Zealand
[88] https://comcom.govt.nz/regulated-industries/gas-pipelines/gas-pipelines-price-quality-paths/gas-pipelines-default-price-quality-path/2022-2027-gas-default-price-quality-path?target=documents

through into the Commission's analysis. Focusing on gas volume profile rather revenue profile leads to problematic conclusions about pipeline viability.

54. We also argued that GTBs needed to be separated from GDBs based on their different forms of control and their different customer profiles.

55. We showed that volume of gas delivered and revenue received from different customer groups are almost inversely related – i.e. the largest customers by volume made the lowest contribution to pipeline revenue (both for GDBs and GTB). For example for the aggregate of all GDBs, the mass market segment accounted for 97% of connections, 23% of the gas volume transported, but delivered 68% of the revenue. For the GTB, Methanex although being 57% of the gas volume accounted for only 9% of the revenue. In contrast the Auckland zone of the GTB was 13% of the volume demand, but contributed 33% of the revenue.

56. In assessing risks of volume loss we concluded that the GDBs are relatively robust given that the residential and commercial sector (which they primarily serve) would be the most resilient in a supply constrained world. Collectively GDBs account for around 33 PJ (17%) of demand out of a total of 190 PJ annual demand. In other words, if overall demand somehow evaporated to the 33 PJ for just GDBs, it would show a significant reduction in gas volume and carbon emissions (something that would align with the CCC demonstration pathway) without impacting GDB revenue at all. This scenario might then seem to challenge the viability of the GTB instead (since it assumes that it would only supply distribution gas gates). However enough significant revenue on the GTB comes from transporting gas to the distribution gates themselves to also keep that system viable (see *Figure 18*).

57. The reality in a lower gas demand world is that we will continue to see significant demand continue from GDBs, as well as from harder to abate industries (steel, petrochemicals, high temperature process heat). Carbon emissions will be reduced and offset to meet national targets.

58. We see no evidence in the Commission's reasoning and analysis that recognise this vital distinction when it looks at economic stranding risk. We consider this to be a fundamental flaw in the Commission's conclusion to act now rather than later.

Para 84 – 93 restated and repeated the issues of different risk profiles of GPBs and their revenue resilience even if gas demand dropped

Para 62 - 77 further addressed modelling issues, specifically that model could be improved by including probabilities and real option value and that it doesn't quantify consumer net benefits

62. It seems markedly inconsistent to us that the Commission can assume to give weight to a speculative natural gas decline pathway but give no weight to the possibility of asset transition to a different gas pathway. This is particularly because the pipelines themselves are promoting this as a solution for their asset viability. In the case of First Gas, they have received government funding to trial adding hydrogen to the pipeline This behaviour is exactly what one would expect to occur with organisations in a competitive market place (i.e. innovate to meet an existential threat).

65. It seems to us that pipeline assets can have a residual value. That residual value is determined by the actions of GPBs to influence the probability of occurrence including supportive

energy policies. GPBs have the further ability to mitigate the costs by having optionality between levels of OPEX and CAPEX. Finally the impact can be absorbed, since we can assume that the GPBs will always maintain a positive cash flow. Losses are opportunity costs, not cash losses. While not economically efficient, they won't make GPBs insolvent

66. Aside from treating residual value as being zero, there are other aspects of the Commission's modelling work that we consider aren't robust. While we accept the common aphorism in statistics that "All models are wrong, but some are useful[89]" we have a number of comments to make on the model and the way it has been used that doesn't make it useful.

67. Firstly, it is not a model that is easy other than for developers, to understand how it has been programmed, or what assumptions have been used to create the model. While a normal IM review process would have given more time to explore its workings, the compressed timeframe for this submission does not. Accordingly we accept that some of our comments might be misplaced through lack of time to properly assess the model.

68. Secondly, what seems to drive the workings of the model is to pick a stranding year (2040, 2050, 2060, 2070) and set a stranding year MAR as a fraction of MAR in 2023. The terminology seems confusing because MAR was also explained at the model briefing as a "*willingness to pay*" by consumers. In other words, while the Commission sets MAR for suppliers of services, this is only a maximum. Service providers are free to set prices lower to achieve revenues below MAR. The Commission seem to assume that this is what suppliers would do. The default value for this in the model is 20% of 2023 MAR. It is not really clear how this "willingness to pay" is being determined. Generally, willingness to pay is affected by a range of variables, including individual preferences, the availability and pricing of substitutes, income level and so forth. An obvious problem is that willingness to pay would be affected by the price of substitutes. As we note later in the submission, setting rate of price increases ahead of substitutes such as electricity connections creates incentives to not connect to gas, or incentivise disconnections earlier than might otherwise occur. The connection between stranding risk being influenced by the price of services is not a feature of this model. Accordingly it can't show for example if setting X value differentials below those for electricity network increases would *improve* "willingness to pay".

69. There is also the persistent conflation between volume decline and revenue decline. We've already noted that customer segments serviced by GDBs are different than for GTBs and customer segmentation within GDBs themselves have different risk profiles. This makes it even harder to justify the decline profile in the MAR.

70. To demonstrate this, the model allows the stranding year MAR to be set at any level of MAR relative to 2023. If we assume the usual trajectory of MAR increasing annually by CPI we can demonstrate that under this scenario where MAR is also what the consumer is willing to pay (because GDB demand doesn't go down even though total overall New Zealand gas demand might) then the X factor is positive and the depreciation adjustment factor is greater than 1. This is illustrated as a screenshot of running the case for Powerco assuming a stranding year in 2050 with a

[89] Generally attributed to statistician George Box

MAR 170% of 2023[90]. The adjustment factor is 1.574, the real MAR increase is -1.91% and the X factor is 1.61% (*Figure 22*)

Figure 22: Powerco case

71. While we agree that this would seem like a strange outcome, this is only because it sets a hard date for 2050 for the service to finish, even if in 2049 demand for service is at a sustainable level. In other words the model only works by assuming that there are end dates set outside of the actual demand for services and that MAR reduces every year starting shortly after 2026.

72. Thirdly the opex and capex profiles (particularly additional asset acquisition) are set exogenously, and independent from each other. i.e. there is normally a trade-off between some levels of opex and capex as a function of technology and ageing assets. Both are also usually set as a result of the view the GPB takes on demand for its services. This is reviewed annually as part of the normal business cycle adding optionality and flexibility to its decision making. This approach is demonstrated in the asset management plans of GPBs. As we noted in our cross submission, an illustration of this is First Gas transmission deferring an investment decision on compressor replacement so as to deal with uncertainty. Deferring CAPEX meant allowing for higher OPEX. In contrast to the usual workings within businesses of continuous adjustment to new information, the model used here is deterministic. Optionality can only be simulated by systematically running different deterministic permutations of the future manually. A more sophisticated simulation would take a stochastic approach treating variables as random distributions with variances and co-variances to reveal both expected (most likely) outcome and the spread of possibilities. That level of sophistication may be warranted considering the consumer exposure in dollar terms of the Commission's decision. This is not practical for DPP3, but would improve the decision making in the normal IM review.

73. Fourthly, as already mentioned the model assumes that there is an economic stranding year which has to be selected and that the level of remaining RAB at this year is unrecoverable and therefore presents the stranding risk. As already discussed a natural gas pipeline may no longer fit the definition of it carrying natural gas under the way that the Commission interprets the Act, but still have residual value for the GPB which means that the RAB is recoverable.

[90] 170 % is approximately 2% compounding over 27 years

74. Lastly, the Commission described the future and outcome of the modelling work as "*feasible*"[91]. This may be a fair statement as a subjective view but it lacks other context, such as what probability should be assigned to the stranding year (or stranding decade). The model generates an un-risked value. If for example the probability assigned to asset stranding occurring at all (regardless of year) was assigned say 50%[92] then the expected closing value of the RAB is 50% of the un-risked value. Because the probability of that outcome is only 50% the other 50% probability is assigned to the asset not being economically stranded (unrecoverable RAB = $0). The weighted average (expected value) is therefore 25% of the stranded RAB. The Commission doesn't assure GPB profit. It only provides a *reasonable expectation* of ex-ante FCM. Presented this way, what constitutes a reasonable expectation?

75. The further important conclusion from the modelling is that **certain current** actions (and costs) are being traded off against **uncertain future** outcomes. In this trade-off between adverse immediate consumer outcomes based on a possibility that these may prove unnecessary, we question whether the Commission should act as aggressively as it is proposing. It seems to be justified on the basis that the Commission can reverse settings later, but it doesn't consider whether the settings themselves create a self- fulfilling outcome of network stranding.

77. So while an assessment of consumer detriments from accelerating revenue can be made, the Commission fails to quantify the benefits of accelerating revenue now. There is therefore no evidence that consumer detriments are being outweighed by consumer benefits.

Para 95 showed that the Commission held an opposite view in 2016 as to whether accelerating revenue for GPBs would have the intended outcome.

95. In 2016 the Commission's view on accelerated revenue was the opposite of what it is now supporting in 2022[93].

> *The Commission has considered whether to allow gas pipeline businesses the option of shortening asset lives to mitigate stranding risk. However, as gas networks are still growing, the burden on each consumer of shortening asset lives to permit accelerated recovery of sunk investment costs would be high. The regulated asset base (RAB) of gas pipeline businesses per connection point is NZ$7,720, compared with NZ$4,384 for electricity networks.* ***This suggests that attempting to recover the RAB over a shorter period of time would imply a disproportionate increase in gas tariffs (relative to electricity tariffs). An increase in gas tariffs might deter future connections growth and/or hamper gas networks' ability to price up to their cap if customers perceive the tariff increase to be untenable and switch off their gas connection****.*

[91] Comment made by one of the Commission modelers at the Gas Infrastructure working Group meeting (2 March 2022)

[92] 50% is picked here because we don't know. If something is not know you assign it equal probability to the counterfactual. The value of RAB as zero in a non-stranded future should be self-evident – the asset isn't stranded and therefore it has a residual value equal to its closing RAB value.

[93] Commerce Commission - *Input Methodologies review decisions – Topic paper 3: The future impact of emerging technologies in the energy sector* 20 December 2016 – p41 para 102

Para 99 argued that it was premature for the Commission to act ahead of the IM review and that the option to wait had value

99. It is not certain that accelerating revenue in 2026 is inevitable given what is still to crystallise beyond the speculative between now and 2026 including:

a) The first Emission Reduction Plan (ERP) to be published in second half of 2022;
b) Recommended further climate policies to emerge from the ERP;
c) Joint work (2023/24) MBIE, Commerce Commission, Gas Industry Company on whether the Part 4 framework and tools are still fit for purpose in an energy transition environment;
d) The extent that the 2023 election outcomes could alter policies;
e) National Energy Strategy (2024) – including gas transition pathway being facilitated by GIC/ MBIE and wider gas sector to develop energy policies, and;
f) The outcome of the CCC first review in December 2024 where it will consider inter-alia; emission reduction progress, and updated assumptions including technology progress.

28/03/22 - MGUG - GPB IM Review and DPP3 Reset – Cross Submission on Draft Advice

MGUG's cross submission focused on other submitter arguments

Para 10- noted that alternative modelling approaches didn't consider the probability of gas pipelines economic lives continuing beyond natural gas

10. MGUG's review of the Commission's modelling[94] identified a number of fundamental issues with the modelling approach that we considered made the Asset Stranding Risk Model unreliable for basing any decision on accelerating revenue in DPP3, including:

d. It makes no comparison between the factual (accelerate revenue in DPP3) and counterfactual (consider Gas IM settings for DPP4) to demonstrate that by acting now consumer benefits would exceed detriments.

e. It incorrectly conflated a (natural) gas pathway with a network revenue pathway.

f. It mischaracterises the net carbon zero 2050 climate agenda as a zero carbon 2050 energy agenda.

g. A number of second order (internal model working) issues related to the arbitrariness of MAR assumptions, the zero residual value assumption, and the lack of optionality in CAPEX and OPEX pathways.

11. Frontier Economics review and suggestions for improving the Commission's asset stranding model[95] don't, in our view, resolve any of the input concerns in para 10. Nor do they alter our

[94] Major Gas Users Group (MGUG) – Submission on Gas DPP3 draft decision- 14 March 2022
[95] Frontier Economics (submitted by Vector, First Gas and Powerco on Gas DPP3 draft decision) – Review of Asset Stranding Model-13 March 2022, including Vector, First Gas and Powerco – Joint letter accompanying Frontier Economics Report – 14 March 2022.

assessment that the model can't address the central question of why "*the need to act now*". While it offers suggestions on mechanical improvements for the modelling, it doesn't offer any improvement on the fundamental input assumptions that underpin the working of the model.

12. The Gas Infrastructure Future Working group (GIFWG) submission[96] adopted its own modelling approach to the Commission's model. These included four possible scenarios:

a. *Fast wind-down scenario* – pipeline use ceases by 2040;

b. *Slow wind-down scenario* – pipeline use ceases by 2050;

c. *Optimistic hydrogen repurposing* – natural gas transitions to hydrogen or biomethane, with **no natural gas throughput by 2050**. Green gas will be 50% of existing natural gas throughput;

d. *Pessimistic hydrogen re-purposing* – As for Optimistic hydrogen repurposing except that green gas throughput will be 20% of existing natural gas throughput.

13. We acknowledge the caveats placed on the GIFWG analysis at the front of their submission include the statement that "*The analysis should not be relied on to inform financial or commercial decisions.*[97]" However to the extent this analysis provides input into the decision-making process we offer below more specific reasons as to why their framework and analysis can't be relied on to make a regulatory decision on accelerating revenue in DPP3. By framing its scenarios in this narrow fashion (para 12), the GIFWG modelling approach is undermined by the same reasoning and unnecessarily restrictive assumptions as the Commerce Commission's own modelling work including:

a. All scenarios mischaracterise the policy environment by assuming zero natural gas by 2050, despite both the Climate Change Commission (CCC) and the Ministerial statements having imposed no such constraint;

b. It remains entirely plausible and consistent with a net zero accounting carbon target that natural gas can continue to be part of New Zealand's energy system by 2050 and beyond[98];

c. Gas use, in whatever colour, need not be at some fraction of existing natural gas throughput. It may be more than 100% of today's use, depending on how gas is being used – including new sectors, such as land and sea transport[99];

d. The model doesn't assess the financial performance or position of any specific gas pipeline business, nor quantify the risks they face[100];

[96] Gas Infrastructure Future Working Group – Submission on Gas DPP3 draft decision – 14 March 2022
[97] Ibid – Title Page
[98] See for example APGA September 2020– "*Gas Vision 2050: Delivering a Clean Energy Future"*. https://www.apga.org.au/resources/gas-vision-2050-publications
[99] Ibid – p44 base case shows increased gas consumption – note modelling work done by Frontier Economics
[100] Gas Infrastructure Future Working Group – Submission on Gas DPP3 draft decision – 14 March 2022 – S3.5 p13

e. While an improvement over the Commission's more simplified qualitative approach, the "willingness to pay (WTP)" assumptions are acknowledged (reasonably in our view) as " *notoriously difficult to assess, let alone forecast accurately;* "

f. The model also doesn't assess the factual vs counterfactual position which is central to the Commission's argument "to act now".

While the GIFWG analysis does offer an alternative approach to the Commission's modelling work, we consider that it offers no other reliable or insightful conclusion other than that the future is highly uncertain and, it is impossible to discern why one view should be preferred over another.

Para 17-25 we disputed that average gas demand was a reasonable proxy for assessing demand destruction risk created out of proposal to accelerate revenue for GPBs but not EDBs

17. First Gas also assert that *delivered gas prices appear well-placed, relative to other energy options, to accommodate increases without demand destruction*[101]. First Gas' evidence for this assertion appears to rely on their interpretation of the historical price information published by MBIE[102]. We think this argument has misinterpreted the data and missed important nuances within the information, specifically:

a. The leverage of the fixed price component of delivered gas on average gas cost is ignored.

b. The importance of the Low User group in the residential/ commercial sector. This is both in terms of GDB revenue impact and the susceptibility to losing customers from this segment when prices rise faster for gas connections than they do for competing alternatives (such as electricity).

c. The options available to industrial consumers to break from gas connection services.

Fixed Cost Leverage

18. While we accept the MBIE data, it is important that the Commission understands that the prices and figure presented are based on *average consumption*. Average consumption for residential is approximately 25 GJ pa[103] and delivered cost includes all fixed charges, variable charges, and taxes and levies (principally GST and carbon pricing).

19. Fixed charges (daily connection charges, or capacity reservation charges) have a leverage effect on the average delivered gas cost to a household that has a material influence on a decision to connect or stay connected.

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[101] Ibid 3.2 – p13

[102] Source: Real annual average fuel prices – 2020 prices, Annual NZD per GJ (real), Ministry of Business, Innovation & Employment, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energyprices/

[103] Energy in NZ records 7.2 PJ consumption in the residential sector. The Gas registry shows that the average active ICPs for 2020 was 293,091 connections. 7.2e6/293091 =24.57 GJ

20. The leverage of the fixed price components is illustrated in *Figure 23*. This demonstrates how average price for gas varies between residential customers depending on regions[104] and consumption patterns[105]. Given that a household may well be an "average" electricity consumer as well as a low gas consumer[106], it is not difficult to see why MBIE's presentation may not be illustrative of individual households. For example, the MBIE data would seem to infer that the gap between average delivered gas cost and average electricity cost *for a household* is $41.54/ GJ ($81.56 GJ-$40.02/ GJ). Analysed at an individual household level however the actual gap can be much smaller (*Figure 23*).

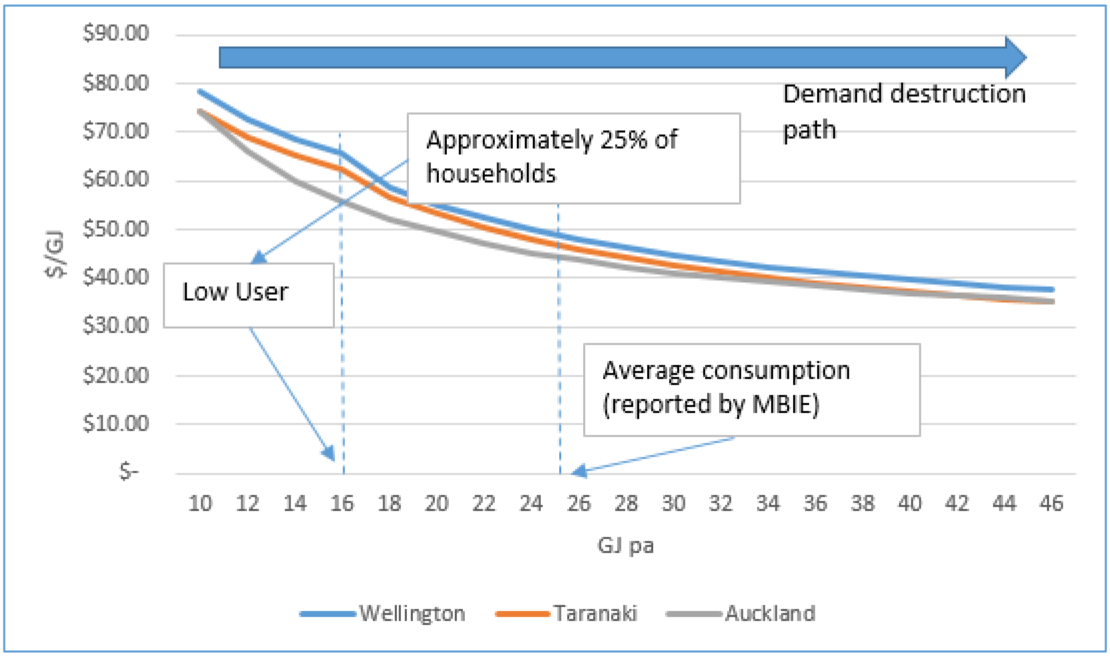

Figure 23: Residential Gas Price for Standard Consumers (2022 - Contact)

21. A further illustration of the demand destruction risk can be given by looking at low user group. In their FY 22 Gas Distribution Pricing methodology,[107] Powerco identifies 26,384 customers falling into the low user category (G06), versus 83,293 customers falling into their residential/ small commercial category (G11). That is, 24% of their residential customers use less than 16 GJ pa. (Powerco created the G06 pricing structure for the reason that low users are particularly sensitive to the connection fixed cost component and a lower fixed cost (but higher variable fee) was designed to keep them connected[108]).

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[104] One reason that it varies, is that gas transmission costs depend on the distance between gas injection and delivery point, and the extent to which it uses both the MPOC and VTC systems.
[105] We used the published prices for Contact Energy Ltd for dual fuel connections which includes 5% dual fuel discount. Note that Powerco is the distributor in Taranaki and Wellington. Powerco offers a low user (less than 16GJ pa) pricing structure. This pricing structure has been used in the figure.
[106] In fact it is more likely that a low gas user will be close to an average electricity user given that households are relatively similar in total energy needs.
[107] https://www.powerco.co.nz/who-we-are/pricing-and-disclosures/gas-pricing
[108] The price structure has been in place for some time. Our records only go back to 2011 and indicate that the G06 has been in place since at least then, but probably earlier.

22. The low user group represents 4% of Powerco's gas volume but 12% of their total revenue. For the G11 load group the numbers are 32% and 60% respectively[109]. Powerco's interest to have low gas consumers choosing to stay connected seems important to their business model. The impact of the G06 consumers leaving in large numbers could be the trigger for accelerating demand destruction (even if a WAPC might initially project the revenue risk onto the GDB). This is especially given that for households, a gas connection is generally a discretionary choice, whereas an electricity connection is not. For example, by dropping the gas connection altogether and switching to electricity, the economic equation changes to considering the marginal (variable cost differences) cost of electricity versus gas. Taking the example of Contact's current pricing, the cost of the gas connection is $1.708/ day, and the difference between the variable cost of electricity ($0.171/kWh) and gas ($0.077/kWh) is $0.094/kWh[110]. What would the gas consumption need to be to justify disconnecting gas? The answer is $1.708/$0.094 = 18 kWh/day. 18 kWh/day = 65.4 MJ/day = 24 GJ pa. So if a consumer uses less than 24 GJ pa of gas, the rational response is to start looking at disconnecting from gas[111]. This is a substantially lower barrier than the MBIE figure would seem to imply. Note, that the reverse option – disconnect from electricity to use more, lower priced gas is not feasible given the wider uses of electricity in a household.

23. Figure 1 in First Gas' submission also doesn't address the choices that industrial users face that lead to demand destruction. The choice for an industrial consumer is not one of just gas vs electricity prices. For a number of larger industrial consumers, including MGUG members and Methanex, the other options to deal with rising delivered energy costs are; to invest in network bypass; switch to other fuels (e.g. biomass); or close operation in New Zealand. Any of these choices helps to accelerate the GPB revenue destruction spiral. To be clear, this is not an argument supportive of First Gas' position that raising prices "doesn't matter" for consumers. Larger users in particular have a deeper concern that the Commission's draft reason undermines long term investment confidence in the gas sector at a time when gas should be supporting an energy transition.

24. We don't consider that First Gas' comparison of energy prices therefore gives a clear view in deciding that accelerating fixed charges can be accommodated without risking demand destruction. In fact, we would argue that the risk is real, and increases with gas connection charges outpacing electricity connection charges.

25. It would require a substantially more extensive analysis than given here to reveal exactly how a price shock in gas connections might flow through to connection choices. Our simplified view however, is that the network price impacts will flow through to households and businesses according to their consumption, location in the distribution network area, energy options, and strategic alternatives to operating in New Zealand. For the residential/ commercial sector low use connections will be impacted first – either disconnecting or choosing not to connect. This in turn

[109] Ibid Figure 3 and Appendix 2
[110] Illustrative of Contact Energy prices in Taranaki.
[111] Other factors would need to be included, such as capital replacement cost of appliances, and consumers may simply prefer gas for reasons other than cost.

shifts the network cost burden on to fewer consumers than otherwise would be the case, increasing their costs relative to substitutes.

Para 27- 47 disputed Vector's evidence that they faced demand decline as a result of current policies that underpinned their argument for a change in the form of control

47. The conclusions that we would draw from this analysis are:

a. It is unclear why Vector should refer to volume loss over the "last four years" when volume loss only started with COVID controls two years ago.

b. Vector's volume loss is not replicated on other networks, and is peculiar to COVID control impacts in central Auckland, which in turn is related to border closure and lockdowns. Both of these measures will no longer apply from April this year and volume recovery seems more likely than not.

c. Vector is perhaps trying to limit its growth opportunities via its connection policy, or anticipating net disconnections as a result of accelerated pricing to argue for a Total Revenue Cap to protect their downside risk. The decisions to limit their own growth are entirely within their own discretion and doesn't justify a switch in the form of control.

d. Gas demand and revenue aren't directly correlated. In this case the data would suggest a negative correlation (volume down, revenue up). The Commission should note that the relationship between gas volume and pipeline revenue isn't a direct one when looking at how declining gas volumes might affect economic stranding risk.

e. Absent other demand shocks Vector is expected to continue to show growth in its connections through to October 2026

11/07/22 - MGUG - Process and Issues/Draft Framework submission

The current IM review was started in 2022 with the Commission issuing a Process and Issues Paper for submissions. MGUG submitted in two parts:

7. This submission is in two parts as it deals with the two separate papers published by the Commission.

a. The first part covers the draft framework where we deal specifically with the current gap in the definition of gas pipeline services and the amendments made in the gas IM determinations.

b. The second part deals with process and issues. In particular we address the need to re-examine the economic principles when faced with long term demand risk and within the context of promoting outcomes that are consistent with outcomes produced in competitive markets.

Framework Issues

Para 22 – delved deeper into why and how Part 4 of the Act would evolve to remove restrictive provision of only considering natural gas.

22. MGUG's earlier submission[112] on this topic addressed the question of interpretation of "*gas pipeline services*" under Part 4 as a regulated service, and disagreed with the Commission that it was confined to considering only natural gas in considering the definition of gas pipeline services:

a. S52 provides for the regulation of the price and quality of goods or services in *markets where there is little or no competition and little or no likelihood of a substantial increase in competition*.

b. S52B(3)(b) identifies *gas pipeline services* as a service that falls under Part 4.

c. While S55A(1) appears to limit this to natural gas it also provides the rider, "*unless the context otherwise requires*".

d. Part 4 subpart 2 (S52G-S52K) anticipated future needs to capture services that couldn't be foreseen when Part 4 was first enacted. Part 4 therefore includes provisions to update the list of services that fall under the definition of markets where there is little or no competition.

23. It appears to us that there is a natural and logic hierarchy in the drafting order of S52, S52B(3)(b), and S55A(1) that should guide decision making when considering areas of conflicting interpretation between them. By emphasising S55A(1) and minimising the possible intent of that clause's rider it seems to us that the Commission has reversed that interpretation order and undermined the intent of Part 4. The Commission's interpretation of S55A(1) within the overall legislative context seems particularly restrictive given that S55A(1) is qualified with "*unless the context otherwise requires,*" and the Commission starts this review describing the changed context.

26. In support of the wider interpretation of S55A(1), is the consumer expectation of gas pipeline services. Consumers will continue to have a demand for a service (gas transport) to deliver them the benefits of gas, i.e. the option of using gas for various purposes (energy carrier, or as a raw material). The possibility that low carbon gases could blend with or displace the traditional natural gas to provide consumer utility is a means to the end that consumers retain gas as a choice for their households or businesses.

Process and Issues

MGUG considered the evidence through legal case law for the interpretation of ex-ante FCM principle in the context of seeking S52 outcomes that are consistent with (workably) competitive markets.

- In a regulatory context FCM is achieved on an ex-ante basis ([2013] NZHC 3289 [11 December 2013] – para [261])
- *Markets where there is little or no competition do not produce price outcomes that are consistent with the outcomes to be promoted in the s 52A(1) purpose. It is the difficult role of*

[112] MGUG – 14 March 2022 "*202203 MGUG- Submission on draft decisions IM and DPP3-Final*"

Part 4 regulation to produce prices that generate the s 52A(1)(a) to (d) outcomes, consistent with the outcomes produced in workably competitive markets. Prices are, therefore, at the heart of Part 4 regulation. -[2013] NZHC 3289 [11 December 2013] – para [29]

- Professor Yarrow in the context of Orion CPP determination (2013) [113] that expectation is that prices should lower when demand reduces

> In the context of supply of a reasonably homogeneous product/service, using long-lived specialised assets, **demand reduction in a competitive market can be expected to put downward pressure on prices, more or less immediately in spot markets and potentially more gradually in contract markets** (depending upon the form of the contracts used: a long term contract for specified volumes at a price determined by a spot price index would likely show a price response almost quick as the spot price response itself). **It would, I think, be surprising if, having lost some customers, competitive firms with excess capacity and short-run marginal costs well below the prevailing price level, then increased prices to remaining customers to restore their profitability.** Cartelisation might do the trick, but the market could not then be said to be workably competitive".

P13, Para 3

Para 64 – 73: MGUG submitted on what is seen in workably competitive markets when demand declines and companies are faced with shortened asset lives

64. In a competitive market, firms who view the demand for their services as being at significant risk take a number of steps to mitigate their potential downside exposure:

a. They mark the value of their impaired assets to market by writing them down to their market value[114]. This is then reflected as a "loss" on their books (an ex-post outcome of an ex-ante decision). This reduces their asset base and their depreciation expense.

b. They shorten their investment horizons to ensure that their ex-ante FCM expectation for new investment can still be met. They may also trade-off higher operating expenditures to extend the life of assets rather than risk not recovering their cost of capital for replacement capital.

c. They look to maximise their fixed cost recovery by using their operating leverage to price their product to maximise assets utilisation. In practice this means that firms to set price that won't recover the full cost of the asset, but that still exceeds the marginal

[113] Yarrow review of claw back issues Orion CPP 30 May 2013
https://comcom.govt.nz/__data/assets/pdf_file/0024/63186/1582851-Yarrow-Further-advice-on-clawback-4-August-2013.PDF

[114] An asset is impaired if its projected future cash flows are less than its current carrying value. An asset may become impaired as a result of materially adverse changes in legal factors that have changed the asset's value, significant changes in the asset's market price due to a change in consumer demand, or damage to its physical condition**. Another indicator of potential impairment occurs when an asset is more likely than not to be disposed prior to its original estimated disposal date**. Asset accounts that are likely to become impaired are the company's accounts receivable, goodwill, and **fixed assets**.

production cost in order to maximise the fixed cost contribution and so maximise their profit.

65. A stylised presentation of what happens in a competitive market using standard microeconomic theory is shown in Figure 24[115]. Figure 24 shows the supply curve of a firm as the sum of fixed (capital recovery and other fixed costs) and variable costs. It also shows the demand curves under two scenarios; normal demand, and curtailed demand. The key point is that supply of service stays fixed but for demand, the curve shifts. The market clears at a lower price point for consumers. For the supplier with fixed assets and high operating leverage it means that while the supplier can recover its variable costs and other fixed costs (e.g. insurance, rates, employee costs) it can only recover a portion of its sunk cost in its asset base. This is a profit maximising strategy for the firm even if it suffers an ex-post economic loss on its investment in fixed assets.

66. Note that this figure can also be interpreted in a temporal dimension if demand (Q) is seen as cumulative in time. In this case the two demand curves reflect a shortened firm life.

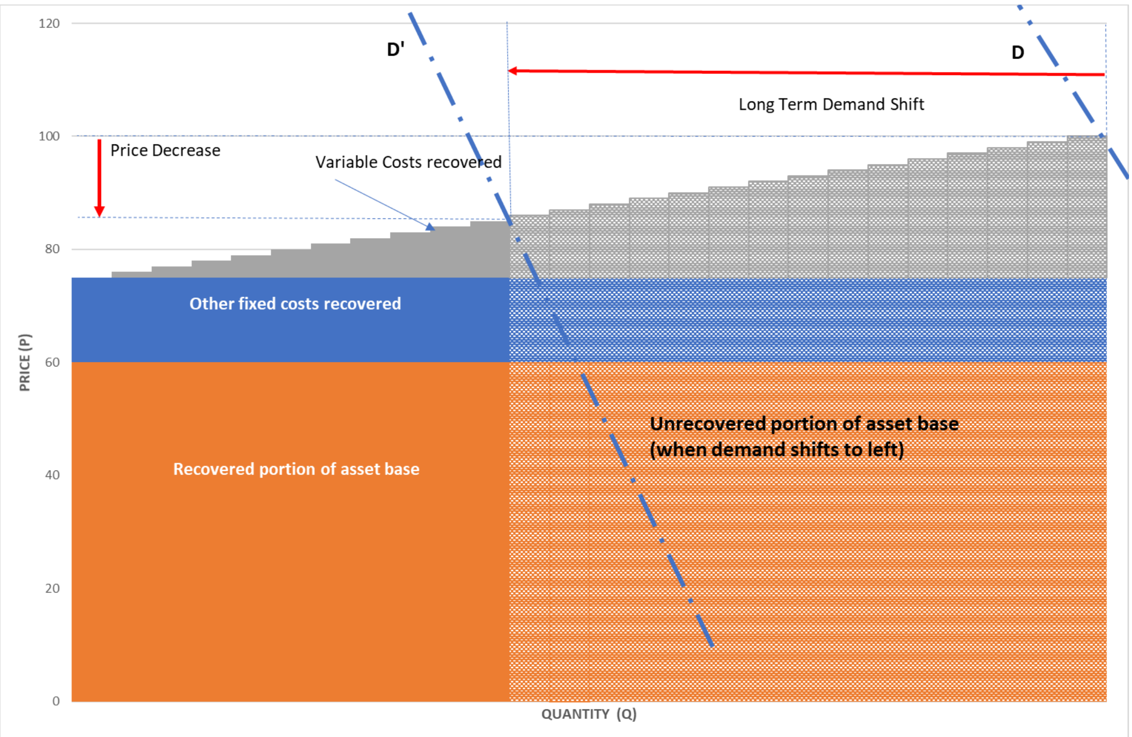

Figure 24: Demand shift effect on price in competitive markets

67. This is how a regulated firm is expected to behave under a price/ quality control framework that promotes outcomes consistent with outcomes seen in competitive markets.

68. Instead of promoting a competitive market outcome, the Commission is promoting the outcome shown in Figure 25. In this case the supplier is approved to recover all (or most) of the

[115] This is illustrative and simplified

capital that it has invested, and instead of seeing a price decrease, as would be the case in competitive markets, the consumer instead sees a price rise.

69. The characteristic of Figure 25 is that not only has the demand curve shifted, so has the supply curve. The only reason a supply curve shifts in a competitive market is for changes in production cost. For a regulated supplier with a fixed asset base the only changes in production cost that relate to falling demand are how this affects their operating expenditures. This could be up or down (less wear and tear, less staff) or more opex but less capex to maintain quality of services. Lifting the entire supply curve to guarantee capital recovery of an ex-ante investment is not consistent with behaviour seen in competitive markets.

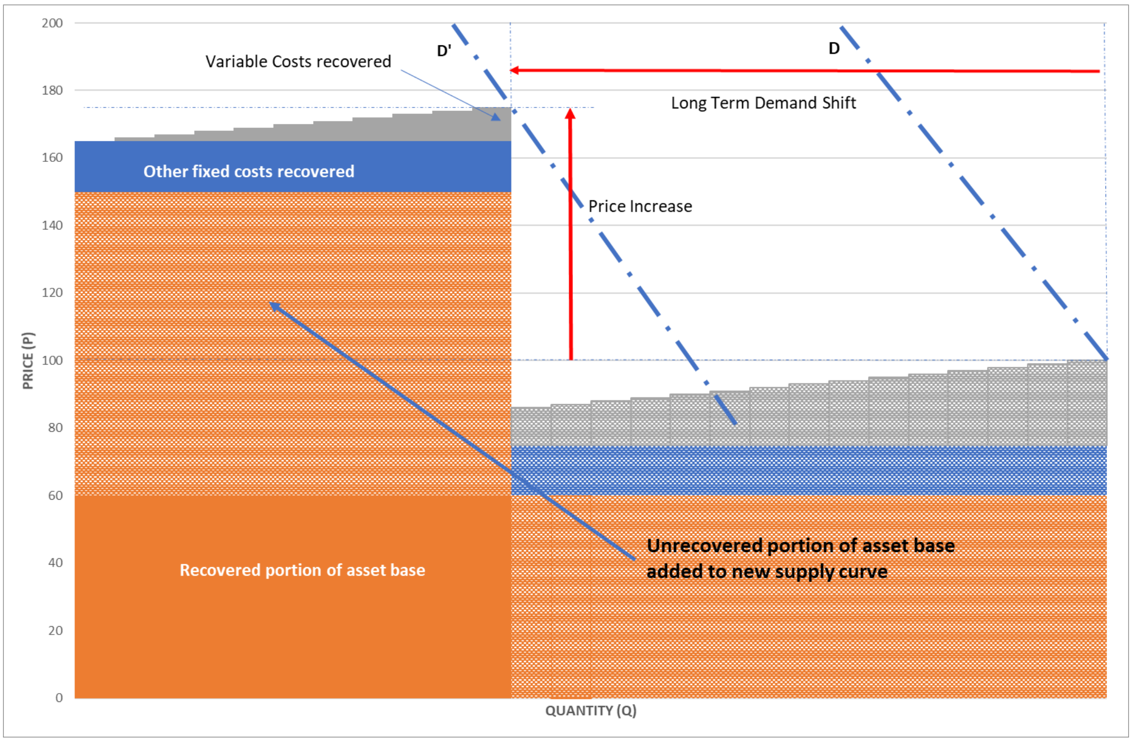

Figure 25: Price behaviour promoted by the Commission

70. Figure 24 and Figure 25 are a static analysis but the same conclusions can be drawn from viewing this dynamically. In (Figure 26,Figure 27, Figure 28) we simulate the residential gas sector. The demand curve is not straight and is concave to the right. The horizontal part (price elastic part) could represent low users in the system who face a high average cost of delivered gas because they only use gas in winter for heating. The curve steepens to the left reflecting consumers who are increasingly less price elastic. There is an assumed maximum limit at which a rational consumer would disconnect. This limit will be different for every consumer, driven by a range of factors, not all economic. For simplicity we've just shown a nominal cap.

d. Figure 26 – shows the equilibrium state of the sector before accelerating depreciation

e. Figure 27– A depreciation adjustment factor of 0.67 is applied and the supply curve lifts. The demand shifts to the left along the demand curve. The most price sensitive consumers disconnect. The supplier doesn't recover all fixed costs. A further price rise is indicated to compensate for the economic loss of the asset base.

f. Figure 28 - supplier is allowed to recover the RAB it didn't recover in the first period. Prices are raised and more consumers disconnect. Prices need to rise again.

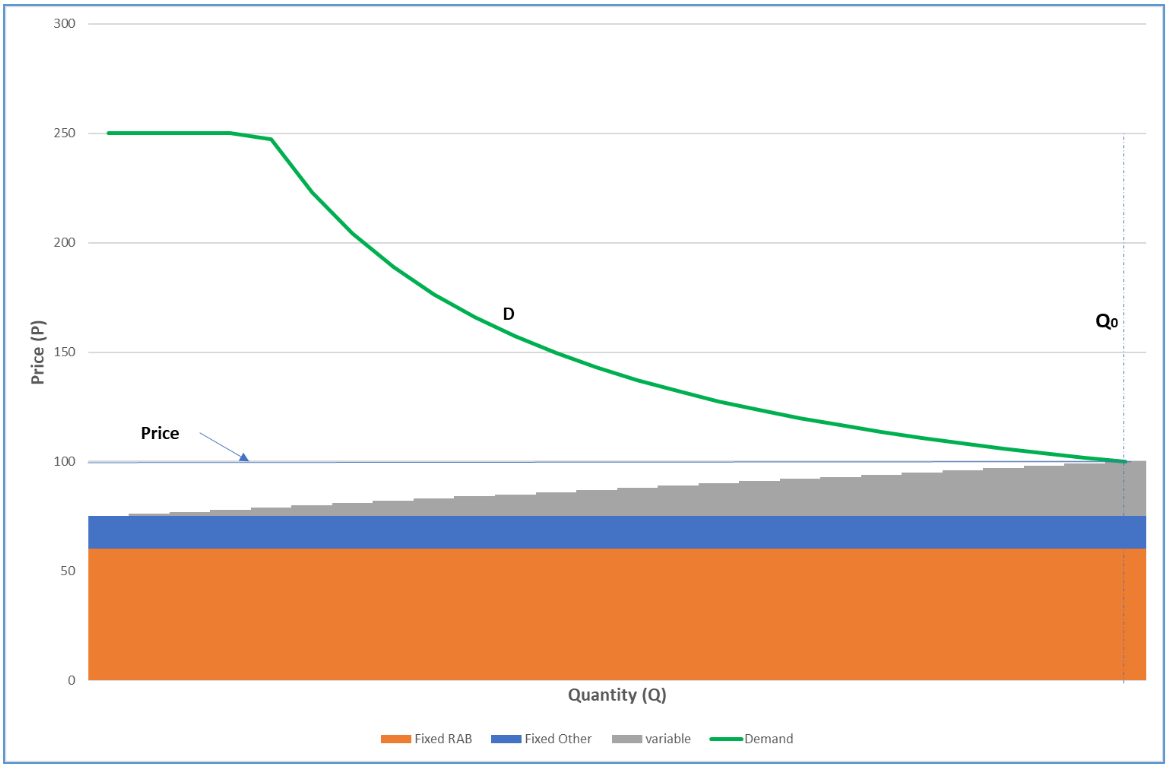

Figure 26: Residential Pricing before shortening asset lives

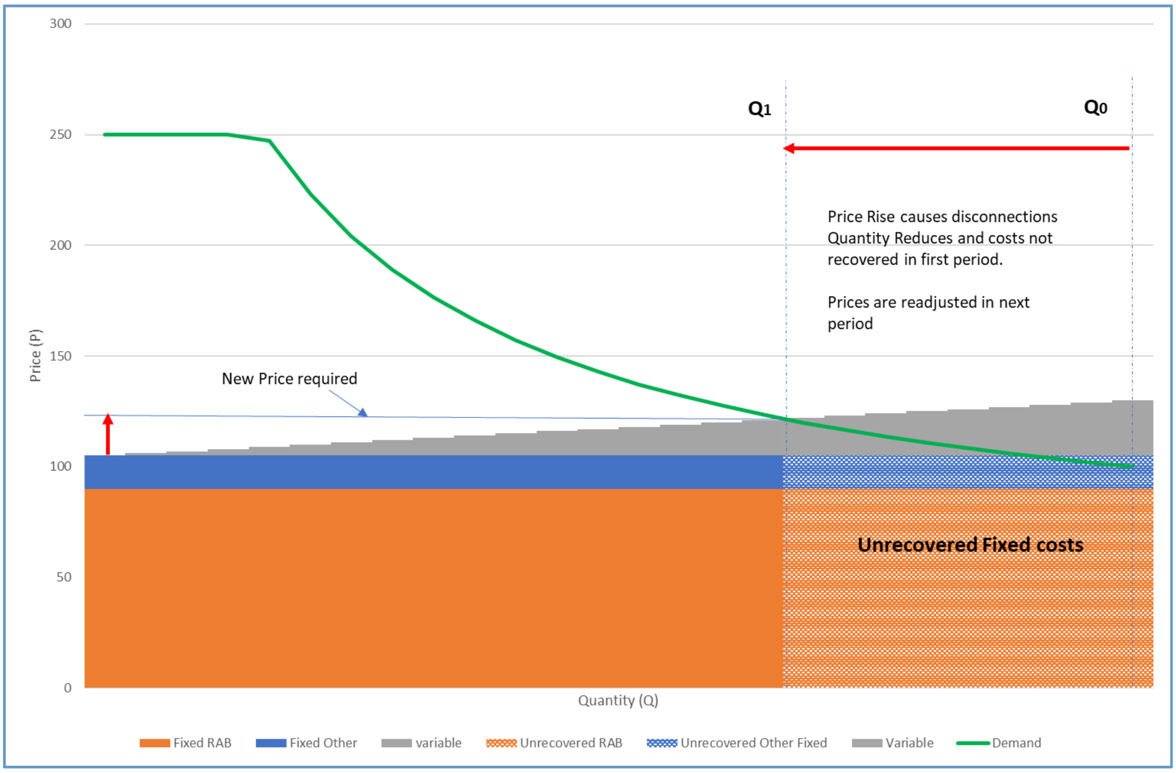

Figure 27: Residential Pricing after shortening asset lives

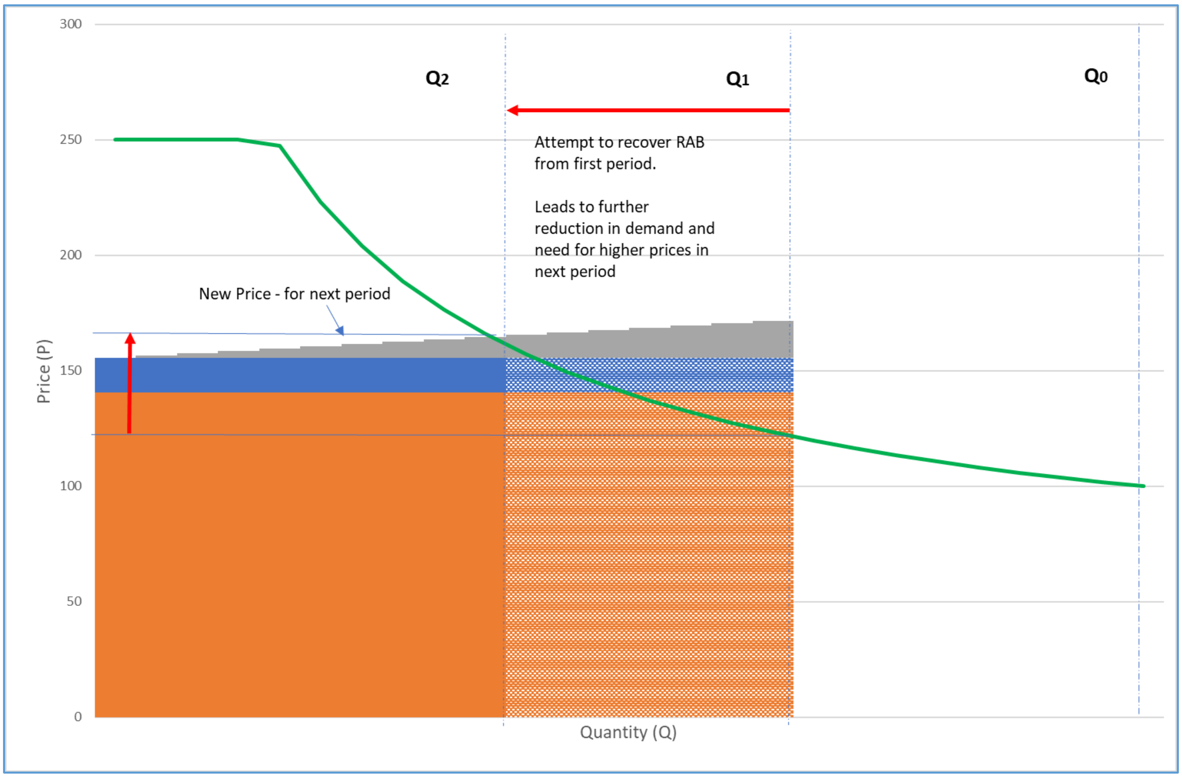

Figure 28: Residential Response- period 2

71. The speed and depth of demand destruction obviously depends on the shape of the demand curve. The only situation where this pattern doesn't occur is where consumers have zero price elasticity (demand curve is vertical) and they'll accept a quantity at any price.

72. This illustrates that this dynamic is not only adverse for consumers, but also for suppliers, as they can't recover all of their fixed costs, and are continuously needing to raise prices to try and get to their MAR. It's not a profit maximising strategy so it's surprising that producers should be advocates for shortening asset lives (or any other mechanisms that provides ex-ante FCM compensation).

Para 86-88 emphasised the importance of empirical evidence against economic theory

86. In attending to the Commission's scope to deal with clawback questions Professor Yarrow observed:

> "As an aside at this point, I think it would prove helpful to the Commission if, given the use of the concept of workable competition in the legislation, those making economic submissions were encouraged to put more weight on empirical material drawn from comparator markets which might be held to be workably competitive. **Sometimes an ounce of fact is worth more than a ton of theory**[116]"

P2, last para

87. We consider this is helpful advice. For example, in arguing that accelerated depreciation was necessary in order to promote S52A(1)(a), i.e. that suppliers have incentives to innovate and to invest, including in replacement, upgraded, and new assets, the Commission seemed to rely solely on assertions and presumptions that suppliers would not invest without the additional regulatory incentive. This was in spite of the empirical evidence in front of them that suppliers were managing investment risk efficiently.

a. Suppliers were already subject to incentives to invest to maintain reliability and ensure that their networks were safe. These included the regulatory framework itself (Price Quality, Information Disclosure), as well as petroleum pipeline regulation, asset management standards, and intrinsic incentives to manage organisational reputation. No further incentives are needed for suppliers to invest to maintain minimum safety and reliability standards.

b. The supplier asset management plans (AMPs) which extend 10-years include a CAPEX program for not only asset replacement and renewal, but also for growth CAPEX. It was also evident that suppliers were managing future risk using tools at their disposal, including deferring major expenditure in favour of smaller projects, additional OPEX, or in the case of new customer connections, requiring the connecting party to pay for the connection.

[116] Our emphasis added

88. So, while a theoretically attractive presumption that suppliers might underinvest in an environment where, ex-ante, they might not earn a normal return, the facts in front of the Commission didn't appear to have been tested.

10/02/23 – MGUG- Options to maintain investment incentives in the context of declining demand – submission

Since this was to be the last opportunity to persuade the Commission ahead of its draft advice MGUG attempted to pre-empt arguments that would continue to support the current gas IM.

Para 8 clarified why S52A emphasised seeking outcomes that are consistent with workably competitive markets, and how prices are at the heart of the regulation

8. The Commission seeks to put S52A at the heart of its decision making. While the Commission relies on its judgement to balance the various outcomes, case law and previous decisions have provided useful clarifications and distinctions. We've considered them to produce this submission. We want to clarify our previous submission and cross submission on the framework and process and issues[117]:

a. Competitive markets were defined as *workably* competitive markets by the High Court[118].

b. Workably competitive outcomes were further defined by the High Court as being synonymous with outcomes produced in ***strongly competitive*** markets – ("*why would regulation aim lower than is desirable*")[119]

c. Outcomes were defined as ***tendencies*** that are ***consistent*** with those produced in competitive markets[120]. i.e., they are average expectations not absolute expectations.

d. "Prices are at the heart of Part 4 regulation"[121]

9. While the Commission may argue that it can't just focus on prices to assess the long- term interest of consumers, in workably competitive markets price generally reflects the other outcomes expressly mentioned in S52A. Workably competitive markets are characterised by firms being price takers, not price makers, and as noted by the High Court, price implicitly embodies the other desired S52A outcomes[122]

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[117] 202207 MGUG Submission on 2023 IM review- Framework and Process and Issues Paper, 202207 MGUG Cross Submission on 2023 IM review- Framework and Process and Issues Paper.
[118] WELLINGTON INTERNATIONAL AIRPORT LTD & ORS v COMMERCE COMMISSION [2013] NZHC 3289 [11 December 2013] – [6]
[119] ibid – [22], [24] (h)
[120] Ibid – [18]-[23]
[121] Ibid – [29]
[122] WELLINGTON INTERNATIONAL AIRPORT LTD & ORS v COMMERCE COMMISSION [2013] NZHC 3289 [11 December 2013] – [22]

> ***The process of rivalry is what creates incentives for efficient investment, for innovation, and for improved efficiency****. The process of rivalry prevents the keeping of all the gains of improved efficiency from consumers, and similarly limits the ability to extract excessive profits*.

In other words, incentives for efficient investment, improved efficiency, and innovation are embedded in price, in markets where firms can't unilaterally raise prices.

Para 10 noted that stranding risk was never contemplated in the design of the BBM, and that raising prices as a result of accelerating depreciation might be an unintended consequence.

10. We think it is significant that it seems that when designing the IM methodologies, the Commission and its advisors *never contemplated having to cope with economic stranding risk within the Building Blocks Model (BBM)*.[123]:

> "*Stranding risk was not envisaged when regulation of natural monopoly infrastructure was designed.* ***Regulatory regimes that apply the building block method assume that once capital expenditure is added to the RAB it will remain there until fully depreciated****. This understanding provides regulated providers with a degree of certainty that they will recover their investment in what are typically very long-lived assets". (MGUG emphasis added)*

Para 6-1041

11. As we discuss further down in this submission, when the Commission proposes to accelerate or otherwise front load depreciation rates to address economic stranding risk, the mechanics of the BBM causes prices to consumers to rise when they should fall. This is not an outcome that is consistent with what is seen in workably competitive markets.

In para 12-16 we proposed that the meaning of ex-ante FCM might be miscommunicated, but that nevertheless that ex-ante FCM expectation, should be just that – ie an expectation of NPV=0 before an investment is made, and accepting the possibility that the actual outcome might disappoint

12. It may seem odd to ask the question given the extent that FCM has been discussed, but having spent considerable time reviewing background material, it is not clear to us now that there is a shared understanding of what the concept of FCM is meant to embody.

13. Our working assumption is that FCM plays an important role in investment decisions on an *ex-ante* basis. That is investment decisions are based on an expectation of achieving a "normal" return on the *overall life* of the asset. Once the asset investment is sunk, the ex-post outcome may be different (better or worse). The risk of disappointing life or return is with the supplier. This seems consistent with how the High Court described it:

> ***"Over the lifetime of its assets****, a typically efficient firm in a workably competitive market* ***would expect ex ante*** *to earn at least a normal rate of return (i.e. its risk-adjusted cost of capital). Because allowing a firm the expectation of being able to earn normal returns over the lifetime of an investment provides it with the chance to preserve its 'financial capital' in real (not nominal) terms, such an outcome is often referred to as*

[123] Fibre input methodologies: Main final decisions – reasons paper 13 Oct 2020 – para 6-1041

'financial capital maintenance' or 'FCM'. ***In a regulatory context, FCM is achieved, on an ex ante basis"*** (MGUG emphasis added)

[2013] NZHC 3289 [11 December 2013] – para [261]

14. However, we now note that the Commission may have a subtly different understanding:

"The FCM principle is that regulated suppliers should have the expectation ex-ante of earning their risk-adjusted cost of capital (ie, a 'normal return'), which provides them with the opportunity to maintain their financial capital in real ***terms over time frames longer than a single regulatory period****.*

Price-quality regulation does not guarantee a normal return over the lifetimes of a regulated supplier's assets. However, given that a typically efficient firm would expect ex-ante to earn at least a normal rate of return over time, application of this principle can assist in promoting the s 52A(1) outcomes and purpose"

(MGUG emphasis added)

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15. With the benefit of seeing the outcome of the recent gas IM amendment determination, we are left pondering whether the Commission sees itself as securing the original ex-ante FCM expectation *after every regulatory period*, rather than the overall life of the asset? If that is the case, we suggest that this is not what the law intended, or the High Court clarified in 2013. We request that the Commission should clarify what it means by FCM.

16. Equally, the Commission may be correct in resetting the ex-ante FCM expectation by marking the value of the assets to market for each regulatory period, but wrong in allowing the capital loss to be passed to consumers instead of suppliers because it relies on BBM methodology not designed for dealing with economic stranding risk. We request that the Commission shows how the BBM simulates competitive market outcomes under the scenario of economic stranding risk.

Para 20-32 addresses asymmetric risk, and whether regulated companies face asymmetric risk because they are capped on the upside, but not the downside.

20. We have searched for evidence that might have supported Commission views as expressly referred to stranding risk. We were unable to find any. The statement presents premises that appear unsupported by evidence (the nature of the asymmetric risk, and what can be seen in competitive markets) and contradicts the basis of Part 4 purpose (promoting outcomes that are consistent with outcomes produced in competitive markets). We did not separately find any balance of empirical evidence to support the position that unregulated firms would increase prices when faced with stranding risk[124].

21. Firstly, as a matter of economic theory, by definition, in competitive markets, firms (on average over time) cannot earn economic profits – i.e., there is an expectation that NPV=0 over the

[124] This does not overlook the later work of advisors for the Commission on the alleged asymmetry of consequences from inadequate regulated return leading to under-investment vs excess profit leading to over-investment

long term[125]. This is the basis for the ex-ante FCM economic principle that the Commission also uses. It is why regulated profits are capped ex-ante at NPV=0.

22. It has been argued that "capping" ex-ante profits at NPV=0 is disadvantaging regulated businesses because they lose the opportunity to earn super-profits in their (random) walk around the average, which for unregulated businesses are the compensation for the periods of below average returns. That argument seems to miss the key condition that attracts regulation. The regulated supplier is regulated because they are not price takers. They can limit their exposure to the normal competitive market business experience of involuntary lower than average returns. Their monopoly power is the protection. Indeed, the Commission will probably be familiar with academic arguments that the returns for a revenue regulated monopoly have more of the characteristics of a bond, than an equity.

23. The BBM regime, with a market derived WACC, was designed to simulate what workably competitive markets tend to achieve over time on average, and applies that to businesses with market power that could otherwise deliver sustained super-profits in order to *restrict their pricing behaviour to observable tendencies in workably competitive markets* (i.e., capped at normal returns). The regime does not take away the supplier's pricing power ability to protect itself from revenue losses below the regulated revenue. Nevertheless, from what we can see in the record is that the revenue risk asymmetry argument seems to have been uncritically relied upon ever since it was offered.

24. If it is the case that there is an expectation by suppliers that there is the prospect of ex post or case by case supplementation of revenues at the expense of consumers, for 'unexpected' or non-systematic loss events, what equity risk remains to justify the equity premium over debt? MGUG sees no justification for asymmetry compensation (for alleged downside risk without upside opportunity) because the pricing risk on the downside remains covered and under the CAPM formula nothing is given away on the upside[126].

25. Of course, unregulated firms might seek compensation for matured risks *ex-post* through price adjustment. This is not what we tend to observe empirically in workably competitive markets (see further below). They are disciplined by competitive market dynamics. The experience of loss might affect expectations about cost, but prices will be determined by the supply and demand curves. Unless suppliers withdraw supply, their view about what they ought to be paid are immaterial. Their revenue in a competitive market is the clearing price. The question in the stranding situation is whether and where the supplier's best interest lies in ceasing to supply. In theory that should not occur until the price does not cover variable costs.

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[125] See for example https://www.investopedia.com/terms/n/normal_profit.asp . "Normal profit is a condition that exists when a company or industry's economic profit is equal to zero, and in macroeconomics, an industry is expected to experience normal profit during times of perfect competition.". In dynamic terms, any firm earning economic profits expect that to be competed away with new entrants undercutting prices to meet their cost of capital.

[126] Note that both regulated and non-regulated firms have the opportunity for earning higher profits in the short- term ex-post. This is a design feature acknowledged in the DPP settings and regulatory control periods which encourages regulated firms to find efficiencies to improve their profitability.

26. We should note that for ex post price adjustments, the view is repeated from the 2020 Fibre determination that unregulated firms, price to compensate for losses:

> *In workably competitive markets existing firms may be exposed to the risk of new entry that would erode upside returns when the market is profitable. When the market is unprofitable entrants are unlikely to arrive so incumbent firms are left to entirely bear any losses**. In workably competitive markets, firms will try to compensate for the downside risk of bearing the losses by increasing prices where they can and thereby keep an expectation of symmetric returns**.*
>
> Fibre input methodologies: Main final decisions – reasons paper 13 Oct 2020 – para 6-996

27. There is something odd about this statement about firm pricing behaviour. If firms could raise prices in a competitive market to cover past losses, or even anticipated future losses, why would they not do so irrespective of the losses. Why only raise prices to compensate for ex-ante FCM loss?

28. Perhaps there is an implicit assumption that the matured FCM loss for which compensation is sought, has a character that applies across all suppliers, and affects their variable costs, so there will be no competitive disadvantage or revenue risk from raising prices in consideration of the loss. If that is the explanation, it is inadequate.

29. Firms in workably competitive can't unilaterally raise prices to compensate for shortened economic lives, and this applies equally to disappointing ex-ante investment decisions. If a new project looks to be NPV negative, rather than raise prices (which competitive price takers can rarely do) firms look for opportunities to lower their costs to restore positivity. They can change CAPEX (including creating timing options) and find OPEX trade-offs, which they can control/ influence. This is also what we see in supplier AMPs when they defer investment through life extension, or select CAPEX solutions that have a shorter economic life but may have to be done more than once.

30. The statement also seems to ignore the fact that for most stranded assets the firms have already incurred the loss when the stranding is recognised. It is a capital loss. It may be progressively recognised, but generally once stranding is seen as likely, the question is for how long they can defer or diminish the loss of revenue. This submission reverts later to the question of how businesses in competitive markets actually behave, with reference to the experience of our members.

31. The reasoning for this position also seems to rely primarily on the Hypothetical New Entrant Test (HNET)[127]. The HNET was examined in a related workably competitive markets context by the High Court in WELLINGTON INTERNATIONAL AIRPORT LTD & ORS v COMMERCE COMMISSION [128]. Specifically, the proposal is that where an incumbent supplier uses long-lived specialised assets to supply services, then its costs will be lower than those of a HNE, i.e. it created a high barrier to entry that would prevent competition from entering the market. In the Fibre IM review it argues that there are high entry barriers ("market is unprofitable"). Without competitive constraint on prices, the incumbent can therefore raise prices. However, the same objections to this proposition apply as it did to the reference case:

[127] Specifically, that there would be no-one willing to enter a market facing decline and that therefore there is no competitive constraint on pricing.
[128] [2013] NZHC 3289 [543]-[547]

a. the HNET is not an argument that relies on the threat of entry to constrain the behaviour of incumbents. Rather, it seeks to place a value on assets such that applying that value would result in outcomes consistent with those in workably competitive markets.

b. The point of the HNET **is to assume away** barriers to entry. Its rationale is to find a means of discovering the costs that would apply to a supplier if it were in a workably competitive market.

c. It seeks to place a value on assets that if applied would result in outcomes consistent with those in workably competitive markets. It assumes that a HNE would be purchasing new assets at their market costs when in the hypothetical framework the new entrants could purchase used assets, including from the incumbent. The price it would be prepared to pay in a workably competitive market would be the price of new assets (the replacement cost) less the additional costs of operating the old assets due to their shorter remaining lives, higher maintenance costs, less efficient configuration, and an expectation of earning ex-ante FCM based on the lower investment cost.

d. it assumes that the incumbent's costs are lower than those of a HNE which, as explained above, is not necessarily the case. (They would be lower than those of a potential new entrant who had to purchase new assets and who would, of course, therefore not enter.)

32. In other words, the proposition that firms in workably competitive markets can raise prices when there is a threat of economic stranding (market is unprofitable) is based on similar fallacies i.e. that they must enter under the same conditions as the incumbent did, when in fact there are many ways that firms can compete with the incumbent to prevent price increases.

More on FCM and incentives for supplier investments

34. MGUG as consumers consider that FCM as applied, has lost the essential qualification that it is only an ex-ante expectation, applied across a market of suppliers. No individual supplier in a market can rely on FCM. The Commission says that FCM is not a guarantee, or a regulatory compact. But the Paper's support for compensation for the maturing of stranding risk on sunk assets (which is a supplier risk in competitive markets) appears to treat it as a guarantee. If suppliers do not carry a normal risk for themselves, why should they be assured a normal return or more?

35. MGUG notes the Paper's references to the consequences referred to in paragraphs (a) and (b) of s 52A(1). They appear to assume that an intent to preserve or to strengthen incentives to invest and to improve efficiency and to deliver satisfactory quality is sufficient to justify negation of the primary purpose – that the outcomes be consistent with those of competitive markets. A normal and expected outcome is that prices reduce when demand reduces more than supply.

36. The Paper also appears to assume that an intention to incentivize investment also outweighs the loss of price discipline consequences in paragraphs (c) and (d) of that subsection. But the Paper does not quantify the costs to consumers of excess supplier profit, to measure against the assumed benefits of more investment. And it scarcely acknowledges that in circumstances of threatened stranding by edict, few of the normal responses to investment returns can be assumed.

37. MGUG members seek the efficiency of services at reduced prices reflecting recognition of actual or impending demand reduction. They seek the normal competitive market recognition of a likely reduction in need for replacement, upgraded and new assets. Realistically there may be a lower likelihood of innovation in an industry seen as heading for a premature sunset, other than innovation designed to reduce the imminence of stranding.

38. The Paper needs two layers of theory to assume net benefit – first that higher returns will incentivise more investment, and secondly that more investment will result in the benefits set out in paragraphs (a) and (b).

39. FCM seems to have metastasized in the IM and DPP regime. MGUG asks that:

a. The Commission now ensure that sustaining FCM expectations does not frustrate the law's requirement of regulatory simulation of competitive market outcomes, particularly for price[129];

b. The Commission define its distinction point between ex ante and ex post. That might help simplify the problem, or at least clarify differences in understanding the basis of reasoning;

c. The Commission note that;

i. MGUG members as consumers neither seek nor approve any subordination of our clearly expressed consumer interest in preventing exploitation of monopoly pricing power) to claimed necessity to maintain supplier's investment incentives in current circumstances;

ii. MGUG as consumers do not ask for the proposed incentives for supplier investment;

iii. We consider that normal pricing and revenue outcomes for suppliers, with the DPP regime contain effective sanctions against breaching prescribed reliability standards;

iv. We consider the weight given to incentivizing investment to be perverse in a potential stranding environment. If it becomes clearer that there will be early termination of service by edict, MGUG members expect suppliers to reduce investment. They expect them to look for alternative uses and to defer expenditure decisions to preserve option values. As consumers they are doing the same things, appraising the same reasons for potential stranding.

40. Even if it was valid to set up potential necessity for FCM supplementation to maintain investment incentives, neither the Paper nor any evidence we have found shows:

i. That the Commission's direct tools for incentivising adequate service capacity and quality are inadequate;

[129] See our discussion under S52A – paragraph 9 – price reflects all the outcomes under S52A

ii. Current or indicated future underinvestment;

iii. That the Commission has empirical confirmation that enhanced returns are an assurance of adequate investment and quality maintenance. As discussed later, AMPs may indicate to the contrary.

Normal price responses to declining demand

45. In workably competitive markets:

a. firms are price takers, not price makers, and the competitive dynamics achieve the outcomes described in S52A. We have seen nothing to establish why this outcome should not be the objective in gas delivery services. Absent regulation, monopoly suppliers have price-setting power. The law has determined they need price and quality regulation because there is little or no competition or no likelihood of a substantial increase in competition (s 52);

b. declining demand is almost invariably associated with price reductions, not increases. We have seen nothing to establish that the outcome should be different in gas delivery services;

c. prices reduce competitively as each supplier endeavours to procure that it retains an increasingly disproportionate share of the demand in an over-supplied market;

d. the circumstances that threaten stranding are promptly reflected as reductions in the market value of potentially stranded assets - in liquid public markets recognised as share price changes showing expectations of lower earnings or lost residual (exit) value;

e. suppliers with assets threatened with stranding can expect to earn their cost of capital on them going forward, but on the reduced asset value after recognition of the stranding risk;

f. hence, suppliers and those who invest in them, not their consumers, carry the cost of stranding risks.

g. consumers bear the cost of stranding risks only to the extent (if any) that it affects the industry cost of capital to suppliers, and it is an element of pricing. At some point in the progression toward stranding, pricing may cover only variable costs.

46. The current IM and DPPs negate all those outcomes through deliberate policy. It is purportedly to satisfy the s 52A requirements to promote outcomes that provide “incentives to innovate and to invest, including in replacement, upgraded and new assets” and to “improve efficiency and provide services at a quality that reflects consumer demand”.

47. Those are commonly consequences of workably competitive market pricing disciplines. The reversal of those consequences to pursue an over-riding FCM instead is an error. We see in the Paper numerous repetitions of the phrase “ex ante” with respect to FCM and to current or potential compensations for situations where the expected FCM is not delivered. But there is no definition or exploration of what distinguishes ‘ex ante’ from ‘ex post’

48. Proposals to continue making consumers carry the stranding risk, or to compensate suppliers if it is passes back to suppliers, subordinates the interests of consumers to achieve lower prices by restricting the supplier ability to "extract excessive profits", to supplier interests to achieve the opposite. (Consumer welfare is made paramount by the Act)

Our evidence on what is in consumer interests.

49. We as major consumers, can assure the Commission **that our main interest if stranding risks mature is in price reductions** and the end of abnormal profit-taking by suppliers:

a. They rank in our priorities far ahead of "improved efficiency".

b. The hoped-for quality of service effects of revenue assurance is overstated. We consider that the sanctions available to the Commission for quality failures, the legal liabilities of suppliers and their officers for safety breaches, and supplier brand reputation risks, are far more significant and reliable incentives;

c. We do not seek more incentives for suppliers facing stranding, to invest in "replacement, upgraded and new assets". The stranding risk is that the entire industry will be closed down prematurely. None of us want new investment past the point of rational spending to safely adhere to quality standards for the reasonably foreseeable future.

Consumers carrying the risk of stranding is inefficient

50. We as consumer businesses in competitive markets have no firm FCM assurance, collectively or individually, to protect us against stranding risks. If we are also made to carry those of suppliers, we have no means to mitigate them. Suppliers also lose the right incentives to mitigate and it creates moral hazard risk where suppliers overinvest knowing that any losses will be paid for by consumers. The Commission has some power. We have little or none. It is not an efficient allocation of the risk. The Paper's discussion in 3.98 to 3.101 recognises this.

Firm conduct in competitive markets - summary

126. Firms in workably competitive markets cannot raise prices to compensate for ex-ante or ex-post losses. The risk of ex-post losses are part and parcel of doing business and are not recoverable from consumers through higher prices. Instead, firms impair their assets to their market value rather than their carrying value. This adjustment leads to losses that are partially compensated through a lower tax expense, with the balance absorbed by the firm/ shareholders, not consumers. The adjusted carrying value of assets going forward is what resets the new ex-ante FCM expectation.

127. The belief that regulated firms are entitled to ex-ante FCM compensation for downside losses because their upside profitability is capped relative to non-regulated firms is based on a wrong premise. The definition of ex-ante normal profits (NPV=0) and the regulatory framework supporting it gives regulated firms the overall return equivalent of non-regulated firm's upside opportunities and downside risks. Further downside protection is not justified on either theoretical or empirical grounds.

128. Economic stranding risk is mitigated and managed through timing options, creation of strategic options on asset utilisation, and life extension of existing assets. These mitigation techniques have already been used by regulated suppliers. This approach benefits both suppliers and consumers and is consistent with what is seen in workably competitive markets.

129. In relation to gas delivery services, it may help to reframe the risk of declining demand as revenue risk. That may help keep in mind the realities of revenue composition, elasticities, and risk tolerance between different gas market segments. This is particularly pertinent given the possibilities for GPBs of Ramsey pricing.

130. The Paper does not exclude the possibility that GPBs could maintain or even raise revenue while volumes of gas transported decline. GPBs incentivised to maintain or increase investment could grow their total RAB. They can acquire assets with lives within the expected span to extinction of demand. That is, on its own, an intended outcome. But if other assets can remain within the RAB as they become obsolete, redundant or stranded, consumers face increasing costs without a relationship to services or the real costs of providing them. They may have no added quality (including reliability) of service.

131. It could be important to distinguish the revenues of individual GPBs, and distinguish between gas distribution (GDB) and gas transmission (GTB). Stranding or demand and revenue deductions will affect them differently. Revenues also need to be further segmented between the different consumer classes or load groups. Without it, conclusions on the overall GPB revenue risk may be superficial. Without carefully connecting 'compensations' to risks or costs actually being incurred or faced, compensations may go to businesses that are not suffering.

132. The perverse impact is worse because the transfer of what is and should remain supplier risk is funded by consumers facing similar or more severe risks of stranding. For example, consumers face carbon cost loadings intended to reduce the use of gas. They need to fund alternative energy technology. If they are fixed with compensating suppliers for their stranding risk, such consumers may carry the burden of artificial imposition on them of what should be GPB asset value write-offs on assets threatened with stranding, as well as losses on their own stranded assets.

133. We need to see modelling that tests the application of any proposed demand risk compensation against a range of scenarios. Most importantly we need to see modelling that assumes a wide range of times and rates of demand decline, and stranding.

134. The Paper's proposed compensation alternatives are offered conceptually. They should be offered with indicative examples, applying actual information drawn from ID, and assuming different future scenarios. They should expressly recognise the probabilistic nature (uncertainty) of different pathways. The future is uncertain. Modelling should set out to learn the sensitivity of intended outcomes of the proposed compensations, to various market conditions and the unexpected.

135. Those drawing conclusions even from disciplined modelling should remain very humble about their ability to foresee the future. That says there should be strong bias toward caution about premature action. Where-ever possible option values should be preserved.

136. For example, current demand expectations for EDBs are the opposite of the expectations prevailing just before and around the 2016 IM reset. At that time a strong consensus thought that distributed generation and other technology was going to reduce utilisation of the EDB networks. There were demands to enable precautionary recovery of losses expected when they were reduced to serving only the residual demand of major consumers not able to rely on the emerging technologies. Now of course EV and other new demands (ironically including through reduced gas demand should it come to pass) are projected to require major new EDB reticulation investment.

137. MGUG believes that price controls should strive to simulate the competitive market dynamics that inhibit front loading of expected costs onto current consumers, and minimize the shifting of risks for uncertain future events to current consumers. An ability for suppliers to shift their risks is characteristic of the monopoly markets described in s 52. The Commission is instead to simulate the competitive markets of s 52A. That simulation should result in suppliers writing off stranded assets as they would have to if they were not under the price control regime – in other words the regime should not enable suppliers to treat the regulated return on the RAB irrespective of practical stranding, as justification for avoiding an uncompensated write-off.

Commission objectivity on timing and severity of stranding impacts

138. The Commission should look at the *empirical evidence* on how firms behave in workably competitive markets, including their control over prices.

139. Professor Yarrow in reviewing claw back issues for Orion noted an expectation that prices should fall, not rise as demand falls[130]. Firms should *lower* their prices when demand falls. As long as the price exceeds the marginal short run cost, the firm will be maximising its revenue by doing this.

140. While it seems logical that prices should lower under this scenario, we also accept that they might remain the same, based on the price taker argument. What does seem self-evident and uncontroversial is that unilaterally raising prices *is not an option* in workably competitive markets.

141. MGUG has looked for evidence that the Paper writers have tested their implicit scenarios against observable behaviours. For example, what do ID reports and AMPs show as revealed preference or revealed 'skin in the game' beliefs about the likely timing and impact of anticipated demand reduction events? AMPs may be empirical evidence on suppliers' central beliefs about the likelihood and urgency of stranding.

142. What is the Commission using to weigh the credibility of current agency and political statements about future policy? Does the Commission consider the possibility of changes in New Zealand's Paris commitments, and corresponding changes in legislation? If not, why not, when participants in competitive markets, and the real incentives on investors cannot thrive

[130] Yarrow review of claw back issues Orion CPP 30 May 2013 – p13, para 3 https://comcom.govt.nz/__data/assets/pdf_file/0024/63186/1582851-Yarrow-Further-advice-on-clawback-4-August-2013.PDF

without such realism? MGUG is advised that the Commission is not prevented from considering such possibilities among the factors to be weighed in deciding how to act, and when.

143. A deep discount for time (sceptical weighting for realism) would seem to be justified, for some politically driven ‘commitments’ around the world, on climate change policies that will adversely affect consumers in democracies. MGUG is advised that the Paris commitments, unlike the Kyoto commitments before them, allow substantial ‘wiggle room’. Definitions vital to the effective dates and requirements of commitments were omitted. Parties faced with democratic political pressure are likely to use that wiggle room. And even countries that do not wish to slow down climate change measures, may be obliged to avoid destroying their economies because others have reneged. For example, countries could decide to measure performance on carbon implicit in consumption, not production, to recognise the burden on countries that export carbon intensive products.

144. Does the Commission know whether there is a mismatch between stated current intentions of agencies to compel reductions in gas use, and the actual expectations of consumers and suppliers? For example:

   a. Consumers are continuing to show confidence in the future of gas as evidenced by connection growth[131].

   b. Suppliers continue to forecast further connection growth in their 10-year Asset Management Plans (AMPs).

   c. Suppliers have adapted their asset management strategies. They continue to invest in replacement/ renewal to maintain safety and reliability of their networks. Asset management plans have shifted towards the greater use of timing options in their investment strategies. Asset management strategies have altered further to look for ways to extend asset lives and to use shorter design lives on replacement/ new assets (without affecting reliability/ safety standards).[132]

   d. Suppliers are investing in projects that give them strategic option to repurpose pipelines for transport of lower or zero carbon gases.

145. Prudent objectivity might suggest that such information need not affect the expected long-term outcomes, but it might drastically affect the speed of decline, or even its onset, and accordingly the imminence of stranding. Such prudent objectivity could support measures to reinforce or at least not to run contrary to incentives to maintain capacity.

Prematurity of compensations

146. Greater objectivity about the timing and degree of measures to reduce demand could highlight the risks and costs of prematurely loading a current generation of consumers with excess cost,

[131] A point we continue to demonstrate in our submissions, particularly to counter supplier assertions (they present without evidence) that consumers in aggregate are pulling back from investment in gas appliances.
[132] https://firstgas.co.nz/about-us/regulatory/ Stakeholder Webinar 2022 16 November - from time stamp 16:25 to 18:45. This is also repeated in the commentary of Powerco’s 2022 AMP (section 5.2).

and facilitating the extraction of excessive profits. MGUG wants evidence that the Commission fully appreciates the risk of unintended or premature consequences from interventions. The Commission is well placed to monitor consumer risk of reliability reduction, from changes in prescribed quality indicators. It may scrutinize supplier AMPs to assess whether pipeline integrity and reliability is being compromised through underinvestment.

Has accelerated depreciation assisted CAPEX commitments?

147. A useful check for the Commission's paper premises, is whether "additional incentives" for suppliers (accelerated depreciation) have caused suppliers to boost their CAPEX spending to support their quality measures for consumers. This check can be done by comparing GPBs CAPEX intentions pre, and post, the Commission's decision[133].

148. GPBs produce 10-year forward looking AMPs every year as part of the Information Disclosure regulation under Part 4 of the Commerce Act. The purpose of the information disclosure (S53) is to ensure that sufficient information is readily available to interested persons to assess whether the Part 4 purpose is being met. A GPB's AMP is a ten-year plan that sets out how the GPB intends to manage its assets. This includes:

    a. How it will meet its service and performance targets,
    b. The considerations behind its investment and operating decisions, and
    c. The way that it intends to manage risk.

[133] We have done this exercise by comparing CAPEX plans for the categories; *Asset Replacement and Renewal*, and *Reliability, Safety, and Environment* since these are the two categories the Commission was most concerned about in terms of asymmetric risks of underinvestment.

149. The AMP also contains:

  a. Details of network assets,
  b. Planned network developments,
  c. Future maintenance needs, and
  d. Forecast expenditures

150. While it is understood that in a dynamic environment there can be no assurances that GPBs will fully implement their plan or undertake the work mentioned in the document, it is equally accepted that the information in the document is prepared in good faith and represents GPBs' intentions and opinions at the date of issue. Given that AMPs are updated annually these provide useful frequently updated snapshots implicitly indicative of GPB risk perceptions.

151. The 2021 AMPs were produced before the Commission determined to allow for accelerated depreciation. Has the Commission compared them with those produced after that decision on accelerated depreciation[134] ? They could show an effect on risk perceptions and activities by the decision. The 2021 AMPs were prepared after the CCC's final advice which was generally seen as hostile to the role of gas in New Zealand's energy system, but before the CCC's ERPs that kept the door open for continued use of gas (including renewable gases) [135]. If such agency views are significant and regarded as compelling by suppliers, who have the strongest incentives to be informed and realistic the 2021 AMPs should reflect a higher risk perception by GPBs of gas demand decline (although not necessarily revenue decline) and a greater caution in CAPEX intentions.

152. If the Commission was correctly apprehending a potential for supplier under-investment because of demand risk, before the grant of accelerated depreciation, we should expect more that after it (other things being equal) we would see more supplier commitment to CAPEX in their new *10-year forward* plans.

153. The opposite occurred. Suppliers opted for *less* CAPEX in their Asset replacement and Renewal, and Reliability, Safety, Environment CAPEX categories[136] . Collectively, GPBs are intending to spend \$20 million less during RCP3, and \$37 million less over the period 2023-2031 (*Figure 29*).

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[134] See Schedule 11a: Report on Forecast Capital Expenditure

[135] The ERPs were notable for being more open to gas continuing to be part of New Zealand's energy mix. Gas connection bans were not announced and pathway for gas left open for MBIE and GIC to consult with industry on gas transition pathway. In other words, the risk perception for gas demand destruction should have altered to lower the risk of economic stranding.

[136] Workings showing the results available on request. The workings were done using Schedule 11a (report on forecast capital expenditure) in the AMPs and can be easily replicated. Note the exception for First Gas transmission across the 10-year period which showed no change.

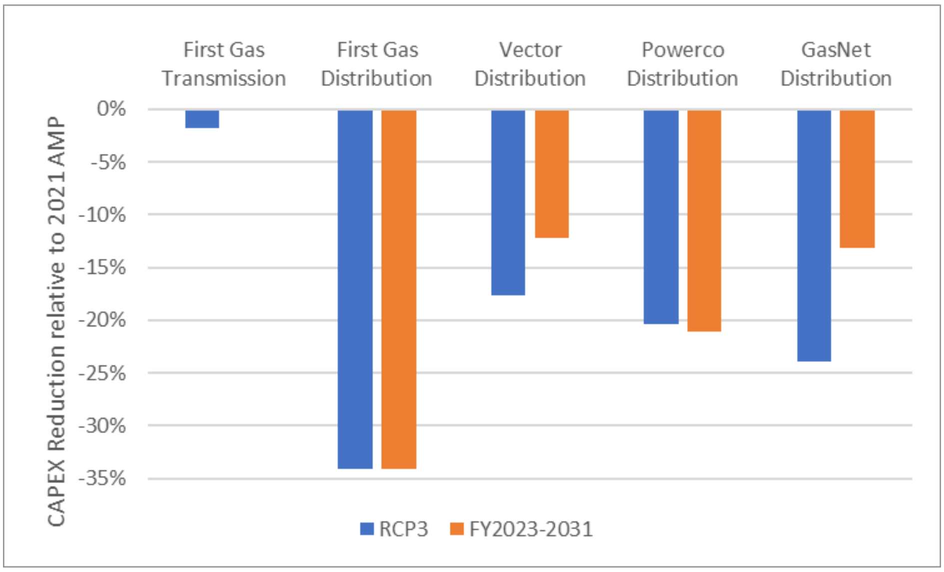

Figure 29: CAPEX difference 2022 AMP vs 2021 AMP (based on $2022) – source GPB AMPs

154. MGUG sees this as a matter requiring careful investigation from the Commission, and explanation. It could be that other things are not equal, that the official agency statements had less to do with supplier expectations than other information. If so, that should tell the Commission to be more wary in its own reliance on official and agency statements.

155. Ironically, as explained by Firstgas,[137] one contributing factor for lower investment has been the Commission imposing CAPEX constraints on GPBs through the DPP3 review. It seems peculiar that the Commission has justified increased prices to consumers to improve incentives to invest, while exercising supervisory discretions to restrict such investment. This demands more explanation.

   a. How does the Commission discern whether it is demand uncertainty, or regulatory capping of CAPEX that creates a risk of under-investment?

   b. Has any element of what the Commission fears will be likely under-investment been identified with confidence as a reliability or quality risk to consumers?

   c. How did the Commission exercises inject that risk to consumers of under-investment, into the exercise of its power in 2022 to consider and cap CAPEX?;

   d. Is there information that will show whether and when a Commission cap on CAPEX is undermining service quality?

156. These questions are not rhetorical. These are very serious. The Paper proposes a range of ways to impose on consumers the costs of higher returns to suppliers, justified solely by a claimed need to sustain incentives for new investment (given that the other claimed reason is FCM, but proposals that include historical RAB are for ex post compensation and are not part of ex ante

[137] https://firstgas.co.nz/about-us/regulatory/ Stakeholder Webinar 2022 16 November - from time stamp 14:00 to 16.22

FCM). We need to know whether the means used to decide on CAPEX constraints can also take into account the risks feared to flow from leaving suppliers to suffer only normal investment returns (that is without compensation for maturing stranding risk).

157. The reduction in CAPEX intentions shown in the latest AMPs seems to have been compensated with higher OPEX forecasts. $11.5 million more is being spent on Network Maintenance in RCP3, and $34.1 million more over the period 2023-2031 (*Figure 30* and *Figure 31*). This is consistent with Firstgas' explanation of looking at life extension of existing assets rather than replacement, as well as adopting shorter design lives of replacement assets[138]. It's behaviour we would also expect to see in workably competitive markets.

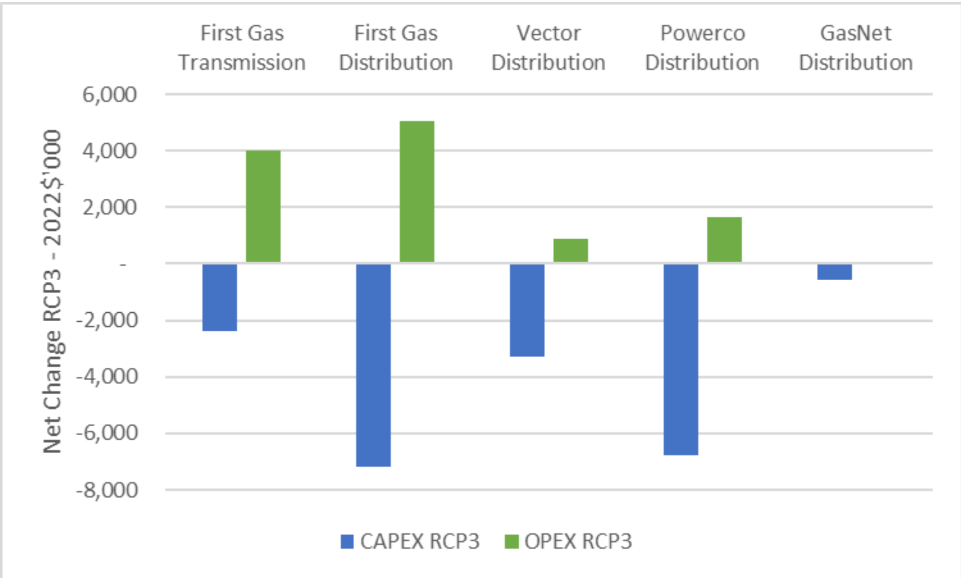

Figure 30: CAPEX and OPEX trade-offs RCP3 (based on $2022)- Source GPB AMPs

[138] From the previous footnote reference

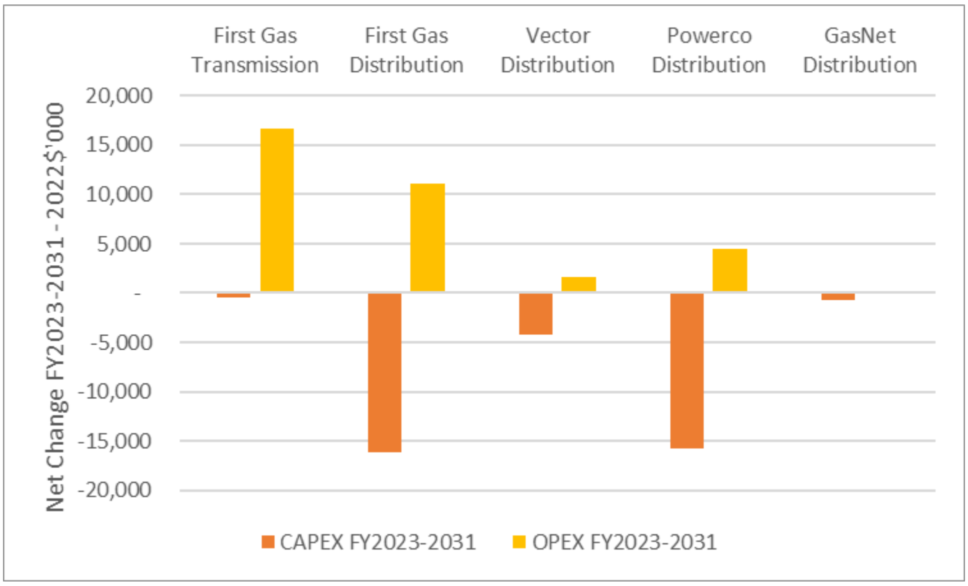

Figure 31: CAPEX and OPEX trade-offs FY2023-2031 (based on $2022) – Source GPB AMPs

158. The gas IM amendment gave GPBs an additional $156 million in revenue over RCP3 through accelerated depreciation[139]. This additional revenue seems intended to go to reducing GPB debt and/or to shareholder dividends[140], i.e. to increasing supplier profitability. We think that before the Commission proceeds with proposals for more 'compensation' to incentivise investment for the benefit of consumers, it should satisfy itself and show how last year's experiment in incentivising with higher returns, has produced benefits for consumers.

159. As major consumers we have seen no evidence to make benefit to consumers likely, or to show a necessity for the extra incentives to invest, whether or not it will benefit consumers. We oppose them and on the basis of the quality control elements of the DPP regime, accept the risk of the alleged adverse consequences for us.

160. In summary, after accelerated depreciation was assured:

    a. *Lower* CAPEX intentions have been signalled for asset replacement and renewal as well as for reliability, safety and environment. This might be because the Commission has capped allowable CAPEX. But it could be because GPBs are preferring and finding ways to extend asset life through alternative maintenance strategies that benefits both consumers and suppliers, that they have incentives to do without the accelerated depreciation.[141]

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[139] $156 million is the difference between the maximum allowable revenue for the periods 2023-2026 "with mitigation" and "no mitigation" financial models that the Commission produced in its DPP3 decision.
[140] For example, debt reduction is noted as a priority for Vector. https://www.nbr.co.nz/hunters-corner/vectors-deal-or-no-deal-moment/ notes "Also at the AGM, Vector chair Jonathan Mason made a clear link between a deal on metering and the company's need to reduce debt."
[141] For example, by investing in more condition monitoring.

b. AMPs seem to show GPBs remaining committed to meeting their quality standards, so consumers aren't experiencing reduced quality because of lower CAPEX intentions[142].

c. GPBs are using the additional cash from accelerated depreciation of sunk assets to improve their balance sheets and support their dividend policies [143].

161. In other words, the apparent effect of accelerated depreciation (as a supposed necessary incentive to asymmetric investment risk) has been to increase supplier profitability at the expense of consumers. This is a materially worse outcome for consumers with respect to S52A[144] (as well as S52R[145]).

162. The experience since the accelerated depreciation decision offers no support for more, or alternative mechanisms for "compensations".

Experience of stranding – empirical evidence

163. MGUG members experience stranding. They know empirically why firms are not free to raise prices ex-post to compensate for potential economic stranding risks in workably competitive markets. All our members operate in such markets (fertiliser, steel, milk products, pulp and paper).

164. For example, Ballance faced an economic stranding risk in the early 2000s as a result of potentially uneconomic gas supply. They could not recover economic losses through unilateral imposed price increases.

165. In 2002, 2003, and 2004 Ballance gradually wrote down the value of the Ammonia Urea Plant, at a time gas shortage and high gas price meant that domestic production of urea might not be economically viable. On the basis of economic life impairment, depreciation was accelerated in 2002, and impairments of $20 million were made in each of the 2003 and 2004 years[146].

> *Depreciation rates on the urea plant assets were increased in 2002 following reassessment of the life expectancy of the Maui gas field and the resulting effect on the residual value of the plant. In 2003 Maui gas field reserves were re-determined and the estimated field life shortened by a further two years to 2007. The Directors consider it prudent to recognise the uncertainty of future gas prices and supply and have made a $20 million impairment write down of the carrying value of the Kapuni ammonia urea facility buildings, plant and spares (refer Note 18). Gas market developments during the current year have increased the uncertainty of the Group's ability to secure gas at an acceptable price beyond the current contract period and a further $20 million impairment write down of the Kapuni plant carrying value has been made in 2004. The residual value is now conservatively aligned to the economic value based on contracted supply to May 2005*.

Notes to Financial Statements for the year ended 31 May 2004

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142 As evidenced by GPBs risk management strategies and statements in their AMPs
143 202207 MGUG-Cross Submission on 2023 IM review Framework and Process and Issues Paper – para 25-26
144 The Commission's modelling showed a transfer of $156 million for RCP3 from consumers to suppliers as a result of the decision to accelerate depreciation
145 The multiplier factor that can be altered by the Commission at each DPP reduces certainty for suppliers.
146 Reference Ballance Agri-nutrients annual reports.

The effect of the accelerated depreciation and impairment write downs reduced their surplus before tax and hence their tax expense. The reduced surplus (lower profits) **could not be recovered through the price of the product** since Ballance was a price taker in a competitive global market for the Urea product[147]. Shareholders, not consumers bore the consequence of the accelerated depreciation and asset stranding risk.

166. NZ Steel had $156 million of asset impairments in its FY2020 reflecting write-down of plant equipment[148]. This was reflected in the reduction of net profit in the annual statement (i.e. it created a loss relative to no impairment). The accounting adjustment did not create an ability for NZ steel to raise its prices to recover this loss[149]. It should be further noted, to address the Commission's assertion that "unprofitable markets" deter new entrants and that this is what allows firms to raise prices when impairing assets[150], that NZ steel did not face the threat of a new entrant entering the New Zealand market to build a competing facility.

167. This is the reality for all of our members. They face economic stranding risks on their coal or gas assets from government policy settings. The prices for urea, processed milk, steel and pulp and paper are set in competitive global markets. Impairing the value of domestic assets creates no opportunity to raise prices in the domestic or overseas markets. Rather the market price restriction is created by overseas firms using overseas assets to maintain price competition in the domestic market.

168. Domestic electricity generators face the same situation with respect to gas generation equipment facing shortened economic lives[151]. It is self-evident and uncontroversial that the competitive nature of the electricity market means that those generators cannot raise their prices to compensate for ex post FCM losses.

169. We are aware of no empirical support for assuming anything other than that the *tendency*[152] in strongly competitive markets is for firms ***not*** to be able to raise prices ex post as compensation for losses from an ex ante decision.

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[147] The loss gave some tax shelter.

[148] http://epublication.net.au/bluescope-ar-2020/ Total impairment write down was $197 million including $5M as a result of planned closure of the New Zealand Steel pipe mill, $36M write-down of spares and $156M impairment of the NZPI cash generating unit. In this case, as for economic stranding risk, the adjusted value of the assets was being marked to market, reflecting its expected economic value, regardless of the actual physical life of the assets.

[149] In essence it was lower prices for its products over the business cycle that created the impairment.

[150] Fibre input methodologies: Main final decisions – reasons paper 13 Oct 2020 – para 6-996

[151] Even if gas generation assets continue they are likely to face a significant reduction in demand for their use as more renewable generation comes on stream. These assets also face an ex-post FCM loss through declining demand.

[152] Input Methodologies (EDBs & GPBs) Reason Paper – 22 December 2010 para 2.6.17 notes that workable competitive markets doesn't require specific, precise outcomes, but rather can be described by tendencies.

170. Ex-post compensation for ex-ante decisions isn't consistent with the principle of ex-ante FCM. We refer the Commission to our earlier submission.[153]

How *do* firms react to risk of economic stranding?

171. In summary, the following is what we observe happens in workably competitive markets, and also what can be seen in regulated suppliers in New Zealand.[154] [155]:

    a. Existing assets are impaired or accelerated in depreciation. The capital losses generated are absorbed by the firms while the forward carrying value of assets reflect the new ex-ante FCM expectation.

    b. Firms look to extend asset lives by adapting maintenance philosophies, such as investing more in condition monitoring techniques or derating the equipment service (e.g., lowering the pressure that equipment runs at).

    c. Firms look to create new opportunities (options) for revenue from use of existing assets (repurposing)

    d. For new assets, forward CAPEX and OPEX are selected to give an expectation of ex-ante FCM. CAPEX may be deferred, or reduced (cheaper options looked for and/or with shorter physical lives)[156].

    e. Prices are determined by workably competitive market forces (including substitutes) Firms are price takers, not price makers. Prices stay the same or reduce.

BBM and treatment of depreciation

172. As noted in the EDB-GPB Input Methodologies Reasons paper, the ex-ante FCM/ NPV=0 principle for monopoly businesses is a principle to put a constraint or limit on the restrictions that implement Part 4 S52A (1)(d) (*are limited in their ability to extract excessive profits*)[157].

    > *The* ***main reason*** *economic regulation is required is to counter the market power of firms (i.e. the ability of firms that are not faced with competition or the threat of competition* ***to charge excessive prices and/or reduce quality)***

    This rephrases the 2013 High Court decision that "*Prices are, therefore, at the heart of Part 4 regulation*" when considering what workable competition outcomes meant[158]. In other words

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[153] 202207 MGUG- Submission on 2023 IM review Framework and Process and Issues papers-final, notably pp 10-11

[154] A number of the following strategies is what we see in supplier AMPs.

[155] It's also important to relate outcomes to the NZ statutory framework. Looking at outcomes in other jurisdictions is only useful if the underlying legislation provides for the same outcomes. For example, we've already pointed out that the Gas Law in Australia requires that the AER provide for an ex-ante FCM compensation mechanism. Part 4 and the various legal decisions create a different context and outcome for NZ regulated suppliers. That limits the usefulness of what can be borrowed from other regulators.

[156] While this may not seem efficient on an ex-post basis, it is an efficient outcome on an ex-ante basis, since it creates an option that the asset won't be replaced

[157] Commerce Commission, December 2010 EDB_GPB Input Methodologies Reasons paper – para 2.6.32

[158] [2013] NZHC 3289 [11 December 2013] – para [29]

when we look at competitive market outcomes, we should look at what their price outcomes are[159].

173. The BBM methodology is what determines the allowable revenue (and hence price to consumers) for regulated firms. It is designed to control prices such that firms are limited in their ability to extract excessive profits. Ex-ante depreciation expense (return of capital) is one component that determines allowable revenue, and provides for the ex-ante return of capital, as well as the return on capital allowed for in the cost of capital to ensure that NPV=0.

174. Depreciation rates are set ex ante. The BBM methodology recognises the significance of ex post (subsequent) changes in depreciation assumptions and methods. **Economic stranding risk maturing is an exception**. It is not provided for in the BBM, which assumes standard physical asset lives will be economically recovered (that economic life matches the physical life).

175. The BBM needs to reflect the loss when an economic life is materially shortened relative to physical asset life in the FCM assumption. That is, to produce outcomes consistent with the tendencies of workably competitive markets. That will mean prices to consumers to lower when they should. Instead, the current and most of the proposed 'compensations' have prices rising when they should lower for competitive market consistency.

176. Any implied (but denied) regulatory bargain to the contrary is invalid, and wrongly purposed in what should be a model to simulate the outcomes and incentives of competitive markets.

177. To summarise from our examples, a business in a competitive environment will adjust the asset depreciation schedule based on the expected economic life (market value) of its assets. Where an asset is deemed to have a shortened economic life, the asset might be depreciated more rapidly or even impaired/written off. It reduces immediate profitability, but it also reduces the remaining book value of the asset. That is likely to parallel a market recognition of the loss and accordingly reduce the capital on which the return is required. The required return on capital going forward does not need to be reset to maintain the ex-ante FCM expectation. The cost of accelerated depreciation is borne by shareholders, not consumers. Contrary to the Commission's mechanics of the BBM for regulated firms, accelerated depreciation does not enable firms in workably competitive markets to raise prices.

Conclusions

178. This part of the submission dealt with the Commission's underlying assumptions framing the paper. Our conclusions from examining the underlying premises are:
    a. We negate the asymmetry argument that has been the justification for offering more than ex ante compensation to sustain FCM when in a competitive market there is no such assurance:

[159] It is implied that competitive prices also achieve other consumer outcomes (innovation, investment in maintaining quality, efficiencies, and prevent excessive profits)

i. Regulated firms are capped at a normal return defined by what happens in workably competitive markets. The restriction on regulated firms' upside is only on their ability to earn economic rents. This is a feature, not a bug of S52A and the provision offers no special favours or disadvantages to suppliers.

ii. Regulated firms should face the same downside loss potential as firms in workably competitive markets- if they are to earn a return regulated by reference to firms in competitive markets.

iii. Raising prices to increase the return on sunk assets is not expected in workably competitive markets when faced with economic stranding risk. Instead, the expected outcome is a tendency to lower prices to consumers as the stranding circumstances reduce demand, to postpone greater revenue loss

b. The BBM needs adjusting to require write offs from the RAB as stranding risk is recognised. This is to simulate price outcomes and incentives on suppliers with what happens and applies in workably competitive markets.

c. A hypothesis seems to infuse the Paper that suppliers are underinvesting in maintaining network services or will, and that they will need more revenue than the regime currently permits, as an incentive to end or avoid that under-investment. The Paper offers no empirical evidence in support. Nor does the Paper suggest that such evidence will be sought. That needs to be remedied

i. It appears that the additional revenue from accelerating depreciation through the gas IM amendment is going to benefit supplier equity holders (reduce debt or pay dividends).

ii. Use of accelerated depreciation revenue to reduce underinvestment is not demonstrated in supplier 10-year asset management plans. The opposite is shown. Investment intentions have lowered in the 2022 AMPs despite additional information suggesting a lower risk concern.

iii. As we would also expect to see in workably competitive markets, supplier AMPs are demonstrating accepted strategies for mitigating investment term risks without sacrificing quality:

(i) They are investing in creating timing options (using shorter physical asset lives in asset selection).

(ii) They are extending asset lives using condition monitoring to set new replacement schedules.

(iii) They are increasing their asset OPEX to maintain reliability and asset integrity.

(iv) They are investing in creating strategic options for asset repurposing.

(v) They derate equipment to extend asset lives and lower OPEX.

iv. Consumers are materially worse off when supplementary “ex-ante” FCM compensation is given to suppliers, without establishing any reliability or other benefit to consumers.

Firm conduct in competitive markets - summary

179. Firms in workably competitive markets cannot raise prices to compensate for ex-ante or ex-post losses. The risk of ex-post losses are part and parcel of doing business and are not recoverable from consumers through higher prices. Instead, firms impair their assets to their market value rather than their carrying value. This adjustment leads to losses that are partially compensated through a lower tax expense, with the balance absorbed by the firm/ shareholders, not consumers. The adjusted carrying value of assets going forward is what resets the new ex-ante FCM expectation.

180. The belief that regulated firms are entitled to ex-ante FCM compensation for downside losses because their upside profitability is capped relative to non-regulated firms is based on a wrong premise. The definition of ex-ante normal profits (NPV=0) and the regulatory framework supporting it gives regulated firms the overall return equivalent of non-regulated firm’s upside opportunities and downside risks. Further downside protection is not justified on either theoretical or empirical grounds.

181. Economic stranding risk is mitigated and managed through timing options, creation of strategic options on asset utilisation, and life extension of existing assets. These mitigation techniques have already been used by regulated suppliers. This approach benefits both suppliers and consumers and is consistent with what is seen in workably competitive markets.

182. In relation to gas delivery services, it may help to reframe the risk of declining demand as revenue risk. That may help keep in mind the realities of revenue composition, elasticities, and risk tolerance between different gas market segments. This is particularly pertinent given the possibilities for GPBs of Ramsey pricing.

183. The Paper does not exclude the possibility that GPBs could maintain or even raise revenue while volumes of gas transported decline. GPBs incentivised to maintain or increase investment could grow their total RAB. They can acquire assets with lives within the expected span to extinction of demand. That is, on its own, an intended outcome. But if other assets can remain within the RAB as they become obsolete, redundant or stranded, consumers face increasing costs without a relationship to services or the real costs of providing them. They may have no added quality (including reliability) of service.

184. It could be important to distinguish the revenues of individual GPBs, and distinguish between gas distribution (GDB) and gas transmission (GTB). Stranding or demand and revenue deductions will affect them differently. Revenues also need to be further segmented between the different consumer classes or load groups. Without it, conclusions on the overall GPB revenue risk may be superficial. Without carefully connecting ‘compensations’ to risks or costs actually being incurred or faced, compensations may go to businesses that are not suffering.

185. The perverse impact is worse because the transfer of what is and should remain supplier risk is funded by consumers facing similar or more severe risks of stranding. For example, consumers

face carbon cost loadings intended to reduce the use of gas. They need to fund alternative energy technology. If they are fixed with compensating suppliers for their stranding risk, such consumers may carry the burden of artificial imposition on them of what should be GPB asset value write-offs on assets threatened with stranding, as well as losses on their own stranded assets.

186. We need to see modelling that tests the application of any proposed demand risk compensation against a range of scenarios. Most importantly we need to see modelling that assumes a wide range of times and rates of demand decline, and stranding.

187. The Paper's proposed compensation alternatives are offered conceptually. They should be offered with indicative examples, applying actual information drawn from ID, and assuming different future scenarios. They should expressly recognise the probabilistic nature (uncertainty) of different pathways. The future is uncertain. Modelling should set out to learn the sensitivity of intended outcomes of the proposed compensations, to various market conditions and the unexpected.

188. Those drawing conclusions even from disciplined modelling should remain very humble about their ability to foresee the future. That says there should be strong bias toward caution about premature action. Where-ever possible option values should be preserved.

189. For example, current demand expectations for EDBs are the opposite of the expectations prevailing just before and around the 2016 IM reset. At that time a strong consensus thought that distributed generation and other technology was going to reduce utilisation of the EDB networks. There were demands to enable precautionary recovery of losses expected when they were reduced to serving only the residual demand of major consumers not able to rely on the emerging technologies. Now of course EV and other new demands (ironically including through reduced gas demand should it come to pass) are projected to require major new EDB reticulation investment.

190. MGUG believes that price controls should strive to simulate the competitive market dynamics that inhibit front loading of expected costs onto current consumers, and minimize the shifting of risks for uncertain future events to current consumers. An ability for suppliers to shift their risks is characteristic of the monopoly markets described in s 52. The Commission is instead to simulate the competitive markets of s 52A. That simulation should result in suppliers writing off stranded assets as they would have to if they were not under the price control regime – in other words the regime should not enable suppliers to treat the regulated return on the RAB irrespective of practical stranding, as justification for avoiding an uncompensated write-off.

Commission objectivity on timing and severity of stranding impacts

191. The Commission should look at the *empirical evidence* on how firms behave in workably competitive markets, including their control over prices.

192. Professor Yarrow in reviewing claw back issues for Orion noted an expectation that prices should fall, not rise as demand falls[160]. Firms should *lower* their prices when demand falls. As long as the price exceeds the marginal short run cost, the firm will be maximising its revenue by doing this.

193. While it seems logical that prices should lower under this scenario, we also accept that they might remain the same, based on the price taker argument. What does seem self-evident and uncontroversial is that unilaterally raising prices *is not an option* in workably competitive markets.

194. MGUG has looked for evidence that the Paper writers have tested their implicit scenarios against observable behaviours. For example, what do ID reports and AMPs show as revealed preference or revealed 'skin in the game' beliefs about the likely timing and impact of anticipated demand reduction events? AMPs may be empirical evidence on suppliers' central beliefs about the likelihood and urgency of stranding.

195. What is the Commission using to weigh the credibility of current agency and political statements about future policy? Does the Commission consider the possibility of changes in New Zealand's Paris commitments, and corresponding changes in legislation? If not, why not, when participants in competitive markets, and the real incentives on investors cannot thrive without such realism? MGUG is advised that the Commission is not prevented from considering such possibilities among the factors to be weighed in deciding how to act, and when.

196. A deep discount for time (sceptical weighting for realism) would seem to be justified, for some politically driven 'commitments' around the world, on climate change policies that will adversely affect consumers in democracies. MGUG is advised that the Paris commitments, unlike the Kyoto commitments before them, allow substantial 'wiggle room'. Definitions vital to the effective dates and requirements of commitments were omitted. Parties faced with democratic political pressure are likely to use that wiggle room. And even countries that do not wish to slow down climate change measures, may be obliged to avoid destroying their economies because others have reneged. For example, countries could decide to measure performance on carbon implicit in consumption, not production, to recognise the burden on countries that export carbon intensive products.

197. Does the Commission know whether there is a mismatch between stated current intentions of agencies to compel reductions in gas use, and the actual expectations of consumers and suppliers? For example:

    a. Consumers are continuing to show confidence in the future of gas as evidenced by connection growth[161].

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[160] Yarrow review of claw back issues Orion CPP 30 May 2013 – p13, para 3 https://comcom.govt.nz/__data/assets/pdf_file/0024/63186/1582851-Yarrow-Further-advice-on-clawback-4-August-2013.PDF

[161] A point we continue to demonstrate in our submissions, particularly to counter supplier assertions (they present without evidence) that consumers in aggregate are pulling back from investment in gas appliances.

b. Suppliers continue to forecast further connection growth in their 10-year Asset Management Plans (AMPs).

c. Suppliers have adapted their asset management strategies. They continue to invest in replacement/ renewal to maintain safety and reliability of their networks. Asset management plans have shifted towards the greater use of timing options in their investment strategies. Asset management strategies have altered further to look for ways to extend asset lives and to use shorter design lives on replacement/ new assets (without affecting reliability/ safety standards).[162]

d. Suppliers are investing in projects that give them strategic option to repurpose pipelines for transport of lower or zero carbon gases.

198. Prudent objectivity might suggest that such information need not affect the expected long-term outcomes, but it might drastically affect the speed of decline, or even its onset, and accordingly the imminence of stranding. Such prudent objectivity could support measures to reinforce or at least not to run contrary to incentives to maintain capacity.

Prematurity of compensations

199. Greater objectivity about the timing and degree of measures to reduce demand could highlight the risks and costs of prematurely loading a current generation of consumers with excess cost, and facilitating the extraction of excessive profits. MGUG wants evidence that the Commission fully appreciates the risk of unintended or premature consequences from interventions. The Commission is well placed to monitor consumer risk of reliability reduction, from changes in prescribed quality indicators. It may scrutinize supplier AMPs to assess whether pipeline integrity and reliability is being compromised through underinvestment.

Has accelerated depreciation assisted CAPEX commitments?

200. A useful check for the Commission's paper premises, is whether "additional incentives" for suppliers (accelerated depreciation) have caused suppliers to boost their CAPEX spending to support their quality measures for consumers. This check can be done by comparing GPBs CAPEX intentions pre, and post, the Commission's decision[163].

201. GPBs produce 10-year forward looking AMPs every year as part of the Information Disclosure regulation under Part 4 of the Commerce Act. The purpose of the information disclosure (S53) is to ensure that sufficient information is readily available to interested persons to assess whether the Part 4 purpose is being met. A GPB's AMP is a ten-year plan that sets out how the GPB intends to manage its assets. This includes:

[162] https://firstgas.co.nz/about-us/regulatory/ Stakeholder Webinar 2022 16 November - from time stamp 16:25 to 18:45. This is also repeated in the commentary of Powerco's 2022 AMP (section 5.2).
[163] We have done this exercise by comparing CAPEX plans for the categories; *Asset Replacement and Renewal*, and *Reliability, Safety, and Environment* since these are the two categories the Commission was most concerned about in terms of asymmetric risks of underinvestment.

a. How it will meet its service and performance targets,
b. The considerations behind its investment and operating decisions, and
c. The way that it intends to manage risk.

202. The AMP also contains:

   a. Details of network assets,
   b. Planned network developments,
   c. Future maintenance needs, and
   d. Forecast expenditures

203. While it is understood that in a dynamic environment there can be no assurances that GPBs will fully implement their plan or undertake the work mentioned in the document, it is equally accepted that the information in the document is prepared in good faith and represents GPBs' intentions and opinions at the date of issue. Given that AMPs are updated annually these provide useful frequently updated snapshots implicitly indicative of GPB risk perceptions.

204. The 2021 AMPs were produced before the Commission determined to allow for accelerated depreciation. Has the Commission compared them with those produced after that decision on accelerated depreciation[164] ? They could show an effect on risk perceptions and activities by the decision. The 2021 AMPs were prepared after the CCC's final advice which was generally seen as hostile to the role of gas in New Zealand's energy system, but before the CCC's ERPs that kept the door open for continued use of gas (including renewable gases) [165]. If such agency views are significant and regarded as compelling by suppliers, who have the strongest incentives to be informed and realistic the 2021 AMPs should reflect a higher risk perception by GPBs of gas demand decline (although not necessarily revenue decline) and a greater caution in CAPEX intentions.

205. If the Commission was correctly apprehending a potential for supplier under-investment because of demand risk, before the grant of accelerated depreciation, we should expect more that after it (other things being equal) we would see more supplier commitment to CAPEX in their new *10-year forward* plans.

206. The opposite occurred. Suppliers opted for *less* CAPEX in their Asset replacement and Renewal, and Reliability, Safety, Environment CAPEX categories[166] . Collectively, GPBs are intending to spend $20 million less during RCP3, and $37 million less over the period 2023-2031 (*Figure 29*).

[164] See Schedule 11a: Report on Forecast Capital Expenditure
[165] The ERPs were notable for being more open to gas continuing to be part of New Zealand's energy mix. Gas connection bans were not announced and pathway for gas left open for MBIE and GIC to consult with industry on gas transition pathway. In other words, the risk perception for gas demand destruction should have altered to lower the risk of economic stranding.
[166] Workings showing the results available on request. The workings were done using Schedule 11a (report on forecast capital expenditure) in the AMPs and can be easily replicated. Note the exception for First Gas transmission across the 10-year period which showed no change.

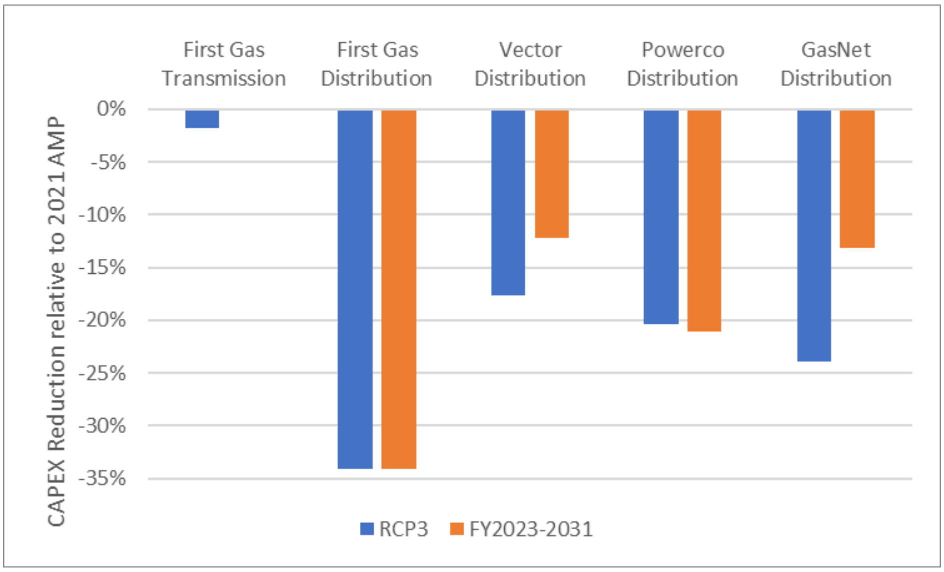

Figure 32: CAPEX difference 2022 AMP vs 2021 AMP (based on $2022) – source GPB AMPs

207. MGUG sees this as a matter requiring careful investigation from the Commission, and explanation. It could be that other things are not equal, that the official agency statements had less to do with supplier expectations than other information. If so, that should tell the Commission to be more wary in its own reliance on official and agency statements.

208. Ironically, as explained by Firstgas,[167] one contributing factor for lower investment has been the Commission imposing CAPEX constraints on GPBs through the DPP3 review. It seems peculiar that the Commission has justified increased prices to consumers to improve incentives to invest, while exercising supervisory discretions to restrict such investment. This demands more explanation.

    a. How does the Commission discern whether it is demand uncertainty, or regulatory capping of CAPEX that creates a risk of under-investment?

    b. Has any element of what the Commission fears will be likely under-investment been identified with confidence as a reliability or quality risk to consumers?

    c. How did the Commission exercises inject that risk to consumers of under-investment, into the exercise of its power in 2022 to consider and cap CAPEX?;

    d. Is there information that will show whether and when a Commission cap on CAPEX is undermining service quality?

209. These questions are not rhetorical. These are very serious. The Paper proposes a range of ways to impose on consumers the costs of higher returns to suppliers, justified solely by a claimed need to sustain incentives for new investment (given that the other claimed reason is FCM, but proposals that include historical RAB are for ex post compensation and are not part of ex ante

[167] https://firstgas.co.nz/about-us/regulatory/ Stakeholder Webinar 2022 16 November - from time stamp 14:00 to 16.22

FCM). We need to know whether the means used to decide on CAPEX constraints can also take into account the risks feared to flow from leaving suppliers to suffer only normal investment returns (that is without compensation for maturing stranding risk).

210. The reduction in CAPEX intentions shown in the latest AMPs seems to have been compensated with higher OPEX forecasts. $11.5 million more is being spent on Network Maintenance in RCP3, and $34.1 million more over the period 2023-2031 (*Figure 30* and *Figure 31*). This is consistent with Firstgas' explanation of looking at life extension of existing assets rather than replacement, as well as adopting shorter design lives of replacement assets[168]. It's behaviour we would also expect to see in workably competitive markets.

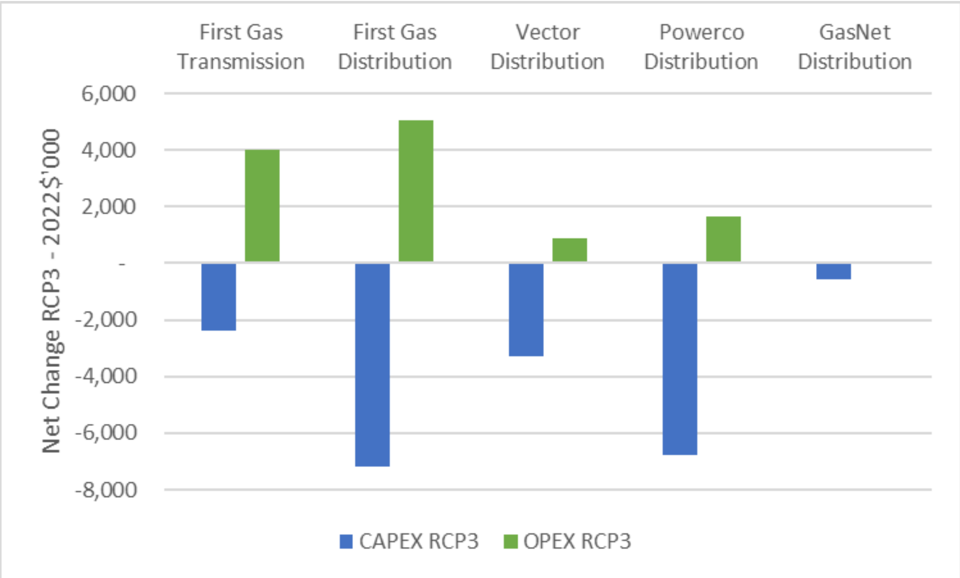

Figure 33: CAPEX and OPEX trade-offs RCP3 (based on $2022)- Source GPB AMPs

168 From the previous footnote reference

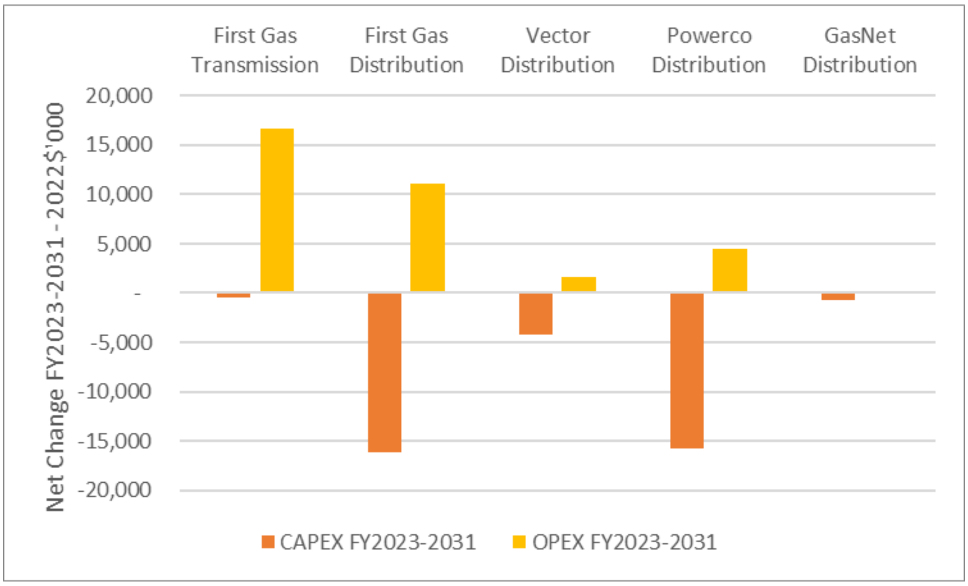

Figure 34: CAPEX and OPEX trade-offs FY2023-2031 (based on $2022) – Source GPB AMPs

211. The gas IM amendment gave GPBs an additional $156 million in revenue over RCP3 through accelerated depreciation[169]. This additional revenue seems intended to go to reducing GPB debt and/or to shareholder dividends[170], i.e. to increasing supplier profitability. We think that before the Commission proceeds with proposals for more 'compensation' to incentivise investment for the benefit of consumers, it should satisfy itself and show how last year's experiment in incentivising with higher returns, has produced benefits for consumers.

212. As major consumers we have seen no evidence to make benefit to consumers likely, or to show a necessity for the extra incentives to invest, whether or not it will benefit consumers. We oppose them and on the basis of the quality control elements of the DPP regime, accept the risk of the alleged adverse consequences for us.

213. In summary, after accelerated depreciation was assured:

    a. *Lower* CAPEX intentions have been signalled for asset replacement and renewal as well as for reliability, safety and environment. This might be because the Commission has capped allowable CAPEX. But it could be because GPBs are preferring and finding ways to extend asset life through alternative maintenance strategies that benefits both consumers and suppliers, that they have incentives to do without the accelerated depreciation.[171]

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[169] $156 million is the difference between the maximum allowable revenue for the periods 2023-2026 "with mitigation" and "no mitigation" financial models that the Commission produced in its DPP3 decision.
[170] For example, debt reduction is noted as a priority for Vector. https://www.nbr.co.nz/hunters-corner/vectors-deal-or-no-deal-moment/ notes "Also at the AGM, Vector chair Jonathan Mason made a clear link between a deal on metering and the company's need to reduce debt."
[171] For example, by investing in more condition monitoring.

b. AMPs seem to show GPBs remaining committed to meeting their quality standards, so consumers aren't experiencing reduced quality because of lower CAPEX intentions[172].

c. GPBs are using the additional cash from accelerated depreciation of sunk assets to improve their balance sheets and support their dividend policies [173].

214. In other words, the apparent effect of accelerated depreciation (as a supposed necessary incentive to asymmetric investment risk) has been to increase supplier profitability at the expense of consumers. This is a materially worse outcome for consumers with respect to S52A[174] (as well as S52R[175]).

215. The experience since the accelerated depreciation decision offers no support for more, or alternative mechanisms for "compensations".

Experience of stranding – empirical evidence

216. MGUG members experience stranding. They know empirically why firms are not free to raise prices ex-post to compensate for potential economic stranding risks in workably competitive markets. All our members operate in such markets (fertiliser, steel, milk products, pulp and paper).

217. For example, Ballance faced an economic stranding risk in the early 2000s as a result of potentially uneconomic gas supply. They could not recover economic losses through unilateral imposed price increases.

218. In 2002, 2003, and 2004 Ballance gradually wrote down the value of the Ammonia Urea Plant, at a time gas shortage and high gas price meant that domestic production of urea might not be economically viable. On the basis of economic life impairment, depreciation was accelerated in 2002, and impairments of $20 million were made in each of the 2003 and 2004 years[176].

> *Depreciation rates on the urea plant assets were increased in 2002 following reassessment of the life expectancy of the Maui gas field and the resulting effect on the residual value of the plant. In 2003 Maui gas field reserves were re-determined and the estimated field life shortened by a further two years to 2007. The Directors consider it prudent to recognise the uncertainty of future gas prices and supply and have made a $20 million impairment write down of the carrying value of the Kapuni ammonia urea facility buildings, plant and spares (refer Note 18). Gas market developments during the current year have increased the uncertainty of the Group's ability to secure gas at an acceptable price beyond the current contract period and a further $20 million impairment write down of the Kapuni plant carrying value has been made in 2004. The residual value is now conservatively aligned to the economic value based on contracted supply to May 2005*.

Notes to Financial Statements for the year ended 31 May 2004

[172] As evidenced by GPBs risk management strategies and statements in their AMPs
[173] 202207 MGUG-Cross Submission on 2023 IM review Framework and Process and Issues Paper – para 25-26
[174] The Commission's modelling showed a transfer of $156 million for RCP3 from consumers to suppliers as a result of the decision to accelerate depreciation
[175] The multiplier factor that can be altered by the Commission at each DPP reduces certainty for suppliers.
[176] Reference Ballance Agri-nutrients annual reports.

The effect of the accelerated depreciation and impairment write downs reduced their surplus before tax and hence their tax expense. The reduced surplus (lower profits) **could not be recovered through the price of the product** since Ballance was a price taker in a competitive global market for the Urea product[177]. Shareholders, not consumers bore the consequence of the accelerated depreciation and asset stranding risk.

219. NZ Steel had $156 million of asset impairments in its FY2020 reflecting write-down of plant equipment[178]. This was reflected in the reduction of net profit in the annual statement (i.e. it created a loss relative to no impairment). The accounting adjustment did not create an ability for NZ steel to raise its prices to recover this loss[179]. It should be further noted, to address the Commission's assertion that "unprofitable markets" deter new entrants and that this is what allows firms to raise prices when impairing assets[180], that NZ steel did not face the threat of a new entrant entering the New Zealand market to build a competing facility.

220. This is the reality for all of our members. They face economic stranding risks on their coal or gas assets from government policy settings. The prices for urea, processed milk, steel and pulp and paper are set in competitive global markets. Impairing the value of domestic assets creates no opportunity to raise prices in the domestic or overseas markets. Rather the market price restriction is created by overseas firms using overseas assets to maintain price competition in the domestic market.

221. Domestic electricity generators face the same situation with respect to gas generation equipment facing shortened economic lives[181]. It is self-evident and uncontroversial that the competitive nature of the electricity market means that those generators cannot raise their prices to compensate for ex post FCM losses.

222. We are aware of no empirical support for assuming anything other than that the *tendency*[182] in strongly competitive markets is for firms ***not*** to be able to raise prices ex post as compensation for losses from an ex ante decision.

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177 The loss gave some tax shelter.

178 http://epublication.net.au/bluescope-ar-2020/ Total impairment write down was $197 million including $5M as a result of planned closure of the New Zealand Steel pipe mill, $36M write-down of spares and $156M impairment of the NZPI cash generating unit. In this case, as for economic stranding risk, the adjusted value of the assets was being marked to market, reflecting its expected economic value, regardless of the actual physical life of the assets.

179 In essence it was lower prices for its products over the business cycle that created the impairment.

180 Fibre input methodologies: Main final decisions – reasons paper 13 Oct 2020 – para 6-996

181 Even if gas generation assets continue they are likely to face a significant reduction in demand for their use as more renewable generation comes on stream. These assets also face an ex-post FCM loss through declining demand.

182 Input Methodologies (EDBs & GPBs) Reason Paper – 22 December 2010 para 2.6.17 notes that workable competitive markets doesn't require specific, precise outcomes, but rather can be described by tendencies.

223. Ex-post compensation for ex-ante decisions isn't consistent with the principle of ex-ante FCM. We refer the Commission to our earlier submission.[183]

How *do* firms react to risk of economic stranding?

224. In summary, the following is what we observe happens in workably competitive markets, and also what can be seen in regulated suppliers in New Zealand.[184] [185]:

  a. Existing assets are impaired or accelerated in depreciation. The capital losses generated are absorbed by the firms while the forward carrying value of assets reflect the new ex-ante FCM expectation.

  b. Firms look to extend asset lives by adapting maintenance philosophies, such as investing more in condition monitoring techniques or derating the equipment service (e.g., lowering the pressure that equipment runs at).

  c. Firms look to create new opportunities (options) for revenue from use of existing assets (repurposing)

  d. For new assets, forward CAPEX and OPEX are selected to give an expectation of ex-ante FCM. CAPEX may be deferred, or reduced (cheaper options looked for and/or with shorter physical lives)[186].

  e. Prices are determined by workably competitive market forces (including substitutes) Firms are price takers, not price makers. Prices stay the same or reduce.

BBM and treatment of depreciation

225. As noted in the EDB-GPB Input Methodologies Reasons paper, the ex-ante FCM/ NPV=0 principle for monopoly businesses is a principle to put a constraint or limit on the restrictions that implement Part 4 S52A (1)(d) (*are limited in their ability to extract excessive profits*)[187].

> *The **main reason** economic regulation is required is to counter the market power of firms (i.e. the ability of firms that are not faced with competition or the threat of competition **to charge excessive prices and/or reduce quality)***

This rephrases the 2013 High Court decision that "*Prices are, therefore, at the heart of Part 4 regulation*" when considering what workable competition outcomes meant[188]. In other words

[183] 202207 MGUG- Submission on 2023 IM review Framework and Process and Issues papers-final, notably pp 10-11
[184] A number of the following strategies is what we see in supplier AMPs.
[185] It's also important to relate outcomes to the NZ statutory framework. Looking at outcomes in other jurisdictions is only useful if the underlying legislation provides for the same outcomes. For example, we've already pointed out that the Gas Law in Australia requires that the AER provide for an ex-ante FCM compensation mechanism. Part 4 and the various legal decisions create a different context and outcome for NZ regulated suppliers. That limits the usefulness of what can be borrowed from other regulators.
[186] While this may not seem efficient on an ex-post basis, it is an efficient outcome on an ex-ante basis, since it creates an option that the asset won't be replaced
[187] Commerce Commission, December 2010 EDB_GPB Input Methodologies Reasons paper – para 2.6.32
[188] [2013] NZHC 3289 [11 December 2013] – para [29]

when we look at competitive market outcomes, we should look at what their price outcomes are[189].

226. The BBM methodology is what determines the allowable revenue (and hence price to consumers) for regulated firms. It is designed to control prices such that firms are limited in their ability to extract excessive profits. Ex-ante depreciation expense (return of capital) is one component that determines allowable revenue, and provides for the ex-ante return of capital, as well as the return on capital allowed for in the cost of capital to ensure that NPV=0.

227. Depreciation rates are set ex ante. The BBM methodology recognises the significance of ex post (subsequent) changes in depreciation assumptions and methods. **Economic stranding risk maturing is an exception**. It is not provided for in the BBM, which assumes standard physical asset lives will be economically recovered (that economic life matches the physical life).

228. The BBM needs to reflect the loss when an economic life is materially shortened relative to physical asset life in the FCM assumption. That is, to produce outcomes consistent with the tendencies of workably competitive markets. That will mean prices to consumers to lower when they should. Instead, the current and most of the proposed 'compensations' have prices rising when they should lower for competitive market consistency.

229. Any implied (but denied) regulatory bargain to the contrary is invalid, and wrongly purposed in what should be a model to simulate the outcomes and incentives of competitive markets.

230. To summarise from our examples, a business in a competitive environment will adjust the asset depreciation schedule based on the expected economic life (market value) of its assets. Where an asset is deemed to have a shortened economic life, the asset might be depreciated more rapidly or even impaired/written off. It reduces immediate profitability, but it also reduces the remaining book value of the asset. That is likely to parallel a market recognition of the loss and accordingly reduce the capital on which the return is required. The required return on capital going forward does not need to be reset to maintain the ex-ante FCM expectation. The cost of accelerated depreciation is borne by shareholders, not consumers. Contrary to the Commission's mechanics of the BBM for regulated firms, accelerated depreciation does not enable firms in workably competitive markets to raise prices.

Conclusions

231. This part of the submission dealt with the Commission's underlying assumptions framing the paper. Our conclusions from examining the underlying premises are:
    a. We negate the asymmetry argument that has been the justification for offering more than ex ante compensation to sustain FCM when in a competitive market there is no such assurance:

[189] It is implied that competitive prices also achieve other consumer outcomes (innovation, investment in maintaining quality, efficiencies, and prevent excessive profits)

i. Regulated firms are capped at a normal return defined by what happens in workably competitive markets. The restriction on regulated firms' upside is only on their ability to earn economic rents. This is a feature, not a bug of S52A and the provision offers no special favours or disadvantages to suppliers.

ii. Regulated firms should face the same downside loss potential as firms in workably competitive markets- if they are to earn a return regulated by reference to firms in competitive markets.

iii. Raising prices to increase the return on sunk assets is not expected in workably competitive markets when faced with economic stranding risk. Instead, the expected outcome is a tendency to lower prices to consumers as the stranding circumstances reduce demand, to postpone greater revenue loss

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i. It appears that the additional revenue from accelerating depreciation through the gas IM amendment is going to benefit supplier equity holders (reduce debt or pay dividends).

ii. Use of accelerated depreciation revenue to reduce underinvestment is not demonstrated in supplier 10-year asset management plans. The opposite is shown. Investment intentions have lowered in the 2022 AMPs despite additional information suggesting a lower risk concern.

iii. As we would also expect to see in workably competitive markets, supplier AMPs are demonstrating accepted strategies for mitigating investment term risks without sacrificing quality:

(i) They are investing in creating timing options (using shorter physical asset lives in asset selection).

(ii) They are extending asset lives using condition monitoring to set new replacement schedules.

(iii) They are increasing their asset OPEX to maintain reliability and asset integrity.

(iv) They are investing in creating strategic options for asset repurposing.

(v) They derate equipment to extend asset lives and lower OPEX.

iv. Consumers are materially worse off when supplementary “ex-ante” FCM compensation is given to suppliers, without establishing any reliability or other benefit to consumers.

Reframing declining demand risk to GPB revenue risk

232. It is not clear from the Paper whether the Commission intends to revisit the evidence on demand decline in this IM review given that it covered this topic in the DPP3 process. The reasoning released to support DPP3 clearly indicates that it would.

233. MGUG has covered the question of the relevance of declining volume demand on network economic stranding risk extensively through its submissions in the DPP3 review[190].

234. The Commission in its current paper doesn't present an explanation of what it means by declining demand or how this is expected to affect supplier investment decisions. Instead, it offers the starting position that the current gas IM was changed because the widely expected decline in the long-term use of natural gas is likely to mean the average remaining economic life of the assets is shorter than their average physical life[191].

235. We have previously pointed out that demand/ supply uncertainty isn't unusual, and is rather, a characteristic of the New Zealand gas market since at least the Maui redetermination in 2002[192]. Gas production profiles have continuously forecast precipitous drops in supply (and therefore demand) 3-5 years in advance with gas always "running out" 10 years into the future. These closer near-term outlooks (rather than a 30-year outlook which is the Commission's focus) haven't shown up materially in GPBs investment plans before, and there is no evidence that GPBs have substantially shifted their investment intentions over the next 10-years in the face of Climate Change legislation or other government policy.

236. We acknowledge the Paper addresses a *hypothetical* scenario of declining demand, rather than, as was the case in the gas IM amendment, an assertion that demand *will* decline to the extent that GPBs have a heightened risk of asset stranding. Nevertheless, our objections to the framing of the issue still remain:

    a. Demand (volume) risk is not a straightforward proxy for revenue risk which is what influences investment decisions and determines Commission DPP settings. While we might expect a positive correlation between demand and revenue, there is no reason to assume that any decline has a fixed and equal timeframe over which it might occur, that the relationship is perfectly correlated, or is linear in its effect.

    b. Revenue risk differs for different segments of the gas market, within and between, different GPBs, and is not proportional to demand. Typically, the smallest volumes create the largest revenue streams for GPBs. Revenue risk to distribution networks is also different from revenue risk for gas transmission. We pointed to the relationships in our earlier submissions in the DPP3 process, and in particular noted the stability and higher confidence in GDB revenues as well as linking the importance of GDB demand to GTB revenue[193]. If the Commission is intending to do further modelling work in this

[190] Particularly, 202109 MGUG- Cross submission on DPP Process and Issues Paper
[191] Para X6
[192] Most recently in our cross submission *202207 MGUG Cross Submission on 2023 IM review Framework and Process and Issues Paper* para 7-13
[193] 202109 MGUG-Cross Submission on DPP Process and Issues Paper-Final

review it needs to apply revenue forecasting that reflect the structural connections between demand and revenue and different demand risks of the gas sector before coming to any meaningful conclusion on overall risk. It is self-evident that there is a wide range of feasible scenarios and speeds of stranding, including changes that eliminate stranding as a significant risk.

c. Demand/ revenue risk perceptions change with time through new information. Based on the Emission Reduction Plans which avoided the most onerous recommendations on discouraging gas demand (including gas connection bans), and various Ministerial statements acknowledging that gas is expected to continue to have an important role in the energy transition, as well as further lack of political consensus on means to reduce emissions we argue that overall demand risk perceptions, particularly in relation to time horizons, have further lessened since the gas IM amendment. This lower risk perception also continues to be reinforced through GPB 10-year asset management plans that continue to show demand growth[194].

237. The Commission, based on what we've been told is its legal advice[195], has considered itself not able to give any real weight to the potential that gas pipeline services could continue with lower carbon gases well past the assumed 2050 economic stranding event. This is unfortunate when evidence before the Commission shows that GPBs are factoring in gas transition opportunities into their business planning to extend the real economic life of their assets[196]. Effectively GPBs are creating a call option on their network investment that extends their future revenue beyond economic stranding of "natural gas" pipeline services.

238. We ask that the Commission advocate a legislative clarification of the legislation[197]. Is there room in the meantime to include an estimated value of the GPBs' call option when assessing stranding risk against residual value of the network? If the issue is assessing *economic* stranding, then can residual value also be an *economic* value test, not a residual book value of assets which the Commission used as the residual value test in the gas IM amendment reasoning.

Risk Perceptions

239. The Commission travels down a familiar road when it tries to explain why it is concerned about declining demand as a consequence of Climate Change legislation and how the landscape might look in 30 years' time. We've covered our response to this framing in the DPP3 process, particularly our submission explaining how the CCC gas demand assumption is neither a forecast nor a prediction, but rather that its purpose is to meet the statutory requirement to "demonstrate" a plausible basis for its recommendations for overall national emission targets [198]. We ask that the Commission make it clear that it is objective on the risks. The CCC outcome

[194] GPB AMPs also demonstrated demand growth expectations during the DPP3 process.
[195] As we understand it
[196] This includes for example a statement from Firstgas' CE on their ongoing work to repurpose their gas network.
[197] MGUG pointed out how S55A in the current context of 2022 vs 1984, undermines the intent of S52A and S52B. While the Act has provisions to keep it updated and relevant to reflect changing circumstances these haven't been exercised.
[198] 202108 MGUG-Cross Submission on DPP Process and Issues Paper

for gas is possible, but it is one possibility among many, including that gas demand may not change materially or might even might increase to 2050. The appropriate sector stance is to monitor new information, and create and use options, but not to exercise them until needed.

240. GPBs are continuing, albeit cautiously, with their asset investment, including growth investment, can be explained by their different risk perceptions. Consumers too appear to be sceptical about an early end to gas usage.

241. We've already described how taking a market sector approach defines different risk perception. The further context is that:

   a. The CCC, nor the Government have proposed that gas should no longer continue as part of the energy mix beyond 2050.

   b. The CCC advice will continue to evolve. Its recent ERP has left the door open for gas to continue past 2050 as its mandate is to set national targets, not dictating and enforcing sector targets. Gas has the lowest carbon intensity of fossil fuels and where gas generation for electricity continues to play a role direct use of gas can be shown to have a lower carbon intensity than electricity.

   c. GDBs have a greater reliance on low volume, high revenue mass market segment. These consumers continue to demonstrate confidence in gas as evidenced by gas connection growth. Likewise, GPBs continue to forecast connection growth for this sector.

   d. GPBs appreciate that consumers are looking for a gas pipeline service and are mostly indifferent to the nature of that gas (renewable or not). That is why GPBs are investing in creating options for gas pipeline repurposing.

   e. Likewise, GTB has a significant and disproportionate contribution from supplying GDBs, closely linking their futures.

   f. There is inevitably considerable uncertainty as to how the future for gas will play out to 2050, but until the direction is clear, the successful strategy is to create options and keep them open as long as possible, and to continue to adapt to changing information as it crystallises.

242. The Commission likewise has options that don't need to be closed early. Despite IM reviews being set at 7-year intervals it has demonstrated a willingness to act outside of that cycle to bring it into 4-yearly DPP reviews on a special case basis. It can also as explained earlier, use supplier AMPs to monitor how suppliers are assessing and responding to future uncertainty. Suppliers can also use the CCP process to respond to any unexpected shocks to adjust their revenues.

243. The gas IM amendments made in 2022 have not obviously produced the outcomes that the Commission said it was pursuing.

244. We see a considerable mismatch with the way that the Commission treats the likelihood of economic stranding, with how the sector itself is responding to that risk. This is not explained by an assumption that there is an information asymmetry where the Commission has superior

insight compared to the rest of the sector. Our position is the opposite. People with skin in the game (those who invest real money betting on the future of gas) are likely to show best the scale of the risk and how to manage it.

245. The different risk perception manifests in how to act in the face of uncertainty. The Commission is seeking early intervention through adjusting its methodology, whereas the sector itself is demonstrating a more gradual adaptive approach within the existing methodology that has provided certainty to date (s52R). The sector approach has been vindicated because it works, while the Commission's intervention has increased uncertainty (undermining S52R) and increased costs to consumers (undermining S52A).

246. For these reasons we believe that the Commission should wind back the premature interventions it made in the gas IM settings, and follow rather than try and lead the conversation on gas demand decline risk.

7/06/23 - MGUG - SYNOPSIS OF SUBMISSIONS FOR APPELLANT

MGUG formally appealed the Commission's final decision under s91 and s52Z through the High Court. The grounds and arguments have been laid out to the Commission and its legal team. These arguments also apply to the current IM review. While confidential to the parties in the appeal, these are available to the Commission as part of the record for the current IM review.

Appendix 2 – Various views on the future of gas in NZ

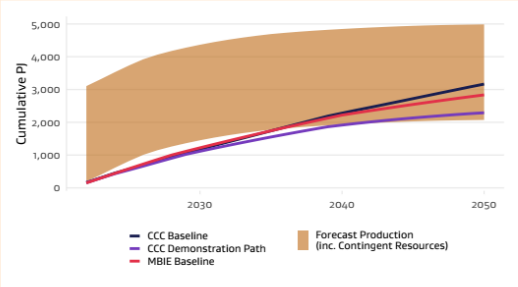
<table>
<tr><th>Document/Report</th><th>Reference</th><th>Extract</th><th>Comments</th></tr>
<tr>
<td>MBIE – Energy in new Zealand 2022</td>
<td>Page 34</td>
<td>Box E.2 The future of natural gas

Natural gas consumption and production have varied over time and can be expected to change in the future. On the one hand, natural gas production is expected to decline after 2024 as New Zealand natural gas fields enter end-of-life. On the other hand, natural gas use is also expected to decline over time. In the past 5 years, annual natural gas production fell 20 per cent (38PJ), but over this period, transformation use fell 12 per cent (6.7PJ), non-energy use fell 35 per cent (20PJ), and consumption fell by 13 per cent (9.9PJ).

Additionally, New Zealand will need to reduce and eventually eliminate natural gas use to help achieve its emissions budgets and 2050 emissions targets.

Based on forecasts from the Climate Change Commission (CCC) and the Ministry of Business, Innovation and Employment, New Zealand will need to produce between 2,290 and 3,165PJ from 2022 to 2050 in order to meet demand. These scenarios represent an average annual usage of between 79 and 109PJ (as compared to 2021 total usage of 155PJ). While this level of use exceeds New Zealand's 2P natural gas reserves of 1,967PJ, contingent resources of 2,915PJ could provide sufficient gas if partially developed.

Figure E.8: Comparison of cumulative expected annual production of natural gas and forecast natural gas use



There is reason to suggest that natural gas reserves and resources will be sufficient to meet New Zealand's energy demands, while fossil gas remains part of our wider energy system.

The Government has recently announced that it will be developing a Gas Transition Plan. This will help to guide the fossil gas sector to reduce emissions in line with legislated targets, emissions budgets, and New Zealand's international commitments.</td>
<td>Notes that resources and reserves are sufficient to meet anticipated energy needs within current consumption patterns while noting that the Gas Transition Plan being developed will further illustrate potential pathways for gas consumption</td>
</tr>
</table>

Document/Report	Reference	Extract	Comments
[Castalia - 2035/2050 Vision for Gas – Final Report (March 2023)]	Page 15 - 18	**Key recommendations for GTP to 2035** Based on our modelling analysis and acknowledging limitations, the optimal pathway to transition New Zealand's gas sector appears to be a combination of CCUS (Carbon Capture Usage and Storage) for large-scale emitters, and using the carbon price to incentivise net emissions reductions. **The future is radically uncertain, so flexibility to adapt to changes in technology and new information in the future (which a dynamic carbon price would promote) is important.** … **Natural gas could continue to play a smaller but more important role in electricity generation. Natural gas can provide flexible, reliable, and cost-competitive energy source for New Zealand's electricity generation needs** (particularly for dispatch), which could support the country's high renewable electricity generation mix. Utilising natural gas for select electricity generation could enable New Zealand to shift to lower economy-wide electricity costs with a higher share of renewable electricity generation than is currently the case, but without incurring the high costs of the additional generation and storage investment required to reach 100 per cent renewable electricity. … The modelling shows that some natural gas users are sensitive to carbon price changes, particularly once the carbon price exceeds $200 tCO2e. However, **natural gas still appears to be the lowest cost source of energy for many sectors, even as energy costs rise because of the lack of viable low-carbon energy substitutes.** As the carbon price rises, it may impact economic viability for industrial firms producing goods exposed to trade on global markets. Those natural gas users may stop production if the carbon price rises significantly and overseas competitors do not have the same climate obligations. **Policy that supports using an ETS with a binding cap would provide emissions reduction opportunities that fully comply with the Climate Change Response Act in an efficient and predictable way.** If the carbon price remains market-based and traded on the ETS, it can reflect the relative value of emitting compared to abating across the economy. This approach can ensure that	• Investment into natural gas, carbon capture technology and gas storage has an important role in supporting New Zealand's climate change commitments. It represents the lowest cost pathway to decarbonisation of emissions • Aggressive phase out of natural gas may increase our emissions

Document/Report	Reference	Extract	Comments
		abatement occurs first where it is cost-effective, thus incentivising emissions reductions across the whole economy. … **The modelled CCC Demonstration Pathway and the Direct Interventions Pathway illustrate the risks of deterministic policies targeting particular gas users or classes of users. Such policies can target the wrong users or technologies, or produce unintended consequences (such as marginal emissions reductions** relative to other pathways, higher costs across the economy that cannot be sustained, and significant economic costs). For instance, the CCC Demonstration Pathway was prepared in 2021 and is already significantly out of date with actual events superseding the CCC's core assumptions. The Direct Interventions Pathway is expected to cost 21.2 percent more than the Reference Pathway over the modelled period. Rather than incur those costs, gas users will probably stop production, leading to negative economic impacts. Methanol production currently underpins New Zealand's gas market through long-term contracts and ceasing it could cause supply uncertainty that might increase electricity prices to pay for new generation and infrastructure investment. This could delay electrification elsewhere in the economy… Higher energy costs would probably cause domestic industrial firms to close or reduce production. **This could result in a significant impact on New Zealand's GDP and loss of strategic industry, job losses concentrated in particular regions, and higher global emissions due if substitute products are made in countries with more emissions intensive processes.** There may be a case for integrating some renewable gases into the gas network, if renewable gas production costs fall significantly. **Integrating renewable gases could be used to extend the lifespan of New Zealand's gas networks, and also provide energy choices to consumers, while achieving emissions reductions.** **…** **Emissions leakage from industry is possible** New Zealand's net zero by 2050 policy objective in the Climate Change Response Act supports its international commitments under the Paris Agreement. New Zealand's domestic objectives sit in the context of global efforts to reduce emissions.	

Document/Report	Reference	Extract	Comments
		Several large users of gas are exposed to downstream global markets for the commodity products produced using gas in New Zealand. For example, methanol, urea, and milk products produced in New Zealand are all tradeable commodities subject to a global price, determined by global supply and demand for the commodities. **Policy decisions that change natural gas input costs may make domestic production of commodity goods uncompetitive** with imports for domestic consumers or uncompetitive on global markets. This may force domestic trade exposed firms to stop production. **If global demand remains unaffected, and global emissions frameworks are not binding on overseas competitors, those overseas producers could keep using fossil fuels to meet demand for those commodities. This could cause higher global emissions**	
Climate Change Commission – 2023 Draft advice to inform the strategic direction of the Government's second emissions reduction plan (April 2023)	Page 14	[From proposed recommendations] We propose that the emissions reduction plan for the second budget period must: 10. Implement an integrated planning system that builds urban areas upward and mixes uses while incrementally reducing climate risks. 11. Incentivise comprehensive retrofits to deliver healthy, resilient, low emissions buildings. **12. Prohibit the new installation of fossil gas in buildings where there are affordable and technically viable low emissions alternatives in order to safeguard consumers from the costs of locking in new fossil gas infrastructure.**	• Phase out of natural gas must be balanced between climate benefits and consumer risk. • Prohibition advice on new gas connections has been overridden before by the Government.
	Page 103 – 104	**Continued fossil gas use and asset expansion will add additional cost to consumers as well as raise equity issues for future generations** Fossil gas assets installed during the second emissions budget period could endure to 2050 and beyond, despite the fact that affordable low emissions alternatives are available now. Continued expansion of the fossil gas asset base may be incompatible with sustainable, intergenerational prosperity (mana whanake) if it locks tangata whenua and other households, communities, and businesses into this path. Electricity is a more efficient and lower emissions source of energy for heating homes and businesses than fossil gas.	

Document/Report	Reference	Extract	Comments
		While the total delivered volume of fossil gas has remained steady, the number of new connections to the network continues to grow. Many households, businesses, marae, and community centres use fossil gas for heating, cooking, and hot water. However, the use of fossil gas needs to decrease to meet the 2050 target. Low emissions gases such as biogas or green hydrogen are currently more expensive than fossil gas. Putting new, low emissions gases through pipelines is also likely to require some reinforcement or replacement. The costs to do so will need to be recovered through users' bills as the gas network is a regulated asset base. **A substantial decline in fossil gas use could mean that those left on the gas network could bear increasing costs as a high proportion of gas pipeline costs are fixed and must be recovered from the remaining user base**. Households are not best placed to manage the risk of economic stranding of gas pipeline businesses' assets or to support continued gas use by large industrial users. There are few levers for households to manage this risk and there are limits to absorbing any price increases, especially during periods of high inflation. For example, vulnerable groups like the elderly, medically vulnerable, or those with disabilities may be less able to change their energy demands or use patterns to manage costs. The Government's *Gas Transition Plan* and *National Energy Strategy*, and the Commerce Commission's regulated investment framework, should provide clear strategic direction on the future of fossil gas and options for regulated cost recovery models for gas pipeline businesses which are equitable, give consumers time to transition, and support hard-to-abate industries.	
	Page 116	**Fossil gas will begin to transition out of the system, but will remain important for the security of electricity supply and some industrial users through the second emissions budget period and beyond** Fossil gas plays an important role in the energy system. It provides secure energy supply for electricity generation (30% of consumption in 2020), and for users of	

Document/Report	Reference	Extract	Comments
		process heat (18%), as well as a feedstock and fuel for chemicals and fertiliser (43%) such as methanol and urea. Many households use fossil gas for cooking, heating, and hot water (4%), and many commercial businesses use it for space heating and cooking (4%). Fossil gas combustion emissions made up 9% of gross greenhouse gas emissions in Aotearoa New Zealand in 2020 and need to be reduced. In the Commission's demonstration path, fossil gas emissions reduce by 18% by 2025 and 37% by 2030, relative to 2020. **However, this must be done in a measured way that ensures the energy system can deliver an equitable transition to net zero long-lived greenhouse gas emissions. Removing fossil gas too quickly from the system could increase electricity prices and reduce reliability.**	
International Energy Agency - New Zealand Energy Policy Review (April 2023)	Page 129	The government's forecast for natural gas projects a steady production downtrend over the coming decade. While gas supply has recently shown signs of improvement from field development work after technical constraints experienced in 2021 and is expected to increase again to over 200 PJ4 in 2023-2024, it will drop sharply after that to around 75 PJ by 2030, around half of today's levels. This will force a commensurate drop in demand that may be especially challenging in industry. However, **there is uncertainty around production profile trends for the future – these are a function of investment and ongoing field development work.**	• Better policy goals can effectively utilise New Zealand's domestic renewable energy resources • New Zealand should explore carbon capture technology to reduce our carbon footprint
	Page 133 - 134	Emissions reductions are likely to occur through lower demand (for example, greater efficiency, and electrification) and lower carbon intensity (for example, blending in renewable gases… The availability of gas reduces the consumption of coal at the site and reduces overall emissions for the electricity sector. The pace for **phasing out natural gas and the "end-state" of the sector is currently uncertain and is dependent on a range of factors, such as emissions pricing, technological adaptation and other economic factors.**	
	Page 140	The government forecasts a steady decline in production over the coming decade. Gas supply increased over 2022 after field development work in 2021 and is expected	

Document/Report	Reference	Extract	Comments
		to rise again to over 200 PJ in 2023-2024. Production will then start a steep decline to around 75 PJ by 2030, or around half of today's levels; however, uncertainty about the exact volumes remains. This will force a proportionate drop in the use of gas. The application of carbon capture, utilisation and storage on large-scale installations that use natural gas would be in line with the government's climate policy. New Zealand has emptied gas fields that are suitable for CO2 storage. As such, **the government could investigate whether continued gas use for electricity generation, coupled with carbon capture, utilisation and storage, could be an option to provide flexibility to the grid** when penetration of variable renewables becomes mainstream and to overcome the "dry year" problem when water inflows to hydropower stations are lower.	
	Page 141	Recommendations The government of New Zealand should: • Expedite the finalisation of the Gas Transition Plan to quickly provide clarity to the market on the role of natural gas in the economy over both shorter and longer time horizons. • Leverage the country's sizeable potential, including in the agriculture sector, to stimulate increased biomethane production to offset declines in natural gas production and lower emissions from the gas supply. • Ensure that **a possible wind-down of natural gas production is accompanied by a robust decommissioning and/or repurposing strategy for both upstream and downstream infrastructure**.	
International Energy Agency – World Energy Outlook 2022 (October 2022)	Page 20	Context for the projections stated in this report: The three scenarios explored in this *World Energy Outlook* (WEO) are differentiated primarily by the assumptions made on government policies. The **Stated Policies Scenario (STEPS)** shows the trajectory implied by today's policy settings. The **Announced Pledges Scenario (APS)** assumes that all aspirational targets announced by governments are met on time and in full, including their long-term net zero and energy access goals. The **Net Zero Emissions by 2050 (NZE) Scenario** maps out a way	• Natural gas has a sustained role in supporting global energy security and affordability. • Retaining gas networks/pipelines

Document/Report	Reference	Extract	Comments
		to achieve a 1.5 °C stabilisation in the rise in global average temperatures, alongside universal access to modern energy by 2030.	important for maintaining flexibility ○ New Zealand should keep its energy resource options open during transition periods
	Page 25	**A new energy security paradigm is needed to maintain reliability and affordability while reducing emissions**. This *Outlook* includes ten principles that can help guide policy makers through the period when declining fossil fuel and expanding clean energy systems co-exist. **During energy transitions, both systems are required to function well in order to deliver the energy services needed by consumers, even as their respective contributions change over time.** Maintaining electricity security in tomorrow's power systems calls for new tools, more flexible approaches and mechanisms to ensure adequate capacities. Power generators will need to be more responsive, consumers will need to be more connected and adaptable, and grid infrastructure will need to be strengthened and digitalised. Inclusive, people-centred approaches are essential to allow vulnerable communities to manage the upfront costs of cleaner technologies and ensure that the benefits of transitions are felt widely across societies. **Even as transitions reduce fossil fuel use, there are parts of the fossil fuel system that remain critical to energy security, such as gas-fired power for peak electricity needs, or refineries to supply residual users of transport fuels. Unplanned or premature retirement of this infrastructure could have negative consequences for energy security.**	
	Page 207 - 208	**Right sizing and repurposing gas networks** A third area requiring close attention is natural gas networks. This is a particularly difficult area, because the networks sit at the intersection of different visions of how transitions should play out. On one side there is the "electrify everything" approach, in which electricity not only increases its share substantially in final consumption (as it does in all our scenarios) but becomes the dominant or even the sole vector for most consumers. This route requires a massive build-out of clean electricity generation and infrastructure, and the role of existing gas networks in this vision is marginal – the main policy issue is how to manage their decline.	

Document/Report	Reference	Extract	Comments
		On the other side are those arguing that most current natural gas pipelines can eventually be repurposed to carry low-emissions gases, whether biogases or low-emissions hydrogen, so grids need to be maintained (and in some cases expanded). Starting points for this debate differ. Nearly all countries have an extensive electricity grid for delivering power to consumers, but the extent of gas infrastructure varies considerably. **Where it has been built, in many cases the gas network provides a larger and more flexible energy delivery mechanism than the electricity network.** In Europe and the United States, gas networks deliver between 50-100% more energy on average to end consumers than electricity grids. **Switching from gas to electricity brings major efficiency gains, but replacing gas entirely with electricity would bring practical challenges, especially if it proves difficult to expand the electricity network quickly due to permitting issues or public opposition. There is an energy security rationale for maintaining overlapping infrastructure and,** indeed, most countries that have considered how to realise rapid and wholesale emissions reductions are looking at a future in which electricity and gas networks play complementary roles. However, these roles are often not well defined in practice, and this creates risks. Without a well co-ordinated approach to the provision of power, gases and heat, the different networks are unlikely to evolve in a harmonious way. For example, there is a distinct possibility of gas infrastructure suffering "death by a thousand cuts" as individual consumers migrate to using electricity. Those making the move are likely to be better-off households in a position to make the upfront investment in electrified heating systems. This could in turn have distributional implications as poorer consumers, along with some industries, would continue to rely on existing infrastructure and, under existing tariff structures, would need to shoulder a higher share of its fixed costs. To avoid these kinds of outcomes, there is a need for early and co-operative resource planning among electric and gas utilities and network operators, mediated by governments to ensure that the outcomes are consistent with rapid, secure	

Document/Report	Reference	Extract	Comments
		transitions that minimise costs to consumers. This kind of ongoing dialogue, **informed by changing technology and deployment trends, can contribute to developing a coherent vision of where gas networks have long-term viability (and where they need to be decommissioned), and how gas and electricity grids can work together to contribute to rapid reductions in emissions.**	
[International Renewable Energy Agency – World Energy Transitions Outlook (June 2023)]()	Page 47 - 48	Over the past few years, global events have complicated action on the energy transition and climate action. A global energy crisis brought about by rebounding demand following the COVID-19 pandemic, adverse weather and reduced fossil fuel supplies escalated in early 2022 owing to the fallout from the Ukraine crisis. The rapid rise in energy prices affected countries around the world, either directly or indirectly. Energy supplies tightened in Europe, particularly supplies of natural gas from Russia. … **the EU passed an act classifying natural gas as a "transitional" energy source for sustainable investment, with technical and emission standards set for corresponding projects.** **…** **Although many countries have kept renewable energy at the top of their investment lists, they risk ending up with stranded assets in their LNG contracts and infrastructure – both complicate the "phasing out" of natural gas. Governments will naturally prioritise short-term responses to the energy crisis, but they need to maintain their strategic direction at the same time.**	• Shows the importance of New Zealand retaining its domestic supply of natural gas in the future • Other regions, such as the EU, have recognised the importance of retaining natural gas as a transitional resource for meeting their climate targets.
Asia-Pacific Economic Cooperation – Energy Demand and Supply Outlook 8th Edition, Vol. 2 (September 2022)	Page 9	Context for the projections stated in this report: • **The Reference scenario (REF)** is a pathway where existing trends in technology development and deployment, and policy frameworks continue in a similar manner. • **The Carbon Neutrality scenario (CN)** outlines potential pathway where energy efficiency, fuel switching, and technological advancement leads to a significant reduction in CO2 emissions from fossil fuel combustion out to 2050.	• Projections in both scenarios assume that natural gas will be phased out between 2040 - 2050 • An aggressive phase out of natural gas (2020 – 2030) is difficult to achieve without significant increase in New

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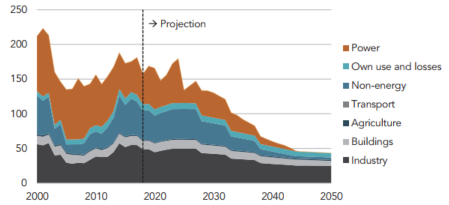
<tr><td></td><td></td><td></td><td>Zealand's energy costs and a potential reduction in economic output.</td></tr>
<tr><td></td><td>Page 386</td><td>

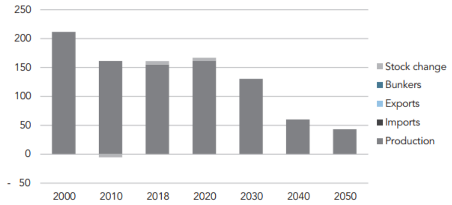
Natural gas in the Reference scenario

Figure 12-29. Natural gas consumption by sector in REF, 2000-2050 (PJ)



Sources: EGEDA, APERC analysis.

Figure 12-30. Natural gas production, imports, and exports in REF, 2000-2050 (PJ)



Sources: EGEDA, APERC analysis.

- New Zealand's natural gas market remains isolated, meaning that domestic consumers are wholly dependent on domestic suppliers, and vice versa. The Maui gas field in the Taranaki region of the North Island was the largest producing field in New Zealand through the 1980s to early 2000s. Production is still occurring out of Maui, but at much lower levels. More recently developed fields, such as Pohokura and Kupe, have supported New Zealand's gas production though the late 2000s and 2010s.
- Natural gas is consumed throughout the economy, with the power and industry sectors being the most prominent users over the last two decades.
- New Zealand's methanol and fertiliser production is sensitive to readily available and affordable natural gas supply, which is imperative to remain cost competitive with international markets. The large fall in industry and non-energy consumption of natural gas in the early 2000s was partly due to Methanex scaling back production in response to tight gas supply. Production recovered in the 2010s with the development of additional gas fields. While output remains at similar levels throughout most of this decade, diminishing natural gas supply causes a significant fall in production from these industrial subsectors in the last two decades of the outlook period.
- Natural gas consumption declines in other industrial subsectors, as well as the buildings and agriculture sectors, due to diminishing supply and decarbonisation policies that favour electricity and biomass.
- In November 2018, the Crown Minerals (Petroleum) Amendment Act restricted the exploration and production of oil and gas to current permit holders only. Future exploitation remains uncertain, and given the diminishing prospects on the demand side, it is likely for natural gas to trace a less prominent trajectory. A reserve replacement ratio of 30% will be required to sustain supply assumptions through to 2050 in REF. Exploration within remaining areas by existing producers may allow supply to meet demand, absent the development of any LNG import terminals.

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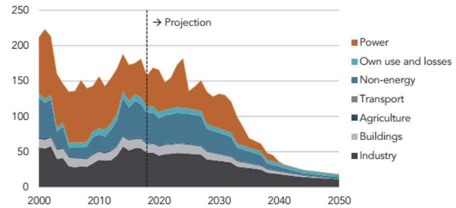
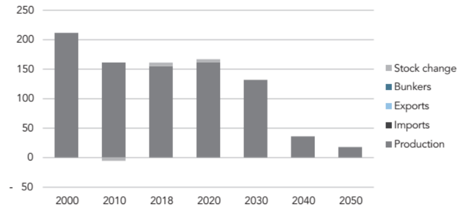
Natural gas in the Carbon Neutrality scenario

Figure 12-31. Natural gas consumption by sector in CN, 2000-2050 (PJ)



Sources: EGEDA, APERC analysis.

Figure 12-32. Natural gas production, imports, and exports in CN, 2000-2050 (PJ)



Sources: EGEDA, APERC analysis.

- The CN natural gas story is comparable to REF, with a slightly more aggressive phase-out in consumption, which occurs in concert with a similarly-sized supply response. Existing reserves are sufficient to meet CN demand trajectory, which suggests that further exploitation is not required.
- The phase-out of natural gas in the power sector occurs in 2040, four years earlier than in REF. However, natural gas consumption is higher in CN out to the early 2030s due to increased electricity demand from all end-use sectors.
- Supply constraints combined with increased policy ambitions in CN curb natural gas consumption in the buildings sector to zero by 2050. This displacement is almost entirely met by electricity.
- Industry sector gas use is more robust than in the buildings sector, though still falls to a level that is less than half REF levels in 2050. Electricity facilitates most of this reduction, but biomass and hydrogen also assist with the transition in heavy industry subsectors.
- The fall in natural gas supply and demand is already very large in REF. In CN, production in 2050 is almost 60% lower than in REF and is only 10% what it was just prior to the pandemic.
- Most of the reduction in natural gas use occurs after 2030, which emphasises its transition role for New Zealand in the context of decarbonisation ambitions. A more aggressive move away from natural gas in the 2020s would be difficult to achieve without a significant increase in New Zealand's energy costs and a potential reduction in economic output.
- Process heat makes up most of the industrial energy use and more than a third of process heat is for high temperate applications (for instance, those greater than 300 degrees Celsius); furthermore, half of such processes use natural gas. The government does not see a pathway to decarbonising high-temperature process heat with current technologies. This could result in fewer switching from natural gas to electricity than has been shown in both scenarios.

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