13 September 2021

Electricity and Gas Regulation Branch
Commerce Commission
P O Box 2351
Wellington
Via email: regulation.branch@comcom.govt.nz

Re: GPB DPP3 Reset –Process and Issues Paper- Cross Submission

1. This following cross submission is in response to the Commerce Commission Process and Issues Paper, "*Resetting default price-quality paths for gas pipeline businesses from 1 October 2022*", dated 4 August 2021, and submissions made by various stakeholders. The cross submission is on behalf of the Major Gas Users Group (MGUG):

    a. Ballance Agri-Nutrients Ltd
    b. Fonterra Co-operative Group
    c. New Zealand Steel Ltd
    d. Oji Fibre Solutions (NZ) Ltd
    e. Refining NZ
    f. Wilmar International
        i. New Zealand Sugar Company Ltd
        ii. Goodman Fielder NZ Ltd

2. Our members have been consulted on the preparation of this submission. Nothing in this submission is confidential and some members may choose to make separate submissions.
3. We have read the various submissions made by stakeholders. We note that of the 13 submissions received by the Commission, nine were made by or on behalf of Gas Pipeline Businesses (GPBs[1]).
4. The strong message from GPBs appears to be that the Commission should make adjustments to the Input Methodology (IM) and Default Price Path (DPP) settings urgently to address their perception on risks to Financial Capital Maintenance (FCM), including ways to accelerate revenue recovery from their investment.
5. Having reviewed the various positions and arguments of the submitters, we maintain our original view that the uncertainties and stranding risks guiding the Commission's thinking and being supported by GPBs have been overstated.
6. While we don't discount that measures proposed by GPBs to accelerate their capital recovery revenue might become necessary at some point, we don't agree that the threshold for doing so within the next DPP has been reached.

[1] Specifically Vector, First Gas, Powerco

7. In particular, we are concerned that the GPB proposal to decide and adopt amended settings outside of the next IM review in a pressured timeframe leads to a greater risk that these measures will prove to be premature and not fit for purpose. While stranding risk is, and has always been possible, we don't consider this has yet moved into the probable range where regulatory mitigation measures are urgently required.
8. Consequently, our view remains that the Commission should proceed with DPP3 settings in the usual way, including resetting prices.
9. While we would accept the usual 5-year period we have no strong objection to a shortened 4-year period if that would help the Commission.
10. There are some advantages in setting a 5-year timeframe, rather than 4-years, including the ability to reflect on updated advice from the Climate Change Commission's next report[2] . Equally important in our view, is that the Commission should have space and time to conduct an orderly and comprehensive review of the entirety of the Input Methodologies (IM) rather than be rushed into making piecemeal amendments for GPBs.

Summary of Problem Assessment by GPBs

11. Fundamentally the issue as framed by GPBs, is whether the Commission should adopt settings in DPP3 that would transfer risk of asset stranding from themselves and future generations of consumers to the current generation of consumers.
12. The argument for accelerating capital recovery revenue is being promoted by GPBs because they perceive that government policy shifts affecting their businesses have crystallised a speculative (possible) asset stranding risk into a highly probable risk that requires the Commission to act now in order to keep price path settings consistent with the principle of FCM.
13. There is an implicit assumption in their argument that GPBs cannot manage this risk and that therefore the risk needs to be transferred away from them. This is despite the fact that they do see a future for pipelines for gas transport in an energy transition environment and are in a strong position to influence that outcome[3].
14. GPBs appear to argue that allowing a higher capital recovery now is the best (no regrets) way to secure that pipeline repurposing scenario, and thereby provide assurance that the long-term benefits of gas pipeline infrastructure will continue into the future. In other words, the best approach should be to plan for the worst (wind down) and hope for the best (repurpose).
15. In doing so, the GPB argument posits that nobody will be worse off; higher prices now will be compensated by lower prices in the future. Furthermore regulated businesses do not make any gains because the principle of NPV=0 across the life of asset is being preserved.
16. Firstly, while this argument appears reasonable on paper, in practice the risk is asymmetric. Future consumers will not necessarily be current consumers, hence there is an intergenerational equity argument to be considered.
17. Secondly the GPB argument presupposes that this approach won't in fact achieve the opposite i.e. accelerate the wind-down scenario to hasten the outcome looking to be avoided.

[2] Due in December 2024

[3] For example, First Gas are investing in proving both technically and commercially in future gases (including gas blends and green gasses.

Summary of our challenges to GPB narrative

18. Much of what appears to be a well structured analysis by the various external consultants employed by Vector, First Gas, and Powerco, in our view is based on questionable premises. Consequently we consider the argument for acting now isn't well supported.
19. The areas where we consider the advice to be built on a weak foundation include:
    a. A presumption that the transmission business and the distribution businesses can be analysed in aggregate and the risk assumed to be the same across all parties.
    b. A presumption on the CCC gas pathway being the most likely outcome for demand for transportation services.
    c. A failure to explain why the demand uncertainty is any different than it has been in the last 20 years given the nature of domestic reserves on forward supply risk
    d. A failure to distinguish between demand risk and the more relevant revenue risk. Customer segments are not equal in risk or contribution to revenue. The customers most susceptible to being lost are also the customers who have the smallest impact on revenue
    e. A failure to reflect that GPBs in their own forecasts are projecting continuing connection and demand growth through the next regulatory period.
20. Our own analysis of the data questions whether the speculative risk of asset stranding is real enough to warrant stepping outside of the normal timetable for the IM review to address regulatory options for capital recovery.
21. Further, the rushed approach being proposed by First Gas in their submission to make IM amendments by the end of this year appears to us to be poor process and creates more opportunities for unintended consequences later.
22. We detail our further line of reasoning to these challenges below.

Gas Transmission and Gas Distribution need to be assessed separately

23. The various reports commissioned by Vector/ First Gas/ Powerco, treat Gas Transmission Business (GTB) and Gas Distribution Businesses (GPBs) as a combined business in terms of risk assessment. We don't think that this simplification accurately reflects the different risk profiles of these businesses and they should therefore be assessed separately.
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
26. The nature of the risk differences is currently reflected in the different forms of control between GTB and GDBs.

27. We've therefore separated GTB from GDB based on the data available in information disclosures and publicly accessible market information to demonstrate their differences.

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 290,000[4]. The total gas volume in the distribution market is around 35 PJ pa (20%) of the total New Zealand gas demand of 183 PJ in 2020 calendar year (Figure 1).

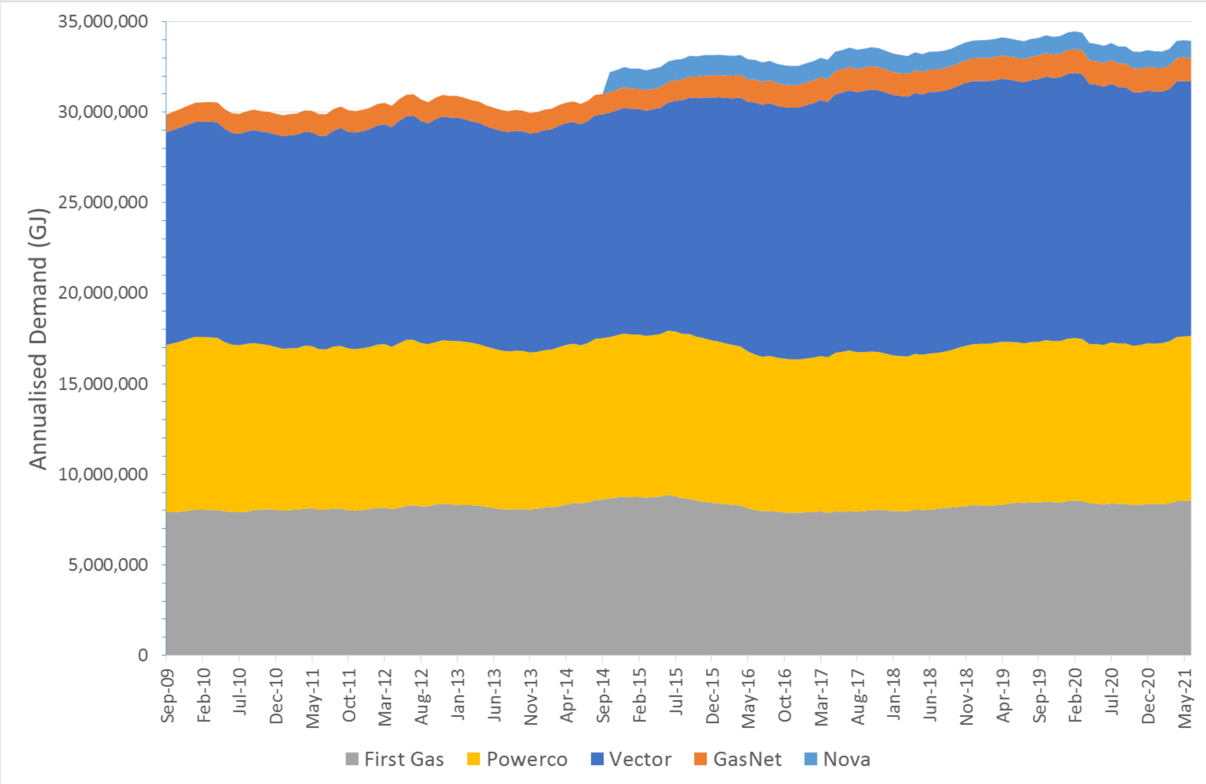

Figure 1: Annualised Demand- Gas Networks[5]

30. The transmission pipeline serves about 126 delivery connections which includes the distribution network gates as well as directly connecting around 37 larger users[6]. The transmission system transported about 170 PJ in 2020 (Figure 2).[7]

[4] Source: Information Disclosures

[5] 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.

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

[7] 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.

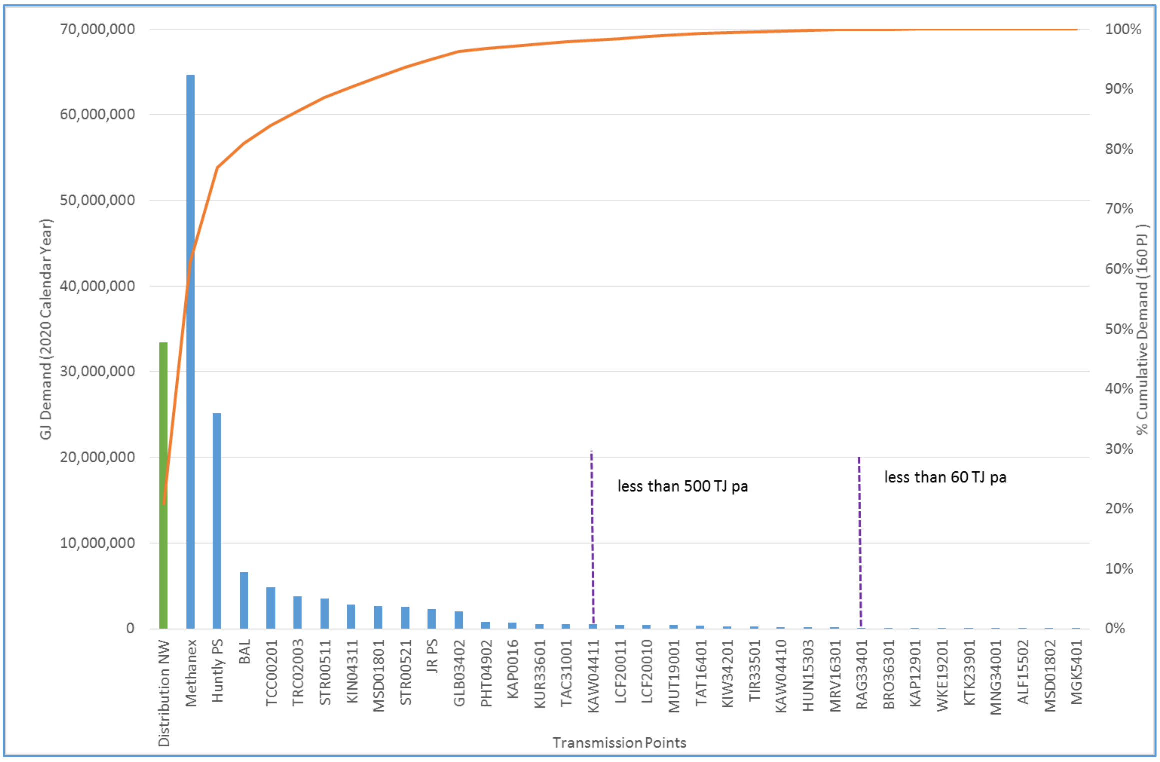

Figure 2: Gas Transmission volume[8]

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[9] with 96%-99% of connections being mass market customers (Figure 3)

32. As we show later in Figure 6, Figure 7, and Figure 8 when we consider revenue, rather than volume, the GDBs maintain their relative similarity. Hence it is reasonable to consider GDBs together but separately from the GTB.

[8] Source: Oatis

[9] 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 3: GDB - Connection Split[10]

The Climate Change Commission gas demand is not a forecast or a prediction

33. Considerable weight is placed by GPB advisors on what the CCC advice[11] 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.

[10] Source – Information Disclosure

[11] 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*

37. Despite the length of the document and accompanying evidence, the CCC report provides specific advice ***only* in relation to the following matters**[12]:
    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[13]. 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)[14].
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[15] (our emphasis added) that combines scenarios with "principles and judgement"[16]
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[17].

> *"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*

[12] 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)
[13] Ibid – Chapter 5 deals with items a, b, c in various tables and figures, item d is covered in Chapter 10
[14] Climate Change Response Act 2002 – 5Q
[15] Demonstration pathway is to 2035
[16] Ibid – figure 7.1
[17] 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[18].

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

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

pathway that might reflect actual outcomes. The only clear objective is net zero (long lived gases) to be reached by 2050.

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[19].

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[20]. 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*[21].

50. This seems sensible and reflects how the real world operates. Nevertheless an emissions 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.

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 4 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.

[19] Ibid – Figure 3.1, p37
[20] Ibid – p275 "Set a timetable to phase out fossil fuel use in existing boilers"
[21] Ibid – p276

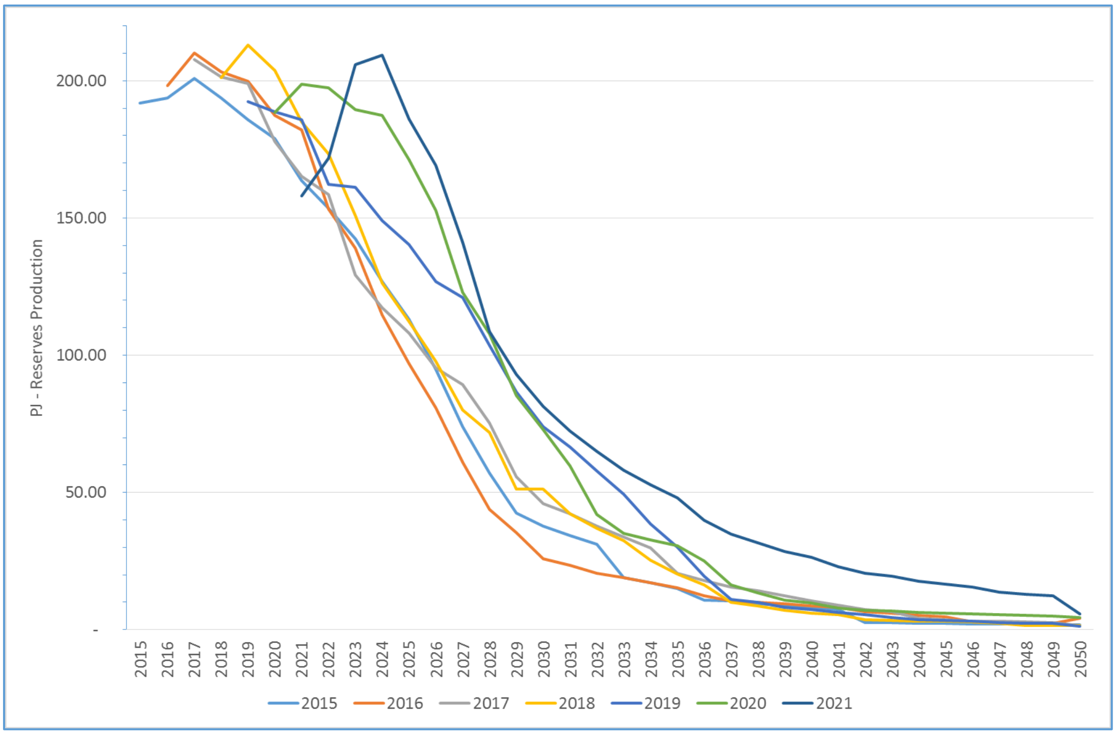

Figure 4: Reserve Forecast Production Profile

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.

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.

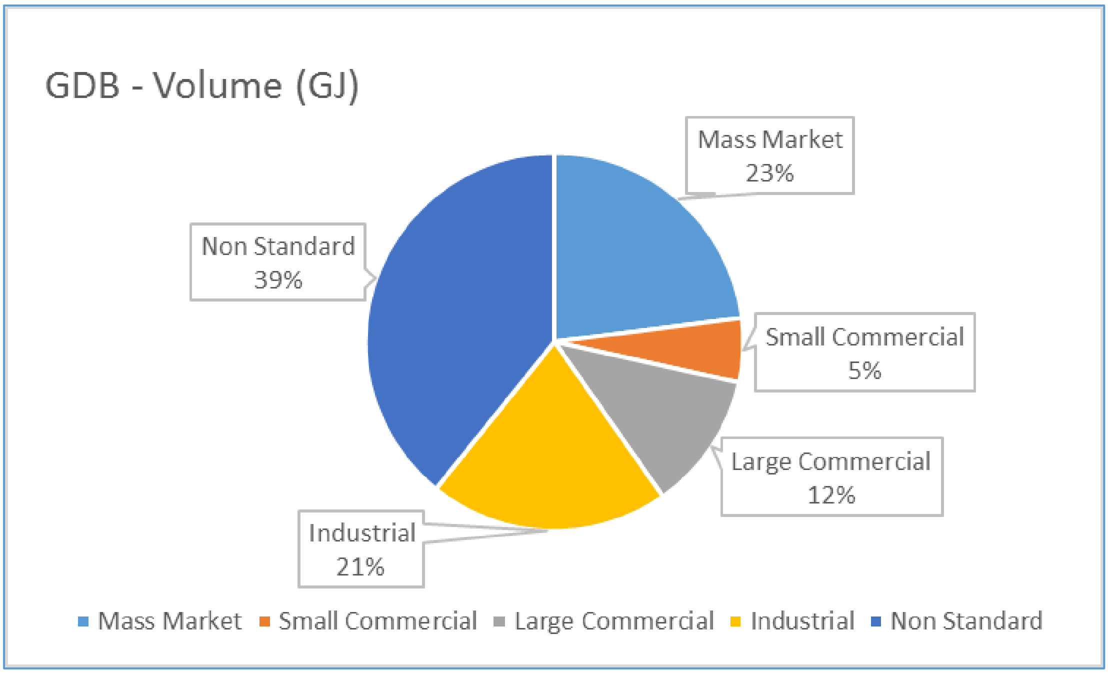

Figure 5: GDB Volume Split[22]

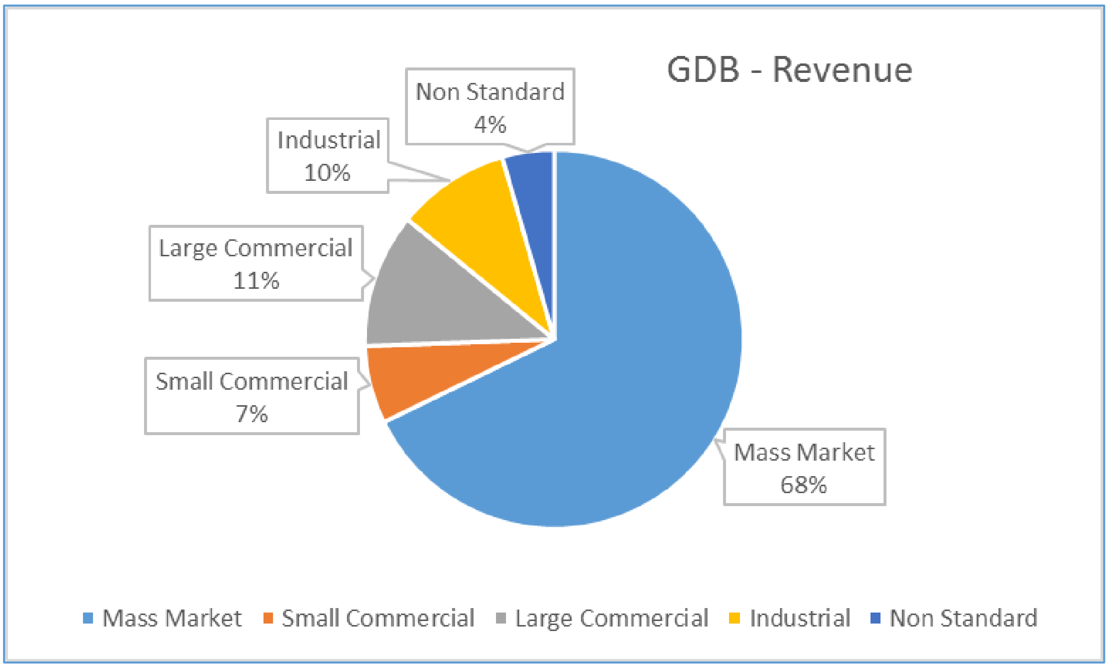

Figure 6: GDB Revenue Split[23]

[22] Source GDB Information Disclosure Schedule 8 - 2020
[23] Source GDB Information Disclosure Schedule 8 - 2020

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

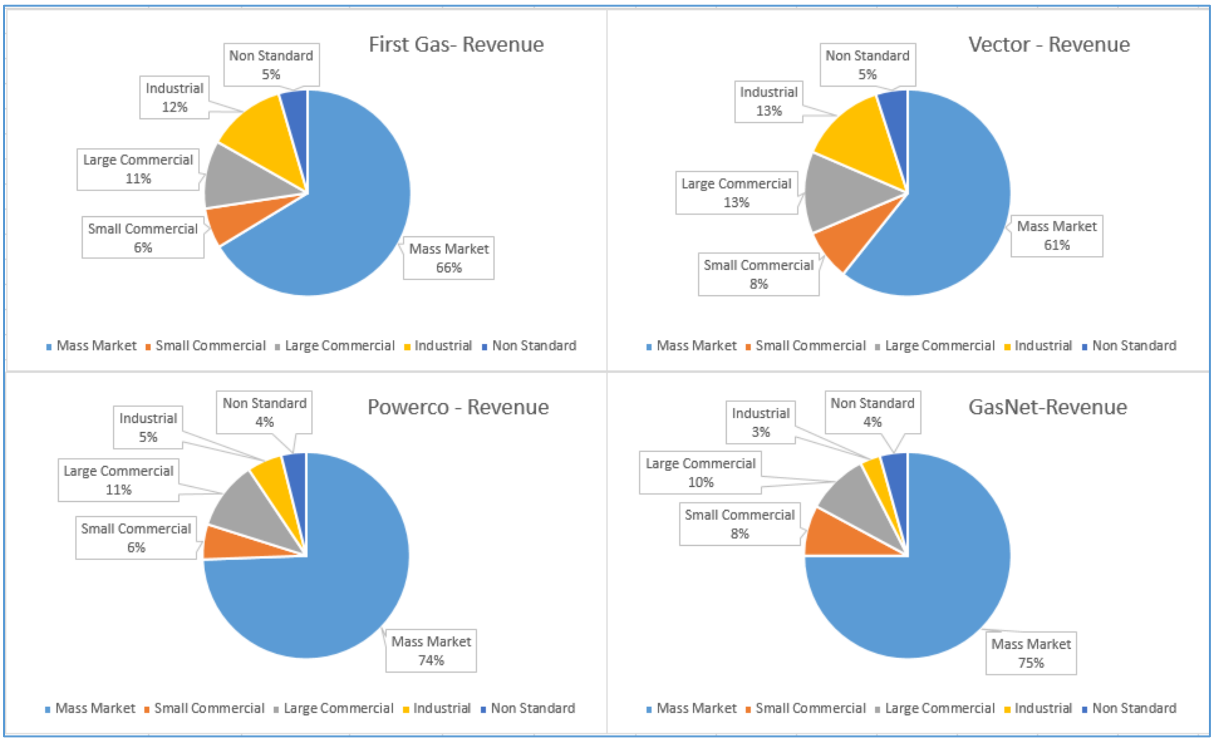

Figure 7: Revenue Split (2020)

59. To give some perspective on why this is so, Figure 8 gives the weighted average pricing by customer type. Residential and other mass market connections on average pay 16 times as much for their gas connection as a non-standard user.

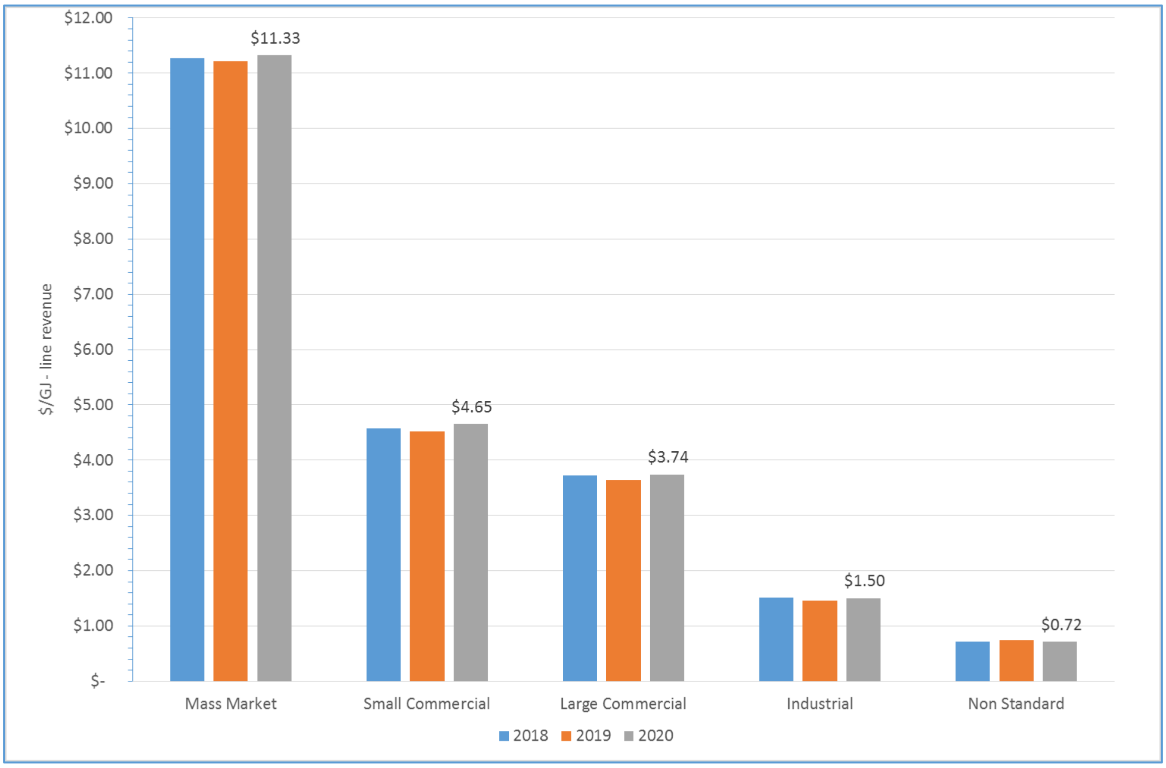

Figure 8: Consumer contribution - Networks

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[24]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 vs non-standards are also not easily separated. It is further complicated by

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

a pricing system based on nominations on MPOC that includes bi-directional flow on the Frankley Rd System[25].

63. Total line charge for the year ended 30 September 2020 was $132.5 million.[26]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[27]

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 affect 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 9[28]. 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[29].

[25] Nominations get charged in both directions. Physical flows will differ from the nominations on this part of the system.
[26] Information Disclosure Schedule 8
[27] 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
[28] With permission from First Gas
[29] Approximately 25% of the demand and 24% of the revenue.

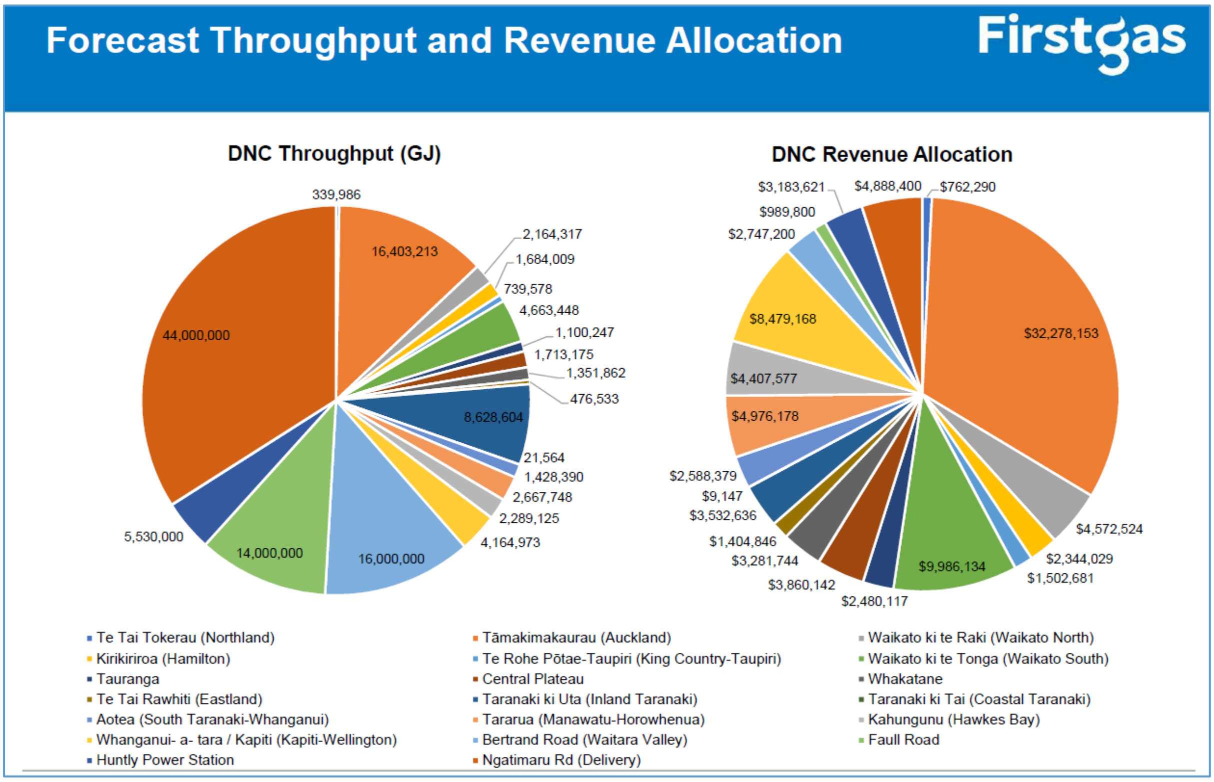

Figure 9: Illustrative connection between revenue and demand for GTB

67. 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 yet provides 33% of the revenue.

68. 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.

What do GDBs forecasts signal?

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[30]), reveal expectations of continued growth in connections and demand (Figure 10).

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

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

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

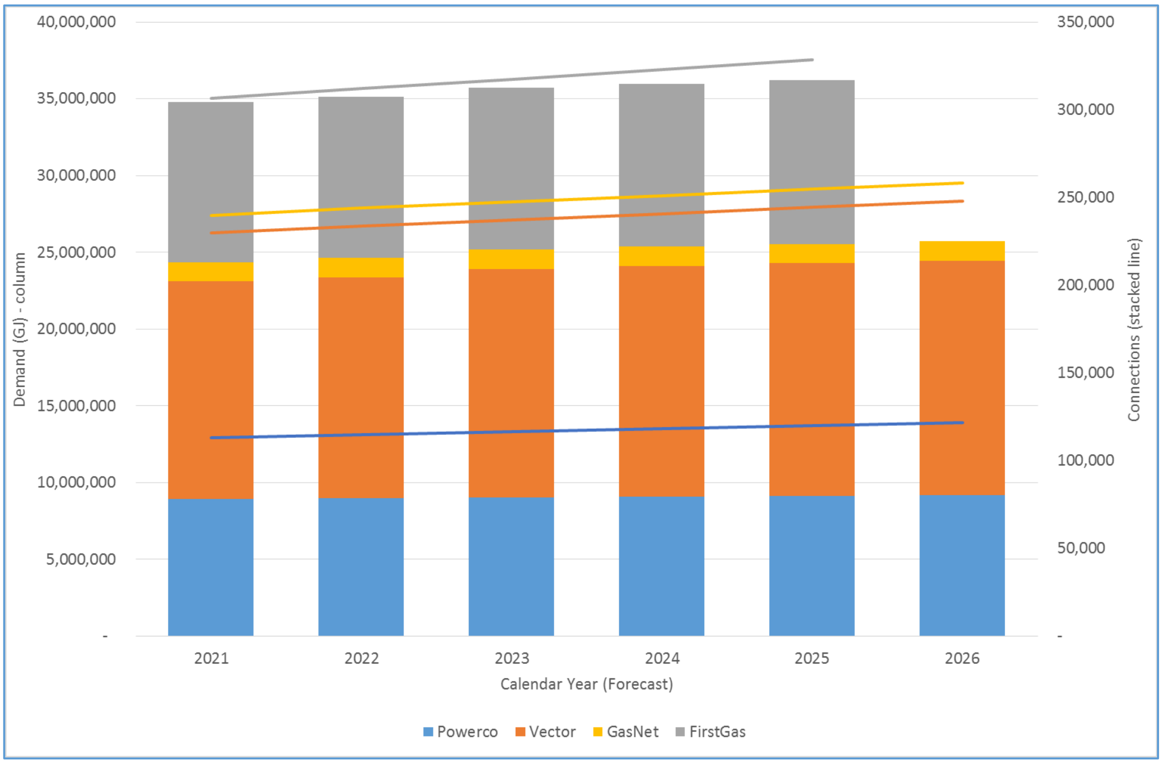

Figure 10: AMP Gas demand and connection forecast[31]

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. 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.[32] In other words, Methanex may pick up some share of that lost revenue.

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

[32] 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.

What is in the best interest of consumers?

75. The GPBs have presented the argument that what they are proposing by accelerating their revenue is in the best interest of consumers. The key argument being that it is better to spread the higher initial costs over a larger volume, than wait and try to recover normal revenue over a smaller customer base later. Accordingly this would also give GPBs confidence to continue to invest to ensure that gas pipelines support the energy transition.

76. While we appreciate the motivation to look after the best interests of consumers we are concerned that these good intentions may have the opposite effect.

77. Firstly, we would argue the incentive is stronger on GPBs to ensure that their assets are able to be repurposed when they haven't recovered the bulk of their revenue up front. This is because the only alternative to repurposing is scrapping and remediation given that they are unlikely to be able to sell the asset.

78. Secondly, what is being proposed by them is a risk transfer from themselves and future consumers to the current generation of consumers. It is not a given that these consumers will necessarily be the same group of people over time. This raises the risk of intergenerational inequity. Nor is it self-evident that current consumers are best able to manage that risk.

79. Thirdly, increasing costs now is in itself a signal that GPBs don't believe in a gas future and they don't want to commit to a long term service. A combination of a higher transport cost, and this belief signal will be factored into consumer decisions to commit to or stay with gas and encourage either early switching away, or close shop and go to other jurisdictions. This applies equally to the upstream who need to have a sense that their investment to develop contingent resources can rely on a transport infrastructure being there. Perversely the so called "death spiral" could happen more quickly because of this approach.

80. We don't discount that proposed measures to accelerate revenue might become necessary at some point. We just don't see that there is sufficient information now to suggest that asset stranding risk for gas pipelines is any more real now, then it has been in the past. We also see more potential costs than benefits for consumers if the Commission was to act on the GPB request.

81. Finally, the best interest of the whole gas industry, not just for consumers, is for the pipeline owners to prove that the repurposing scenario is more likely than wind-down. They can do this by accelerating their proof of concept timetable so that technical demonstrations have a more ambitious timetable than waiting to 2030 to start introducing blended gases into the network.

Conclusion

82. The key conclusion from our analysis is that we don't believe that the speculative risk of stranding risk is any stronger than what it has been in the past and that the threshold to act on this perception has been reached.

83. In our view there is time to review this matter in an orderly and deliberative manner further through the normal scheduled IM review and consider whether adjustment to FCM settings should apply from 2026/2027.

Next Steps

84. First Gas in their submission proposes that the Commission considers a stakeholder workshop on capital recovery options is warranted as early as October.[33] This presupposes that the Commission should be acting on capital recovery risk within this DPP process.

85. While we are open to the idea of participating in such a workshop, we consider this premature and only useful if the Commission believes on the balance of the evidence that it is necessary for them to act now.

86. We therefore believe that the central issue for the Commission at this point is forming a view on whether the speculative risk of asset stranding is real and/or urgent enough that it needs addressing within DPP3 before it addresses various alternatives to deal with this.

87. We would prefer the Commission to decide on this matter first. We consider that we have raised a number of questions and objections to the arguments for haste that could warrant the Commission investigating this further. We are happy to be included in this process.

88. Once the Commission is confident that it has arrived at a balanced position, it would then be useful for the Commission to publish a paper that crystallises the issues ahead of them, and their further approach to completing the process.

Yours sincerely

Richard Hale/Len Houwers
Hale & Twomey Ltd/Arete Consulting Ltd
Secretariat for the Major Gas Users Group

[33] First Gas submission on gas DPP 2022 process and issues paper-30 August 2021 – Summary P2, Next Steps P13