14 March 2022

Matthew Clark
Manager, Price-Quality Regulation
Commerce Commission
P O Box 2351
Wellington
By email to regulation.branch@comcom.govt.nz

Dear Matthew

Re: GPB IM Review and DPP3 Reset.

1. This following submission is in response to the Commerce Commission's *Proposed amendments to input methodologies for gas pipeline businesses to the 2022 default price-quality paths* (IM paper), and the draft reasons paper *Default price-quality paths for gas pipeline businesses from 1 October 2022* (DPP paper) dated 10 February 2022. This submission is on behalf of the Major Gas Users Group (MGUG)[1]:

    a. Ballance Agri-Nutrients Ltd
    b. Fonterra Co-operative Group
    c. New Zealand Steel Ltd
    d. Oji Fibre Solutions (NZ) Ltd
    e. 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.

[1] Refining NZ left the group at the end of 2021 as a result of its decision to close the refinery and convert to a fuel import terminal.

Summary of Our Submission

Gas IM amendment process

X 1 We believe that the measures proposed by the Commission on the IM amendments are the reverse of the Commission's intention that these assist the purpose of S52A. The Commission has not followed appropriate process and in this instance appears to have elevated the principle of ex-ante FCM ahead of long term consumer interest.

X 2 The proposed DPP3 price shocks are not in the interests of consumers and would reasonably be expected to accelerate demand destruction to the detriment of those majority of consumers who are unable to fuel switch and seek alternative gas delivery options.

X 3 The announcement on 10 February 2022 of substantive changes to the gas IMs ahead of the normal IM review created a window of less than 4 weeks to respond to all of the issues and reasoning outlined across 24 documents. Under s52V(2)(b) of the Act[2] we don't consider this compressed timeframe to give parties a "*reasonable opportunity*" to engage effectively on extensive amendments to a foundational building block of gas IM.

X 4 There are a number of other errors in process and reasoning that we see as potential challenges to the Commission's findings, including:

a. The Commission interpretation of "gas pipeline services" as being restricted to "natural gas" conflicts with the overall intent of part 4 to regulate markets with little or no competition. s52G provides an opener to consider goods and services that fit this definition. The restrictive interpretation of what constitutes gas pipeline services has also led to unreasonable assumptions that RAB of GDBs would be left economically stranded despite RAB having a residual value for repurposing. The Commission's interpretation also discounts the long term interest consumers have in gas pipeline services continuing to offer consumer energy choices.

b. In setting up the factual, as changing the gas IM settings to create a *certain* price shock for consumers ahead of the usual IM process, the counterfactual becomes letting the usual IM review address the foundational building block parameters to apply from the next regulatory period in 2026 which *may* lead to a price shock. In using its economic stranding risk model to justify accelerating settings to DPP3 the Commission hasn't assessed whether the detriments of the certainty of proposed price shocks in DPP3 are outweighed by the benefits to consumers of the counterfactual where price shocks may not be needed, or indeed are likely to be shared across a *larger* consumer base.

c. We believe that the Commission has confused climate policy with energy policy in its reasoning. While climate policy is substantially formed, new energy policy has not[3]. The Commission is acting ahead of yet to be determined energy policy for gas.

X 5 The combination of a rushed process and reasoning errors, has led to the wrong conclusion that accelerating revenue for GDBs is in the best long term interest of consumers. If the Commission

[2] S52X gives effect to s52G in this context.

[3] Existing energy policy is agnostic towards gas.

had allowed for a more measured and deliberative assessment process we consider that the Commission would have arrived at the opposite conclusion on the best long term interest for consumers.

X 6 The current energy transition is being driven by policy rather than technology as has been the case historically. The policy driven transition is also expected to occur up to three times faster than previous energy transitions[4]. The current regulatory settings of five and seven year reviews of price paths and input methodologies no longer appear to be fit for purpose in this accelerated energy transition environment. We consider this gas IM process demonstrates the need for regulatory reform in Part 4.

X 7 The reasoning for considering that the urgency of the IM amendments should override the opportunity to do this in the normal IM review process is not convincing. Accordingly we submit that for foundational building block IM matters for gas that these should be left to the usual IM review process starting in 2022. The updated IMs from this process would be expected to apply from DPP4 starting in in October 2026.

Gas IM Reasoning

X 8 The key assumptions underpinning the Commission's arguments for urgency have come from the Commission's interpretation of the public policy environment and the revenue models of the GPBs. We believe that the Commission's reasoning is fundamentally flawed:

a. There are no energy policies for gas on which it is necessary to act now. Specific new policies are yet to be announced and may become more apparent through the development of a national energy strategy in 2024. The Commission is acting ahead of policy. We think that it sets a poor precedent to base fundamental decisions on what policy decisions *might be*, rather than what has actually been decided.

b. While there is political consensus on the purpose of the Climate Change Response Act 2002 that "*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*" there is no political consensus for the energy policies being promoted by the Climate Change Commission. The lack of the current government's support for some of the CCC advice is also evidence that energy policies may not be durable over the political cycle.

c. While MGUG do not dispute a reduction in natural gas demand is likely, we've previously made the distinction between different types of demand and revenue drivers for GPBs in our earlier cross submission on the process and issues paper. By differentiating consumer classes and mapping these to GPB revenues it is possible to have both a significant reduction in gas demand, and still retain the majority of the revenue to maintain a viable pipeline business.

[4] The Oxford Institute for Energy Studies (October 2019) " *A road map to navigate the energy transition*" - https://www.oxfordenergy.org/publications/a-road-map-to-navigate-the-energy-transition/

X 9 The counterfactual (applying IM settings from DPP4) hasn't been adequately addressed in the reasoning. The stranding risk model used by the Commission offers no answer as to why making IM amendments in DPP3 versus in DPP4 is in the long term interest of consumers. It only offers an answer to the value of acting now, versus never acting at all.

X 10 The modelling work also falls short in assuming that there is no residual value in the pipelines in addressing ex-ante Financial Capital Maintenance (FCM) risk. This seems largely an outcome determined from the Commission's interpretation from statute on the scope of "gas pipeline services" in the Act. We think that this is a significant assumption to make without more robust analysis of the legislation. Part 4 deals with a type of market (little/ no competition) and S52G allows the Commission to consider which goods and services may be regulated. Clearly pipelines have an economic life beyond transporting 100% natural gas. In assessing this against S52A the Commission also hasn't considered that consumers may have a preference for gas and care less about the narrow distinctions of "natural gas" with blended gases if it continues to deliver wider consumer energy choices for them.

X 11 To the extent that the assets do have a residual value, the legal fiction created by the Commission's interpretation of gas pipeline services creates an asymmetric risk for consumers. Consumers are expected to compensate GPBs for economic stranding of natural gas pipelines, but then receive no claw back benefit when these same lines are repurposed for other gases.

X 12 The pipeline repurposing options are under active consideration by GPBs (including First Gas receiving funding from the government for funding hydrogen trials) demonstrating that GPBs are also the parties best able to manage natural gas economic stranding risk. GPBs also have the ability to influence and shape future energy policies to keep gases in the energy mix through the development of the national energy strategy.

> *The Government expects to consult on the National Energy Strategy later this year.*
>
> *Woods says this will require a more interactive approach than previous consultations, with regular industry input rather than a discussion document and a six-week submission period.*
>
> *She has asked officials to look into running regular industry workshops so Government can listen to – and incorporate – their concerns and ideas.*
>
> *"We need to have an ongoing conversation."*
>
> https://www.energynews.co.nz/news/electricity/116667/woods-welcomes-industry-dry-year-solutions-work

X 13 The qualitative statements on why DPP3 amendments are in the long term interest of consumers seem misplaced:

a. The argument that this avoids "unmanageable" future price shocks (because they are assumed to be shared across a smaller customer base) is countered by the fact that the consumer base, especially for GDBs, is expected to grow through DPP3. The price shocks of DPP3 will fall on a smaller base now than it would in 2026.

b. Future price shocks are speculative and may not occur, whereas the current price shock is being guaranteed. The net benefit test has not been demonstrated by the Commission.

c. GPBs do not need additional incentives to invest in safety and reliability. These are already prescribed as a condition of business in both Price Quality (PQ) regulation as well as petroleum pipe regulation under Health and Safety legislation.

X 14 The best long term interests of consumers as well as pipeline companies, other gas market participants, and New Zealand in general comes from gas in its various forms continuing to be an energy choice for households and businesses. The DPP3 settings creating price shocks for consumers undermines further confidence in the gas sector and creates a greater risk that gas demand is being destroyed from within the gas economic system, rather than through government policy.

X 15 On balance of the evidence and arguments, we believe that the measures proposed by the Commission on the IM amendments are the reverse of the Commission's intention that these assist the purpose of S52A. The Commission in this instance appears to have elevated the principle of ex-ante FCM ahead of long term consumer interest.

Structure of the Submission

3. This submission is in two parts:
    a. The gas IM amendments, and why the case for deferring decisions on IM amendments are better left for the IM review and why this would better promote the purpose of S52A.
    b. Other DPP settings.
4. The significantly reduced window of time for responding to the impacts of the surprise draft decision on gas IM matters has meant that we've had to focus most of our time, energy, and resources on reviewing and challenging the draft IM decision. Significantly less time was left to review other decisions on DPP3 settings. This has affected the depth on which we could respond to other DPP settings and may have to deal with these matters further in the cross submission process.
5. We consider the process for setting the parameters for DPP3 and IM to have fallen well short of what we have previously experienced with the Commission on IM and DPP reviews. MGUG would not be alone in having assumed that the Commission's announcement of 8 December 2021 on setting a four-year regulatory period for DPP3 was the substantive extent of changes to the Commission's usual process for determining starting prices. The only reference to IMs in that communication related to WACC adjustment for a four year regulatory period. The notification on 10 February 2022 of comprehensive amendments to gas IMs gave less than 4 weeks to absorb 24 separate documents to submit on. The direction being taken by the Commission surprised our members as the justification for accelerating revenue in the process and issues papers appeared to us to be weak once the proper context was considered. MGUG provided a detailed set of evidence to the Commission as to how the Commission's evidence base was being misread. So while we were prepared for a shorter regulatory period as was announced on 8 December we did not expect the Commission to go ahead with anything more than that. The lack of notification until 10 February on a significant shift of IM assumptions to be used in DPP3 has constrained our ability to respond effectively.

Gas IM amendments for Economic Stranding Risk

Summary

The following table summarises the points expanded on in further detail below:

Table 1: Economic Stranding Risk Reasoning

Commission Reasoning	MGUG Response
• Context = Government emission target. • Policies seem likely to lead to reduction in gas. • Network stranding in 2050 "feasible"	• Context is energy policy, including policies for gas in the energy system. New policies haven't been set. Existing energy policies agnostic to gas provide the correct context. • Emissions target is a climate policy and specifies a target of *net accounting carbon zero* by 2050. Not zero carbon, not zero carbon gas, and the accounting reference implies that reductions can come from purchase of overseas carbon credits. • Political consensus on durable long term energy policies may not eventuate • It is possible to have significant lowering of national gas demand whilst still having viable GPBs when revenue rather than physical demand is considered. • Gas pipelines have a comparative advantage in transporting energy, and energy storage vs energy transport via electricity wires. In providing an *energy transport service* gas pipelines are not inherently redundant assets. • Network stranding risk is highly speculative at best, and only feasible if we accept a range of assumptions to be true.
• Part 4 limits CC to consider only "natural gas" in definition of gas pipeline services. Repurposed pipeline is outside scope. • CC can consider residual value of gas pipelines in determining economic stranding risk, but; • CC has determined that residual value should be zero – RAB is "stranded"	• Part 4 overriding purpose is to address a type of market (little competition). Act is silent on whether repurposed gases could be included, but S52G provides an opener for it to be included within pipeline services. • Repurposing implies that gas pipelines do have residual value. • Residual value in repurposing implies RAB is not stranded (including for non-depreciable assets such as easements).
Counterfactual (term not used, but implied) = Do not adjust IM settings for gas in DPP3 and allow IM review to occur first and apply settings in DPP4.	• Agree with the counterfactual. But, if consumer detriments of factual equate to approximately \$160 million of immediate price shock, and higher future costs and a higher risk of asset stranding, then what is the consumer benefit to meet the net benefit test?

Commission Reasoning	MGUG Response
"Compelling Reasons to act now"	**"Compelling reasons" overplayed or non-existent**
• Considered amending asset valuation in 2016 – current circumstances warrant taking such actions now	• Covered in discussion as to why current context should have a more nuanced interpretation. The Commission has misread the situation.
• In 2016 review noted GDB risks less than for EDBs. Could revisit gas IMs if future developments were to impact on gas networks	• 2016 reasons as to why accelerating prices for GDBs faster than EDB is a bad idea still hold in 2022.
• "material risk" of accelerated decline in the use of gas pipelines.	• CC has conflated demand with revenue in a way that is simplistic. The risk to *revenue* is not material. • Rather the Commission's proposal is what creates the material risk • CC also discounts repurposing value (see argument above).
• Proposed mechanism is NPV neutral • Less serious implications for errors	• Creating certain price shocks now vs speculative price shocks later increases stranding risk. • Consumers carry an asymmetric risk where they pay for preserving the ex-ante FCM principle but receive no clawback if assets are repurposed for other gases.
• Important to signal confidence in ex-ante FCM by acting now • Early action *lessens* the chances of network stranding becoming unavoidable. • Incentivises GPBs to continue to invest to maintain safe and reliable services for consumers.	• S52A benefit to consumers overrides ex-ante FCM expectations. • Ex-ante FCM not guaranteed (only reasonable expectation) • Early action *increases* the chances of network stranding (through substitution effects and lessening of sector confidence to invest) • Ex-ante FCM guarantee better where assets can continue to be provided for transporting "gas". • More capital recovery certainty doesn't incentivise safe and reliable services. Incentives to invest to maintain safe and reliable services isn't optional. PQ regulation and petroleum pipeline regulations already provide for minimum acceptable reliability and safety standards. Protection of corporate reputation also isn't optional.
Asset stranding Risk model quantifies the material risk. "Proves" that amending asset valuations is effective in providing reasonable expectation of ex-ante FCM.	• Counterfactual argument is not demonstrated by the model. Asset stranding risk model quantifies risk of not acting now. It doesn't quantify risk of not acting now vs acting in DPP4 (the counterfactual)

Commission Reasoning	MGUG Response
	• Asset stranding risk model flawed in assuming zero residual value (i.e. RAB is stranded). • Asset stranding model assumes declining MAR – (demand revenue conflation error). MAR growth still feasible.

Key Assumptions – Commerce Commission

6. We engaged directly with Commerce Commission officials to better understand their underlying thought process which led to their draft advice[5]. Our interpretation of these engagement sessions was that a key consideration was the government's net zero carbon agenda [6] (although this terminology seemed to be used interchangeably with the phrase "2050 zero carbon agenda" which is clearly not the same thing). This seemed to form a strong and persistent view from Commission staff that this created a level of certainty for loss in gas demand to the extent that gas pipeline economic stranding was a more than likely outcome by 2050[7].

7. From this belief framework the Commission then developed a spreadsheet model for stranding risk to quantify the extent of economic stranding and how various mitigation measures (accelerating depreciation, or non-indexing of RAB value) might help meet the principle of ex-ante Financial Capital Maintenance (FCM). The various modelling permutations trialled then suggested the X values and adjustment factors for each GPB [8].

8. For further clarity all modelling was based on what constituted "*gas pipeline services*" particularly whether gas could be anything other than natural gas.

> *when exercising our judgement, we are guided by what best promotes the long-term benefit of consumers of natural gas pipeline services[9].*

DPP paper – 2.10.3

> *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.*

DPP paper – 3.30

[5] Meetings 2 March, including presentation on the Commission's Asset Stranding Risk model
[6] Also in DPP paper – Chapter 3 Context of our draft decision
[7] The Commission's modelling tested 2040, 2050,2060, and 2070 as stranding years, with 2050 considered the reference case
[8] DPP paper – tables 4.3 and 6.2
[9] Note that the Act doesn't mention "natural gas pipelines" it only refers to "gas pipeline services"

9. It is not explicit how this interpretation by the Commission flows through the reasoning and advice. However by limiting the definition of gas pipeline services to the conveying of natural gas, this has seemingly created the counterintuitive scenario where natural gas pipelines can be repurposed without interrupting revenue for GPBs but argue nevertheless that the asset is being economically stranded.

What is the counterfactual being considered?

10. The Commission acknowledges that the IM amendments proposed for the draft decision affect foundational building blocks of the regime and that under "normal" circumstances these changes would only be considered as part of the statutory IM review cycle[10].

11. The Commission then outlines its "*compelling reasons*" to make the amendments outside of the normal statutory IM review cycle[11]. A number of these appear to be supporting statements, rather than compelling reasons. For example, while it describes the 2016 IM review as having set a precedent in considering economic stranding this isn't a compelling reason to commit to a pathway in 2022. The main compelling reason we can see, is described as "***material risk** of accelerated decline in the use of gas pipelines for conveying natural gas*". The material risk is considered so urgent by the Commission that mitigation can't wait to be applied in DPP4 through the normal IM review process.

> *"If we were to wait until the upcoming IM review then the proposed solution would not be available to be implemented until DPP4. We consider being able to address the current risk of economic network stranding in DPP3 is important **to support the expectation of real ex-ante Financial Capital Maintenance (FCM)** over the long-term and consistently apply our regulatory framework going forward. Early action lessens the chances of network stranding becoming unavoidable and helps preserve optionality for managing future uncertainty. As a consequence, we expect GPBs to be incentivised to continue to invest to maintain safe and reliable service for consumers while being limited in their ability to extract excessive profits."*

IM paper – para 3.25.5

12. The statement seems somewhat revealing that a pressing concern for the Commission was supporting the real ex-ante FCM principle rather than balancing benefits and detriments for consumers.

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.

14. The statement that "e*arly action lessens the chances of network stranding becoming unavoidable and helps preserve optionality for managing future uncertainty"* is also one we would disagree

[10] IM paper – para 3.24
[11] IM paper – para 3.25

with. We argue that early (and possibly unnecessary) action **increases** the chances of network stranding. We cover this in more detail further in our submission.

15. The Commission's statement does reveal what appears to be the counterfactual. It is one we agree with and underpinned our submissions in 2021. T**he counterfactual is waiting until DPP4 to implement possible measures for preserving FCM (should these be needed).** While the counterfactual is never explicitly stated as being such we infer this from the Commission's various other statements:

> ***In response to increased risk of economic network stranding we could wait for more certainty***
>
> *Under our existing framework we can either take action now, or credibly commit to acting in a future regulatory period if the risk remains or increases e.g., an early shut down becomes unavoidable.*

DPP paper – para 6.64

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 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.

Where is the evidence to promote the factual?

18. With respect to the claim that gas IM amendments *can't wait* for the outcome of the normal IM review we tried to find something more than an assertion that explained the Commission's reasoning for holding this view.

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[12] 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

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

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[13]. We think that this question needs an answer given that what the Commission proposes for DPP3 will be significant price 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[14].

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.*

[13] 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*."

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

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, 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.

Key Assumptions – another view

28. Considering the emphasis given by the Commission on their view of the future and its design into their in-house financial model we consider it appropriate to examine the plausibility of some of the assumptions being made.

What are we uncertain about?

29. Much of the uncertainty that the Commission appears to be grappling with is trying to decide what energy choices will be available in 2050 (28 years from now) , and how consumers might decide on which energy option they prefer, in order to make an assessment whether gas pipelines can be considered as economically viable.

30. In an era where change is happening exponentially, including technology progress, and cost reductions for those, these decisions can only ever be speculative, and assumptions will need to be continually updated.

31. By framing the question in a different way we can however have more certainty that gas, and gas pipelines offer a comparative advantage in energy transport, reliability, and storage, particularly over electricity. In other words, gas pipeline services, viewed as an *energy transport service* is much easier to assess as likely to continue as a viable consumer service. This approach doesn't require any assumptions about which energy form is better, or cheaper. It also

minimises other assumptions to ones that are likely to continue to hold based on what we know now. These include:

a. The government has a long term objective to reach net carbon accounting zero emissions by 2050.

b. Primary energy choice should be as broad as possible in order to maximise optionality. Energy forms aren't inherently bad and externalities have a number of alternatives to mitigation.

32. These minimal assumptions are all that is needed to frame the question whether gas pipelines themselves can continue to facilitate choice in the energy mix in 2050.

33. The Australian Pipelines and Gas Association (AGPA) has recently published a techno-economic analysis on least cost energy transport and storage in a net zero future evaluation on pipelines vs powerlines[15]. While this is in an Australian context, and there are differences with a New Zealand context in terms of end use energies and extent of underground gas storage, other techno-economic matters are less geographic specific.

34. Australia has also set out a 2050 vision for gas, which New Zealand hasn't. However New Zealand is likely to develop a similar 2050 vision for gas as part of the national energy strategy conversation. Crucially, Gas Vision 2050 sets out the ways that Australia's gas system is set to achieve net-zero emissions by 2050.

35. The key conclusions from that study were:

a. Lower historical cost of energy transport via pipeline than via powerline;

b. Pipelines are more reliable and have less local impact than powerlines;

c. Energy transport via new pipelines costs less than energy transport via new powerlines;

d. Energy storage in new pipelines costs less than energy storage in BESS or pumped hydro;

e. Hydrogen customer benefits greater than lower transport and storage cost alone.

36. Equally the conclusion that we should draw from this is that we should have more confidence that gas pipelines can continue to provide an energy transport service, even within a net-zero emissions 2050 environment.

Confusing transition definition

37. Our interactions with various central government officials and general conversations since the CCC released its draft advice in February 2021 indicates considerable confusion between the distinction in meaning between *transition to a decarbonized economy* and a *transition from fossil energy to renewable energy*. While linked, they are not the same in terms of the intended outcomes. One is a climate policy, the other is an energy policy.

[15] Pipelines vs Powerlines: a summary Least-cost energy transport and storage in a net zero future https://www.apga.org.au/resources/research-and-other-reports

38. The Climate Change Response Act (CCRA) and Paris Climate Accord align with the decarbonised economy definition of transition, where the ETS scheme is the primary market based scheme for achieving a climate policy outcome. The *energy* policy settings advised (but not formulated) by the CCC e.g. renewable energy targets, fossil fuel bans, etc. tend to promote a renewable energy transition[16]. The two definitions are not mutually exclusive but it would be wrong to assume that New Zealand's primary climate goal in 2050 has to be met by eliminating natural gas from the energy mix.

39. We commented extensively on how to interpret the CCC process and advice, in our 13 September 2021 cross submission. In summary, the CCC had to provide a *demonstration pathway* to back its advice on how *overall national emission targets* could be achieved. It is neither a forecast nor a prescription and was heavily constrained by the requirement to consider only currently commercially demonstrated technologies in New Zealand. Biogas and hydrogen blending in gas systems was considered out of scope (ironically in the same way as the Commission's interpretation on gas pipeline services)

Confusing policy interpretation and durability

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"[17].

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.)[18]. Technologies considered as unproven (e.g. methane

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[16] We believe as a means to achieving the first, but constrained heavily by the caveat that the Commission could only rely on what is commercially proven to provide a demonstration pathway to their advice. The reality is that decarbonizing options will continue to become available.

[17] NZIER Insight 100-2022 "*Fast forwarding technology to address climate change*" https://nzier.org.nz/publication/fast-forwarding-technology-to-address-climate-change

[18] Azhar A. (2021) "*The Exponential Age: How Accelerating Technology is Transforming Business, Politics and Society"* - ISBN: 9781847942906

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[19]. The other is around the idea that gas connections should be banned by 2025.

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[20] (Figure 1)

45.

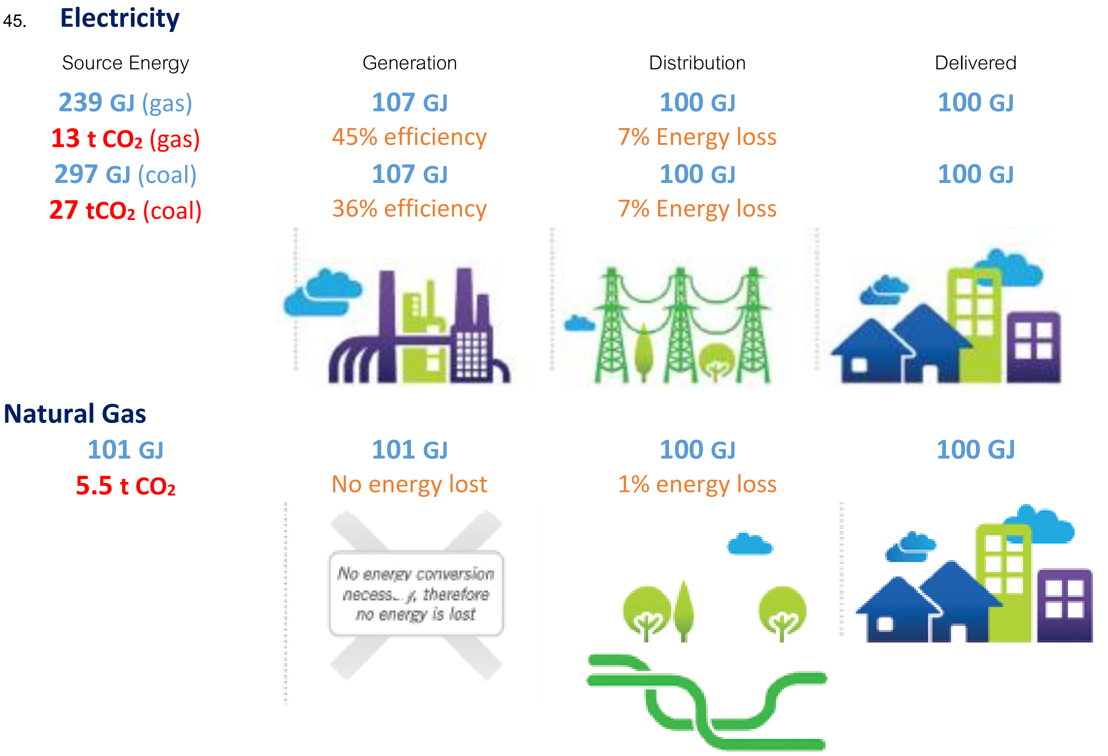

Figure 1: Fuel Cycle Comparison - Consumer Energy

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[19] Business Desk – 3 March "*Govt backs down on permanent exotic forests in ETS*"

[20] 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[21]. The Minister made a statement at the BusinessNZ Energy Council webinar on 10 March 2022 supporting gas[22].

> *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.[23] 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%[24].

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[21] Note that lower carbon gases would include blending zero carbon gases with natural gas.
[22] https://www.energynews.co.nz/news/electricity/116667/woods-welcomes-industry-dry-year-solutions-work
[23] 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.
[24] Note this doesn't include associated liquids that net off against oil imports.

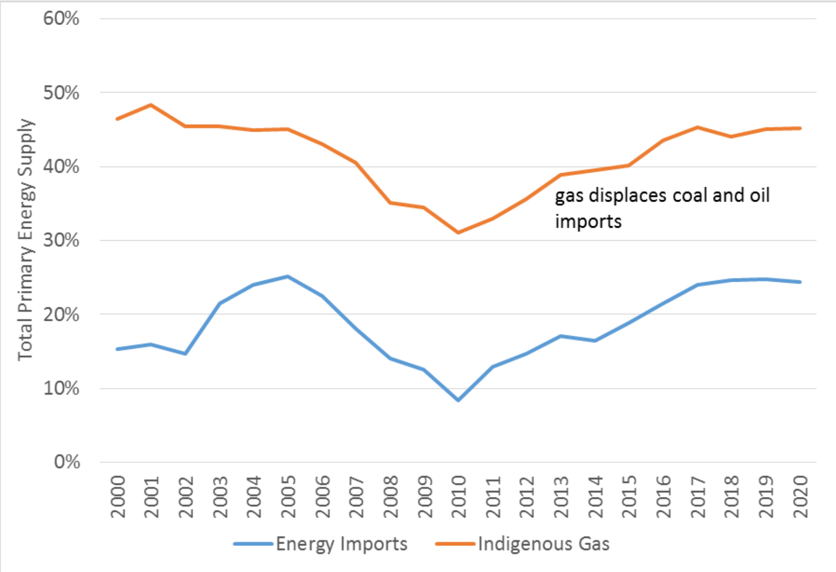

Figure 2: Indigenous gas contribution to energy independence and carbon minimisation[25]

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.

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[26]. We haven't seen this important distinction carried through into the Commission's analysis. Focusing on gas volume profile rather revenue profile leads to problematic conclusions about pipeline viability.

[25] Source: MBIE - Energy In New Zealand
[26] 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

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 6).

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.

Economic stranding risk model

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.

60. Nevertheless even while we appreciate the narrow definition of "*natural gas*" that the Commission works with assumes that gas pipeline services can't be considered in the current regulatory framework for "other gases", we note the Commission does accept that economic loss is reduced by the residual value of the asset.

> *However, we can account for potential residual network value for GPBs under current policy settings.* ***There is the potential for residual value from repurposing towards 'clean' gases*** *or because existing networks conveys natural gas longer than expected.* ***To the extent that the residual value is realised, it would reduce the risk of economic network stranding*** *(Chapter 6) and costs to existing consumers of natural gas.*

DPP paper – para 3.32

61. Unfortunately we do not see any attempt within the Commission's modelling work to consider residual value as part of the economic stranding risk. Rather the Commission's modelling explicitly assumes that there will be no residual value.

> *"we consider it credible given the 2050 target that networks could shut down by 2050 with no residual value".*

DPP paper – para 6.112

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).

63. The Commission's stance on treating pipeline assets as having no residual value in a repurposing scenario also adds up to an asymmetric risk for consumers. Consumers are required to compensate GPBs for natural gas asset stranding but get no claw back opportunity when these are repurposed to convey other gases.

64. The risk allocation principle also states that risks should be allocated to the party most able to manage the risk.

> *In our 2016 IM review decisions framework we stated that managing risks includes:*
>
> *6.58.1 actions to influence the probability of occurrence where possible;*
>
> *6.58.2 actions to mitigate the costs of occurrence; and*
>
> *6.58.3 the ability to absorb the impact where it cannot be mitigated*

DPP paper – para 6.58

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[27]” 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 MAR 170% of 2023[28]. The adjustment factor is 1.574, the real MAR increase is -1.91% and the X factor is 1.61% (Figure 3)

[27] Generally attributed to statistician George Box

[28] 170 % is approximately 2% compounding over 27 years

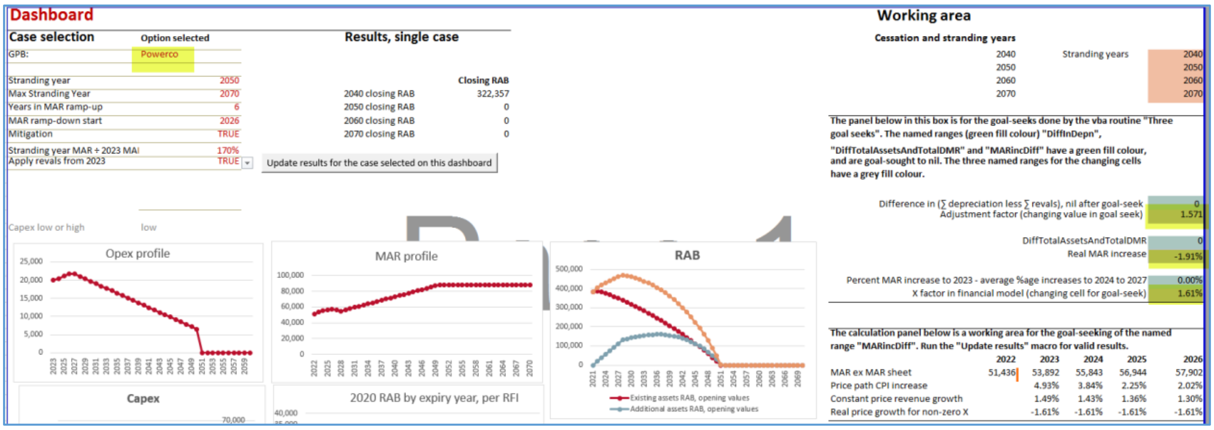

Figure 3: Powerco case

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.

74. Lastly, the Commission described the future and outcome of the modelling work as "*feasible*"[29]. This may be a fair statement as a subjective view but it lacks other context, such as what

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

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%[30] 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.

76. An approximation for consumer detriments in acting now, is the additional revenue transferred from consumers to GPB. At $41 million pa for 4 years that is $164 million. In addition, through price elasticity and substitution effects it is likely that more consumers will opt out of gas during DPP3 than otherwise would (switching to LPG or electricity instead). The future consumer base will be smaller, risking the death spiral the Commission is hoping to avoid.

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.

78. The next step for the Commission, having run these models was to demonstrate why addressing FCM risk by significantly raising prices now should also be in the "*long term interests of consumers*"[31]. The counterfactual test requires that the Commission considers ***net*** long term benefit.

Best Interest of Consumers

79. A key implicit contention of the Commission is that the market for GPB services is likely to be worse in 2026 relative to its current state. This gives both less time to react, as well as a reduced customer base on which to reduce the impact of revenue shocks. Without knowing what the policies towards gas might actually be, or indeed whether these might have any material impact on GPB revenue, the Commission proposes to create a price shock now to minimise future (speculative) pain.

80. This has generated an assertion that the long term interests of consumers are being served by giving GPBs more consumer revenue now in the hope that it might be paid back later so that

[30] 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.

[31] For clarity we assume that the principle of FCM is not overriding the principle of consumer benefit.

no-one can be considered worse off. The Commission would presumably label this a “no regrets strategic move”. In contrast we see the potential for regret.

81. We’ve already addressed the assertion that accelerated revenue gives GPBs greater incentive to maintain the safety and reliability of its services and that consumers should value that. Safety and reliability of gas pipeline services aren’t options that GPBs can choose to have less of. Aside from statutory obligations to provide minimum (socially acceptable) standards of performance we would also expect that corporates would value their social license to operate and would be reluctant to put their brand reputation on the line. For companies such as Vector and Powerco who also run EDBs we think this would be especially important.

82. The Commission hasn’t explored this as a benefit, but presumably all the additional revenue could be put to investing in assets that secure a repurposed future, which would be beneficial for consumers. The GPBs would need to do this outside of Part 4 as the Commission has already determined that CAPEX and OPEX for repurposing are not allowable expenditures. We see no tangible evidence from GPBs that they would take on this commitment beyond the very small steps being taken in this direction.

83. This only leaves the issue of whether a price shocks starting in 2026 would be materially worse for consumers than one starting in 2022.

Gas Market and GPB Market as is

84. We’ve already covered this extensively in our cross submission but we repeat some important points here:

    a. Revenue drivers for GPBs are determined by customer segments.

    b. The mass market (residential and commercial) connections are particularly important for GDBs;

       As we noted in our cross submission, GDBs driver of revenue (68%) is mass market connections (Figure 4) which also delivers the highest average revenue by customer ($11.33/ GJ) (Figure 5). The question is why would any commercial entity look to undermine its revenue driver?

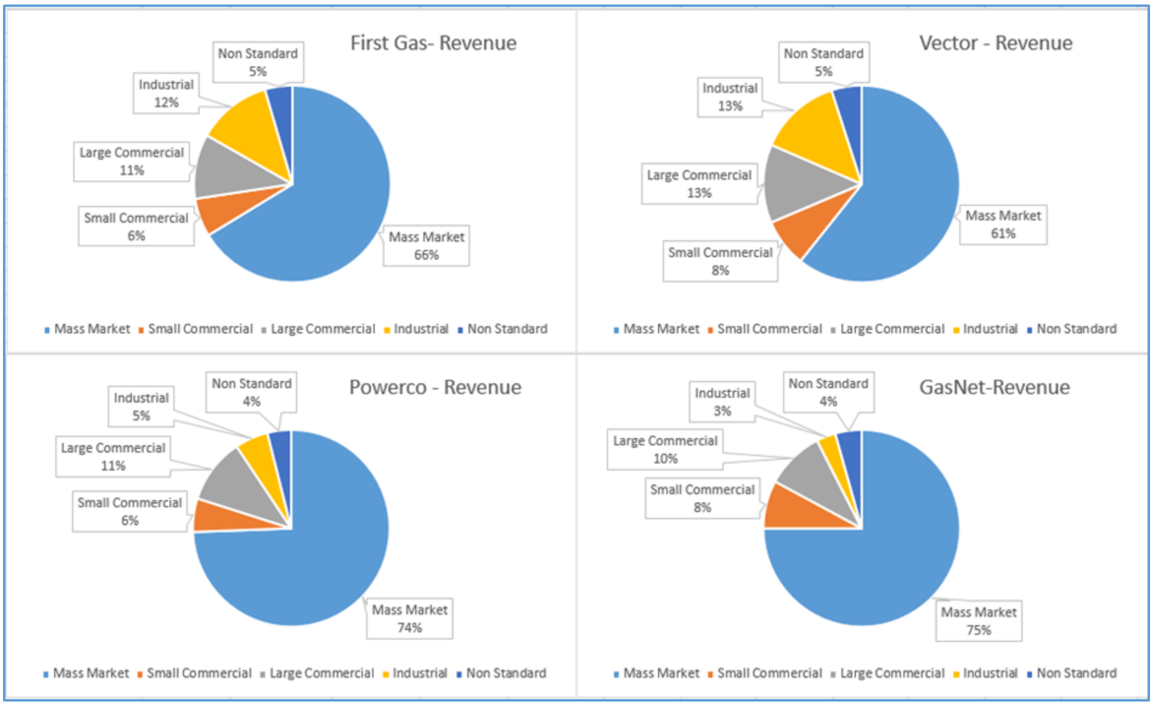

Figure 4: Revenue Drivers for GDBs

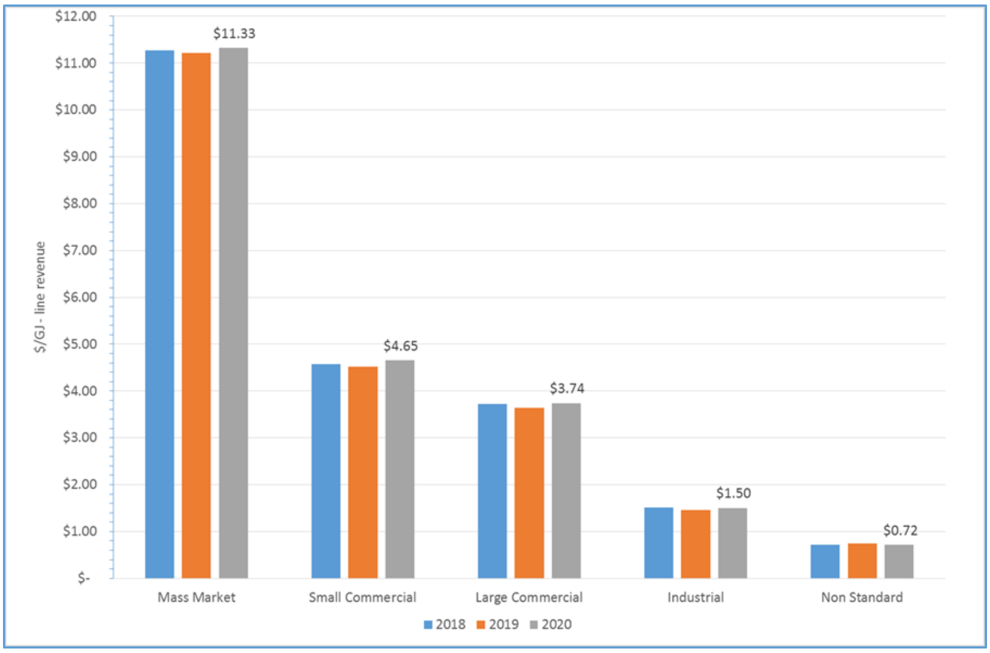

Figure 5: Average revenue

85. Even for GTBs, gas demand is not a good indicator of revenue generated (Figure 6).

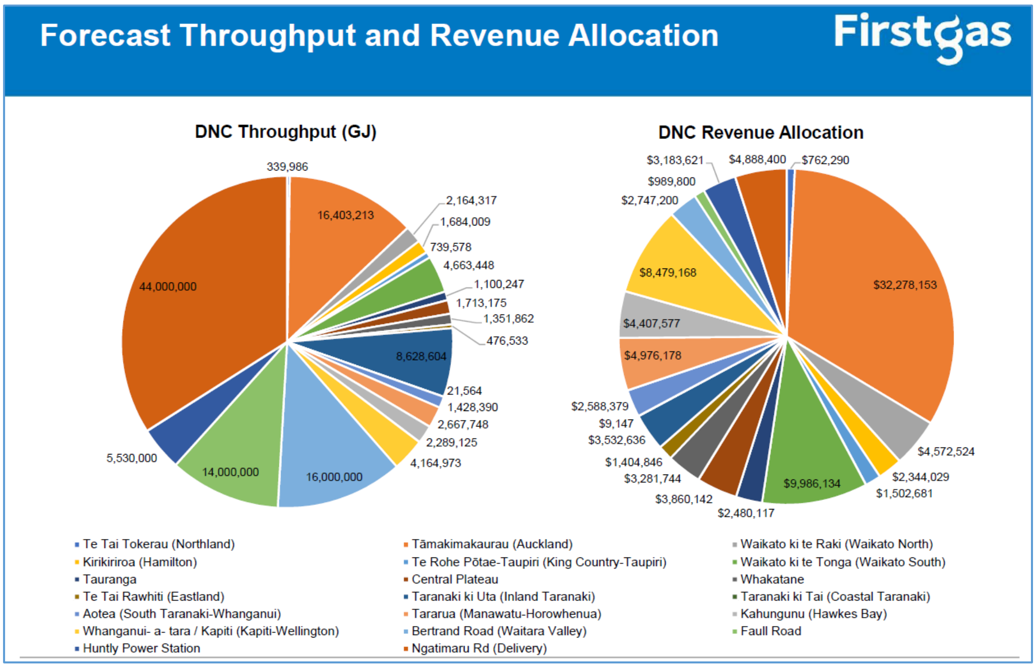

Figure 6: Illustrative connection between revenue and demand for GTB[32]

86. 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.

87. 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 have a lower carbon cost under the ETS because the economic risk to New Zealand of carbon leakage is high. These industries will take some time to transition, and gas is likely to be a preferred option for some time for them.

88. GTBs operate under a total revenue cap so revenue risk is lower for them than GPBs. Again we think it's important to put that in the context of what the landscape might look like in 2026, not in 2050.

89. GPBs operate under a WAPC and are incentivised to grow demand (connections). Their AMPs indicate that they are still projecting connection growth through DPP 3.

90. Perhaps it's not self-evident for the Commission that customers serviced by GDBs represent the most resilient part of the consumer demand for gas and are expected to be the last to exit the market. This has been a generally accepted principle for people working within the gas sector. The most recent statement of this is found in GIC's Gas Market Settings Investigation. As part of its work the GIC commissioned Concept Consulting to produce the study "*Gas demand and*

[32] With permission from First Gas

supply projections – 2021 to 2035". The following extract highlights the assumption of demand resilience in the mass market/ industrial sector .

> *"Ultimately, the availability of gas for all users depends on producers' willingness to invest more capital in supply-side assets. The investment requirements are potentially very large. Gas Industry Co estimates the industry needs to invest $300-500 million every 3 to 5 years to produce existing reserves and maintain production levels. Some industry experts project even higher requirements. For example, Enerlytica recently projected that over $2 billion would be required during the 2020s to maintain current production levels.*
>
> ***The level of investment will be influenced by wholesale customers' willingness to sign multi-year contracts. Looking forward, we expect mass market and industrial gas customers to continue to be attractive to producers as a source of contracts to underpin investment. Similarly, we expect petrochemical producers (especially for methanol production) to remain as a foundation to underpin investment in reliable gas supply".***

P3 – Outlook for **2022 to 2035**

91. We touch on the wider gas sector investment in the next section as to why the Commission's IM amendments would undermine investment confidence. The above statement is to reinforce the claim that GDB gas demand is resilient.

92. While forecasts will always need caveats, they can't predict the random disruptions/ shocks that might affect the outcome. One such shock is the impact of raising line charges at rates faster than CPI and faster than competing energy (electricity and LPG). While the Commission's model doesn't test this, from an economic theory perspective we would predict that connection growth would be less under these circumstances. (i.e. create a downward demand as a result of raising prices, not government policy)

93. A further feature of the connection projections is that it demonstrates that if the Commission is concerned about mitigating price shocks over the largest possible consumer base it should *defer* the price shock, not bring it forward.

Accelerating revenue now

94. We looked at the argument that accelerating revenue now is more beneficial than deciding to do this in 2026.

95. In 2016 the Commission's view on accelerated revenue was the opposite of what it is now supporting in 2022[33].

> *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***

[33] 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

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.

96. Aside from competition from electricity, natural gas consumers also have a choice of LPG as an alternative to both electricity and natural gas. For existing gas appliance connections, conversion kits are widely advertised[34]. For new connections, LPG offers a relatively straightforward comparison ahead of investing in appliances. Monthly rentals for 2 x 45 kg bottles are around $10 ($0.33/ day) versus current natural gas connection of $1.14/ day[35]. Using the Commission's example of the average residential user seeing a $55 pa increase in line charges (nominally $1.29/ day in 2023 rising to $1.86/ day in 2026) these accelerated price rises for connections also increases the incentive to switch to LPG.[36] LPG would be a good choice for consumers who prefer gas but are increasingly concerned by a regulator signalling that natural gas may cease to be an option for them.

97. In 2016 the Commission acknowledged that the effect of accelerating revenue was to actively discourage natural gas connections. It's difficult to see why this argument shouldn't continue to hold in 2022.

98. For GDBs, the consumer base under current market settings and expectations, appears to become larger in 2026 than in 2022 by *not* accelerating revenue now. We see greater potential for reduced connections as a result of accelerating prices *now* (although whether connections would fall below the total in 2022 as a result is less clear).

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.

[34] E.g. https://collinsplumbing.nz/2016/11/28/guide-gas-conversion-new-zealand/
[35] Example using Genesis rates on their website.
[36] We acknowledge that the (variable) cost of the fuel itself is also a consideration, but unlike natural gas supply which is entirely domestic reliant, LPG is also imported. Long term supply security is not an issue, and pricing is set differently. Also the lower fixed cost means that the consumer has less concerns for paying for gas that it is not using.

100. The Commission appears to argue that the 2022 price rises can be offset later[37]. In doing so, the Commission would seem to argue that their approach is only precautionary, and is designed to avoid loss in confidence that might actually lead to economic stranding becoming real. Our argument is the opposite. It's precisely by acting too soon that this creates *a greater risk* of economic stranding. This comes from a better understanding of the unique features of the New Zealand gas market.

Why acting now would increase economic stranding risk

101. We consider it commercially naïve to assume that consumers would just wait and see whether conditions reverse at some point in the future and that price rises could be clawed back later rather than act on the prices in front of them today. This is particularly so in a context where these price increases are climbing faster than for natural gas substitutes.

102. The New Zealand gas sector is one characterised by *co-dependence* between different parts of the value chain. The upstream relies on the downstream demand, the downstream relies on the upstream continuing to invest in resource recovery, and the GPBs rely on both sectors remaining viable.

103. The balance of confidence between different parts of the value chain is a delicate one. The fragility of this is being tested given the current government's prevailing attitude towards the fossil energy sector in general and other policy decisions it is considering[38]. The topic of investment confidence was covered extensively in the GIC's Gas Market Settings report[39].

> *In relation to the gas development and production investment that New Zealand needs during the transition, there are three key factors that put it at the high-risk end of the spectrum and contribute to difficulties in committing the capital required:*
>
> *• Demand for gas (and therefore investment into gas development and production)* ***is affected by concerns about businesses or industries shutting down or becoming uneconomic,*** *a lack of clarity about the expected timing and balance between reduced gas use and overall decarbonisation for major gas users, and a lack of confidence that gas supply will be available to meet this demand.*
>
> *• There are fewer opportunities to manage risk as the size of the industry decreases during the transition (e.g. reduced opportunity for diversification and fewer parties willing and available to share risk).*
>
> *• Investors (in both production and demand) understand and expect that the policy and regulatory levers that will inevitably be pulled through a transition will change the economics of their investments, but are unsure to what extent. This includes changes in both the energy and broader environmental and social context – including, for example, resource management reforms impacting demand.*

Market report – p3

[37] DPP Paper – para 6.83.3
[38] Including RMA amendments to ban or restrict fossil fired boilers
[39] GIC – 30 September 2021- *Gas Market Settings Investigation Report to the Minister of Energy & Resources*

104. We've added the emphasis to the above quote since these explain what we are trying to impart to the Commission, i.e. confidence is something that communicates through the whole value chain. The upstream looks at what happens downstream, and vice versa. If businesses shut down because they become uneconomic it tends towards an overall spiral of confidence decline.

Conclusion - Best Interest of Consumers

105. **We consider that increasing prices now will increase the risk of economic stranding. This is not in the long term interests of consumers.**

106. **We submit that the best long term outcome for consumers, pipeline asset owners, and New Zealand in general is one where gas remains part of New Zealand's primary energy mix.** It is a future where gas offers consumers energy options to address New Zealand's energy trilemma (affordability, reliability, and sustainability) whilst also meeting New Zealand's net zero carbon commitments.

107. The draft decision by the Commerce Commission to accelerate GPB revenues, give increased cost allowances, and further options for capital re-openings to address a wind-down scenario makes this goal harder to achieve by encouraging consumers to switch away from gas.

108. Arguments that future (greater) price shocks can be avoided because they can be managed over a larger consumer base are contradicted by the growth connections of GDBs and the way that the market for gas pipeline services is structured.

Commerce Act Part 4 no longer fit for purpose?

109. The Commission justifies its draft decision as one supporting its decision framework that "promotes the Part 4 purpose in s52A of the Act more effectively" and where S52A has overriding priority in governing the Commission's decision making[40].

110. If the raft of proposed cost increases is the outcome from following the processes under the regulatory framework of the Commerce Act, then it seems that Part 4 is no longer fit for purpose. Uncertainty and rapidly changing assumptions would require maximum flexibility to respond and adapt to better information. The rigid definitions and timeframes and timetables set under Part 4 do not seem to align with the nature of a more rapid energy transition environment being shaped by policy rather than technology[41]. While the average energy transition in the past has been 95 years[42], climate change policies are requiring this to occur in a 20-30 year timeframe. This rate of change requires a more responsive and adaptable regulatory framework than 5-year and 7-year timeframes for DPP and IM settings allow.

111. The question of whether the regulatory framework for gas pipelines is fit for purpose has also surfaced in the GIC's market settings Investigation report and has been identified as a joint

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[40] IM paper – p14 2.25.1, and 2.26

[41] Previous energy transitions have been the result of the development of a better technology or the emergence of a new source of energy with superior technological attributes.

[42] Fouquet, Roger (2016). 'Historical energy transitions: Speed, prices and system transformation', Energy Research & Social Science, 22: 7–12. https://www.sciencedirect.com/science/article/pii/S2214629616301979.

project with MBIE and the Commerce Commission to review Part 4 framework and tools[43]. The need for the review was highlighted in the report[44].

> *A number of participants raised concerns around future gas transmission pricing given that some major gas users are reviewing their business operations, with some likely to leave the market. This demand contraction could lead to the regulated revenue of transmission infrastructure being distributed over a smaller number of users, with marked increases in transmission prices likely. The same issue applies to gas distribution*

112. In this context it seems even more premature to accelerate price rises in the transport market rather than go through the review process first, given the identified risk to the overall gas sector.

[43] Gas Industry Company (30 September 2021) "Gas Market Settings Investigation Report to the Minister of Energy & Resources" – pp5, 45
[4444] Ibid – p45

Other DPP3 Settings

Summary

113. The DPP paper has helpfully flagged which decisions are unchanged, are minor changes, or are major changes.[45] Some of the changes flow from the IM changes being proposed and we don't comment any further on these. We generally agree where settings remain unchanged, if only because we haven't been advised of any experiences in DPP2 where these have proven unworkable or unreasonable.

114. It has proven difficult to unwind draft decisions on other DPP3 matters from the reasoning being applied to the gas IM amendments. The DPP paper crosses frequently between the two matters. If, as we have already argued, the Commission has misread the contextual background shaping its decision on IM amendments, then the same possible mischaracterisations of the environment should also be discounted for other DPP3 draft decisions linked to the same argument. In other words, how many of the policy measures summarised in the table marked as "*major change*" have been because of the Commission's view of the climate agenda context vs those found to need improving based on experience within DPP2?

Table 2: Summary of Submission points

Unchanged	Minor Change	Major Change	Change relative to DPP2

#	Policy Measure	MGUG response
Price Path		
P1	Set starting prices on the basis of current and projected profitability of each Gas Pipeline Business (GPB) using a building blocks allowable revenue (BBAR) model.	**Agree**
P2	Set alternative rates of change for each GPB (X-factor).	We were unable to find any reasoning why this is flagged as a major change from DPP2, hence we can't comment.
P3	Apply a revenue cap with a wash-up mechanism for the Gas Transmission Business (GTB) as the form of control	**Agree**
P4	Apply a weighted average price cap for Gas Distribution Businesses (GDBs) as the form of control	**Agree**
P6[46]	Use GDBs' Installation Control Point (ICP) and gas demand growth forecasts to forecast Constant Price Revenue Growth (CPRG).	**Agree**

[45] DPP paper – p6

[46] P5 is missing from the list

#	Policy Measure	MGUG response
Uncertainty		
U1	Set a regulatory period of four years.	Agree – suitable compromise to deal with more rapidly changing policy environment.
U2	Introduce a capital expenditure (capex) capacity reopener for projects and programmes that were unforeseen at the time of publishing supplier expenditure forecasts that we based its allowances on (via an Input Methodologies for gas pipeline services (Gas IM) amendment).	Partially Agree – we agree with reopeners if allowable CAPEX is set below historical CAPEX. (see C1)
U3	Introduce a capex capacity reopener for projects and programmes that were foreseen for later regulatory periods, but changes in circumstances mean that the project or programme is brought forward into the current regulatory period (via a Gas IM amendment).	Agree – more fit for purpose where technology and policies change more quickly.
U4	Introduce a mechanism via a Gas IM amendment to allow us to adjust asset lives when calculating depreciation for a DPP as doing so would better promote the purpose of Part 4.	Disagree – arguments already outlined. Normal IM review process should be followed.
U5	Shorten asset lives in DPP3 to an extent that we consider addresses most of the risk of economic network stranding, preserving investment incentives. This is the main driver of MAR increases for DPP3	Disagree – arguments already outlined. Normal IM review process should be followed.
Operating Expenditure		
O1	Use a base, step, and trend approach to forecast real operating expenditure (opex).	Disagree – scrutinising opex forecasts disclosed from latest AMPs available as was adopted in DPP2 captures the suppliers' knowledge and understanding of risk moving forward. We consider this a more reliable starting point for the Commission even though it may be more resource intensive for the Commission
O2	Use actual opex from DPP2 Year 3 (Disclosure Year 2020) as the opex base value.	Disagree – see O1

#	Policy Measure	MGUG response
O3	Model and provide for step changes in opex for First Gas Transmission and GasNet.	Agree – This is based on AMP scrutiny, which we do support.
O4	Inflate opex using a weighted average of all-industries Labour Cost Index (LCI) (60%) and Producer Price Index (PPI) (40%).	**Agree**
O5	Apply an opex partial productivity factor of 0%.	**Agree**
O6	Use GPB projections of ICP growth	**Agree**
O7	Scale base opex for forecast of network length and ICP growth based on historical relationship of network length to ICP growth.	**Agree**
O8	Update elasticity factor based on the most recent available Australian and New Zealand gas supplier data.	**Agree** (seems like a technical adjustment)
Capital Expenditure		
C1	Use a top-down historical network real capital expenditure (capex) projection approach to limit network capex forecast allowances.	No strong view on this. Approach appears pragmatic, but the outcome also adds further evidence against accelerating depreciation for GPBs in DPP3.
C2	Accept GPB non-network capex following high level scrutiny of forecasts and Asset Management Plan (AMP) material.	No strong view on this. Approach appears pragmatic, but the outcome also adds further evidence against accelerating depreciation for GPBs in DPP3.
C3	Accept GDB consumer connection capex as this aligns with our CPRG forecast.	**Agree**
C4	Not add margins to historical network capital expenditure projections.	**Agree** – consistent with approach to capital under uncertainty.
C5	Obtain nominal capex series by inflating real $2021 capex using NZIER forecast of all-industries PPI.	**Agree**
Other Inputs to the financial model		
M1	Weighted average cost of capital (WACC) of 6.07%. The WACC figure for the final decision will reflect the four-year average risk-free rate observed in December 2021- February 2022.	**Agree** with principle that shortened regulatory period is influencing this
M2	Increase the tax-adjusted market risk premium (TAMRP) from 7.0 to 7.5% (via a Gas IM amendment).	Neither agree, nor disagree. Haven't had the time or resources to have an informed view.

#	Policy Measure	MGUG response
M3	Base Consumer Price Index (CPI) forecasts on Reserve Bank of New Zealand's forecasts of inflation as per IMs.	Agree
M4	Include an allowance for disposed assets, based on historical levels.	Agree
M5	Include an allowance for other regulated income, based on historical levels.	Agree
Quality Standards		
QS1	Retain response time to emergencies (RTE) standard for GPBs.	Agree
QS2	Retain major interruptions standard for the GTB.	Agree
QS3	Do not introduce new quality standards for GPBs.	Agree
Compliance Reporting		
CO1	Retain price-path and quality compliance reporting requirements for GPBs.	Agree
CO2	Do not introduce new price-path and quality compliance reporting requirements for GPBs.	Agree

Forecasting Operating Expenditure

115. For DPP2, the Commission scrutinised the opex forecasts disclosed from the latest AMPs available to set opex allowances. The reasons for adopting this methodology are explained in the DPP paper (A23, A24), including tailoring the opex allowances to the circumstances of individual suppliers.

116. MGUG promoted this approach for DPP2 and we continue to promote it for DPP3. The AMPs are the most accurate reflection of the GPBs view of their businesses and what is needed to maintain its viability. This provides a good starting point for the Commission to scrutinise the assumptions they contain and assess the reasonableness of their budgets.

117. The Commission's primary reason for reversing this approach seems to be that it is "*resource intensive and time consuming*[47]" (for them). This seems like an unacceptable reason given the Commission's role is to provide the best advice to act in the interest of consumers.

118. The Commission further justifies the switch back to base step and trend as being more consistent with the overall approach:

> *We decided that the base, step, and trend approach is more appropriate for setting opex allowances in this DPP. Base, step, and trend modelling is more in line with our framework of*

[47] DPP paper – para A25

> *applying the same or similar treatment to all suppliers on a DPP and setting expenditure with reference to historical levels of expenditure.*
>
> DPP paper – A27

Yet in the next paragraph notes that the Commission isn't ruling it out for future DPPs

> *We are not ruling out taking a more tailored bottom-up opex allowance setting approach in future Gas DPPs probably in conjunction with a natural gas sector efficiency study.* ***It may also be necessary to tailor GPB opex allowances in future to assess how risk is informing capex/opex investment decisions and to factor in natural gas sector uncertainty****.*
>
> DPP paper – A28

119. It is difficult to understand why an approach that was accepted as better in DPP2, and could be reapplied in future DPP setting, is not fit for purpose in DPP3. It seems that the closing sentence of the statement in A28 (highlighted) is precisely why the Commission should *stay* with the approach adopted in DPP2.

120. The statement in A27 to treat GDBs collectively also appears inconsistent with the Commission's proposal to set alternative rates of change for each GPB (X-factor).

121. It is difficult to not conclude that the base, step, and trend approach is being used here purely as a matter of convenience for the Commission.

122. Ultimately it seems to have made little difference to the outcome as judged by figures A2-A5 other than for First Gas Distribution and Gas Net where DPP3 allowances are below the AMP forecast, so our disagreement rests mainly on a matter of principle.

123. We therefore disagree with the Commission's proposal and submit that they should keep with the approach adopted in DPP2.

Forecasting Capital Expenditure

124. The Commission's hybrid approach to setting capex allowances seem pragmatic, although we make the same comment as for opex, that citing the DPP2 process as "*requiring a significant level of scrutiny and engagement*" shouldn't be a driver to alter the approach.

125. More importantly, we think the level of capex allowed supports a model that looks more BAU than a response to an industry wind-down threat. We think that this supports the substance of our submission against the Commission's proposal to accelerate depreciation for GPBs.

126. We also think that new GDB connection forecasts might be low based on statistical time series forecasting (see our analysis in previous section). However the Commission seem to have conducted some sensitivity analysis relative to historical growth that concluded revenue impacts are not material[48]. We haven't investigated this further.

[48] DPP paper – para C53, C54

Yours sincerely

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