SUBMISSION

Part 4 Input Methodologies Review 2023

Process and Issues paper

Draft Framework Paper

First Gas Limited
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Executive Summary

First Gas Limited (Firstgas) welcomes the opportunity to input to the Commerce Commission's 2023 Input Methodologies (IMs) review, and its recently published Process and Issues and Decision-Making Framework Papers.

When the IMs were first introduced in 2010, regulation of the gas pipelines services was undertaken within relatively stable environment. For good reason – which Firstgas supports – the Government now intends that the gas sector will over time reduce its emissions, in line with legislated targets, emissions budgets and Aotearoa New Zealand's international commitments.

Such a transition will:

- Lead to profound and enduring changes over time to the gas infrastructure sector, affecting both gas suppliers and consumers
- Change the risk profile for gas infrastructure investors.

It is timely, therefore, that the Commission undertakes a important review of the current regulatory framework that applies to regulated gas infrastructure businesses to ensure that it is fit for purpose and delivers for New Zealand's gas consumers.

Context for the IMs Review

The Government's recently announced plans to develop a Gas Transition Plan (GTP), and feed this into its Energy Strategy, provides important context for this IMs review.

The GTP development process will occur in parallel with this IMs review. Further significant Government policy development is therefore likely – and will potentially materially affect gas and energy sector investment and / or disinvestment decisions. Such policy and decisions are likely, therefore, to affect gas pipeline services, both immediately after the 2023 IMs review is complete, and in the longer term.

As the Commission has noted, any changes to the IMs should promote consumers' long-term benefit. In doing so, it is easy to jump to making changes that will reduce prices in the short-term. However, such changes are unlikely to promote long-term benefits through an energy transition that is essential to meeting New Zealand's climate change objectives.

We welcome the Commission's focus on the Task Force on Climate-Related Financial Disclosures Framework (TCFD framework). We have had an initial go at applying that framework to assess climate-related risks and opportunities that affect Firstgas' gas transmission business (GTB) and gas distribution business (GDB) and our consumers. Although preliminary,[1] this analysis shows that:

- There are a complex set of climate change transition risks faced by Firstgas' GTB and GDB and our consumers, arising from the expected reduction in demand for gas pipeline services
- The main physical climate change risks assessed as affecting Firstgas' pipeline assets arise from expected river / sea erosion
- There is potential opportunity for repurposing gas pipelines.

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[1] We will undertake a more detailed assessment in the future.

In our view, key to promoting the long-term benefit of consumers and the transition to net zero emissions over the medium to long-term is ensuring that the regulatory settings for Gas Pipeline Businesses (GPBs):

- Provide an ongoing expectation of financial capital maintenance (FCM)
- Promote the efficient operation and maintenance of gas pipelines and new investment needed to support customers through the transition
- Encourage innovation and support the potential introduction of renewable gases[2] to help achieve New Zealand's transition to net zero emissions by 2050.

Renewable gases

The Government recognises that repurposing gas pipelines to transport renewable gases could play a significant role in New Zealand's transition to net zero by 2050.[3] Expenditure on renewable gas innovation is modest at present. However, if there is to be significant investigation and development of the potential for repurposing of gas pipelines, then the overall level of innovation expenditure required will need to increase significantly (even if the payoff from that expenditure is unclear). This is evident in other jurisdictions, for example Australia, which the Australian Renewable Energy Agency is currently providing support of A$60.8 million to develop two commercial-scale renewable hydrogen projects being developed by gas pipeline companies.

There are several options for how activities and projects related to gas pipeline repurposing could be funded. For instance, renewable gas innovation could be funded through charges on current customers. And although the Commission did not accept that this could apply under the current legislation when making its recent Default Price-Quality Path (DPP) decisions for GPBs, there are good policy reasons for why we may end up there – whereby some (but not all) costs for certain gas pipeline repurposing activities are allocated to current consumers in a way that supports the Part 4 purpose.

If it is legislative restriction that is the barrier, then a potential solution is for the Government to take steps to amend the *Gas Act 1992* and / or the *Commerce Act 1986* to clarify in what circumstance the Commission can allow for innovation-related costs in current charges where it promotes that purpose. As such, we suggest that the Commission:

- Keep an open mind on considering the role that IMs could play in identifying activities and projects that are supportive of repurposing of gas pipelines for transportation of renewable gases and which are supported by charges on current customers
- Consider how it could manage any uncertainty arising from the concurrent development of the GTP while not inhibiting an appropriate pace of change and
- Recognise that efficient investment the promotes the future of gas infrastructure could benefit consumers because, if successful, it will help extend the life of the network and help reduce long-term energy costs to consumers.

Summary of issues the Commission should prioritise during the IMs Review

The Commission should prioritise the following issues in the IMs review:

- Ensuring that when applying the FCM principle that there are continued appropriate incentives for gas businesses to incur efficient capital and operating expenditures in a way that maintains safe and secure services as demand for (and supply of) fossil gas falls

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[2] Renewable gases include hydrogen blended at low levels (10-20%) with fossil gas or biogas, biogas replacing fossil gas, higher levels of hydrogen (>10-20%) blended with fossil gas or biogas, and 100% hydrogen gas.

[3] As evidenced in MBIE's New Zealand hydrogen scenarios and its Roadmap for hydrogen in New Zealand, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/a-vision-for-hydrogen-in-new-zealand/roadmap-for-hydrogen-in-new-zealand

- Recognise that the GTP and related policy –which is being developed in parallel with the IMs review processes – will have a fundamental impact on the future of gas. This means that the Commission should consider how best to balance uncertainty over future policy and market developments, with the need to act now to shore up confidence in the regulatory settings to promote consumers' long-term benefit
- Whether to provide in the revised 2023 GPB IMs some form of reopener that allows for amendments to DPP and CPP Determinations to address either a "material change" arising from Government policy or other relevant matters related to the future of reticulated gas or a "Climate change event"
- Ensure that the cost of capital for *gas* businesses is set in a way that recognises the risks specific to those businesses, including in the asset beta and the percentile adjustment (as appropriate). We note that the approach to calculating asset beta from international data may be more problematic now, given the considerable differences in the policy environment of different countries.
- Consider how the regulatory framework should encourage efficient innovation to support the potential introduction of renewable gases to help New Zealand's transition to net zero emissions.
- How risk (primarily demand and investment) is allocated between consumers and GPBs and how that risk is compensated for
- When deciding how to approach asset lives and depreciation, how best to balance the level of detail in the specifications of parameters between the IMs and a DPP (or CPP) determination.

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1. Introduction

First Gas Limited (Firstgas) welcomes the opportunity to submit on the Commerce Commission's 2023 Input Methodologies review (IMs review), which has commenced with the release of two papers: *Part 4 Input Methodologies Review 2023 - Process and Issues paper* (Issues Paper); and *Part 4 Input Methodologies Review 2023 – Draft Framework Paper* (Draft Framework paper).

We are making this submission on behalf of our gas transmission business (GTB) and gas distribution business (GDB). The discussion of an issue applies to both the GTB and GDB business unless stated otherwise. Nothing in this submission is confidential.

1.1. Structure of this submission

This submission discusses the following key points and our recommendations to inform the Commission's decisions on how it will approach the IMs review:

- **Section 2** explains that the gas industry outlook is now uncertain and changing rapidly. We discuss the Government's Gas Transition Plan and Energy Strategy, noting that there is now a much higher level of risk and uncertainty facing gas infrastructure investors. We discuss the critical aspects that the regulatory framework needs to address to promote the long-term benefits of consumers and the transition to net zero emissions.
- **Section 3** discusses the approach to the IMs review. We explain the need to manage rapid change and uncertainty and how we have addressed the key contextual issue affecting the framework for decisions – being the impact of the transition to a low carbon economy. The section also discusses the engagement processes for undertaking the IMs Review.
- **Section 4** discusses risk allocation and incentives. We have applied the Task Force on Climate-Related Financial Disclosures Framework (TCFD Framework) to identify climate related risks and opportunities. This section then deals with the allocation of demand risk, and tools to reduce risk, reallocate risk and to compensate for residual risk.
- **Section 5** discusses cost of capital matters. We explain the overarching challenges affecting capital markets currently and then discuss the following specific topics: asset beta, Tax Adjusted Market Risk Premium (TAMRP), cost of debt, debt issuance costs, the regulatory period and the WACC percentile.
- **Section 6** deals with expenditure. We discuss several expenditure issues and questions including the overall approach to setting expenditure allowances and whether there is evidence of efficiency and innovation by GPBs.
- **Section 7** deals with renewable gases. It discusses the innovation challenges for New Zealand to move to a future where renewable gases are transported through repurposed gas pipelines.

1.2. Contact details

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2. The energy transition context is important

When the IMs were first introduced in 2010, regulation of the gas pipelines services was undertaken within a relatively stable context. The industry context is now uncertain and changing rapidly. This section discusses the energy transition context.

2.1. Gas Transition Plan and Energy Strategy are intended to significantly affect the future of gas in New Zealand

For good reasons – which Firstgas supports – the Government intends that the gas sector will over time reduce its emissions, in line with legislated targets, emissions budgets and Aotearoa New Zealand's international commitments.

The Government has begun work on a Gas Transmission Plan[4] (GTP) to develop a plan for an equitable transition for the gas sector. This will be a key input into the broader Energy Strategy.

The GTP is expected to identify opportunities and benefits and provide a framework to assist in making the "difficult decisions that Aotearoa New Zealand may face through the transition".[5] The GTP is expected to establish "realistic, but ambitious, transition pathways for the gas sector to decarbonise in line with the 2022-2025, 2026-2030, and 2031-2035 emissions budgets, noting the inherent uncertainties involved".[6] Publication of the GTP is expected by the end of 2023.

The Aotearoa New Zealand Energy Strategy will also likely have an important influence, for example in providing guidance on increased electrification in different end-use sectors and the future potential roles of gas and green hydrogen in electricity generation. The Government intends to develop the strategy by the end of 2024.

2.2. IMs Review is timely

Given the Government's focus on gas transition, it is timely therefore that the Commission undertakes a review of the current regulatory framework is fit for purpose.

The Commission's IMs review needs to take account of the GTP and the Energy Strategy. Any changes to the IMs should promote consumers' long-term benefit.

In doing so, it is easy to jump to finding changes that will reduce prices in the short term. However, that is unlikely to promote long-term benefits through an energy transition that is essential to meeting NZ's climate change objectives.

2.3. Energy equity outcomes

Promoting Energy Equity outcomes is an important consideration for the GTP and affects the Commission's review.

One of the Government's desired outcomes for the overall transition for gas out to 2035 is to promote "energy equity". This involves: [7]

> *Ensuring that adverse and unexpected effects on fossil gas consumers are prevented or mitigated and consumers retain access to affordable, reliable and abundant energy. This*

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4 MBIE, *Terms of Reference – Gas Transition Plan*, May 2022.

5 MBIE, *Terms of Reference – Gas Transition Plan*, May 2022, Section 8.

6 MBIE, *Terms of Reference – Gas Transition Plan*, May 2022, Section 16(a).

7 MBIE, *Terms of Reference – Gas Transition Plan*, June 2022, Section 14(c).

includes minimising the broader effects on prices paid by consumers, as well as pricing of inputs for businesses in the transition.

It will be important for the IMs review to consider how energy equity should be interpreted in practice. We note that the Commission has a limited range of tools to promote Energy Equity outcomes within the Part 4 framework, and its work needs to be integrated with other work developing the GTP.

A critical aspect of energy equity that we discuss in this submission is that under any future transition – whether to a winddown or repurposing future – gas infrastructure services will need to continue to be provided, and in some cases for many years. This means that there is a need for some minimum ongoing expenditure to maintain safe and secure services for the remaining gas customers until they can transition to alternative energy sources.

2.4. Changes to risk

The Government's intention for the gas sector to support a transition to a net zero emissions future means that there is now a much higher level of risk and uncertainty facing gas infrastructure investors. The IMs Review needs to understand this risk and consider how it is best managed.

The future risk and uncertainty is illustrated by the two very different future scenarios identified[8] for the future of gas infrastructure: 'Infrastructure winddown'[9] and 'Infrastructure repurposing'.[10] These scenarios represent the "bookends" of what could occur in practice, as the future could fall somewhere between.

At this time, there is considerable uncertainty about the extent to which infrastructure repurposing to utilise renewable fuels will be viable. The phase out of gas by, say 2050, will, to the extent repurposing is not viable, result in estimated economic lives for many assets being considerably shorter than past economic lives or their technical lives.

Some future risk has been mitigated by the Commissions recent DPP decision to accelerate depreciation – which we support. It remains to be seen to what extent risk and uncertainty will be reduced following determination of the GTP and the Energy Strategy, and subsequent Government implementation of the decisions in this plan. It is reasonable to expect that a significant level of risk and uncertainty will likely remain into the medium-term.

2.5. Regulatory framework

There are three critical aspects that the regulatory framework needs to address to promote the long-term benefits of consumers and the transition to net zero emissions:

- *An ongoing expectation of financial capital maintenance (FCM)*
- *The efficient operation and maintenance of gas pipelines and new investment needed to support customers through the transition as gas demand falls and*
- *Encouraging innovation and support for the potential introduction of renewable gases to support New Zealand's transition to net zero emissions.*

First, we agree with the Commission that it is important that the regulatory framework provides regulated businesses with the ongoing expectation of FCM. The *ex-ante* regulatory framework applied by the

8 New Zealand Gas Infrastructure Working Group, *Findings Report,* 16 July 2021, Sections 2.3 and 2.4.

9 Infrastructure winddown is where gas consumption is phased out and gas pipelines are decommissioned in a safe and orderly way, and all consumers switch to other zero (or low) carbon energy sources.

10 Infrastructure repurposing is where gas consumption transitions from natural gas to 'renewable gasses' and some or all existing pipelines are repurposed to deliver these renewable gasses to consumers.

Commission only provides for the expectation of FCM where it assists in promoting Part 4 purpose (5.143), which ties into long term demand risk.

A directly relevant example is the Commission's recent gas DPP decision, where it opted to accelerate depreciation of existing and new assets in response to a heightened risk that climate change related policies would significantly reduce demand for and supply of reticulated gas. The Commission made clear that this was needed to maintain an expectation of FCM for GPBs.

Second, it is important for the Commission, when applying the FCM principle, to ensure that there are continued appropriate incentives for gas businesses to incur efficient capital and operating expenditures in a way that maintains safe and secure services as demand for (and supply of) fossil gas falls.

Capital and operating expenditures will continue to be required to maintain safe and secure gas infrastructure as gas demand falls and customers transition to renewable energy sources and / or potentially use renewable gases transported through repurposed gas pipelines. As recognised by the Commission in its 2022 gas DPP draft decision,[11] it is important that it continues to provide a reasonable expectation of FCM for the GPBs, which in turn provides incentives for investment to maintain safe and reliable networks.

Third, the regulatory framework should encourage efficient innovation to support the potential introduction of renewable gases to help New Zealand's transition to net zero emissions.

Firstgas is playing a leadership role in exploring the potential introduction of renewable gases. In March 2021, we released the results of Hydrogen Trial Study.[12] This outlined a plan for decarbonising our gas pipeline network in New Zealand; involving Hydrogen being blended into the North Island natural gas network from 2030, with conversion to a 100 per cent hydrogen grid by 2050 and supported by biogas and bioLPG.

Substantial further innovation effort is required to create credible options to enable the potential repurposing of gas pipelines. This work is inherently risky for investors – it may not prove to be successful. While some of this effort will be funded or co-funded by Government, a considerable portion should be funded by the gas pipelines and other private sector participants in the future renewable gas sector. The willingness of gas pipeline owners to undertake such innovation depends critically on whether it is supported – or at least not disadvantaged – by the regulatory framework.

Other jurisdictions are tackling this challenge head on. For instance, in Australia, the Australian Energy Market Commission has initiated a review of the National Gas Rules and National Energy Retail Rules to extend the economic regulatory framework to include low-level hydrogen blends and renewable gases. Its March 2022 draft report recommended extending the framework to:[13]

> *facilitate connections of other covered gas suppliers, increase market transparency, and provide, where necessary, more clarity on the regulatory treatment of pipelines transitioning to transporting another covered gas.*

11 Para 2.45 Commerce *Commission, Default price-quality paths for gas pipeline businesses from 1 October 2022, Draft reasons paper*

12 *Aqua Consultants and element energy: New Zealand Hydrogen Pipeline Feasibility: A study for Firstgas, March 2021*. The study was supported by funding managed by the Provincial Development Unit, and co-funded by Firstgas.

13 AEMC, *Draft Report – Review into extending the regulatory frameworks to hydrogen and renewable gases*, 31 March 2022, p.i.

3. The approach to the IMs review

This section discusses the Commission's approach to the IMs review. We also discuss the engagement processes for undertaking the IMs Review.

We agree with the Commission that the key contextual issue affecting the decision-making framework is the impact of the transition to a low carbon economy; in particular, the risk of significantly reduced demand in the gas sector. Given this, the Commission should recognise the need to manage this rapid change and uncertainty, which may involve a staggered approach to refining the regulatory settings.

3.1. Managing uncertainty and change

As discussed in chapter 2, the future of reticulated gas in New Zealand is uncertain and changing rapidly. But this uncertainty will not be resolved quicky.

Some potential changes to the IMs should involve considerable investigation to determine whether they are warranted. The changes may turn out to be beneficial even if they are not a high immediate priority. They may also require considerable effort to implement and so may require the balancing of costs and benefits.

We discuss options for how the Commission could manage the change process and workload through this period of uncertainty. This may involve a staggered approach to refining the regulatory settings, with some implemented through the 2023 IMs review and others left for subsequent DPP and CPP determinations or future IMs reviews.

3.1.1. Overview

The Commission is statutorily required to review each IM at intervals of no more than 7 years.[14] The Commission's practice has been to undertake a single review of gas pipeline (and other) services IMs in line with this review cycle.[15] This approach was appropriate when regulation of gas pipelines services was undertaken within a relatively stable context, but this is no longer the case.

The future of reticulated gas is now much more uncertain and changing rapidly. In the short term, the GTP will be developed through the remainder of 2022 and into 2023. This means that the GTP will be developed in parallel with this IMs review.[16] Further important changes in Government policy for the gas pipeline and electricity sectors are likely to follow as part of the Aotearoa New Zealand Energy Strategy that the Government intends to develop by the end of 2024 – and which seeks to support the transition to a low carbon economy while addressing strategic challenges in the energy sector.[17] There may also be other important developments or decisions following the publication of the GTP and Energy Strategy, such as major investment or disinvestment decisions in the energy sector that will affect the future of reticulated gas. The process of change is likely, therefore, to be ongoing for at least the next few years.

Given this, we believe that it is unrealistic to consider that the 2023 IMs amendments can address all future challenges, especially given that these challenges are not all known. But neither can we wait until the subsequent IMs review to address them. The likely pace of change is such that it is unlikely to promote the long-term benefit of consumers to wait until the next IMs review – which may not be until 2030 – to address

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14 *Commerce Act 1986*, s.52Y(1).

15 Specified gas pipeline service IMs were determined in December 2010, the first review was completed in December 2016, and the current review is taking place for implementation seven years after the 2016 review. Although the Commission often makes targeted IM changes at the same time as its DPP and CPP determinations, these do not represent a full review of the IMs.

16 The IM Review process proposes that a Draft Report will be issued in Quarter 1 2023 and a Final Report in Quarter 3 2023. The tentative timeline for finalisation of the GTP is in in the second half of 2023. As it is very early in the planning of the GTP, it is uncertain as to what decisions may ultimately be made, and how GTP decisions will affect the IMs. Also, the timeline for developing the GTP is indicative and therefore may change.

17 See: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/aotearoa-new-zealand-energy-strategy/.

any material policy or other changes that may occur in the period prior to 2030. Such changes will undoubtably include implementing the GTP and the Energy Strategy or major investment or disinvestment decisions in the energy sector by government or market participants. The Commission needs to balance uncertainty over future policy and market developments with the need to act now to shore up confidence in the regulatory settings to promote consumers' long-term benefit.

In our view, the Commission should consider managing uncertainty and the pace of change by:

- Developing a package of changes for the 2023 GPB IMs
- Potentially signalling a phased review of certain other IMs elements prior to the next statutorily required GPB IMs review in 2030 and any issues to be focused on at the 2026 DPP reset and
- Consider either providing for a reopener provision in the DPP / CPP Determinations to address any "material change" arising from Government policy or other relevant matters that affect the future of reticulated gas or amending that the existing provisions (in Part 4, Subpart 5 of the gas IMs) to make clear that they capture such changes (e.g., from the GTP or Energy Strategy).[18]

These proposals are discussed below.

3.1.2.Develop a package of changes for the 2023 IMs reviews

The Commission should consider prioritising a package of changes for the 2023 IMs review based on the following principles:

- That the case for change is clear at this time and is not significantly affected by policy or other uncertainty and
- The overall work required to consider and make changes are manageable for the Commission, the businesses, and stakeholders.

This approach could help balance uncertainty over future policy and market developments with the need to act now to shore up confidence in the regulatory settings.

3.1.3. Further phased reviews of certain IM elements

The Commission can review aspects of the IMs outside the conventional seven-year review cycle, as evidenced by the targeted amendments it commonly makes at the same time as its DPP and CPP Determinations. Such flexibility allows for further phased reviews of certain IMs elements after 2023.

One example is whether to shift to a Totex approach to expenditure for GPBs (see section 6.1). While making such a change may well benefit consumers, it may not be considered a priority at this time, especially given the potential implementation challenges that need to be worked through. A staggered approach to considering this issue could enable more effective management of the substantial work required should this change be actively considered and implemented.

The 2023 GPB IMs decision could include a timeline and work programme for considering issues that warrant future consideration, but which are not covered by the 2023 IMs amendments.

3.1.4.DPP and CPP material change reopener

Part 4, subpart 5 of the gas IMs include a DPP reopener for a "Change event" that occurs when legislation or a regulatory requirement that applies to a GPB is introduced or amended that was not provided for in the DPP and leads to additional reasonable costs or means that the IMs cannot be applied. Although this reopener may pick up some policy that may affect the future of gas, it is narrowly focused on legislation or regulation that

[18] Our concern is that the existing provisions may not capture some or all of these changes because its narrow focus on legislation and regulation that applies to GPBs.

applies to a GPB. For instance, it does not appear to cover policy that affects others in the supply chain that could materially affect the costs faced by GDBs or the operation of their networks. It also does not appear to pick up where there is a loss of revenue (e.g., because demand is restricted in some way).

Given this, the Commission should consider providing in the revised 2023 GPB IMs some form of reopener that allows for amendments to DPP and CPP Determinations to address any "material change" arising from Government policy or other relevant matters related to the future of reticulated gas. To ensure such a reopener were used only where appropriate, the IMs amendments should include criteria and materiality thresholds that would trigger a reopener.

Alternatively, the Commission could consider adding a "Climate change event" to subpart 5 of the gas IMs that links to specific climate change-related policy, such as the Gas Transition Plan, the Emissions Reduction Plan, or the Aotearoa New Zealand Energy Strategy. Doing so, will ensure that the reopener is targeted to the Government policy that may affect the future of reticulated gas.

3.2. Framework for decision making

In our view, the Commission's decision-making framework should apply both to issues that are determined in the 2023 IMs amendments ('2023 IM package'), and to other issues that could be subject to phased review.

We agree that the key contextual issue is the impact of the transition to a low carbon economy and – in particular – the risk of significantly reduced demand in the gas sector.[19] This has led to the Commission's proposal to use language from the Task Force on Climate-Related Financial Disclosures Framework TCFD (Framework) to identify risks across three themes – transition risks, physical risks, and opportunities.

We agree with the Commission's view that this framework is useful in obtaining a comprehensive view of climate change-related risks and opportunities that affect our businesses and consumers. Firstgas and the gas infrastructure sector has already undertaken significant work on transition risks and opportunities. Section 4.1.1 summarises the risks and opportunities identified from applying the TCFD Framework and further detail is set out in **Attachment 1**.

3.3. Engagement

This section sets out our comments on the engagement processes for undertaking the IMs Review.[20]

3.3.1. Workshops

There is considerable value in the Commission sponsoring well-structured workshops focused on key topics. While written submissions are important, workshops can be useful in:

- Drawing out different views and ensuring stakeholders feel that they have been heard
- Addressing some stakeholder's resource constraints (while regulated business have sufficient resources, other parties are more resource constrained) and
- Considering large volumes of material, particularly where expert work is commissioned.

We encourage the Commission to use a mixture of delivery options (webinars, in person meetings) to ensure that all stakeholders have opportunities to both hear from the Commission and experts and engage in discussions.

[19] Commerce Commission, *Draft Framework paper*, 20 May 2022, para.4.29.

[20] Commerce Commission, *Process and Issues Paper*, 2- May 2022, paras. 1.36–1.38 and Table 4.

We also suggest that there would be value in organising one of more joint workshop sessions with the Ministry of Business, Innovation and Employment (MBIE) and the Gas Industry Company (GIC) that focus on developing a common understanding of the impact of the GTP and the Energy Strategy.

3.3.2.Expert "hot-tubs"

Expert hot tubs can be a useful way to deal with input on highly specialist topics, such as rate of return. They can help cut out the back and forth of submissions on detailed technical issues, by quickly finding areas of common ground and disagreement. They can also allow stakeholders to engage in – or at least observe – discussions on these topics without having to engage their own experts, which helps improve transparency.

3.3.3.Cross submission timeframes

We suggest that – at least as far as the gas pipeline IMs review process is concerned – stakeholders have longer than 2 weeks to make cross-submissions.

The Commission's standard practice of allowing 2 weeks may work in some instances where primary submissions are expected to be short and easily digested. However, when issues are complex and potentially far reaching, such short timeframes do not promote stakeholder confidence.

Many stakeholders have limited resources and find it challenging to fully digest and respond to primary submissions over a 2-week window, which potentially limits the effectiveness of the Commission's engagement.

We propose that at least 3 weeks is allowed for cross-submissions during the IMs review process.

4. Risk allocation and incentives

This section discusses risk allocation and incentives. Section **Error! Reference source not found.** sets out an overview of risk identification including how we have applied the TCFD Framework to identify climate related risks and opportunities. The questions the Commission has posed on allocation of demand risk are addressed in section 4.2.

Sections 4.3, 4.4 and 4.5 deal with tools to reduce risk, reallocate risk and to compensate for residual risk respectively.

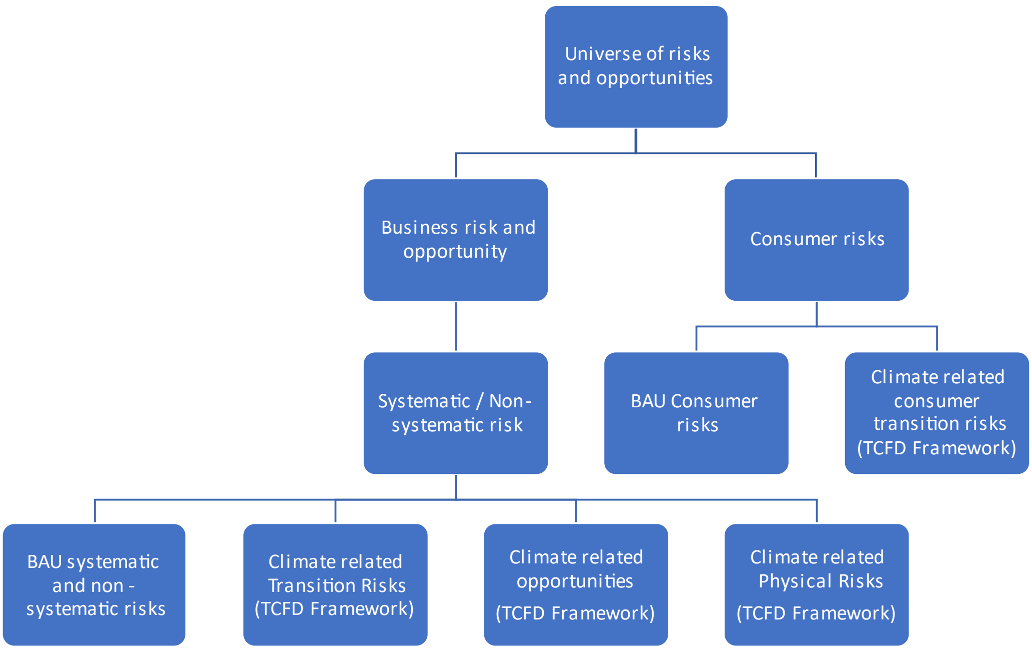
4.1. Overview of risk identification

This section overviews the risks affecting our business and our customers. There are two related risk frameworks we have considered:

- The **TCFD framework** for assessing climate related risks that the Commission proposes to adopt, and which applies three "risk themes" – transition risks, physical risks, and opportunities. This is a new set of risk concepts.
- **Systematic and non-systemic risk**. This is the risk framework stemming from the finance literature that the Commission has used in the past and continues to use to inform its approach to setting the cost of capital.

It is useful to consider how these two risk frameworks could fit together. A simplified view is shown in Figure 1.

Figure 1. Overview of Climate Related, systematic and non-systematic risks and opportunities



As the *Commerce Act*'s Part 4 purpose is to promote the long-term benefit of consumers, this suggests first dividing the 'universe' of relevant risks and opportunities into those that sit with consumers and businesses (GPBs) respectively before mitigation or reallocation of risk. Business and consumer risks respectively can then be divided into BAU risks – that is, the baseline of 'Business as Usual' risks that apply now – and the emerging climate related risks defined by the TCFD Framework. Our preliminary analysis (discussed in detail below) indicates that consumers face a wide range of climate-related transition risks. The GPBs face the full range of climate-related risks and opportunities (transition, physical and opportunities). The rest of this subsection is structured as follows:

- Section 4.1.1 applies the TCFD Framework to comprehensively identify climate-related risks and opportunities and identify which of these are relevant – at least to some extent – to the Part 4 Purpose.
- Section 4.1.2 considers how non- systematic and systematic risk has changed, including due to uncertainty over the future use of regulated gas infrastructure.

4.1.1.The TCFD Framework used to identify climate related risks and opportunities

Table 1 below summarises climate related risks and opportunities that affect Firstgas' GTB and GDBs and our consumers, that we have identified using the TCFD framework. These appear relevant to the Part 4 Purpose of promoting the long-term benefit of consumers. **Attachment 1** details this analysis.

Key insights from that analysis are as follows:

Insight 1: *The Commission should be cognisant of transition risks*

The analysis shows that there are a complex set of transition climate change risks faced by Firstgas' GTB and GDB and their consumers. The expected reduction in demand for gas pipeline services over time gives rise to many transition risks for our businesses and consumers. Table 1 identifies those risks that appear most relevant to the long-term benefit of consumers.

We appreciate that the Commission may not necessarily have clear responsibility or the powers or tools pursuant to the *Commerce Act 1986* to mitigate all risk (assuming there was a desire to do so). Effective management of many of these transition risks will also require actions by GPBs, consumers, the Government, the electricity industry, and other parties.

Nonetheless, in our view, the Commission should be cognisant of these transition risks when making decisions about managing the decline in demand for gas pipeline services and the incentives created on our business to continue to invest and to manage these risks, or not.

Insight 2: *Physical risks*

The main physical climate change risks assessed as affecting Firstgas' pipeline assets arise from river / sea erosion. The emergence of these risks over time could lead to increased expenditure requirements including: the need for anticipatory capital or to proactively manage emerging physical risks; increased external or self-insurance costs; and the need for expenditure following a significant event, for example to rectify damage to assets not covered by insurance.

Insight 3: *There are opportunities to repurpose gas infrastructure*

We believe that there are potential opportunities for repurposing gas pipelines – which could underpin, and require, a larger scale renewable gas industry in New Zealand. A future involving transportation of green hydrogen using repurposed gas pipelines will require a large enough current and future market to justify the high fixed investment costs required to repurpose, maintain and replace pipeline and consumer assets over time. Confidence in the size of the market will require widespread acceptance of hydrogen by consumers. This opportunity is discussed further in section 7 below.

Table 1. Summary of risk analysis adopting the TCFD framework

Risk Theme		Risks analysis
Transition risks Transitioning to a lower-carbon economy may entail extensive policy, legal, technology, and market changes to address mitigation and adaptation requirements related to climate change. Depending on the nature, speed, and focus of these changes, transition risks may pose varying levels of financial and reputational risk to organisations.	**Overview**	Transition risks are the dominant climate change risks faced by Firstgas' GTB and GDB and their customers. Demand risk is a key overarching risk that gives rise to many of the risks described below.
	Firstgas GTB and GDBs	Transition risks affecting Firstgas are: - FCM risk. - Financing risk - Decommissioning cost risk - Reputation risk.
	Consumers	Transition risks that could affect consumers include: - Customer safety, reliability, and price risk - Energy switching risk - Consumer transition cost risk - Energy suitability risk - Resource availability risk - Vulnerable customer risk - Industrial customer risk.
Physical risks Physical risks resulting from climate change can be event driven (acute) or longer-term shifts (chronic) in climate patterns.	**Firstgas GTB and GDBs**	The main physical climate change risks assessed as affecting Firstgas' pipeline assets arise from river / sea erosion.
Opportunities Efforts to mitigate and adapt to climate change also produce opportunities for organisations.		There is potential opportunity for repurposing gas pipelines, which could underpin, and require, a larger scale renewable gases industry in New Zealand.

See **Attachment 1** for details of this analysis.

4.1.2. There has been a significant change in both non-systematic and systematic risk for gas pipeline services

Risk for our business and other gas infrastructure owners has increased significantly. As discussed in section 2.1, Government policy to reduce emissions from the gas sector has raised non-systematic risk, in particular demand risk – which is a risk specific to the gas industry.

The Commission's decision in its final gas DPP decision to accelerate depreciation goes some way to addressing asset stranding risk from a future reduction in demand. Yet, to a material extent, it does not completely address stranding risk of the current regulatory asset bases (RABs) for regulated gas infrastructure, nor does it address asset stranding risk for future required investment.[21]

At the same time, systematic risk has also increased.[22] We are currently seeing a confluence of systemic risk factors including the effects of the pandemic, war, global increases in energy costs and related inflation and increases in interest rates. These systematic risks affect the market risk premium component of the rate of return and will feed into the level of the risk-free rate and may also affect measures of systematic risk such as equity beta.

[21] See section 2.2 *Firstgas submission, Default price-quality paths for gas pipelines for 1 October 2022, Draft reasons paper and proposed IMs amendments*.

[22] Systematic risk is the risks that impacts the entire market which cannot be managed by portfolio diversification.

4.2. Allocating demand risk

The Commission is interested in further information to advance its thinking on the consumer perspectives on how best to manage long-term demand risk for gas pipeline service providers.[23] This section sets out our views on the Commission's questions on:[24]

- Whether the gas pipeline service IMs should be changed to allow for more long-term demand risk to be allocated to gas pipeline service providers
- Whether long-term demand risk should remain primarily with consumers and
- What IMs changes would assist to provide more certainty for consumers in allocating risk between current and future consumers.

This section first summarises the future context. It then sets out why we consider consumers should bear long term demand risk at this time. We then consider the available tools that could be used to manage demand risk categorised by whether they reduce, reallocate, or compensate for demand risk

4.2.1. The future context

In addressing the Commission's questions, it is useful to first summarise the future context for demand for gas pipeline services discussed in section 2 above.

This context includes:

- The Government's intention to phase out use of fossil gas
- The need for a carefully managed transition that continues to provide services to consumers – in some cases for many years – which will warrant minimum ongoing expenditure to maintain safe and secure services for remaining fossil gas consumers until they can transition to renewable energy sources
- Present uncertainty about the extent to which it is viable to repurpose gas pipeline infrastructure to transport renewable fuels and
- To the extent that repurposing is not viable, the phase out of fossil gas by say 2050, will, lead to expected economic lives for many assets being considerably shorter than the economic lives assumed previously or their technical lives.

4.2.2. Long-term demand risk should to the extent possible be allocated to consumers

The Commission's Process and Issues Paper discusses the benefits and costs of allocating long-term demand risk to suppliers compared with consumers.

It is important to understand the current situation. The Commission's recent DPP decision for GBPs applied accelerated depreciation to better reflect the expected decline in gas demand. Analysis by the Gas Infrastructure Future Working Group following the Commission's draft DPP decision suggests that although such accelerated depreciation *reduces* cost recovery and asset stranding risk from what might otherwise be the case if asset lives were not changed, it does not remove it (i.e., by allocating it to consumers).[25] Nor does it appear to be the Commission's intention to do so.[26]

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[23] Commerce Commission, *Process and Issues Paper*, 20 May 2022, para. 5.178.

[24] Commerce Commission, *Process and Issues Paper*, 20 May 2022, para 5.182.

[25] Gas Infrastructure Future Working Group*, NZ Gas Infrastructure Future - Further Analysis Paper, 29 June 2022.*

[26] *The Commission noted that its intent was to address most, but not all stranding risk in DPP3. It noted that further price increases may be needed in the default price-quality path for the fourth regulatory period beginning on 1 October 2026 (DPP4), but this depends on how the stranding risk evolves in DPP3*.
See: Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2022, Draft reasons paper*, para 6.8.

In our view, and to the extent possible, long-term demand risk should be allocated to consumers and not the GDPs because:

- The regulatory framework restricts GPB's ability to manage that risk (e.g., revenue and price caps have not allowed GPB's to price that risk)
- The alternative approach of incorporating a risk premium to compensate GPBs for bearing long-term demand risk:
    - May not be practical (e.g., how should the compensation be determined) and
    - Would likely add considerably to prices paid by current customers
- Allocating long-term demand risk to consumers is a well-accepted regulatory approach overseas
- The risk of future declines in natural gas usage are driven, to a large extent, by policy decisions and consumer responses to those decisions, which are outside of GPBs control and
- There are asymmetric consequences to consumers of over- and under-investment.

These points are discussed below.

Regulatory framework restricts GPBs' ability to manage risk. By design, the revenue and prices caps applying to GPBs limit their ability to price in risks and costs that the Commission has not otherwise allowed for. If the Commission takes a different view of these risks and costs or is slow to recognise them in DPP and IM decisions, then those GPBs are restricted from managing them by adjusting prices. This contrasts to competitive markets where participants can adjust prices, almost in real time, to changes in risks and costs.

Risk premium is not practical. As noted by the Commission, an *ex-ante* risk premium for bearing demand risk would be required to maintain an expectation of FCM. A risk premium needs to be determined with sufficient accuracy so that it will not lead to an unacceptable risk of windfall gains or losses to GPBs or consumers. The difficulties in estimating an accurate risk premium to compensate for asset stranding risk include:

- Defining and estimating the probability of a range of different scenarios ranging between complete winddown of infrastructure through to a high level of repurposing
- Estimating the costs associated with each scenario given the high level of cost uncertainty at this time and
- Estimating the trajectory of demand for pipeline services in each scenario given the uncertainty.[27]

The Gas Infrastructure Future Working Group has undertaken preliminary modelling along these lines, which was previously made available to the Commission.[28] While undertaking such analysis is useful for scenario planning purposes, using such an approach to calculate a risk premium in exchange for bearing demand risk would be entirely speculative at this time, given the high level of uncertainty on each of the key modelling inputs (e.g., scenarios, costs, and demand projections).

Any risk premium would add considerably to prices paid by current consumers. Work undertaken by CEG for Vector highlighted that the quantum of *ex-ante* compensation required to address the risks from net zero 2050 is significant, especially if no complementary measures are adopted to bring forward capital

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27 See also Incenta, *Using asset lives to manage stranded asset risks*, prepared for Jemena Gas Networks, December 2019, which said:

> *It is very difficult to accurately estimate the probability and consequence of a stranding event occurring. It requires an estimate of how likely it is asset stranding will occur, and then a view about when asset stranding is likely in order to discern the expected consequences of it (that is, how much investment remains unrecovered). These are very difficult things to estimate with the degree of precision that would be necessary to avoid material windfall gains or losses arising.*

28 See: Gas Infrastructure Future Working Group, *Initial Analysis Paper* 14 March 2022; and Gas Infrastructure Future Working Group, *Further Analysis Paper*, 29 March 2022.

recovery.[29] For instance, CEG estimated that an asset stranding uplift of 2.88% may be needed if the Commission did nothing to adjust cash flows and lower if it took steps (e.g., by accelerating depreciation).

Accepted regulatory approach overseas. As noted in the Process and Issues Paper, a common response by overseas regulators to address concerns about falling demand caused by the transition to a low carbon economy is to allocate demand risk to consumers. For example, the Australian Energy Regulator's (AER's) final decision on Evoenergy's 2021–26 access arrangement included accelerated depreciation due to the ACT Government mandating that there could be no new gas connections from 2025 onwards.[30]

The risk of future declines in natural gas usage are largely driven by policy decisions and consumer responses. GPBs have very little control over this risk. However, there are ways to allocate network utilisation risk that provide GPBs with "skin in the game" to actively promote solutions that will enable the infrastructure to be used.

Given some demand risk currently sits with the GDBs, we already have strong incentives to explore renewable gases such as hydrogen and biogas. This is evidenced by the work we have underway to explore options that will see our assets used in a net carbon zero energy system.

Asymmetric consequences of over- and under-investment. The asymmetric consequences of over- and under-investment in gas pipelines support measures to ensure that investors continue to allocate capital to maintaining pipeline infrastructure.

As discussed in our submission to the draft DPP3 decision, a clear example of asymmetric consequences in gas pipeline investment comes from contrasting the 2011 Maui pipeline outage with the recent Pariroa investment project.[31]

4.3. Tools to reduce risk

4.3.1. We support continuing accelerated depreciation to address long-term demand risk

The Commission in its final GPB DPP decision decided to shorten asset lives for the following reasons:[32]

- There would be a shorter expected economic life for assets to convey fossil gas than previously assumed, given expectations for declining demand
- It would better maintain incentives for GPBs to invest in their networks while there is still demand for fossil gas and
- It would smooth price increases over time to help reduce the impact on consumers.

When deciding how to approach asset lives and depreciation, an issue that the Commission should consider is how best to balance the level of detail in the specifications of parameters between the IMs and a DPP (or CPP) decision. While the IMs can provide some certainty about the approach, setting asset life parameters at each DPP gives an opportunity to consider the known circumstances at the time of the decision. This suggests that the IMs should include the mechanism that could be used to apply accelerated depreciation (e.g., a common asset life scaler), while the DPP (or CPP) decision considers how to apply that mechanism if at all.

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29 CEG (on behalf of Vector), *Stranding risk depreciation vs uplift* August 2021.

30 AER, *Final Decision, Evoenergy Access Arrangement 2021 to 2026*, *Overview*, April 2021.

31 In the first case, pipeline investment did not occur ahead of an integrity failure because the threat to the pipeline was not known. The economic cost of the pipeline outage was estimated to be around $200 million. More recently, early detection of pipeline integrity risks at Pariroa ensured that investment could be made ahead of failure, at a cost of around $8 million. While the underlying facts in both situations were similar, not identifying the risk and investing accordingly in 2011 led to economic costs that were over 20x higher than investing ahead of time to prevent the outage. We continue to invest in technology to identify these risks even earlier. For example, by using LIDAR for very early identification of geotechnical risks. This allows us to better manage risk and cost.

32 Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2022, Final Reasons Paper.*

In Australia, the National Gas Rules – the equivalent of the gas IMs – give the AER and the Economic Regulatory Authority of WA (ERA) the ability to adjust economic lives in response to changes in Government policy. For instance, in its 2021 decision for the gas distribution network in the Australian Capital Territory, Evoenergy, the AER accepted shorter standard asset lives for new assets. The AER considered that:[33]

> *there was sufficient evidence to justify that new pipeline assets in the ACT would have shorter economic lives than their technical lives due to the ACT Government's policies to move away from gas use even though there were still some uncertainties regarding the path the ACT Government would choose to achieve net zero emissions.*

4.3.2. Capital contributions

The Commission notes that:[34]

> *Capital contributions offer suppliers the ability to manage a significant portion of the long-term demand risk. This is particularly relevant to GPBs which face the associated risk of economic network stranding.*

We agree with this statement. As outlined in our cross submission on the gas DPP reset,[35] we believe it is appropriate to adjust our policy to fit with the new policy and operating environment we are facing.

To mitigate the economic stranding risk for new investments on our distribution network, we have increased the forecast proportion of Incremental Cost that is to be met by capital contributions. This proportion has moved from 7% to 16% in FY2023, growing up to 20% in FY2031. Work is underway to update the capital contributions policy to this effect and the new version will be released for application from 1 October 2022.

4.3.3. RAB indexation and inflation forecasting

The Commission intends in the IMs Review to address issues concerning allocation of outturn inflation risk, the appropriate method for implementing if any change is requires; whether there are other unbiased inflation forecasting methodologies to apply, and whether these would be appropriate for application with RAB indexation.[36]

We support the Commission investigating these issues, but we do not consider it a priority to necessarily make decisions at this time. The Commission should clearly define the problem and not make any changes unless these are clearly preferable to the status quo.

4.4. Tools to reallocate risk

4.4.1. Form of control

As noted in the Issues paper, GDBs are currently subject to a limit on the maximum average price (a Weighted Average Price Cap, WAPC). We support moving to a revenue cap for GDBs. A revenue cap (in contrast to a WAPC) does not provide an incentive on suppliers to grow demand. This would appear more supportive of New Zealand's climate change objectives, the ERP, and the GTP, which all encourage a reduction in fossil gas use. We note that government policy objectives in relation to fossil gas use have become much clearer since the 2016 IMs review when the Commission last considered the form of control for GDPs.

We recognise that the design of a revenue cap mechanism needs to consider consumer concerns about year-to-year volatility in prices. Consideration should be given to a mechanism that allows for smoothing annual revenue cap wash-up amounts. Transpower's revenue cap includes such a mechanism. Referred to as an 'EV

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[33] AER, *Final decision – Evoenergy Access Arrangement, 2021 to 2026*, *Attachment 4 – Regulatory Depreciation*, April 2021, pp.5–6.

[34] Commerce Commission, Process and Issues Paper, 20 May 2022, para 5.171.

[35] Firstgas submission on the Commerce Commission's draft DPP reasons paper, 29 March 2022, https://firstgas.co.nz/wp-content/uploads/Firstgas-cross-submission_DPP-draft-decision-_29-March-2022_FINAL.pdf

[36] Commerce Commission, *Process and Issues Paper*, 20 May 2022, para 5.218.

account', the mechanism can be used to carry-forward any under or over recovery of revenue from one regulatory control period to the next.

If a WAPC is to be retained for GDBs, then attention will need to be given to demand forecasting. Demand forecasts should be conservative mindful of a likely decline in natural gas use.

4.4.2. Reopeners

The Commission notes issues related to reopener mechanisms including: ambiguity in the evidential requirements for certain trigger events; and uncertainty about reconsiderations and the framework it applies when assessing whether to amend a price-quality determination.[37] The current uncertainty means:

- We may expend management effort on considering whether or not to seek a reopener – the need to incur such costs is likely to be inefficient and could be avoided with greater clarity
- We may decide to only seek a reopener in relation to a very large unexpected cost event – this may lead us to not seek a reopener for some lesser events and thereby potentially incur a material loss, which would be contrary to meeting the FCM principle.

We suggest that the Commission consult on and prepare a guideline to provide greater clarity on the thresholds and evidence that the Commission requires when assessing whether to amend a price-quality determination.

4.4.3. Asset write downs

Some stakeholders have raised asset write downs as an option and the Commission has identified this as a potential change.[38] We do not support asset write downs.

First, asset write downs will likely undermine incentives for gas pipeline businesses to continue to invest, contrary to the purpose of Part 4.[39] As noted above, there is need for some ongoing minimum expenditure, likely for many years, to maintain safe and secure services for remaining fossil gas customers until they can transition to renewable energy sources. Asset write downs may cause gas pipeline owners to stop or limit future investment, with adverse impacts on service continuity.

Second, other sectors subject to Part 4 regulation may see asset write downs applied to gas pipeline business as creating a precedent that may discourage efficient investment in those sectors. This will have wider consequences for New Zealand and all energy consumers.

4.5. Tools to compensate for residual risk

Even after reducing or reallocating risk, some residual risk will inevitably remain. There are several ways that such risk can be compensated for in a way that continues to promote FCM. For instance, it could be compensated for via the cash flows through *ex-ante* allowances (e.g., allowances for innovation or self-insurance), or via the allowed WACC (e.g., through adjustments to the asset beta).

However, rather than step through these here, we cover them in the chapters to come:

- Chapter 5 discusses how risk can and should be considered when setting the rate of return, especially when determining the asset beta
- Chapter 7 sets out our views on how the regulatory settings could evolve to better support renewable gases and pipeline repurposing (e.g., using innovation allowances).

[37] Commerce Commission, Process and Issues Paper, 20 May 2022, paras 9.9.1, 9.9.2.

[38] Commerce Commission, *Process and Issues Paper*, 20 May 2022, paras.5.151.2 and 5.15.3.

[39] Section 52A (1) (a) states the purpose of Part 4 is to promote the long-term benefit of consumers….so that suppliers of regulated goods and service… have incentives to innovate and to invest, including in replacement, upgraded, and new assets.

Other tools include explicit allowances for asset stranding risk, like what the Commission has allowed for regulated fibre businesses. As raised in our response to the Commission's open letter last year,[40] we encourage the Commission to consider whether such allowances could be used to mitigate for asset stranding risks.

[40] Firstgas, *Firstgas response to open letter on fit for purpose regulation*, 28 May 2021, p.10.

5. Cost of capital

This section first discusses the overarching challenges affecting capital markets. The specific topics discussed are asset beta; TAMRP; Cost of debt; debt issuance costs; the regulatory period and the WACC percentile.

5.1. Overarching challenges

A confluence of challenges is affecting capital markets. Inflation is much higher than it has been in recent years and is projected to persist for some time. Monetary policy is responding, and interest rates have increased noticeably over the past year and may increase further. Russia's invasion of Ukraine and the lingering effects of the Covid-19 Pandemic have contributed to increased perception of market risks.

Added to this, investors are unclear as to the role that gas infrastructure may play in New Zealand's energy supply chain as we transition to net zero by 2050. Government policy is evolving, and the economics of repurposing that infrastructure is still coming to light as investment in renewable gases picks up globally.

With this backdrop, it is timely that the Commission is reviewing the cost of capital IMs for GPBs. We are but one of the stakeholders pushing for change to how the Commission has estimated the cost of capital the past. Our particular focus is on what, if anything, should be done differently to reflect the unique circumstances facing GPBs over the coming years.

Below we identify the issues that we consider the Commission should prioritise, with a particular focus on how changes to gas-specific risks are relevant to how the Commission estimates the asset beta and its choice over whether to set the WACC at its 67th percentile for GPBs.

5.2. Asset beta

The Process and Issues paper asks whether the effects of the Covid-19 pandemic on capital markets means that the Commission needs to rethink the approach to estimating the asset beta. This is an important question.

The Commission's current approach relies primarily on stock market data to estimate the asset beta, and so is affected by any temporary or permanent changes to how such markets operate that may be brought about by events like the pandemic. The pandemic significantly affected the New Zealand and global stock markets, especially immediately following March 2020 when the initial round of lockdowns were imposed.[41] It is conceivable, therefore, that during this period the traditional presumption that the covariance of stock returns with that of the market provide an appropriate measure of systematic did not hold.

Absent other information, this suggests that the Commission should take care before relying on betas estimated during that period. It should also consider whether any adjustments are needed before doing so. Ordinarily, we strongly favour relying on more recent information as a better indication of the market's perception of risk than older data. However, abnormal market behaviour may warrant us rethinking this at the present time.

Just like the recent gas DPP decision, the Process and Issues paper (paragraph 5.69) also calls out changes to the risk faced by GPBs, especially long-term demand risk. However, the paper does not directly consider how that – or other gas specific – risks may affect estimated asset betas or whether they warrant changes to how those betas are estimated.

41 See, for instance, Elie Bouri, Muhammad Abubakr Naeem, Safwan Mohd Nor, Imen Mbarki & Tareq Saeed, 2021: *Government responses to COVID-19 and industry stock returns*, Economic Research-Ekonomska Istraživanja; link: https://www.tandfonline.com/doi/pdf/10.1080/1331677X.2021.1929374.

Inherently, the Commission's current approach relies on historical movements in stock prices to estimate the asset beta. If those movements do not reflect recent changes to risk, then relying on betas estimated using them may misrepresent the true systematic risk faced by the GPBs that the Commission regulates.

Given this, we strongly encourage the Commission to critically review whether the current approach remains appropriate in circumstances where there is a step-change in risk faced by GPBs that may not apply to the other infrastructure that it regulates. This may mean, for instance, that it needs to rethink the magnitude of the adjustment (currently 0.05) that it added to the asset beta for EDBs to determine that for GPBs. It may also mean that the Commission should further investigate the extent of any changes in risk, for instance, by looking at how income elasticity of demand has changed or by using a comparator sample that only contains GPBs.

Now, it may be that the risks identified by the Commission are non-systematic and so do not affect beta. But that may not be the case for all risks. We look forward to engaging further with the Commission on how the changes to the risk facing GPBs should, if at all, affect how the cost of capital is determined.

5.3. Tax-Adjusted Market Risk Premium

The Commission increased the Tax-Adjusted Market Risk Premium (TAMRP) from 7% to 7.5% when making its gas DPP determination and associated IM amendments. We support that increase.

A key rationale adopted by the Commission was:[42]

> *The TAMRP is an economy wide parameter and therefore should be the same across all sectors. Our most recent estimate of TAMRP was for Fibre IMs in 2020 and that arrived at a best estimate of 7.5%.*

That is a sensible position to take, just as is updating it from time to time to reflect more recent information. As with almost all cost of capital parameters, the 'true' market risk premium evolves over time in response to changes in perceptions of market risk and how much the market is willing to compensate for market risk.

Ignoring evidence of such changes risks leading to a cost of capital allowance that over or under compensates GPBs for their efficient financing costs. It would be inappropriate, for instance, to revert the TAMRP back to the 7% estimate adopted prior to the Fibre IMs unless there were new evidence that supported such a reduction.

In the past, the Commission has tended to revise the TAMRP as part of its sector-wide review of cost of capital parameters (i.e., as it did in 2016). The Fibre IMs development clearly prompted the Commission to re-estimate the parameter in 2020 and its subsequent targeted update to the gas IMs in 2022 was an opportune time to roll that update out further.

What this more recent experience suggests is that there is scope to revise the TAMRP at each DPP / CPP determination because, in practice, the corresponding IMs are almost always updated by the Commission at the same time. We would support that practice and encourage the Commission to consider adopting it going forward, whereby a routine part of its DPP / CPP decision-making involves reviewing whether the TAMRP parameter should be refreshed or not.

If that practice is considered too onerous, then an alternative approach could be to have the TAMRP update automatically as part of the annual WACC determination process in a way that better reflects more recent information. We look forward to engaging with the Commission further on this point.

[42] Commission, *Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths – weighted average cost of capital*, 25 March 2022, para.3.10.

5.4. Cost of debt

The Commission's current approach to determining the cost of debt relies heavily on prevailing yields over a relatively short debt estimation period close to the start of the relevant DPP / CPP period.[43] This has two key consequences:

- **First**, the measured cost of debt can change significantly from one regulatory determination to the next in a way that looks a lot like a lottery. As we have seen over the last year, interest rates can swing wildly in response to domestic and international shocks. This exposes both consumers and GPBs to significant risk that can harm confidence in the regulatory framework.
- **Second**, it leads to a significant mismatch between how the cost of debt is determined and how GPBs finance themselves in the real world. Implicit in the current approach, GPBs are assumed to finance / re-finance their entire debt portfolio during the debt estimation period, or at least enter hedges that mimic that. In practice, however, we stagger our debt issuance over time in a way that reduces interest rate and refinancing risk. This mismatch means that there can be a significant difference – either positive or negative – between our actual debt financing costs and those allowed by the Commission.[44]

Given these consequences, our initial view is that the Commission should re-think its approach to setting the cost of debt. To better align with how debt is raised in practice and to reduce price and revenue volatility, we consider that the Commission should adopt a trailing average approach to estimate the cost of debt. Such an approach is widely applied by economic regulators in other developed countries, including Australia and the United Kingdom.[45] The Process and Issues Paper (paragraphs 6.72–6.74) already identifies this approach as a possible way forward, an approach that we agree with.

Importantly, *if* the Commission were minded to adopt a trailing average approach like other regulators, then it will need to consider how best to transition to it. One option would be to apply a transition like that adopted by the Australian Energy Regulator when implementing the trailing average over the last 10 years across the Australian energy networks it regulates.

Even if the Commission were not so minded, then it should consider extending the length of period used to estimate the risk-free rate component from the three months used currently. This would help reduce the 'lottery' risk noted above. We would support a period of at least 1 year. We look forward to engaging with the Commission on this issue further.

5.5. Debt issuance costs

The Process and Issues Paper (paragraphs 6.75 and 6.80) raises a concern that we and other regulated business may be double recovering debt issuance costs, once through the allowed cost of capital and then again through the Opex allowance.

Clearly, if that were the case, then it should be addressed. All we can say is that, from Firstgas' perspective, there is no double recovery because we do not include issuance costs in our reported operating expenditure. Rather, our debt issuance costs are capitalised against the loan / debt that we issue. They are recognised as financing costs in our Profit and Loss over the period of the loan/debt. As such, they are not recorded in Opex for regulatory purposes.

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[43] The Commission combines a prevailing estimate of the risk-free rate (i.e., using a 3 month period) with a longer-term estimate of the debt risk premium (i.e., using an average of annual debt premia observed over a five year period).

[44] For the most part, because the Commission adopts a 5-year term when estimating the risk-free rate, the Commission's approach tends to undercompensate for GPB's that issued debt with a longer term to maturity. This occurs because, in normal market conditions, yields tend to increase with term (i.e., an upward sloping yield curve).

[45] See, for instance: AER, *Draft 2022 Rate of Return Instrument*, June 2022; and Ofgem, *RIIO-2 Final Determinations – Finance Annex (REVISED)*, February 2021.

If the Commission remained concerned about the risk of double recovery, then it could clarify in the Information Disclosure IMs that debt issuance costs should not be included in the reported Opex – a practice that Firstgas already follows.

5.6. Regulatory period

As part of its gas DPP determination the Commission amended the cost of capital IMs to allow for a 4-year regulatory period when determining the risk-free rate. We support those amendments.

If the intent is to align the term of the risk-free rate with the length of the regulatory period, then the cost of capital IM should align with that. We made this point in our submission on the draft IM changes.[46]

Given the interaction between parameters used to estimate the cost of capital, it is important to ensure that all parameters are estimated consistently. The Commission recognised this when amending the cost of capital IMs by adjusting the TAMRP to reflect the shorter regulatory period adopted then.

5.7. WACC percentile

A cornerstone of the Commission's approach to cost of capital is its recognition that the risk of under or over investment is asymmetric. Consumer harm arising from under investment is significantly greater than that resulting from over investment.

There are good reasons why the Commission's current approach of setting the WACC at the 67th percentile should remain. Cost of capital parameter estimates are inherently uncertain and subject to estimation risk. Setting the cost of capital slightly above its mid-point estimate helps reduce the risk that cost of capital is set too low, undermining efficient investment.

Other stakeholders will no doubt provide their own views on the merits or otherwise of setting the WACC at its 67th percentile. And we will consider those in due course.

For the most part, the rationale above is generic to all regulated infrastructure, including GPBs. But, in our view, there is an even stronger rationale for erring on the side of caution for GPBs by setting the WACC for them at the 67th percentile. An increase in long-term demand uncertainty for GPBs puts them in a tight spot. Faced with both demand risk and the risk that the WACC is set too low, investors in GPBs will be cautious before committing funds for the long-term. Such caution could significantly undermine efforts to repurpose gas infrastructure to transport renewable gases.

Given this, even if the Commission decides to no longer adopt the 67th percentile when setting the WACC for regulated infrastructure, there are good reasons to retain it for GPBs. We look forward to engaging with the Commission further as part of the 2023 IMs review.

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46 Firstgas, *Proposed Weighted Average Cost of Capital IMs amendments* 4 March 2022.

6. Expenditure

The Process and Issues Paper raises several issues and questions that relate to expenditure. This chapter focuses on several of these, including the overall approach to setting expenditure allowances and whether there is evidence of efficiency and innovation by GPBs.

6.1. Rethinking allowance setting

The Process and Issues paper discusses the potential shift to a Totex regime which has been raised in the EDB DPP3 process[47] and discusses the OFGEM Totex incentive mechanism.[48] There are potential benefits in shifting to a Totex regime:

- **First**, the current settings of the allowances tend to favour Capex over Opex.[49] This may not be optimal. Adopting a Totex regime could remove that favour.
- **Second**, a fit for purpose Totex incentive mechanism could provide greater flexibility and improved incentives for pipelines to substitute short term expenditure – such as increased reliance on repairs and maintenance – for capital investment. This could more effectively address stranded asset risk resulting from declining pipeline demand, the uncertainty about demand and potentially minimise the need for investment in replacement assets which may not be utilised in the long term.

Totex can also be used as a tool to address risk. A key design feature of the mechanism is the ability to specify the speed of cost recovery by allocating costs to fast or slow cost recovery. Allocating a greater portion of those costs to fast recovery will reduce risk and vice versa.

If a Totex incentive mechanism were investigated by the Commission, then the Commission would need to:

- Have a clear articulation of its objectives
- Have confidence that incentive design would promote the objectives and that it would not be overly complex or have unintended consequences; and
- Recognise that implementing such a mechanism can be challenging in practice.

The Commission should consider reviewing the experience in other jurisdictions that have applied totex or similar mechanisms (e.g., Germany) to see whether there are any insights that could be relevant to New Zealand. The Commission could adopt such a mechanism within the current IMs review process. It could, however, defer consideration until later in the period (i.e., 2030 IMs review) when there is greater clarity on the GTP and the future of gas infrastructure. Doing so may better help manage workload and stakeholder attention. (See discussion in section 3.3 above).

6.2. Assessing efficiency

The Process and Issues Paper notes that the Commission has found little information on the efficiency and innovation performance of GPBs.

As a GPB, we have strong incentives to ensure that our capital expenditure is efficient. There *is* evidence from how we manage our GPBs that we are operating efficiently and seek to improve the performance of our businesses.

[47] Commerce Commission, *Process and Issues Paper*, 20 May 2022, para 5.92.
[48] Commerce Commission, *Process and Issues Paper*, 20 May 2022, para 5.113.
[49] See Unison submission cited in Commerce Commission, *Process and Issues Paper*, 20 May 2022, para 5.92.

- **Incentives for capital efficiency**. Notwithstanding the FCM principle, there remains uncertainty as to whether we will fully recover future capital expenditure. Faced with such uncertainty, we have strong incentives not to avoid unnecessary capital expenditure.
- **Continuous improvement.** At Firstgas Group, we have adopted a continuous improvement philosophy focusing on finding ways that we can improve how we operate and manage our networks. We have a dedicated continuous improvement team tasked with leading this activity across the group. In recent years, for example, we have made several improvements to our asset management practices, introducing a Maximo Asset Health Insights (MAHI) application to better understand the condition of our assets.[50]
- **Independent reviews.** Our focus on efficient management is also reinforced by various independent reviews. Risk management provides one 'lens' through to which to assess an organisations efficiency. In 2019, the Commission commissioned AECOM to undertake an independent review of risk management. In regard to both our GTP and GDB business AECOM found: [51]

  > *[the businesses are approaching the level of risk management we believe to be best appropriate for such an organisation. We consider the current rating is commendable considering:*
  >
  > - *the organisation is very new, and has needed to implement changes to systems and approaches established by the previous networks owner to reflect the size of FGL and the relevant networks; and*
  > - *there is clear evidence of ongoing improvement activities*

  Another review undertaken by AECOM for the Commission of geotechnical risk management in our GTB found: [52]

  > *First Gas have good, well documented processes in place to identify geohazards and to evaluate and manage the risks associated with the identified hazards.*

  In 2021, we requested that AECOM return to review our progress since the 2019 report. We were very pleased with the outcome of AECOM's 2021 report, that highlighted our improvements and commitment to continuous improvement around managing risk.
- **Performance dashboard**. The Commission has prepared a performance dashboard for all GPBs and in December 2021, released its Trends in Gas Pipeline Business performance report.[53] The report looked at the performance overtime of GDBs and GTBs. The Commission noted that consumers were now paying less (on average) for gas distribution than they were in 2014 and are experiencing fewer outages, and that GPBs have generally not made excessive profits over the last seven years.

In the absence of evidence to the contrary, these examples help reinforce our strong view that GPBs are efficient and have every incentive not to overspend while the future for gas in New Zealand is being resolved. We look forward to engaging with the Commission further on these points.

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50 Improvements to our operations are outlined in our annual Asset Management Plans for our GTB and GDB.

51 AECOM, *Review of gas pipeline businesses' asset management plans*, 4 October 2019, s.4.2 and s.4.3.

52 AECOM, *Geotechnical Risk Management Review - Firstgas Transmission Pipelines,* September 2019, s.6.1.

53 https://comcom.govt.nz/regulated-industries/gas-pipelines/gas-pipelines-performance-and-data/trends-in-gas-pipeline-business-performance.

6.3. Compressor Fuel

Firstgas recommends that the Commission review the way that compressor fuel is treated across the GTB – incorporating both the Maui and non-Maui (ex-Vector) transmission pipeline.[54]

At present, compressor fuel used at Mokau (Maui pipeline) is treated as a recoverable cost for our GTB, while all compressor fuel used on the ex-Vector (non-Maui) pipeline is treated as Opex. Mokau compressor fuel was introduced as a recoverable cost in December 2016, as it was concluded at that time that Mokau compressors were used almost exclusively for balancing, and therefore should be treated the same as balancing gas (i.e., a recoverable cost).

Since the establishment of Firstgas in 2016, and the operation of the two transmission systems as one network, we have changed the way we manage compression across the network. We believe that this warrants a review of how all compression costs are treated across the transmission system. We would support a consistent approach to compressor fuel in the GTB IMs, as consistent treatment of compressor fuel will remove any incentives to use compression differently based on where a compression plant is located.

6.4. Other expenditure issues

Table 2 below identifies two other expenditure issues that should be considered by the Commission as part of its IMs review.

Table 2. Other expenditure issues

Issue	Description	Suggested solution
Court-imposed pecuniary penalties	Ambiguity as to whether the Opex definition includes court-imposed pecuniary penalties.	Support change to definition of Opex to exclude court imposed pecuniary penalties. No case for different treatment to EDBs.
Fire and Emergency Management New Zealand (FENZ) levy	The 2020 EDB DPP reset introduced a new recoverable cost that allows for FENZ levies to be passed through to consumers.[55] This change has not been included in the gas DPP reset, noting that only GasNet received an uplift for this levy. This levy is applicable to all GPBs.	Consider this cost should be treated as a recoverable cost for all GPBs. No case for different treatment to EDBs.

54 See Firstgas' *s* for an overview of the gas transmission network, page 16, https://firstgas.co.nz/wp-content/uploads/Firstgas-2021-Transmission-AMP-Update.pdf.

55 Commerce Commission, *Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision; reasons paper*, 27 November 2019, para X88.2, https://comcom.govt.nz/__data/assets/pdf_file/0020/191810/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2020-Final-decision-Reasons-paper-27-November-2019.PDF.

7. Renewable gases

Quite rightly, the Process and Issues paper raises as a key issue whether there should be incentives on GPBs to investigate the viability of low carbon gases. Our strong view is that it should, both to benefit existing consumers by ensuring that pipeline infrastructure remains used and useful (keeping average costs down) and as a means to help promote New Zealand's net zero ambitions.

This section deals with the innovation challenge for New Zealand to move to a future where renewable gases with net zero carbon emissions would be transported by repurposed gas pipelines.[56] Given the importance of these innovation questions for the future regulation of gas pipelines we consider it is sensible to treat this as separate topic (rather than following topic headings of the issues paper).

7.1. The Government recognises the potentially important role of repurposing of gas pipelines to transport renewable gases

The development of the GTP provides important context for the IMs Review. The GTP terms of reference are clear that an important aspect of the GTP will be development of government policy regarding potential repurposing of gas pipelines and how to maintain the option value of gas pipelines. The Minister of Energy and Resources has signalled that the development of the GTP: [57]

> *will help to provide greater certainty to enable investments in our fossil gas system to continue to support an equitable transition. It is intended to be focused and sufficiently technical to outline a realistic – but suitably ambitious – pathway for the fossil gas industry's transition.'*

The Minister also stated:[58]

> *I expect that as [hydrogen and other] technologies are developed and deployed the best mechanism for transportation will become clear. I consider that there is option value in ensuring that our gas pipelines continue for such a time to ensure that these options can be developed.*

7.2. Gas pipeline expenditure on renewable gases innovation is modest at present but may expand

At present, the level of Firstgas' expenditures on these activities and projects is modest and they have been funded from within our own resources or co-funded with Government.

In the gas DPP reset, the Commission approved $200,000 per annum for our GTB and $135,000 for our GDB for our blended gas investigations. This is approximately half of what we have forecast in our GTB and GDB 2021 Asset Management Plan (AMP) Updates for the first stage of our hydrogen trial. We note that as we move to subsequent phases of this trial, the level of expenditure will increase substantially. Our 2021 feasibility study *Bringing zero carbon gas to Aotearoa* estimated that to convert the entire gas distribution network to support hydrogen could cost in the magnitude of $270 million over the coming 30 years.[59]

Therefore, the lack of specific regulatory mechanisms to encourage such innovation has not so far been a significant barrier *at that scale*.

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56 This includes gas composition ranging between a 10-20% hydrogen / biogas blend or greater through to 100% hydrogen gas.

57 Minister of Energy Hon Dr Megan Woods, Cabinet Paper *Managing the phase out of fossil gas and opportunities to repurpose infrastructure for renewable gases: report back and proposed next steps,* published 9 June 2022, para 104.

58 Minister of Energy Hon Dr Megan Woods, Cabinet Paper *Managing the phase out of fossil gas and opportunities to repurpose infrastructure for renewable gases: report back and proposed next steps,* published 9 June 2022, para 94.

59 Firstgas, *Bringing zero carbon gases to Aotearoa: Hydrogen feasibility study – Summary Report*, 2021, p.13.

If there is to be significant investigation and development of the potential for repurposing of gas pipelines then the overall level of expenditure required will likely need to increase significantly. We note that this expenditure will also involve significant risk.

The International Energy Agency (IEA) recently advocated for developed economy governments to support Research and Development to bring down hydrogen costs: [60]

> *Alongside cost reductions from economies of scale R&D is crucial to lower costs and improve performance, including for fuel cells, hydrogen-based fuels and electrolysers. Government actions, including use of public funds, are critical in setting the research agenda, taking risks and attracting private capital for innovation.*

The NZ Gas Infrastructure Work Group suggested that:

> *As New Zealand will largely be a global technology follower, the rationale for funding support for the development of green gasses would be to assist in taking risks, attracting private capital for innovation, building the local market, and understanding local issues. Such issues may include the technical and commercial issues associated with repurposing New Zealand natural gas networks for hydrogen and how to mitigate impacts on consumers.*

Immediate opportunities identified by the working group for government support include:

- Supporting demonstration projects for hydrogen production and blending (along the lines of the ARENA's Australian hydrogen projects)
- Supporting studies into the use of biogas for industrial applications in New Zealand.

Projects funded by ARENA in Australia illustrate the substantial scale of government funded innovation expenditure potentially required to explore the potential for repurposing of gas pipelines. Two Australia gas pipeline companies were provided with conditional funding support to develop commercial-scale renewable hydrogen projects as part of ARENA's Renewable Hydrogen Deployment Funding Round. These projects are:

- ATCO Australia Pty Ltd which was provide up to $A 28.7 million by ARENA towards a 10 MW electrolyser for gas blending at ATCO's Clean Energy Innovation Park in Warradarge, Western Australia and
- Australian Gas Networks Limited (AGIG) which was provide up to $A 32.1 million in funding for a 10 MW electrolyser for gas blending at AGIG's Murray Valley Hydrogen Park in Wodonga, Victoria.[61]

7.3. Options for funding innovation for repurposing of pipelines

There are a range of options for how innovation activities and projects related to gas pipeline repurposing could be funded:

- Self-funding by gas businesses
- By government (taxpayers)
- Future consumers and
- Current consumers.

We expect such funding options will be considered as part of developing innovation policy towards gas pipeline repurposing in the GTP.

60 IEA, *The Future of Hydrogen – Seizing today's opportunities*, June 2019, p.16.
61 ARENA Media release, *Over $100 million to build Australia's first large-scale hydrogen plants*, 5 May 2021.

The New Zealand government has already funded hydrogen demonstration project. Given the potential scale of required the innovation expenditures required and the level of risk, we expect that the government will need to play a significant ongoing role in funding such work, as advocated by the IEA and as is occurring in Australia. There is also a role for gas businesses having some ‘skin in the game’ though appropriately designed co-funding and risk sharing arrangements.

In relation to funding through charges on current customers, the Commission notes that in its Gas DPP3 draft decision, that it had clarified that expenditure (including R&D costs) for renewable gases (e.g., biogas and hydrogen) cannot be attributed to the current regulated service. [62] We consider that a principled policy case can be made that allocating some (though not all) of the required funding costs for certain gas pipeline repurposing activities to current consumers would support the purpose of Part 4. For instance:

- Some – though not all – current consumers will become future consumers who may benefit from current innovation activities
- It may be considered more equitable that consumers who have access to piped gas should contribute to innovation repurposing costs, rather than the full cost falling on taxpayers, some of whom do not have access to piped gas
- Funding that may increase the likelihood that pipeline assets are repurposed could reduce the need to bring forward cost recovery and benefit current consumers (e.g., using accelerated depreciation)
- Other regulatory regimes with objectives similar to the Part 4 accept that current consumers should contribute to innovation funding.[63]

A potential solution is for the government to amend the *Gas Act* and / or the *Commerce Act* to clarify in what circumstance the Commission can allow for innovation related costs in current charges where it promotes the Part 4 purpose.

7.4. The Commission may need to consider how to manage the concurrent GTP Review

As noted in section 3.1.1, the GTP is being developed in parallel with this IMs review. Relevant government policy (or details on the implementation of government policy) may not be clear by the time the Commission is completing the 2023 IM Review. The Commission could consider managing this uncertainty - whilst not inhibiting the required pace of change - by:

- Developing a package of changes for the 2023 GPB IMs and
- Signalling a phased review of IMs aspects related to renewable gases and funding of innovation expenditure prior to the next statutorily required GPB IMs review in 2030.

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62 For example, the Part 4 regime cannot facilitate the recovery of the costs of conveying any gas other than natural gas, unless the gas conveyed contains a blend of natural gas with relatively small proportion of other gases. Firms can still carry out investigations and invest in the conveyance of renewable gases, but that cost would be part of establishing a new service and cannot be recovered through lines charges from consumers of natural gas.

63 For instance, the AER commonly includes a demand management innovation allowance, or DMIA, in its revenue determinations for regulated electricity networks. Although the allowance is recovered via tariffs charged to existing consumers, the innovation that the allowance funds will benefit future consumers as well through lower long term network costs. See: AER, *Demand Management Innovation Allowance Mechanism – Electricity transmission network service providers*, May 2021.

7.5. Proposed way forward

We suggest the Commission should:

- Keep an open mind on considering the role that IMs could play in identifying activities and projects that are supportive of repurposing of gas pipelines for transportation of renewable gases and which are supported by charges on current customers and
- Consider how it could manage any uncertainty arising from the concurrent development of the GTP while not inhibiting an appropriate pace of change
- Provide guidance on what types of expenditure to support renewable gases that it considers is appropriate and could be recovered through regulated tariffs.

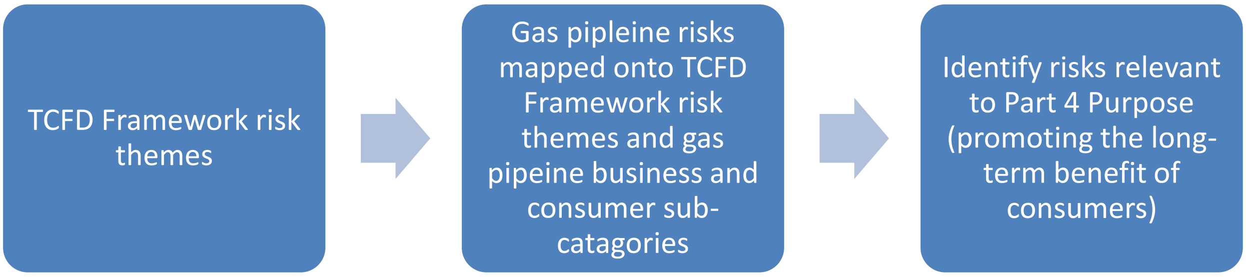
Attachment 1: Risks and opportunity analysis adopting the Task Force on Climate-Related Financial Disclosures Framework

The Commission proposes to use the Task Force on Climate-Related Financial Disclosures Framework (TCFD Framework) which adopts three risk themes – transition risks, physical risks, and opportunities.

This Attachment sets out details of our analysis of climate related risks and opportunities that affect Firstgas' GTB and GDBs and our consumers using the TCFD Framework themes.

The following diagram and table shows how we have undertaken this risk analysis.

Figure A1: Process for risk analysis



This analysis of transition risks draws on analysis that Firstgas and the other major gas infrastructure business have undertaken over the past 12 month. Further details are set out in footnotes. A fuller discussion can be found in NZ Gas Infrastructure Future Findings Report, 13 August 2021.[64]

The assessment of physical climate risks set out below is based on our current understanding. Firstgas has note undertaken a comprehensive assessment of these risks at this stage, but is expecting to undertake further work in the near term.

We have opted not to use the TCFD Framework transition risk sub-categories[65] (policy and legal, technology, market, reputation). The subcategory definitions, examples and impact have been considered in this analysis, but are not presented using the transition risk sub-categories. Rather, we have used a sub categorisation based on assessing transition risks to our gas pipeline businesses and customers respectively. This approach better aligns with the design of Part 4 of the *Commerce Act* which is focused on the long-term interest of consumers and in our view provides more useful insights for economic regulation.

There are also significant interrelated risks related to the future expansion of electricity supply chain to enable timely and efficient switching of current gas demand to electricity. These are not considered here.

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64 See: https://gasischanging.co.nz/assets/uploads/Gas-infrastrucutre-future-working-group-Findings-report-FINAL-August-2021.pdf.

65 See: Table on page 2. Attachment A, *The Task Force on Climate-Related Financial Disclosures*, Draft Framework paper.

Risk Theme		Risks analysis	Part 4 risks
Transition risks Transitioning to a lower-carbon economy may entail extensive policy, legal, technology, and market changes to address mitigation and adaptation requirements related to climate change. Depending on the nature, speed, and focus of these changes, transition risks may pose varying levels of financial and reputational risk to organisations.	**Overview**	Transition risks are the dominant climate change risks faced by Firstgas' GTB and GDB and their customers.	
		Demand risk. This risk is a key overarching risk that gives rise to many of the risks described below.	Demand risk is relevant to the Part 4 purpose statement. It gives rise to many other risks discussed below that could adversely affect the long-term interest of consumers.
	Firstgas GTB and GDB	The main transition risks affecting Firstgas are: - **FCM risk.** The risk to Firstgas that expected revenues will be insufficient to meet the ex-ante financial capital maintenance (FCM) principle.	The Commission seeks to provide regulated suppliers with an *ex-ante* expectation of earning their risk-adjusted cost of capital (i.e., a 'normal return'), and of maintaining their financial capital in real terms over timeframes longer than a single regulatory period. This maintains incentives to invest in line with the Part 4 purpose (section 52A(1)(a) of the Act).[66]
		- **Financing risk**. The risk that as demand and revenues for GPB services fall that they cease to be financially viable (i.e., unable be able to obtain financing).	GPBs that are not financially viable may struggle to maintain their assets, which may pose safety risks to the community and consumers or may deliver reduced reliability to consumers, both of which may not support the Part 4 purpose.
		- **Decommissioning cost risk**. The risk that there will be inadequate provision of costs for decommissioning and, related to this, that the FCM principle will not be met.	Significant provisions will be required to prepare for and undertake decommissioning of gas pipelines if they cease to be used under a winddown scenario. It is currently unclear how the responsibility for decommissioning costs will be allocated. If these are to be allocated to GPBs and the FCM principle is to be met, then provisions will be required for either consumers or taxpayers to meet these costs.

66 Commerce Commission, *Draft Framework Paper*, 20 May 2022, para. X22.1.

Risk Theme		Risks analysis	Part 4 risks
		- **Reputation risks.** The risk to gas businesses – and potentially also government and Commission's reputation – arising from any significant harm to consumers through the transition, or lack of understanding by consumers of the transition process.	Negative perceptions of GPBs and the Commission can undermine confidence in the regulatory regime, which is likely to undermine the Part 4 purpose.

Risk Theme		Risks analysis	Part 4 risks
	Consumers	Transition risks that could affect consumers include: - **Customer safety, reliability, and price risk**. As consumers transition their consumption to renewable gases or alternative renewable energy sources, the risk that gas supply may not be safe or reliable; and the risk that delivered gas prices are unaffordable. - **Energy switching risks**. The risk that switching consumer demand to alternative energy sources, such as electricity, that consumers, may lead to a short-term gap in the provision of energy.[67] - **Consumer transition cost risks.** The potential significant costs to consumers to make the required changes to space and water heating appliances in homes and commercial buildings.[68] - **Energy suitability risk**. The risk that alternatives for fossil gas do not meet consumer needs.[69] - **Resource availability risks.** The risk of a lack of skilled human and other resources to undertake works to enable consumers to transition to alternatives to fossil gas – which may translate to higher costs or service interruptions to consumers.[70] - **Vulnerable customer risks.** The risk to vulnerable customers to meet appliance conversion and other costs.[71] - **Industrial customer risks**. The risk to the viability of major industrial customers that could otherwise be manageable or avoided.	These transition risks may be inconsistent with the Part 4 purpose to promote the long-term interests of consumers. This is not to say that the Commission necessarily has a clear responsibility or the powers or tools pursuant to the *Commerce Act 1986* to take account of or to mitigate each risk.

67 In a wind down scenario a coordinated process will be required to ensure that all residential and commercial customers have switched to an alternative energy source before gas supply in a street or suburb is shut down. Risks of consumers having continuous access to energy arise if the coordination process fails.

68 Climate Change Commission analysis indicates $5.3 billion out to 2050 to make the required changes to space and water heating appliances in homes and commercial buildings. See: Gas Infrastructure Future Working Group, *Findings Report*, 13 August 2021.

69 Initial feedback from consumers such as restaurant, horticulture, and crematoria sectors highlight potential difficulties with moving away from natural gas. Similarly, feedback from residential gas consumers has been strongly against removing the option of using gas for home heating and cooking. See: Gas Infrastructure Future Working Group, *Findings Report*, 13 August 2021.

70 Gas transmission and distribution businesses will need to retain a workforce until their gas networks are ready to be switched off. Sufficient gas fitting skills will be critical to the safe withdrawal of gas services. There may be potential issues in organising and coordinating a sufficiently large workforce in an area to install electricity (and other) appliances, and for undertaking building and electrical, plumbing and gas fitting trades. See: Gas Infrastructure Future Working Group, *Findings Report*, 13 August 2021.

71 Preliminary analysis suggests that there are over 140,000 existing gas consumers that could be categorised as vulnerable that are located in low-income areas. For these consumers, covering their share of the $5.3 billion in estimated appliance conversion costs will be challenging.

Risk Theme		Risks analysis	Part 4 risks
	Regional communities	Transition risks that could affect consumers include: - **Regional economic risks.** The risk that abrupt changes to the sustainability of industrial consumers, brought about by phasing out natural gas, could have material adverse economic impacts in local areas.[72]	This is not a risk that relates to the Part 4 purpose to promote the long-term benefit of consumers.
Physical risks Physical risks resulting from climate change can be event driven (acute) or longer-term shifts (chronic) in climate patterns.		The main physical climate change risks assessed as affecting Firstgas' pipeline assets are river and sea erosion. A portion of the GTB current capital expenditure is committed to riverbank defences and relocations. This increased risk in the medium term is caused by more frequent storm events and rainfall changes (particularly low likelihood and high impact events). This impacts the required capital expenditure to mitigate this risk, due to the high number of river and stream crossings in the GTB which were designed/constructed based on 1970s projections. Several spot locations are also vulnerable to sea cliff erosion and require active management.	The emergence of physical risks over time could lead to increased expenditure requirements to proactively and efficiently manage this risk
Opportunities Efforts to mitigate and adapt to climate change also produce opportunities for organisations.		There is potential opportunity for repurposing gas pipelines, which could underpin, and require, a larger scale renewable gas industry in New Zealand. A future involving transportation of green hydrogen using repurposed gas pipelines will require a large enough current and future market to justify the high fixed investment costs required to repurpose and maintain and replace pipeline and consumer assets over time. Confidence in the size of the market will require widespread acceptance of hydrogen by consumers.[73]	This opportunity is relevant to the Part 4 purpose to promote the long-term benefit of consumers. Repurposing of assets may: reduce the need to accelerate recovery of costs from consumers and may enable provision of renewable new gas services to consumers. It may also avoid the transition costs faced by consumers.

72 These issues are being monitored through the Just Transition Unit in MBIE.

73 See: Gas Infrastructure Future Working Group, *Findings Report*, 13 August 2021, Chapter 7.

