First Gas Limited
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4 August 2016

Ms. Keston Ruxton
Manager, Input Methodologies Review
Regulation Branch
Commerce Commission
Wellington

Dear Keston,

Submission on Input Methodologies review draft decisions (excluding cost of capital)

This is one of two submissions[1] by First Gas on the draft decisions papers for the Input Methodologies review (including the report on the IM review, but excluding draft determinations) published by the Commission in June 2016. Our other submission focuses on cost of capital issues for Gas Pipeline Businesses (GPBs). This submission covers all other issues relevant to us raised by the draft decisions.

The structure of this submission uses the same headings as the groups of existing IM decisions described in the Commission's Report on the IM review.

General provisions ('GE')

We support the proposal to add provisions to allow a Next Closest Alternative (NCA) to be determined if an IM becomes unworkable. We appreciate the real world examples provided in the draft decisions paper, and agree that a measure of flexibility as described by the Commission can be useful and appropriate.

With respect to requirements for a supplier, we suggest the following clarifications.

- A supplier should be permitted to identify an unworkable IM to the Commission, accompanied by an explanation of why it considers the IM to be unworkable, without a requirement to propose an NCA as well.
- Unless a supplier proposes an NCA itself, it should not be required to assess whether an NCA is likely to have an equivalent or non-equivalent effect to that of the unworkable IM.
- Certification should only relate to new supplier information that would have specifically been required to be certified if provided otherwise as part of information disclosure or a price-quality path compliance statement.

Cost allocation ('CA')

We consider that the current cost allocation IMs are largely fit for purpose in how they apply to GPBs.

1 We are also providing a separate submission on the Gas DPP 2017 reset paper.

We are concerned about the Commission's proposal to amend decision CA04 to require justification, without any regard to materiality, for every use of a proxy cost allocation. There are many examples of relatively trivial expenditures, such as the purchase of office supplies, which require proxy allocators because causal links between the expenditure and particular regulated activities cannot be practically determined. There are also many cases where, even if a causal linkage might be able to be established, the required administration and accounting for detailed allocation of expenditure would be excessively cumbersome and costly. As a result, the widespread use of proxy allocators should not be surprising.

To avoid cumbersome justifications for every use of proxy allocators, we suggest this requirement should be subject to a materiality threshold. The relevant threshold for costs could be a percentage of revenues and for assets could be a percentage of RAB value.

Asset valuation ('AV')

Many of the proposed amendments that can affect our asset valuation are about implementation improvements. These appear reasonably straightforward and we have no comments for them.

The proposed change that is of greatest interest to First Gas is for decision AV17 to allow an option to adjust asset lives. We agree this is a modest proposal to partially mitigate potential economic stranding risks. We understand it is primarily driven by consideration of the impact that emerging technologies may have on Electricity Distribution Businesses (EDBs).

At this stage, we cannot provide evidence or make reliable assessments of the degree to which our assets may be impacted by emerging technologies. In the short term, we expect that the risks may be lower for us than for EDBs. In the medium term, however, our economic stranding risks will depend on the future relative prices of delivered gas (including transmission and other charges) compared with other energy sources (such as electricity). Since relative prices can change quickly, economic stranding risks can also change.

We note that the IMs being amended now will not only be used for setting gas DPPs from 2017 to 2022, but likely for those from 2022 to 2027 as well. Within that time frame we cannot rule out a potential impact of emerging technologies on GPBs. Therefore, it would be prudent to provide the same option to GPBs as is being provided to EDBs.

We support the implementation changes for decision AV17 proposed in paragraph 124 of the Report on the IM review.

We appreciate the invitation from the Commission to propose new standard asset lives for Schedule A of the IMs. If time permits, we may include such a proposal in our follow-up submission on the draft determinations. However, we also note the Commission's desire to obtain combined views from most of the suppliers in each relevant sector. Generating such a combined view may require some more time for gas distribution, and we would appreciate an opportunity to work out such a combined proposal at a slightly later stage.

With respect to decision AV54 we appreciate the Commission's invitation to discuss the alignment of disclosure years for GPBs. Our views are as follows.

- We are keen to align the disclosure years for our GTB and our GDB with the Commission's preferred 30 September year end.
- If this requires that provisions for changes to a disclosure year must be included in an IM then we are happy to participate in the discussion and design of such provisions.
- As owner of the only GTB in New Zealand, we do not see a need to specify a common disclosure year in the IM for GTBs.

- Despite our own preference for a 30 September disclosure year, we see no need to impose our preference on other GDBs. Different suppliers may have good reasons to maintain different financial year ends, and for audit as well as practical reasons we expect it would remain most sensible to align disclosure years with financial years for each supplier.

Treatment of taxation ('TX')

We do not have particular comments on the proposed changes.

The unique tax issues faced previously by MDL will no longer be an issue for our GTB. We will liaise with the Commission to find an acceptable treatment for our GTB's tax balances resulting from our acquisition of the Maui pipeline and its related assets from MDL.

Cost of capital ('CC')

We have major concerns about the proposed cost of capital amendment in the draft decisions to reduce the asset beta for GPBs from 0.44 to 0.34. We have provided a separate submission on this topic (along with an expert report from Oxera), and we also support the submission provided by First State Investments on cost of capital.

Gas pricing methodologies ('GP')

The Commission does not propose to make any changes to the IM provisions for gas pricing methodologies. We are comfortable with that approach for gas distribution, but consider that it misses an opportunity to improve arrangements for gas transmission pricing – as we explain below.

Gas distribution pricing methodologies

Section 52T(1)(b) of the Commerce Act 1986 requires the Commission to include provisions on pricing methodologies "… except where another industry regulator (such as the Electricity Authority) has the power to set pricing methodologies in relation to particular goods or services". The industry regulator for gas is Gas Industry Company (GIC). The extent to which GIC has powers to set pricing methodologies for gas distribution may be debatable. For practical purposes, however, this may be a moot point. GIC has not pursued any such powers and does not currently have an active workstream for gas distribution pricing. Faced with that situation, we can accept the Commission's lead role on pricing methodologies for GDBs.

We consider the pricing principles determined by the Commission as broadly suitable for GDBs. They were based on the principles adopted for the Gas Authorisation for selected gas distribution companies, which in turn were based on pricing principles that were originally derived for EDBs. In practice, all GDBs use a similar pricing approach. In their information disclosures all GDBs express some reservations in assessing all of the pricing principles against their pricing methodology. Nevertheless, their pricing methodologies appear to be practical and sensible, and it seems unlikely that the Commission would intervene and impose a different pricing methodology if a GDB applied for a CPP.

As a result, we are comfortable with the current pricing methodology provisions for GDBs. We do note, however, that distribution pricing is a topic of active discussion by the Electricity Authority. If this results in changes for EDBs, it could lead to a need or desire to update the pricing principles for GDBs as well. It could also lead to a future workstream in which GIC takes a leading role for gas distribution pricing methodologies. In either case, this suggests that the Commission may need to be prepared to review GDB pricing methodology provisions again when that becomes appropriate.

Gas transmission pricing methodologies

The process for setting the pricing methodology for our GTB is fundamentally different to our GDB. "Transmission access and pricing" is a major workstream in GIC's statement of intent for 2017-2019, which also identifies the area of gas transmission code convergence as a central focus for GIC. We have committed to lead the development of a new gas transmission operating code that will replace the current MPOC and VTC. We see a new transmission pricing methodology being an important component of that work – with transmission access and pricing going 'hand in glove'. In other words, it would not be sensible to determine a transmission pricing methodology in isolation from the access regime. GIC has indicated that regulation is an "obvious backstop" if agreement on a new code cannot be voluntarily achieved[2].

It appears to us that GIC clearly has the power to set pricing methodologies for gas transmission services. Given GIC's other responsibilities in relation to transmission codes, this makes sense to us. Faced with the prospect of GIC having to regulate transmission pricing arrangements, we do not support the retention of pricing methodology provisions for gas transmission in the IMs. In our view, leaving provisions relating to gas transmission pricing in the IMs creates a risk that different regulators are asked to sanction particular pricing approaches, working to different legislative objectives (the Gas Act 1992 for GIC, the Commerce Act 1986 for the Commission).

We are also concerned about the potential retention of GP05 that allows the Commission to impose a pricing methodology on a GTB as part of a CPP determination. If we were to apply for a CPP for our GTB and the Commission exercised this power then the following scenarios are possible.

- The MPOC is still in force for the Maui pipeline. Amendments to the MPOC tariffs and tariff principles that may be needed to comply with the Commission's determination are subject to support from GIC.
- The MPOC and VTC have been replaced with a new gas transmission operating code agreed by gas industry participants. We expect the new code will already include an agreed pricing approach. Changes to such a code may be subject to approval by GIC.
- The MPOC and VTC have been replaced by, or pursuant to, regulations on transmission access and pricing recommended by GIC.

All these scenarios seem to create a risk of conflict between the powers of GIC and the Commission. Considering section 52T(1)(b) of the Act, it seems advisable to us to remove GP05.

Specification of price ('SP')

With respect to SP01, we support the continuation of a weighted average price cap for GDBs, combined with an implementation change to adopt the same pass-through balance approach as currently used for EDBs to deal with forecast disparities in pass-through costs and recoverable costs.

We also support the Commission's draft decision to amend SP02 to move to a 'pure' revenue cap for GTBs, with a revenue wash-up. Our comments on the main implementation features for this are set out in our separate submission on the Gas DPP 2017 reset paper, published by the Commission on 28 June 2016 with the subtitle "Implementing matters arising from proposed input methodologies changes".

The consequential implementation changes for SP02, i.e. the removal of the need to make Constant Price Revenue Growth forecasts and to calculate a delta-Q factor, are benefits from moving to a 'pure' revenue cap.

We support the proposed changes to SP03 and SP04 to widen criteria-based pass-through costs.

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2 For example, in GIC's "Transmission Access; Options for Improvement Paper #2" issued on 8 May 2015.

We support the proposed changes to SP06 and SP07 to: (i) have a 'wash-up' of forecast capex for the year(s) prior to the setting of a DPP; and (ii) allow for recovery of prudent expenditure incurred in response to a catastrophic event. We appreciate that these provisions for EDBs are extended to GDBs and our GTB as well.

We appreciate the proposed amendment to SP07 to allow compressor fuel gas as a recoverable cost in some instances. We understand the Commission wants to limit this to circumstances when compressors are used to avoid balancing gas transactions that would impose higher costs on consumers. This raises questions on how to determine those circumstances in the first place, and how to subsequently verify or certify that recoverable costs have been limited to those circumstances. An appropriate value for those costs would also need to be ascertained.

These are not simple questions and we do not have ready answers. Optimisation of compressor use is a complex topic in its own right, and becomes even more complex when interrelated with pipeline balancing. We would like to explore this topic further with the Commission; particularly now that First Gas owns all transmission pipelines and is keen to design better optimised approaches for compressor use and balancing across the gas transmission network. Such optimisation may be constrained in the short term, however, by the different gas transmission operating codes that are currently in place. As a practical solution for now, we suggest that the Commission allows for compressor fuel costs to be recoverable as part of the IMs, subject to arrangements and requirements set out in a DPP or CPP determination.

We similarly appreciate the proposed clarification of balancing gas costs as recoverable. We note, however, that the different balancing regimes that are currently set out in the MPOC and the VTC are expected to be replaced with a new (integrated) balancing regime in a new gas transmission operating code. It is important to note that any balancing regime consists of both costs and credits; for pipeline owners as well as for pipeline users. The net result of all costs and credits tallied up for a period can be positive or negative. They may also be reduced to zero for the GTB if the balancing regime includes neutrality arrangements (as set out, for example, in Chapter VII of the EU Network Code on Gas Balancing of Transmission Networks[3]). We suggest that the IMs should be made flexible enough to accommodate a future balancing regime without imposing undesirable restrictions.

We also appreciate the proposal to introduce a new recoverable cost allowance to enable suppliers to recover prudently incurred expenditure in response to an urgent project. Our more detailed comments on that proposal are provided below under the heading of CPP requirements.

Reconsideration of the price-quality path ('RP')

We broadly support the Commission's proposals to amend RP01, RP02 and RP03. We support the extension of CPP reopener provisions in RP04 for GDBs and EDBs as well.

In the case of our GTB, we submit that the reopener provisions in RP04 should also be extended to our DPP. The reasons are essentially identical to those provided by the Commission for extending those provisions to GDBs and EDBs. In our case, there is no possibility that a DPP reopener would impact on any other GTB (the extension could be made subject to such a restriction). Therefore, this would allow the Commission to accommodate incremental expenditure for projects where the time, scope or cost was not known at the time our DPP was set. In our case, we expect that this would be just as appropriate as under a CPP, because the Commission would already have been able to apply appropriate and proportionate scrutiny to our underlying expenditure when it initially determines the unique DPP for our GTB, without concerns that the project may be already provided for.

3 European Commission Regulation (EU) No 312/2014 of 26 March 2014

Such an extension would be consistent with the Commission's statement (paragraph 37 in Topic paper 2): "… we intend to continue to evolve the regime by increasing consideration of supplier-specific circumstances in the default path where possible…"

The existence of projects, contingent as well as unforeseen, for which the time, scope or cost are not known when a DPP is set is a normal feature for any gas transmission business. The existence of 'lumpy' project-based expenditures is business as usual for the transmission sector. This can include major asset renewals and alignments as well as projects targeted at growth opportunities. In the transmission sector, any such opportunity is not merely incremental. It would be disappointing – and a disincentive to investment – if every growth opportunity for a GTB would require a CPP.

Allowing such extended provisions does not mean that the Commission must approve every application for a DPP reopener. We accept that on a case-by-case basis the Commission may still deem a project to have too many implications for other elements of a DPP, and require a CPP instead. By the same token, however, there will be situations in which a project's scope is narrow and its assessment can be relatively straightforward. Having a mandatory CPP requirement even in such circumstances may lead to unnecessary costs and delays.

Amalgamations ('AM')

We note the Commission is not proposing amendments to the provisions for amalgamations. In view of the potential complexity, and noting that the large transactions involving our GTB and GDB have already been completed, we support the Commission's draft decision to not pursue such amendments at this stage.

However, we point out that current arrangements (in particular decision AM02) do not provide for the situation where a supplier amalgamates with another supplier with a different disclosure year, or for the situation in which a disclosure year for a new supplier has not been defined. We also note there are no arrangements at all with respect to information disclosure after an amalgamation. As a result, we suggest the Commission may wish to consider updating the IMs with such arrangements when it is reviewing Information Disclosure provisions again.

Incremental rolling incentive scheme (IRIS) ('IR')

Based on reasons provided in earlier submissions, we support the removal of all IRIS provisions for GPBs.

Other regulatory rules and processes ('RR')

We support the Commission's draft decision to leave these provisions unchanged.

CPP requirements ('CP')

We understand that the Commission intends to review the CPP information requirements for GPBs in 2017. In the interim, we are encouraged by the changes to CPP information requirements that are being proposed for EDBs. Those changes appear helpful and sensible, and we assume that similar changes will be proposed for GPBs.

We broadly support the proposed changes for CPP verification requirements. These changes may not resolve all of the issues that have been identified – for example, the role of the verifier in assessing insurance remains questionable – but we consider them a step in the right direction.

We also support the proposed changes to audit requirements.

We appreciate the clarification of consumer consultation requirements to include the need for consultation on the price/quality impact of any proposed investment alternatives. We agree that this is appropriately within the scope for GPBs. We note, however, that there should be flexibility in interpreting the quality impacts. Most investments, for example, would not be expected to have an impact on the current Response-Time-to-Emergencies (RTE) quality measures. Investments can be made to more directly improve security and reliability instead. In order to compare investment alternatives, a wider interpretation of quality may need to be applied.

We question the need for the verifier to report on the extent and effectiveness of consultation with consumers. It is not obvious to us that this would be within the normal scope and expected capabilities of a verifier engaged for a CPP.

We support the Commission's intention to also design a CPP rollover mechanism. This would become particularly important if our GTB is effectively forced into a CPP through an inability to provide for project-based expenditure in its DPP. However, we hope that scenario can be avoided. For now, we agree that CPP rollover arrangements may be more effectively addressed at a later stage.

With respect to the costs incurred for meeting the CPP requirements, we appreciate the Commission's clarification that EDBs only bear 34% of these costs as a result of their IRIS arrangements. In our case, GPBs do not have those IRIS provisions. We understand the Commission's view that suppliers should bear some of the costs of preparing a CPP application in order to create appropriate incentives to minimise those costs. For consistency, we propose that GPBs should have a provision to allow up to 66% of costs for preparing a CPP application to be classified as a recoverable cost.

We appreciate and support the Commission's proposal to allow the recovery of costs in response to an urgent project that were prudently incurred prior to the determination of a CPP. However, we do not understand the Commission's reason for limiting this to costs incurred only after the submission of a CPP proposal. The Commission has helpfully illustrated the CPP application process in Attachment A of Topic paper 2. This indicates that even for a small scope CPP application the process is expected to take 9 or 10 months. In practice we expect a supplier would also need to prepare and present a business case to its Board of Directors prior to starting the formal process for a CPP application. That preparatory process could also take at least 2 or 3 months. In combination this means it would probably take 11 to 13 months from the start of identifying a need for a CPP to the submission of a CPP application.

The implication for an urgent project is that a supplier cannot recover any prudently incurred costs unless it delays the start of that urgent project by 11 to 13 months for the preparation of its CPP application. This seems undesirable to us and may create a disincentive to timely investment. It is presumably also inconsistent with the Commission's proposal to allow recovery of prudent expenditure incurred in response to a catastrophic event. We think that it would be undesirable for urgent actions to only be compensated in response to a catastrophe. Considering that the Commission has discretion over approval of such costs anyway, we submit that the inclusion of specific time restrictions in the IMs should be reconsidered.

Conclusion

We appreciate the opportunity to comment on proposed changes to the IMs. We would be happy to provide additional clarifications and information if this is helpful. Please feel free to contact me at any time at jelle.sjoerdsma@firstgas.co.nz or in our Wellington office on (04) 460 2535.

Yours sincerely

Jelle Sjoerdsma
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