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ECONOMIC CONSULTING

Firstgas Transmission

Transmission Pricing Review

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Executive Summary

Firstgas is undertaking a 'first principles' review of the pricing policies applied to its Gas Transmission Business. The purpose of the review is to define a best practice model of pricing using key information about future demand, customer willingness to pay and the cost of service of Firstgas' pipelines so that, to the extent possible, prices achieve the following objectives:

- are economically efficient, as provided in the Pricing Principles set out in the ID Determination;
- are reasonable to customers, including charging customers fairly for their use of the transmission system, promoting price stability and avoiding price shocks;
- facilitate the use of gas, and avoid demand destruction, by ensuring that prices remain below the willingness of users to pay for the transmission service before they either bypass the service or cease their gas demand;
- future proof Firstgas' pricing approach to manage anticipated changes in technology, policy and regulatory requirements as the New Zealand economy transitions to a low carbon energy system;
- earn the allowable revenue set under the Default Price Path Determination (including avoiding future risk of asset stranding); and
- simplify tariff structures.

Where these pricing principles conflict, a reasonably balanced outcome will be pursued.

This report provides recommendations to guide Firstgas' approach to pricing in the medium to long term.

Efficient pricing design

In order to achieve economically efficient pricing outcomes, principles for efficient pricing are typically based on the following concepts:

(a) prices should fall between a band set by floor and ceiling prices. The floor price reflects the incremental cost of providing the service and the ceiling price is based on the stand-alone cost of supply;

(b) within the floor/ceiling band, price discrimination should be permitted to reflect the capacity to pay of the user (which may be capped by the price of bypassing the service) – that is, having regard to their price elasticity of demand, to achieve minimal distortions to consumption relative to marginal cost pricing;

(c) the extent of price discrimination is typically constrained to ensure that price discrimination does not affect competition in dependent markets, with commercial negotiations between the service provider and customer a key mechanism to reveal a customer's willingness to pay limitations; and

(d) tariff structure can assist in enhancing the efficiency of pricing solutions by incorporating price signals that indicate the forward-looking costs of additional consumption and capacity.

These principles can be most practically implemented through the development of standard tariffs that reflect a broad application of these principles, with individual negotiation of tariffs in circumstances where the standard tariff exceeds a customer's willingness to pay, but there is material value in retaining that customer's demand.

Demand environment and energy transition

A critical consideration in developing pricing methodologies is the current gas demand environment and how this is expected to change. This will most critically be influenced by New Zealand's transition to a low carbon energy system as part of the movement to net zero emissions by 2050.

While it is expected that reliance on natural gas will continue beyond 2035, usage will reduce significantly given an anticipated increased use of renewables for electricity generation and broader decarbonisation of the natural gas sector. The speed of this reduction will depend in part on specific Government decisions and areas of focus along with developments in technology and social preferences.

In addition, low-emission gases (such as green hydrogen and biomethane) will increasingly be introduced into the pipeline network. However, these gases are likely to be created and injected into Firstgas pipelines at multiple locations outside the Taranaki region, which will alter the operational demands on the transmission system and require investment in new connections. While there is considerable uncertainty about, the number of connections and quantities of gas that will be available, it is most likely that the total supply (and associated demand) for low emission gases will be substantially lower than historic natural gas demand. The transmission pricing framework should support these changes.

Critical pricing constraints

Floor and ceiling cost

In order to assess how Firstgas' current transmission charges fall within the floor and ceiling limits, we have developed a detailed floor/ceiling cost model based on a cost of service 'building block' methodology. Revenue is then assessed, based on current transmission prices, and compared to the calculated floor/ceiling price in order to determine whether, and to what extent, Firstgas' current prices comply with these constraints.

For the purpose of this assessment, the Firstgas transmission network was broken into logical groupings of delivery points based on usage characteristics and current pricing arrangements. Floor and ceiling prices have then been assessed for 19 floor and ceiling assessment regions (FCARs) and compared to modelled revenues based on FY23 prices and FY22 actual gas demand. In doing so:

- for the floor price:
  - the costs that are included in the floor price include the compressor fuel required to transport gas from Taranaki to delivery points in the target FCAR, as well as all maintenance and other operating costs that relate directly to that FCAR; and
  - the relevant comparison revenue is all revenue derived from delivery points in the FCAR.

  This reflects that although the floor price for an individual customer is limited to the avoidable costs of transporting its gas (i.e. principally compressor fuel), the price needs to also needs to consider logical groupings of services. Revenue from all delivery points within a given FCAR must at least also meet the area-specific pipeline operating costs, in order for it to be economically viable to continue to deliver gas to that area.

- for the ceiling price:
  - the ceiling price also includes the capital costs[1] for the target FCAR, plus all operating and capital costs for other FCARs that the gas traverses from Taranaki to reach the target FCAR;
  - the relevant comparison revenue is the revenue from delivery points within the target FCAR as well as other FCARs that the gas traverses to reach that FCAR.

[1] Capital costs include return on assets plus depreciation, otherwise referred to as return on and of assets.

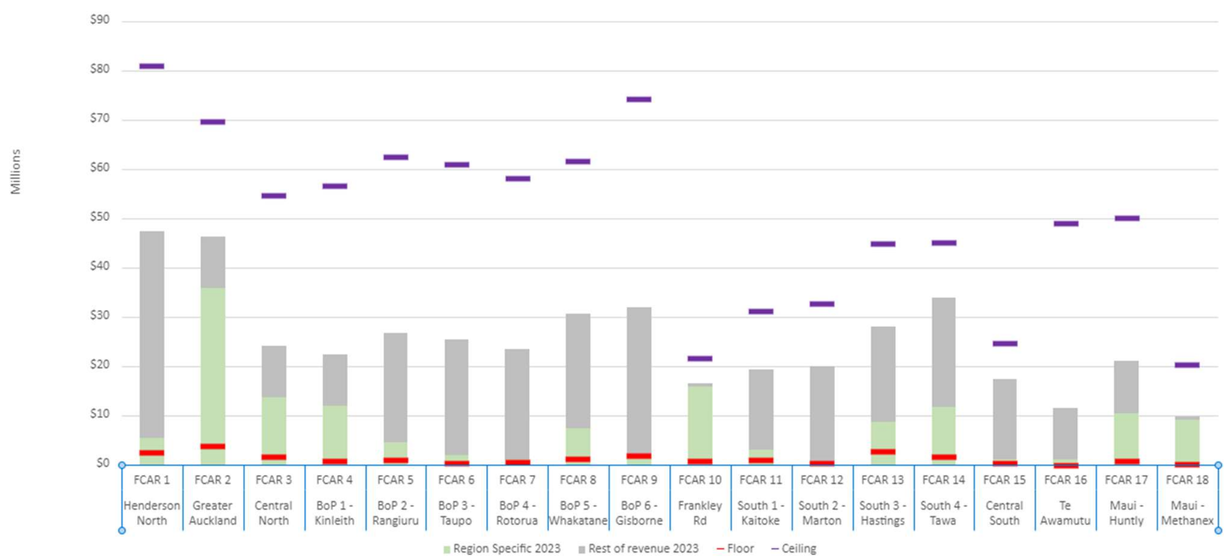
> This reflects that the ceiling price for a FCAR must include all costs (operating costs and capital costs) required to transport the gas from Taranaki to the FCAR. However, as the ceiling price is also considered for logical groupings of services, the revenue from customers within the target FCAR is combined with the revenue from all other customers that can be served by the relevant assets.

Optimised Depreciated Replacement Cost (ODRC) is the most common valuation methodology applied in a building block assessment of full economic cost, as it represents the value of assets from the perspective of a hypothetical new entrant, consistent with setting the maximum price achievable in a competitive market. Therefore, while Firstgas' overall transmission revenues will continue to be constrained by the Commerce Commission's determined Maximum Allowable Revenue (MAR) (which is in turn based on the Regulatory Asset Base (RAB) value of the assets), in assessing compliance with the ceiling price limit, we have used a high level estimate of the ODRC value of the assets. However, given the limited scope of the ODRC estimate which excludes of a number of costs and assets that would normally be considered, it is likely that this estimate is understated. If Firstgas' prices appear to be approaching the ceiling price assessed using this high level ODRC estimate, a robust ODRC valuation should be undertaken in order to provide higher confidence in the ceiling price evaluation.

The graph below shows the results of this assessment, with the floor and ceiling prices denoted by the red and purple lines, the green bar showing revenue relevant to the floor price, and the grey bar showing the additional revenue relevant to the ceiling price.

This assessment shows that there is only a single FCAR area – the Gisborne area (FCAR 9) at the eastern extremity of the Bay of Plenty pipeline – that may fail to meet the floor cost at FY23 prices.

Figure 1 Summary of assessment against floor-ceiling costs FY23



Source: Synergies

No FCAR areas are assessed as exceeding ceiling price based on FY23 prices and FY22 actual gas demand.

Customer willingness to pay

In addition to considering how Firstgas' current transmission charges fall within the floor and ceiling limits, we have undertaken an assessment of the 'willingness to pay' transmission charges for consumer groups (where willingness to pay refers to the capacity of a consumer to pay for transmission services). Where prices are materially below a consumer's willingness to pay, then the consumer can be considered to have a low sensitivity to an increase in prices. However, where prices are approaching a consumer's willingness to pay, this will result in it having a high sensitivity to increases in transmission charges.

Importantly willingness to pay is driven by the gas consumer, and in most instances the final gas consumer is not the Shipper (who may be Firstgas' direct customer). Further, for the most part, consumer willingness to pay relates to the delivered cost of gas, and not transmission charges in isolation, with transmission charges generally constituting less than 20% of the delivered cost of gas. Given this small proportion, a wholesale gas pricing response from gas producers is likely to be required in order to maintain demand from price sensitive consumers. Conversely, if other components of the delivered cost of gas are increasing (eg wholesale gas prices, carbon price) there may be only limited opportunity for transmission pricing to promote demand.

Notwithstanding these limitations, the sensitivity of each consumer/consumer class to a change in transmission tariffs will be a function of several factors, which can be summarised into either being levers (those factors which enhance pricing flexibility) or constraints (those factors which constrain pricing).

Our conclusions on consumer willingness to pay are summarised in the following table, with price sensitivity assessed in terms of it being low, intermediate or high:

Table 1 Price sensitivity of gas consumers

		Price sensitivity		
User	**Load factor**	**Short term (<4 years)**	**Medium term (4-10 years)**	**Long term (>10 years)**
Petrochemical producers	Flat	Part intermediate/ part high	Part intermediate/ part high	High
Electricity generator	Peaky	Part high/part Low	Low	Low/ intermediate
Industrial - dairy	Counter cyclical	Low	Low	Intermediate
Industrial – high temperature	Intermediate	Low	Low	Low/ intermediate
Industrial – low temperature	Flat or intermediate	Low/intermediate	Intermediate	High
Commercial/ residential	Peaky	Low	Intermediate	Intermediate/ high

Source: Synergies

Most consumers have low price sensitivity in the short term, but in the medium term, expected significant increases in transmission prices and increasing carbon charges are likely to increase consumer sensitivity to transmission charges and increasingly make substitute fuel sources commercially attractive. Notwithstanding this, there are a range of applications where gas is strongly preferred and is likely to be retained in the longer term. Gas demand is likely to continue at a lower volume, but for use in higher value applications.

This assessment therefore indicates that:

- in the short term, there should be limited need to provide discounts to standard gas transmission prices;
- there is likely to be a high, and increasing, value placed on gas as a variable source of energy, particularly for electricity generation, indicating that there may be opportunity to charge a premium for providing a more variable gas supply service; and

- it is unlikely that the medium to long term decline in gas use can be avoided by maintaining or reducing transmission prices, given Government policy is aimed at increasing delivered natural gas prices in order to incentivise users to move to alternative energy sources. However, constraining the extent of transmission price increases applied to vulnerable demand may help to support overall demand, particularly as opportunities for renewable gases are being developed.

Tariff design considerations

Recommended pricing directions

New Zealand's energy transition will result in fundamental changes for Firstgas, in particular:

- demand for natural gas will significantly decline over time; and
- low emission gases will increase in importance and are likely to be injected at locations distributed across the Firstgas transmission system.

Reflecting this, we have identified the broad pricing directions that will most effectively enable Firstgas to adapt to this future environment. These include:

(a) Standard tariff structures should be developed to more closely align to value of service. While value of service (willingness to pay) is largely a function of each customer's business requirement for gas, there are some key directions that we consider will promote alignment between standard tariffs and value of service:

   – apply a flattened relationship between price and distance resulting in limited price differentiation between geographic areas, but with some flexibility to tailor prices in a region to reflect the value of the typical use of gas in that area. In the current market environment, this recognises that geographic distance from Taranaki is not a significant driver of willingness to pay, and that only limited differentiation is required to ensure floor and ceiling prices are met. However, this issue becomes more important as renewable gases are injected into the transmission system at distributed locations. All gases injected into the network are interchangeable and it is not necessary, or indeed possible, to physically ship any particular gas in line with the commercial arrangements between the buyer and seller. Therefore, the physical movement of gas (and the actual incremental cost to the pipeline system) is unlikely to vary depending on whether renewable gas is 'delivered' to a close or distant delivery point. However, differentiating transmission charges according to the geographic location of gas receipt and delivery points could limit the market for each renewable gas producer and may reduce liquidity in the market for renewable gases;

- apply higher prices for higher value use, noting that there is a general correlation between price sensitivity and the variability of a consumer's usage: for consumers with a peaky demand, there is typically a high value attributable to their peak demand. For a significant number of gas users, there is a likelihood that they will transition to alternative fuel sources for part of their demand, but retain access to reticulated gas for some functions, and as a backup (variable) fuel source. Where future gas demand is expected to be lower, but increasingly peaky, as customers move to the use of gas for high value backup or peak energy, this approach will assist in maintaining revenue from those customers.

(b) Compliance with cost-based floor and ceiling limits is not only fundamental to ensuring economically efficient transmission charges that are 'subsidy free', but in practical terms, it is also the minimum requirement for the 'fair' treatment of customers. Our floor/ceiling price modelling indicates that the Gisborne area on the Bay of Plenty pipeline may currently fail the floor price test. However, as gas demand continues to contract, it is possible – and even likely - that other geographic areas will also emerge as potentially failing the floor price constraint. Firstgas should closely examine the avoidable costs of providing gas in such areas and adjust prices and/or service offerings for these delivery points to ensure that the floor price is met. The pricing methodology for the Maui pipeline specified in Schedule 10 of the MPOC, and potentially more generally the existence of two separate Codes for the two pipeline systems, constrains Firstgas' ability to develop tariff structures on an integrated basis across its pipeline network, consistent with cost-based floor and ceiling limits and having regard to value of service and willingness to pay.

(c) Reduce perceived barriers to ongoing gas connections – options that may assist include:

- reducing the requirement for customers to commit to capacity and bear fixed costs associated with their use of the transmission system; and
- simplifying transmission charges.

Evaluation of tariff reform options

We have identified several broad tariff reform options, including some options raised by customers during our consultation process, as well as options that we have identified as potentially aligned with the recommended pricing directions as summarised in the table below.

Table 2 Identified tariff reform options

Option	Description
1. Current tariff structures	Continued application of current tariff structures for the Maui and GTC pipelines, with the value of GTC tariff components modified where appropriate to reflect recommended broad pricing directions.
2. Fully variable tariffs for all transmission pipelines	All charges would be applied on a fully variable ($/GJ) throughput basis (using approved nominations for the Maui pipeline and delivery quantity for GTC pipelines)
3. Partial capacity-based tariffs for all transmission pipelines	All charges would include a regionally specified $/GJ/day capacity use charge as well as a $/GJ throughput charge (using nominated quantities for Maui pipeline and actual quantities for GTC pipelines) Capacity charge could either be determined: (a) using customer-specified volumes, in which case overrun charges would be necessary to encourage accurate demand specification (similar to current GTC charge structure) (b) using previous year's maximum volumes, avoiding the need for overrun charges
4. Fully variable tariff for all transmission pipelines with load factor multiplier	All charges would be applied on a fully variable ($/GJ) basis (using nominated quantities for Maui pipeline and actual quantities for GTC pipelines) and include the following elements: • a regionally-specified base throughput charge • a load factor multiplier, based on the customer's maximum use relative to average use Load factor multipliers could be determined and applied on either a daily or hourly basis
5. Differentiate charges by consumer segment	Differentiate regionally-specified charges by user segment either defined by: • categorising users according to the nature of the consumer's business. Initially a minimal categorisation of 'electricity generators' and 'other uses' could be applied, with a premium applied to transmission prices for 'electricity generators' reflecting highly variable and high value usage. However, additional categorisation of 'other uses' could potentially be considered, breaking this into further categories of petrochemical, large industrial (>10TJ) and residential/commercial • categorising each shipper at each delivery point according to their usage characteristics (eg. highly variable large volume, highly variable small volume, low variability). This would allow a simple $/GJ charging structure to be applied within each group, although the charging structure could reflect any of the other tariff reform options, if preferred

Source: Synergies

The following table presents a summary of the evaluation of each potential tariff reform.

Table 3 Evaluation summary – tariff reform options

Criteria	1. Current tariff structure	2. Fully variable tariffs	3(a). Partial capacity charge – customer specify	3(b). Partial capacity charge – historic usage	4. Variable with load factor multiplier	5. Customer differentiation of charges
Cost-based limits	Partly meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria
Limits differentiation for distance	Partly meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria
Applies differentiation for user value	Meets criteria in limited way	Does not meet criteria	Partly meets criteria	Partly meets criteria	Fully meets criteria	Fully meets criteria
Reduced fixed cost and complexity	Meets criteria in limited way	Fully meets criteria	Does not meet criteria	Substantially meets criteria	Substantially meets criteria	Fully meets criteria
Ease of implementation	Fully meets criteria	Partly meets criteria	Meets criteria in limited way	Partly meets criteria	Does not meet criteria	Partly meets criteria

Legend:

Fully meets criteria
Substantially meets criteria
Partly meets criteria
Meets criteria in limited way
Does not meet criteria

This evaluation summary shows that, if the implementation issues for the regional load factor charge were able to be resolved, this option would provide the most effective long term standard pricing structures, having regard to the principles of economic efficiency, the expected demand environment, and Firstgas' pricing objectives particularly if hourly load factor charging is included. However, practical issues make implementation of this option unlikely for all but large industrial users, and even for those users, this option is likely to cause practical complexity.

Applying customer differentiation of charges may enable Firstgas to implement the required long term pricing directions with less disruption to customers and less implementation risk, and would allow a simple $/GJ tariff structure to be applied for each group. The groups could be defined either according to the nature of the consumer's business, or with reference to the usage characteristics of each shipper at each delivery point. The latter approach may result in less complexity around defining the appropriate charging category to apply for delivery points serving multiple consumers, as well as for shippers passing transmission charges onto their customers. It may also be more acceptable to consumers and shippers if the charging groups are based on quantifiable data, rather than just at the discretion of Firstgas.

Implementation considerations

Based on our recommended pricing directions, together with our identification and evaluation of specific tariff reform options, we have identified both near term and longer term opportunities for Firstgas to consider.

Near term opportunities include:

- further examining incremental cost for regions that are below, or close to, floor price, and adjusting prices and/or costs in those regions in order to align prices with floor prices to promote efficiency of existing prices;
- develop a pricing policy to apply for transmission of renewable gases, which better reflects the broadly distributed nature of production, and assists in developing the market for renewable gases;
- identify a preferred long term price structure, so that all parties have an understanding of Firstgas' intentions; and
- modify existing prices to progressively align with the preferred long term price structure.

Opportunities that will require action over a longer time frame include:

- commence the process to review and amend the MPOC to remove constraints on efficient pricing, in particular:
  - removing the constraints created by Schedule 10;
  - removing distance based charges; and
  - providing for supplementary agreements;
- once the preferred long term price structure has been established:
  - seek to modify both the MPOC and the GTC to enable this to be implemented; and
  - develop a price reform implementation plan, including indicative price paths.

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1 Introduction

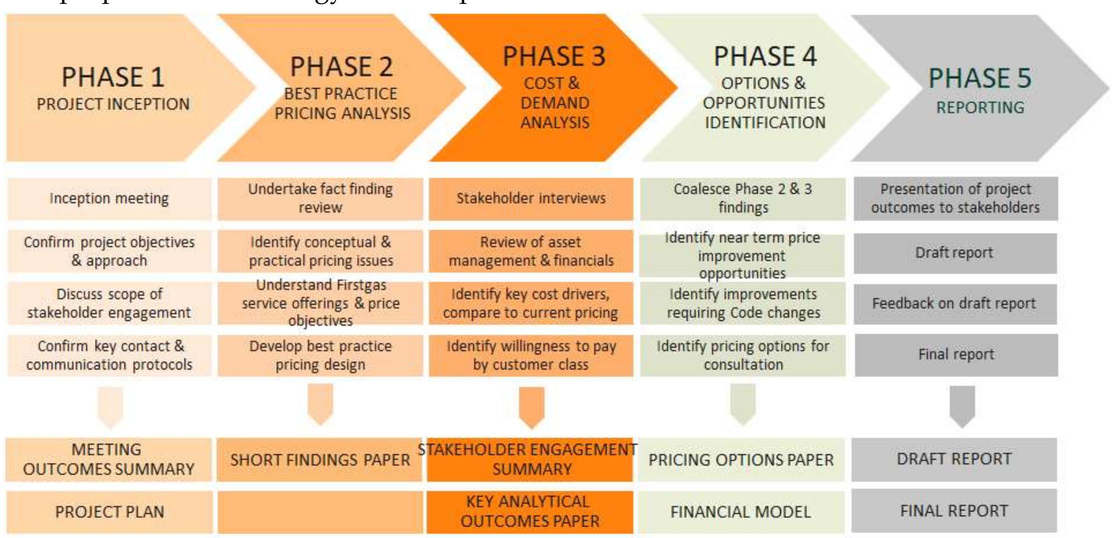
1.1 Purpose of the review

This report sets out the results of work performed by Synergies of a first principles pricing analysis and review for Firstgas Transmission. The purpose of the review is to define a best practice model of gas transmission pricing from an economic efficiency point of view using key information about future demand, customer willingness to pay and the cost of service of Firstgas' pipelines. This model has then been applied to Firstgas' pricing objectives to provide recommendations that can guide Firstgas' approach to pricing in the medium to long term.

This review is focussed on transmission charges only, with charges relating to capacity balancing not falling within the scope of this review.

1.2 Methodology

Our proposed methodology had five phases as described below.



1.2.1 Phase 1 – Project inception

The Synergies' project team initially met with Firstgas to confirm key objectives of the project and approach and establish other major elements of the project.

1.2.2 Phase 2 – Best practice pricing analysis

This phase involved:

(a) a fact gathering exercise to capture best practice design across a broad sample of regulatory frameworks, and

(b) linking the best practice findings to Firstgas' current transmission pricing environment

resulting in a summary of findings about best practice pricing design in the context of the market environment, commercial structures and regulatory framework applicable to Firstgas.

1.2.3 Phase 3 – Cost of service and willingness to pay analysis

Phase three comprised:

- the development of a detailed cost of service model to calculate the floor prices (avoidable cost) and ceiling prices (stand alone cost) of gas transmission to relevant groupings of customers and provide a basis for testing different pricing designs; and
- assessing the willingness to pay of customers grouped by demand type; and
- customer/stakeholder consultation to further assess customers' willingness to pay and better understand customer needs, what they value about the transmission service and their sensitivity to transmission pricing.

1.2.4 Phase 4 – Develop options for pricing reform

This phase used our findings from Phases 2 and 3 to identify options opportunities and options for improving Firstgas' transmission pricing methodology. It involved:

- identifying the broad pricing directions required to effectively reflect efficient pricing outcomes;
- identifying several relevant pricing structure options for review;
- developing criteria for the assessment, including identifying if code change is required;
- application of criteria to the options, including using the cost-of-service model where applicable, to identify preferred likely pricing approaches;
- identifying pricing options and recommendations for consultation, which will include the preferred approach amongst other options.

The cost-of-service model was used to test the impact of the selected pricing options on revenue and transmission price, based on transparent assumptions, including volumes. These outcomes can be compared to the status quo based on current pricing arrangements.

1.2.5 Phase 5 – Reporting

A draft report was developed which set out the work undertaken and findings and draft recommendations for consultation with stakeholders. Synergies then facilitated a workshop involving Firstgas and industry stakeholders, to present the draft report and obtain stakeholder views on the draft findings.

This final report reflects feedback received from Firstgas and the industry stakeholder workshop on our draft report findings.

1.3 Structure of the report

The structure of the report is as follows:

- Section 2 provides an overview of the Firstgas Transmission business, including its services provided, current pricing arrangements, demand outlook and critical objectives for the pricing review;
- Section 3 summarises the principles for economically efficient pricing design;
- Section 4 provides an analysis of Firstgas' current prices against its key pricing constraints including:
  - floor and ceiling price limits;
  - customer willingness to pay;
- Section 5 identifies our recommended pricing directions, and identifies and evaluates several tariff reform options;
- Section 6, considers the steps required in the short and medium term to progress towards the recommended pricing option.

2 Firstgas transmission business overview

2.1 Service offering

Firstgas' operates around 2,500 kms of high-pressure gas transmission pipelines and stations that supply deliver gas from gas fields in the Taranaki area to consumers throughout the North Island, including:

1. the ~300km larger diameter Maui pipeline, which runs from the Maui onshore gas production station in South Taranaki to Rotowaro and the Huntly power station. It also feeds other significant Firstgas transmission pipelines (referred to in this report as GTC (Gas Transmission Code) pipelines at Frankley Road, Pokuru, Pirongia and Rotowaro. Several short laterals from the Maui pipeline are also part of the GTC pipeline system. The Maui pipeline is shown in green in Figure 2 below.
2. ~2,200km of GTC pipelines runs in several directions: a northern leg running to Auckland and beyond and along a main branch east from Pokuru to Gisborne with various laterals; the southern leg which runs from Frankley Road to Wellington with a major branch to Hastings. The GTC pipeline system has numerous laterals and sub-laterals. The GTC pipelines are shown in blue in Figure 2 below.

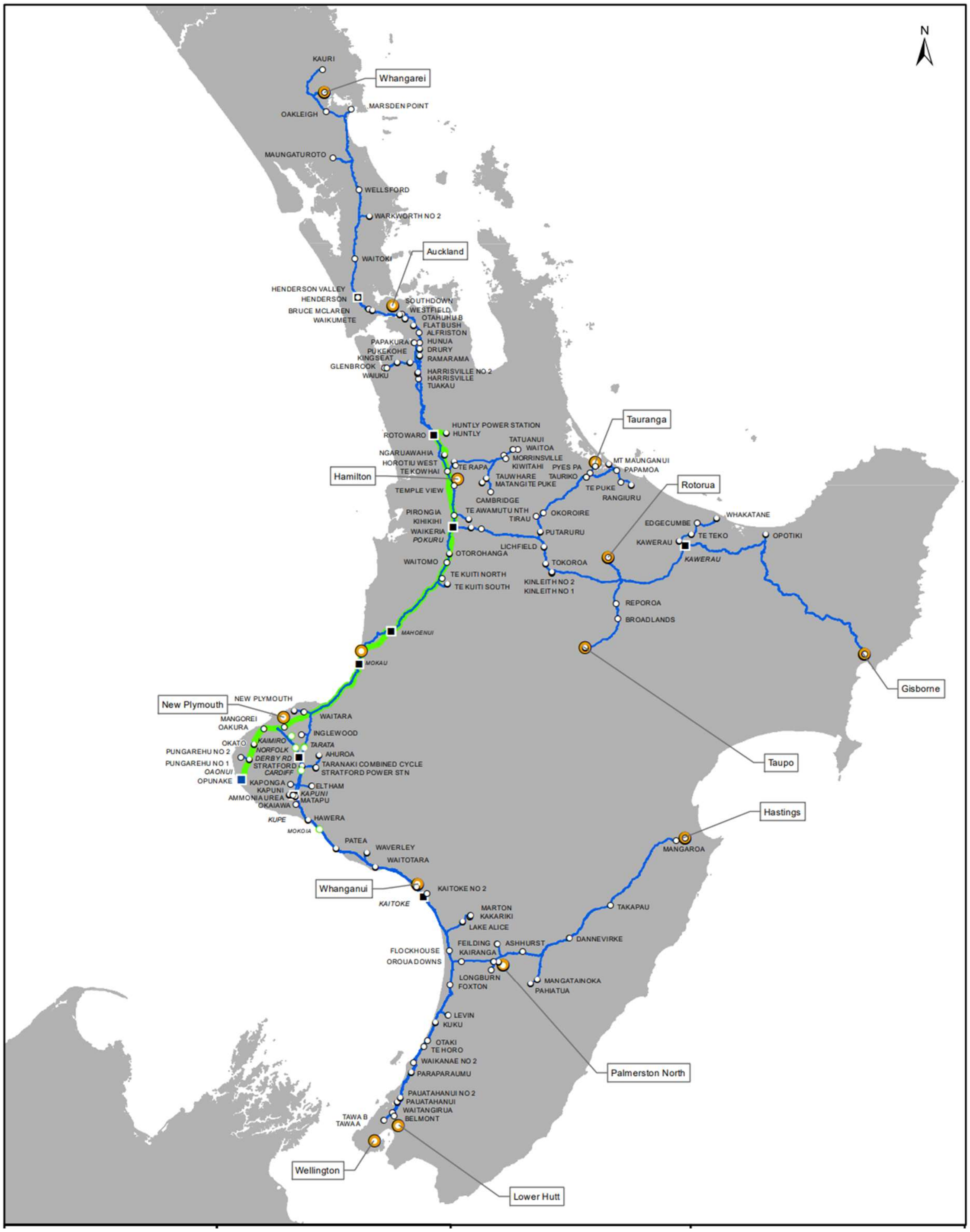
The services provided by Firstgas include:

- for the Maui pipeline, the main service provided is an interruptible gas transportation service[2] with gas delivered from receipt points within the Taranaki area to directly connected end-users as well as interconnection points with the GTC pipelines. The large capacity of the Maui pipeline provides the line pack flexibility to enable the current balancing regime for the entire transmission system.
- for the GTC pipelines, the main service is a firm transportation service to around 120 delivery points throughout the North Island. Balancing is made available to GTC Shippers by allocating a share of the operating imbalance at the relevant Maui pipeline interconnection in proportion to each Shipper's running mismatch on the GTC pipeline.

Firstgas does not distinguish, or price separately for, different service levels or any additional benefits that consumers may receive through the transmission service.

[2] A Maui Shipper's nominations may be curtailed at any time by Firstgas or the "Welded Parties" at either Receipt Points or Delivery Points on the Maui Pipeline.

Figure 2 Firstgas' gas transmission pipelines



Source: Firstgas

2.2 Demand outlook

2.2.1 Key customers

Firstgas provides its services to thirteen Shippers, including several large gas consumers directly connected to a Firstgas pipeline, as well as gas retailers supplying consumers both directly connected to the transmission network and downstream distribution networks. Therefore, while Firstgas' direct customer base is small, it ultimately provides gas transmission services for many gas consumers.

Gas consumers can be grouped into the following categories:

- petrochemical producers;
- power generators (including co-generation plants);
- industrial customers;
- horticultural/agricultural users, including dairy factories, meat and food processors;
- commercial consumers; and
- residential users.

The transmission system transported around 145.6PJ of gas in 2021, with around 38% for Methanex, 20% to electricity generation and 12% to agricultural and other industrial producers directly connected to Firstgas' transmission pipelines. However, for the very large majority of gas consumers connected via the distribution networks, Firstgas Transmission has no visibility of their identity or the nature of their use.

2.2.2 Demand outlook

A critical consideration in developing pricing methodologies is the current gas demand environment and how this is expected to change. This will most critically be influenced by New Zealand's transition to a low carbon energy system as part of the movement to net zero emissions by 2050.

Most New Zealand gas usage is delivered via Firstgas' transmission pipelines. Therefore, the medium-term demand outlook for Firstgas' transmission network will broadly align with the national outlook for gas supply and demand.

Since 2018, gas transmission demand has contracted, substantially influenced by gas supply issues in the Pohokura gas field and the expansion of renewable electrical generation. Gas supply constraints contributed to the mothballing of the Methanex

Waitara Valley plant, as well as reduced production from Methanex's Motunui plants as gas was on-sold to Genesis to cater for the winter peak demand for electricity production.

Analysis by Concept Consulting for the Ministry of Business, Innovation & Employment (MBIE) concluded that 2021 represented the nadir for gas production: projected increases in supply from the Maui field meant that by 2023 projected gas production levels would exceed the levels seen in recent history,[3] potentially enabling a restart of Methanex' Waitara Valley plant.

Further out, gas demand is expected to gradually decline. The New Zealand Government is progressing a Gas Transition Plan which will set out the immediate steps on a long-term pathway to phase out natural gas usage in New Zealand. The Plan will focus on actions through to 2035 for the natural gas sector to reduce emissions and support the transition to a net zero carbon economy by 2050. In addition, the Government is funding specific projects, such as biomass, to substitute for natural gas through its Government Investment in Decarbonising Industry (GIDI) Fund[4], to hasten this transition.

While it is expected that reliance on natural gas will continue beyond 2035, usage will reduce given an anticipated increased use of renewables for electricity generation and broader decarbonisation of the natural gas sector. The speed of this reduction will depend in part on specific Government decisions and areas of focus along with developments in technology and social preferences.

Concept Consulting has prepared gas projections under a reasonable range of assumptions for gas demand and supply. Their central case demand and supply projection is for reducing demand from most categories of users, as shown in Figure **3**.

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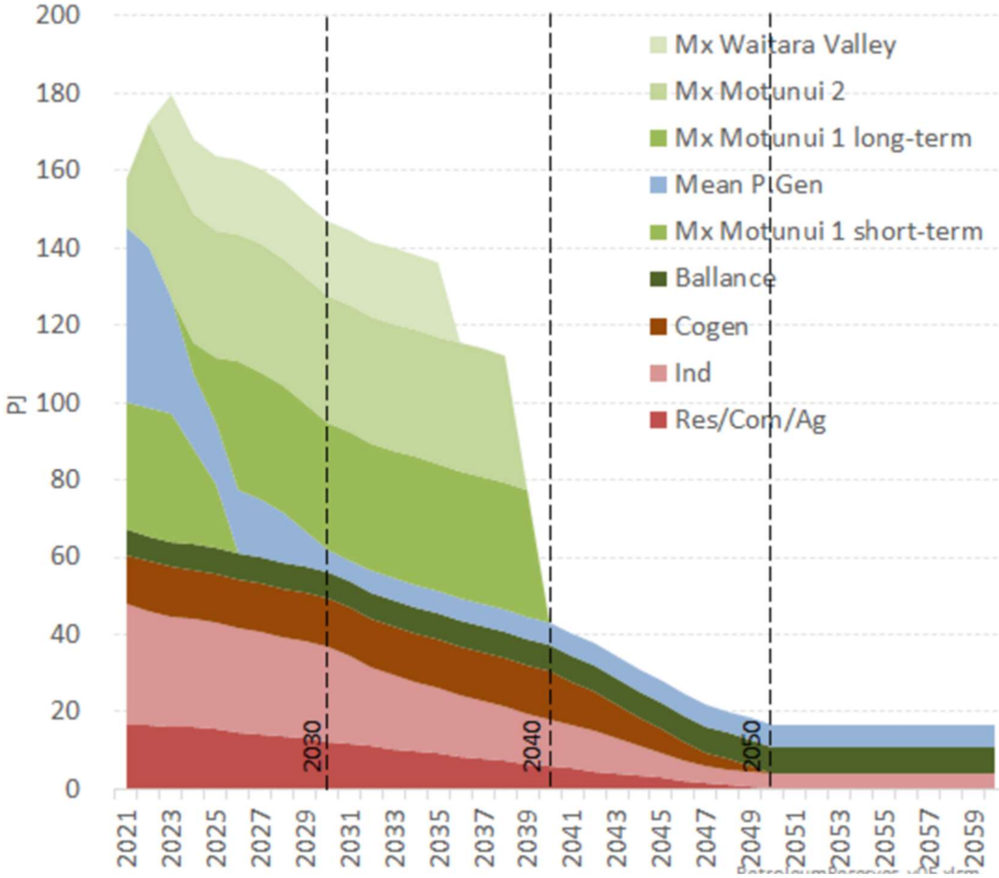
3 Concept Consulting (2022); Gas supply and demand projections; 24 March 2022; p.20.

4 See link: [About the Government Investment in Decarbonising Industry Fund | EECA]

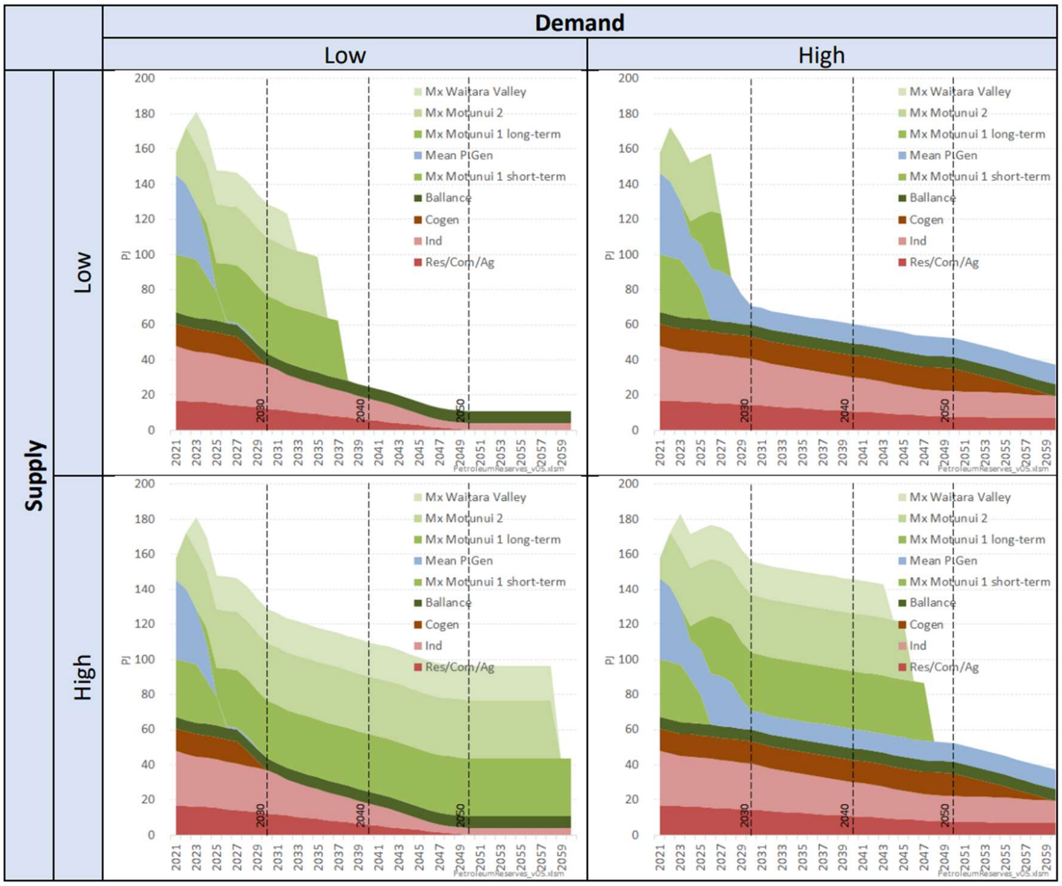
Figure 3 New Zealand gas projection – central demand/central supply



Source: Concept Consulting, Gas supply and Demand Projections, 24 March 2022, p.27.

Concept Consulting's sensitivity assessment on combinations of high and low demand and supply shows that there is a significant range around the rate of reduction, as shown in Figure 4.

Figure 4 New Zealand gas projections – low/high combinations for gas supply and demand



Source: Concept Consulting, Gas supply and Demand Projections, 24 March 2022, p.28

The factors influencing this demand outlook are most usefully considered by examining various consumer categories.

Residential and commercial

These segments effectively reflect the mass market, with the demand outlook reflecting the aggregate outcome of decisions by many individual consumers. As can be seen from the chart above, in total, they represent a relatively small proportion of total gas transmission volumes.

The primary demand from these users is for natural gas for heating (both space heating and water heating) and to a lesser extent cooking. Gas demand from these users will be influenced by a combination of population growth, levels of economic activity and the impact of carbon related policies designed to influence these users to procure more sustainable energy options.

The main substitutes to natural gas for these users are LPG and electricity. LPG and electricity are both generally priced above natural gas, with LPG largely used where natural gas is unavailable (although some residential users prefer bottled LPG, reportedly to avoid high fixed charges of reticulated gas). However, electricity will become an increasingly attractive energy source as rising carbon costs increase the price of gas.

As decisions from these consumers to switch energy source to electricity will typically involve capital expenditure for appliances and modifications to premises, there is unlikely to be rapid shifts in their annual gas demand. Rather, a gradual reduction can be expected with increasing fixed connection charges (including both distribution and transmission charges), particularly as existing appliances reach end of life and require replacement. The Climate Change Commission forecasts a decline in natural gas demand of 40% by 2035 for this segment, however the impact on gas transmission volumes could be mitigated if reticulated gas pipelines were to include an increasing proportion of green gasses (bio-methane or hydrogen).

Power generation

Gas demand for power generation will be strongly influenced by two key factors:

- Electricity demand growth, which is expected to accelerate as the number of electric vehicles increases and more of New Zealand's energy needs generally are met from electricity; and
- Continued growth in renewable sources displacing older thermal plant, although it may not be economic or technically feasible to invest in enough renewable power capacity to meet peak demand in all circumstances.

Together, these factors mean that gas demand for electricity generation is expected to decline, especially for baseload, though gas will remain critical to meet peak electricity demand or when supply from renewables is insufficient. The thermal alternatives to gas (such as coal or petroleum fuels), are higher cost and have worse carbon emissions. The remaining gas demand for electricity generation will be increasingly peaky but will be of higher value since it will be used only when renewable generation is less available and electricity prices are correspondingly higher.

As new renewable energy projects are commissioned, over 4,000GWh of thermal generation is expected to be displaced by 2025. Thereafter, gas demand may be broadly maintained reflecting gas' ongoing role in providing peaking generation capacity.[5]

[5] Concept Consulting (2022) Generation Investment Survey 2022, p.13-15.

In the longer term, gas' role in providing peaking generation capacity may be partly or even fully substitutable with large scale electricity storage.

Industrial users

Large industrial consumers may use gas in a variety of ways, but the provision of process heat is generally the largest source of gas demand. While industrial users face ongoing pressure to improve their sustainability performance, in the short term, there are limited substitutes for natural gas available to these users, although, other fuel sources are possible with investment in new plant.

Electricity provides an alternative energy source for lower intensity process heat, however the cost of electricity, and the potentially very large investment required to increase electricity supply infrastructure (particularly in rural areas) mostly makes its use prohibitively expensive at present. Further, current technology does not allow electricity to provide the heat intensity required for some larger users, and further technological development is required for electricity to be an effective substitute for these users. Biomass is also a potential alternative to natural gas, with the benefit of being renewable. However, there are limitations on the availability of biomass in some areas.

Substitution decisions for industrial users will be driven largely by economics as the carbon price increasingly makes alternatives more viable. However, substitution may be only partial, with industrials users retaining access to reticulated gas for processes that are more difficult to substitute.

For some industrial users, there is a risk that increasing energy costs will result in them becoming commercially unviable and exiting the market. De-industrialisation has been a feature of the New Zealand economy over recent decades, with increasing labour and other production costs making local production uncompetitive against imports. Increasing gas costs may further contribute to these pressures.

Agriculture

The largest agricultural gas demand is for dairy production, with smaller agricultural uses including horticulture and meat processing. Agricultural consumers largely use gas to provide process heat, with similar substitution opportunities and constraints as industrial users.

Petrochemical manufacturing

Where natural gas is used as a feedstock for petrochemical producers, it is most commonly a source of both carbon and hydrogen. Alternative feedstocks are other hydrocarbons such as LPG, and naphtha or coal. Natural gas is preferred because of its ease of handling and because it has a higher hydrogen to carbon ratio. In New Zealand, petrochemical users will almost certainly close down rather than transition to another fossil fuel feedstock.

Petrochemical manufacturing consumes a large proportion of New Zealand's natural gas production, and natural gas forms a very high proportion of production costs (particularly for methanol). The continued use of gas in methanol manufacturing will largely depend upon whether there is sufficient available gas supply (at an acceptable delivered price), with this critical decision being required before committing to a plant 'turnaround' (approximately each five years). Accordingly, medium to long term gas use in petrochemical manufacturing will substantially depend on the continuing availability of affordable gas supply.

Other competitive threats to Firstgas demand

The threat of physical bypass of Firstgas' transmission network is small, with only a small number of very large customers potentially having both the scale and proximity to gas fields for this to be a consideration.

2.2.3 Development of low-emission gases

The evolution of the gas market away from natural gas to renewable gases – biomethane and green hydrogen – is a crucial element in the future of Firstgas Transmission's business. The development of biomethane and green hydrogen is a key focus for the gas infrastructure industry worldwide[6]. Firstgas is actively exploring the potential for biomethane and hydrogen, including an assessment of potential impacts on the Firstgas transmission system.

Biomethane has significant advantages over hydrogen, in that biomethane is substitutable for natural gas to any level without requiring modifications to pipeline equipment or customers' appliances, which is not the case with hydrogen. To date studies have identified potential for 20 PJ per year of biomethane to be produced in the long term[7]. While a large quantity, this is a small proportion of the existing market, so if throughput were to remain similar to current levels, renewable hydrogen would also be needed to replace natural gas. Consequently, Firstgas is currently planning a trial of blending 10% hydrogen with natural gas.

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6 Two notable expressions of the direction the gas infrastructure industry globally are: the Gas Vision 2050 developed by the Australian Pipelines and Gas Association and Energy Networks Australia and the developments in the UK of its HyDeploy project with Cadent Gas, Northern Gas Networks, Progressive Energy Ltd, Keele University (Keele), Health & Safety Laboratory and ITM Power and the development of European Biomethane Road Map

7 EECA, BECA, Fonterra & Firstgas Group (2021); Biogas and Biomethane in New Zealand; p.4

Having widely distributed gas production has both operational and commercial implications for the delivery of gas.

Firstgas is considering how its transmission system could operate, including potential reconfiguration, to accommodate and transport the variety of gases that may become available, and which are likely to be injected at locations distributed across the transmission system. With more localised gas production, the need for compression may be reduced as gas will flow shorter distances between receipt points and delivery points and variations in demand may also need to be managed differently. Segments carrying hydrogen may need to be separated from others carrying biomethane.

With more distributed gas sources, the most important premise underlying Firstgas' current transmission pricing, being the transport of gas from a central production hub to delivery points located at various distances downstream, will become less relevant.

2.2.4 Key trends

While competitive threats to gas utilisation are generally low in the short term, measures to encourage movement away from fossil fuels towards more environmentally sustainable energy sources are expected to have profound implications for Firstgas over the medium to longer term. In particular:

(c) an increasing carbon price applied to natural gas will encourage substitutes such as electricity and biomass, as well as cause some loss of demand by making some users commercially unviable, both of which will reduce demand for gas transmission. Further, as quantities of gas purchased reduce, gas field prices may increase, placing further upward pressure on the delivered price of gas. In the short term, the most significant reductions in gas demand will be from electricity generators, as base load gas generation is displaced by renewables. More broad-based reductions in gas demand are expected in the medium term;

(d) over the medium to longer term, remaining gas use is likely to become more variable. This is particularly likely in electricity generation where gas will continue to be used for high value peaking capacity;

(e) low-emission gases (such as green hydrogen and biomethane) will increasingly be introduced into the pipeline network. However, these gases are likely to be created and injected into the transmission network at multiple locations outside Taranaki, which will alter the operation of the transmission system and require investment in new connections. While there is considerable uncertainty about, the number of connections and quantities of gas that will be available, it is most likely that the total supply (and associated demand) for low emission gases will be substantially lower than historic natural gas demand.

Pressure for more environmentally sustainable energy sources may be driven both by demand, as gas consumers embrace less carbon intensive forms of energy, as well as by supply factors, particularly if the New Zealand Government places further constraints on gas exploration or usage to accelerate movement towards carbon reduction targets. In that regard, a key driver will be the carbon charge, which will impose increasingly higher costs on carbon emissions and make alternative fuels increasingly more attractive.

Box 1 Stakeholder consultation – demand outlook

Stakeholder questions:

1. Does the summary of the demand outlook reasonably identify the key issues affecting future demand? Are there additional issues that need to be considered?
2. Do you agree that, over the medium to longer term, gas use will decline, and remaining gas use be more variable?

Stakeholder responses:

Stakeholders generally agreed that the discussion around gas demand outlook identified the key issues affecting future demand. However, noting our draft report relied on Concept Consulting's central demand/central supply case, stakeholders highlighted the uncertainty around future gas use and the potential for much slower reduction in usage (eg under the high demand/high supply case). Our report now recognises a broader range of outcomes that may occur. In all scenarios, gas usage by all sectors is expected to decline, however there is a significant range around the potential speed of decline.

2.3 Pricing arrangements

2.3.1 Regulation under Commerce Commission

Firstgas is subject to regulation by the Commerce Commission, which ensures that its overall allowable revenue from its gas transmission business does not exceed its total cost of providing the service (assessed using a building block cost of service methodology approved by the Commerce Commission). Within this overall limit, Firstgas has flexibility to set prices for individual services, though it must also comply with the two transmission codes.

The Commerce Commission's regulatory methodology includes key features which will assist Firstgas in managing its exposure to the New Zealand economy's energy transition, including:

- use of a revenue cap form of regulation. This means that demand risk is borne in the first instance by customers, rather than by Firstgas. Any over-recovery or under-recovery of revenue in a pricing year can be passed through to customers in the prices that can be charged in a subsequent year.

- the Commerce Commission has recognised the risk of economic stranding of transmission assets due to the forecast decline of natural gas demand in coming decades. Accordingly, in the DPP decision, the Commission has adopted an accelerated depreciation profile in setting the building block cost of service. This is a significant factor in the increase in Firstgas' allowable revenue from $132m in FY2022 to $200m in FY2026,[8] with allowable revenue potentially peaking in around FY2029 at over $300m[9].

2.3.2 Pricing structures

The price structures applied by Firstgas differ for the Maui and GTC pipelines, reflecting the terms of the relevant transmission codes. In summary:

- for the Maui pipeline, the MPOC provides for a form of 'common carriage', with charges applied purely on nominated gas throughput. Shippers are required to nominate the amount of transmission capacity required on any day between a receipt point and a delivery point. Two tariffs are payable by Shippers – tariff 1 is applied on a $/GJ.km, and tariff 2 is applied on a $/GJ, where the GJ quantity is the approved nominated quantity. While there is an option for long term reservation of capacity through an Authorised Quantity, this feature has never been used in practice. Demand is managed, where relevant, by the process of curtailing nominations which exceed available capacity. Non-standard transmission tariffs and interconnection fees are not permitted.

- for the GTC pipelines, the GTC provides for a form of 'contract carriage'. Customers annually reserve capacity between specific receipt points (in most cases being the offtake point from the Maui pipeline) and delivery points, at what they consider to be their optimum quantities. Three standard transmission charges are payable:
  - a fixed capacity reservation fee (CRF) payable on a $/GJ of reserved capacity (except for the Frankley Road pipeline, where no CRF is payable). The CRFs vary by pricing region, and generally increase modestly with distance from the relevant receipt point. CRF's account for over two thirds of Firstgas' revenue from the GTC pipelines;
  - a variable throughput fees, $/GJ; and
  - an unauthorised overrun fee, payable for gas taken in excess of reserved capacity on a day, and charged at 10 times the relevant capacity reservation fee.

[8] Commerce Commission (2022); Default price-quality paths for gas pipeline business from 1 October 2022; 31 May 2022; p.61.

[9] Commerce Commission (2022); Asset Stranding Model.

The GTC allows Firstgas to apply non-standard pricing (through Supplementary Agreements) to cater for gas consumers' specific circumstances, including to maintain gas demand if standard prices exceed a consumer's capacity to pay.

Where GTC pipeline customers require use the Maui pipeline for their gas transmission, they will pay transmission charges under both pricing systems.

These pricing structures create very different price signals and utilisation incentives for users on the two pipeline systems. On the GTC pipeline, the fixed capacity reservation fee, together with the high premium applied to unauthorised overruns, places a high value on capacity and uses pricing as a means of managing capacity utilisation and flattening demand. However, on the Maui pipeline, the fully variable pricing approach (on nominated quantities) means that pricing is not used to manage capacity utilisation or flatten demand – instead, to the extent that demand exceeds available capacity, nominations are curtailed.

These different price signals are applied on the different systems notwithstanding that there is ample available capacity across both pipeline systems, with no expectation of capacity constraints emerging given the future transmission demand profile.

2.4 Objectives for transmission pricing review

Firstgas' objectives for this price review are that, to the extent possible, prices:

(a) are economically efficient, as provided in the Pricing Principles set out in the ID Determination;

(b) are reasonable to customers, including charging customers fairly for their use of the transmission system, promoting price stability and avoiding price shocks;

(c) facilitate the use of gas, and avoid demand destruction, by ensuring that prices remain below the willingness of users to pay for the transmission service before they either bypass the service or cease their gas demand;

(d) future proof Firstgas' pricing approach to manage anticipated changes in technology, policy and regulatory requirements as the New Zealand economy transitions to a low carbon energy system;

(e) earn the allowable revenue set under the Default Price Path Determination (including avoiding future risk of asset stranding); and

(f) simplify tariff structures.

Where these pricing objectives conflict, Firstgas will pursue a reasonably balanced outcome, which seeks to apply efficient pricing arrangements to both maximise demand and maximise recovery of Firstgas' costs (as per its allowable revenue).

Box 2 Stakeholder consultation – objectives for pricing review

Stakeholder responses
Stakeholders have highlighted the risk that there may be conflicts between the listed objectives for the price review, and a preference that Firstgas provide a ranking of priorities, to guide outcomes where the pricing objectives conflict. Stakeholders generally consider that the objective of facilitating the use of gas and avoiding demand destruction should be the highest priority objective.

3 Principles of economically efficient pricing design

3.1 Economic concept of efficient pricing

The following dimensions of economic efficiency must be considered from a best practice pricing perspective:

- *allocative efficiency* — is achieved where resources used to produce a set of goods or services are allocated to their highest valued uses (i.e. those that provide the greatest benefit relative to costs);
- *productive efficiency* — is achieved where individual firms produce the costs of services at least cost; and
- *dynamic efficiency* — reflects the evolution of allocative and productive efficiency over time, due to the need for industries to make timely changes to technology and products in response to changes in consumer tastes and in productive opportunities.

Standard economic theory provides that optimal prices are achieved when (absent the existence of fixed costs) the price for a service is equal to the short run marginal cost of providing that service. This is considered the most effective way to maximise allocative efficiency at a given point in time as users will be incentivised to use the service, provided the value they derive from it exceeds the short run marginal cost of its provision – in other words, this is the price that encourages efficient marginal demand.

However, where fixed costs exist (as is the case for infrastructure services such as gas transmission pipelines), pricing at this short run marginal cost level would prevent the infrastructure owner from recovering its full costs. This will reduce or prevent future investment to the detriment of long-term efficient outcomes and will inevitably cause the firm to exit the industry. Therefore, for businesses such as Firstgas with significant fixed costs, an efficient price must necessarily be one that captures fixed costs as well as marginal costs, including an amount to recover the necessary investment in the assets.

However, to maintain allocative efficiency, price mark-ups above marginal cost should be applied in a way that minimises distortions to consumption. Conceptually, this is most effectively achieved where services (or customers) with relatively inelastic demand (or greater willingness to pay) incur a higher mark-up above marginal cost.[10] In practice,

[10] This is known as the *Ramsey pricing rule*, also sometimes referred to as the *inverse elasticity rule*, which is aimed to optimally trade off the requirement to increase profitability with the inefficiencies of raising price above marginal cost. It aims to set prices to achieve a price quantity trade-off that minimises demand loss subject to the firm at least breaking even.

practical constraints (e.g. the use of standard prices to simplify the management task and bundled prices which 'hide' the cost of product sub-components) and information limitations (e.g. customer preferences may not be clearly visible to the service provider) mean that this is not possible to perfectly achieve. However, this concept provides a useful guide to the application of prices in order to minimise the risk that the approach used to recover fixed costs causes those who value the service at more than avoidable cost but less than average cost are priced out of utilising the service.

To maintain long run efficiency, the aggregate mark-up above marginal cost should be enough to cover (but not materially exceed) the fixed cost of providing the service. For Firstgas, this is the maximum allowable revenue that it is permitted to earn under Commerce Commission's default price-quality path.

3.2 Principles for efficient pricing

In a competitive market, an efficient pricing outcome is achieved via the effect of market forces, which will, over the long run, constrain aggregate charges to the level that reflects the cost of a new supplier entering the market (although, in the short run, prices will vary in response to changes in demand and supply conditions). This is achieved as the price for a product in a competitive market will fall between marginal cost and the price of substitutes, which may be the cost of the next entrant to the market, with prices increasing as customer demand increases and capacity becomes scarce. As prices increase to the point where they reflect the costs that would be incurred by a new supplier entering the market, new supply will be triggered so long as there is enough demand to warrant entry. If not, prices will rise to ration demand to the then available capacity (i.e. until capacity is augmented) - this means that existing customers with the lowest willingness to pay will be displaced by customers who value the service more highly.

However, in a regulatory setting where the service provider is a natural monopoly, pricing principles are intended to set the conditions for efficient prices. To achieve efficient pricing outcomes as described in section 3.1, principles for efficient pricing are based on the following concepts:

- prices should fall between a band set by floor and ceiling prices. The floor price reflects the avoidable cost of the service and the ceiling is the stand-alone cost of supply;
- within the floor/ceiling band, price discrimination is permitted to reflect the capacity to pay of the user – that is, having regard to their price elasticity of demand to achieve minimal distortions to consumption relative to marginal cost pricing.

These concepts are discussed further below.

Floor and ceiling limits

The purpose of floor and ceiling limits within efficient pricing principles is to rule out clearly inefficient prices:

- the ceiling price is designed to ensure that prices are not set above a level at which bypass could theoretically occur, because such a price is prima facie likely to be inefficient. The ceiling price is assessed based on the 'stand alone cost' of providing the service, either to an individual customer or to any feasible combinations of customers (referred to as the 'combinatorial' stand alone cost test). This approach is used, as it is unlikely that a well-informed customer would agree to a price where, either for its services alone or in combination with other customer's services, it would be cheaper for customers to build their own infrastructure.
- the floor price is designed to ensure that prices are not set below the avoidable costs of service provision, as this would require the service provider to incur a loss in providing the service. This would be inefficient because the price of the service would be less than the cost of the additional resources needed to supply it. The floor price is therefore assessed based on the avoidable cost of providing the customer's service, including both incremental operating cost and any incremental investment required to meet the customer's requirements. Avoidable costs are also considered both on an individual and combinatorial basis.

The use of floor and ceiling limits also prevents cross-subsidy in the form of prices above stand-alone cost being used to subsidise services with prices below marginal cost. For this reason, this pair of rules is often termed the cross-subsidy rule.

Setting prices within the floor and ceiling limits

Within the floor and ceiling limits, efficient pricing principles provide for prices to be recovered in a way that minimises the loss of allocative efficiency:

- price differentiation is permitted to maximise the ability of the service provider to meet its full economic costs while also maximising the commercially viable use of the infrastructure (or in other words while also minimising negative impact on demand). This recognises that there are limitations on the willingness of customers to pay for the service, perhaps reflecting the opportunity for substitute services, or the point at which some or all their usage will cease being commercially viable. Setting prices to reflect the user's willingness to pay will allow for the recovery of fixed costs above the floor limit from users of the network in the least distortionary way, with users with a higher willingness to pay making a greater contribution.

This recognises that all network users (and the infrastructure owner) will be better off if a user is not priced off the network, provided they pay at least avoidable cost;

- in practice, multi-part tariffs provide a useful vehicle for achieving cost recovery for an infrastructure service provider with significant fixed costs providing a range of services, because it enables marginal consumption to be charged at a price closer to marginal cost, with fixed tariff components providing a means to recover fixed costs (with price discrimination most effectively applied to the fixed tariff components); and[11]
- the extent of price discrimination is typically constrained to ensure that price discrimination does not affect competition in dependent markets (suggesting that price discrimination between competitors in the same market should be minimal).

These principles can be most practically implemented through the development of standard tariffs that reflect a broad application of these principles, with individual negotiation of tariffs in circumstances where the standard tariff exceeds a customer's willingness to pay, but there is material value in retaining that customer's demand.

Box 3 Stakeholder consultation – efficient pricing principles

Stakeholder questions

1. Are the principles for efficient pricing for natural monopoly facilities adequately explained?
2. Do you have any concerns with Firstgas using the principles for efficient pricing, as described in this report, as the foundation for this price review? If so, please explain your concerns.
3. Do you think that there is a need for negotiated tariffs in some cases, rather than reliance on standard tariffs? What would be the practical consequence of greater reliance on negotiation of charges?
4. What do you expect to be the practical implications for Firstgas transmission in applying these principles in setting standard tariffs, particularly in an environment of ample transmission capacity and declining natural gas usage?

Stakeholder responses

One stakeholder questioned whether there was any contention around the economic theory of efficient pricing. Synergies confirms that this economic theory is well established, well accepted and consistently used by economic regulators as the basis for efficient pricing design for infrastructure. Otherwise, stakeholders generally accepted the efficient pricing principles, as described in the report.

In applying these efficient pricing principles, stakeholders noted the important role of supplementary agreements, but considered that it was important that this be implemented in a transparent way. Firstgas has confirmed that it maintains clear policy guidelines governing the development of supplementary agreements, which are available on its website. This policy is reviewed periodically to ensure it remains fit-for-purpose. Further, since 2014, all supplementary agreements have been published. We consider that these arrangements provide a high degree of transparency around the circumstances in which supplementary agreements are used, consistent with stakeholder preferences.

[11] Contractual take-or-pay commitments are another means of efficiently allocating scarce capacity.

3.3 Application of efficient pricing principles in regulatory pricing frameworks

We have reviewed a sample of regulatory pricing frameworks across the energy, water and transport sectors in New Zealand, Australia and the UK to assess how they incorporate the principles of efficient pricing design. Appendix B sets out a summary of these arrangements, which shows that regulatory pricing frameworks are typically structured to reflect the principles for efficient pricing, as described in section 3.2.

The ID Determination sets out several requirements around transmission pricing, including specification of the following Pricing Principles:

1. Prices are to signal the economic costs of service provision, by

   (a) being subsidy free, that is, equal or greater than incremental costs and less than or equal to standalone costs, except where subsidies arise from compliance with legislation and/or other regulation;

   (b) having regard, to the extent practicable, to the level of available service capacity; and

   (c) signalling, to the extent practicable, the effect of additional usage on future investment costs.

2. Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall is made up by prices being set in a manner that has regard to consumers' demand responsiveness, to the extent practicable.

3. Provided that prices satisfy (1) above, prices are responsive to the requirements and circumstances of consumers to

   3.1. discourage uneconomic bypass; and

   3.2. allow negotiation to better reflect the economic value of services and enable consumers to make price/quality trade-offs or non-standard arrangements for services.

4. Development of prices is transparent, promotes price stability and certainty for consumers, and changes to prices have regard to the effect on consumers.

The pricing principles specified in the ID Determination are consistent with the principles of economically efficient pricing design and with many features of the other regulatory frameworks that were reviewed in Appendix B. In particular:

- Principle 1 incorporates cost-based floor and ceiling limits, designed to rule out clearly inefficient prices, and provides, to the extent practicable, that prices signal to users the cost of their usage on the network (including in relation to the level of available service capacity and the effect of their usage on future investment) to promote allocative and dynamic efficiency; and

- Principles 2 and 3 allow the service provider to price discriminate between customers to recover the fixed costs of providing the service in a way that minimises the drag on allocative efficiency and provides for negotiation to reveal the value that users place on the service.
- Principle 4 is generally aligned with promoting the long-term interests of users of the service, consistent with achieving a long-term efficient outcome for society.

4 Critical pricing constraints

4.1 Floor and ceiling limits

4.1.1 Approach

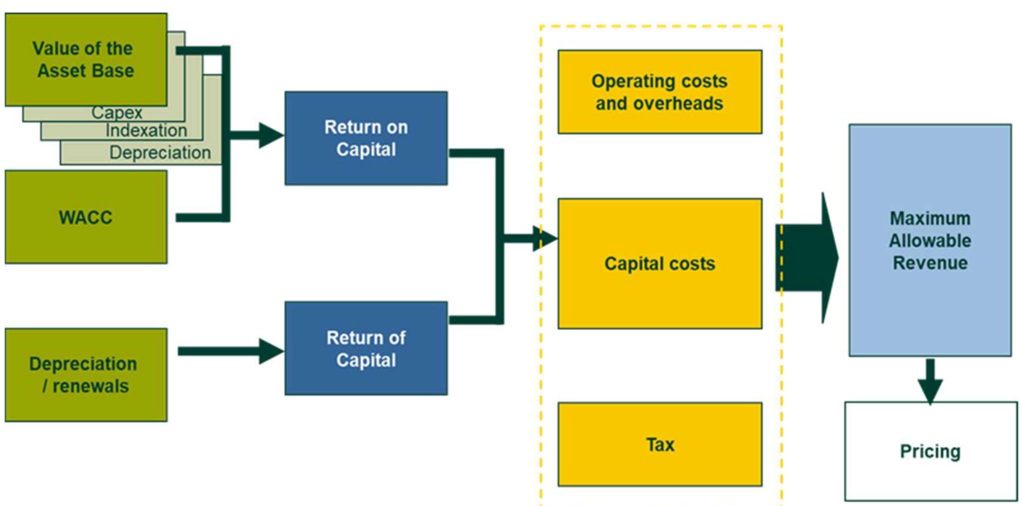
In order to assess how Firstgas' current transmission charges fall within the floor and ceiling limits as described in section 3.2, we have developed a detailed floor/ceiling cost model. Revenue was then assessed, based on FY23 transmission prices and FY22 demand, and compared to the calculated floor/ceiling price in order to determine whether, and to what extent, Firstgas' FY23 prices comply with these constraints.

Modelling approach

The modelling approach adopted reflects a cost of service 'building block' methodology, which is an approach that has been developed by economists in order to assess the full economic cost of infrastructure provision.

The objective of the building block approach is to ensure that the infrastructure provider is fully compensated (but not over-compensated) for the costs of providing infrastructure services, including earning a risk-adjusted return for shareholders. This objective is fundamental to providing incentives for the efficient investment in infrastructure. The diagram below demonstrates the different components of the calculation of maximum allowable revenue (or MAR) under a building blocks model.

Figure 5 Components of the building block model



Source: Synergies

The MAR can be specified as follows:

MAR = Return on capital + Return of capital + Opex + Tax

A brief description of each component is provided in the following table.

Table 4 Components of the MAR

Component	Description
Return on capital (**RoC**) (also called return on assets)	The infrastructure provider needs to generate an adequate return on capital for its shareholders that is commensurate with the risks borne. This is determined by estimating a Weighted Average Cost of Capital (WACC) and applying this to the value of the assets.
Depreciation or return of capital	For depreciating assets, the infrastructure provider can recover a return of the capital consumed in the process of providing the regulated services (representing depreciation). This requires the determination of an appropriate depreciation methodology which is applied to the RAB. For non-depreciating assets, there is no adjustment for depreciation.
Operating costs	The infrastructure provider is entitled to receive an allowance for the efficient costs incurred in maintaining the network plus other efficient operating costs (including corporate overheads).
Tax	The infrastructure provider is entitled to recover an allowance for its expected income tax liabilities. This is usually adjusted for the estimated value of franking credits.

Note, the MAR can alternately be assessed on a 'pre-tax' basis, by adopting pre-tax formulation of the WACC, and excluding tax from the assessment of costs. Our floor/ceiling model has been developed on a 'pre-tax' basis.

In applying the building block model, it is necessary to assess the initial value for each parameter in the MAR equation, and then forecast the values over the modelling period. The MAR can then be translated into prices based on expected levels of demand.

The Commerce Commission, as regulator of New Zealand gas pipelines has established a MAR for Firstgas' transmission business using a building block model based on Firstgas' regulated asset base (RAB), its permitted operating cost allowance and WACC.

However, in assessing whether a price charged for access to infrastructure with monopoly characteristics complies with the floor/ceiling limits, the fundamental test is whether that price is consistent with the firm recovering the forward-looking efficient costs of providing the services. The forward-looking efficient costs of providing the services may be thought of as the total cost of a hypothetical new entrant to the market producing the services currently provided by the owner of the infrastructure assets.

Optimised Depreciated Replacement Cost (ODRC) is the most common valuation methodology applied in a building block assessment of full economic cost. This is because it represents the value of assets from the perspective of a hypothetical new entrant, consistent with setting the maximum price achievable in a competitive market. ODRC reflects the current cost that would be required to install assets with the same service potential as the existing assets, hence the value reflects an optimised set of assets, that are depreciated to account for their decline in service potential.

Therefore, while Firstgas' overall transmission revenues will continue to be constrained by the Commerce Commission's determined MAR (which is in turn based on the RAB value of the assets), in assessing compliance with the ceiling price limit, we have used the estimated ODRC value of the assets.

ODRC continues to be the most relevant valuation method for the purpose of assessing the ceiling price, even where there is a high degree of uncertainty around the future economic use of the asset – in this case this would be reflected as a requirement for the hypothetical new entrant to recover the cost of the asset over a shorter time frame (consistent with the period in which it is confident that it will be economically used). This is consistent with applying an accelerated depreciation profile to both determine the ODRC value, and to assess the prices that would be required by the new entrant, in order to reflect this shorter economic life.

Firstgas has provided a high-level estimate of the ODRC value of its pipeline systems, and for non-pipeline assets we have used their RAB value as an approximation of their ODRC value. While we have used this estimated ODRC valuation as the basis for our assessment of floor and ceiling costs, it is likely that this high level ODRC estimate understated, reflecting that:

- the replacement cost estimates used in the ODRC are dated and have been escalated to current dollar terms using CPI. However this is likely to underestimate current construction costs, which reflect substantially different inputs as well as the changes in safety and environmental requirements that have occurred since most of Firstgas' pipelines were constructed;
- replacement cost estimates have been provided for pipeline assets only, with RAB values applied for all other assets, such as stations;
- preliminary costs normally included in a ODRC valuation (including costs of planning, design and approvals) may not be adequately covered in the ODRC estimates;
- owner and contractor construction management costs may not be adequately covered in the ODRC estimates; and
- interest during construction has not been included in the ODRC estimate.

If Firstgas' prices appear to be approaching the ceiling price assessed using this high-level estimate, we recommend that a more robust ODRC valuation be undertaken in order to provide higher confidence in the ceiling price evaluation.

In addition, we have included in the model an option to assess the floor and ceiling costs using RAB values for all assets. We have adopted the Commerce Commission approved values for opex, WACC and depreciation rates, including the application of an accelerated depreciation factor. While we have aligned inputs, where relevant, to the Commerce Commission financial model for the Firstgas transmission business, modelling differences mean that our floor/ceiling model provides only an approximation of the Commerce Commission modelled aggregate allowable revenues. The most significant reasons for the differences in our modelled results include:

- our floor/ceiling model uses pre-tax cashflows, rather than the post-tax terms adopted by the Commerce Commission model;
- we have not applied mid-year adjustments and working capital allowances, as provided for in the Commerce Commission model;
- we have assessed depreciation at an individual asset level, rather than using a weighted average asset life, with resulting changes in the assumed profile of depreciation.

Further, the high level ODRC valuation applies remaining pipeline asset lives that are significantly longer than the remaining lives assigned to pipeline assets in the RAB. This results in a proportionally lower depreciation charge under the ODRC model.

Table 5 Comparative values for Firstgas Transmission FY23 $million

	Commerce Commission	Synergies' RAB model	Synergies' ODRC model
Opening asset value	$918.0	$922.7	$1,204.1
Return on assets (pre-tax)	$76.4[a]	$76.8	$100.2
Asset appreciation (indexation)	($22.9)	($23.1)	($30.1)
Asset depreciation	$54.1	$48.0	$48.7
Opex	$53.5	$53.5	$53.5
Total Building Block Allowable Revenue[b]	$164.6[c]	$155.2	$172.2

a: Includes Commerce Commission return on capital, term credit spread differential and tax allowance.

B: The Commerce Commission BBAR reflects the sum of the assessed building block components in each year of the regulatory period. In determining the MAR for each year, the Commerce Commission has applied a smoothed price path to transition from current revenues. The resulting MAR increases from $132m in FY2022 to $200m in FY2026. The FY2023 MAR is $147m.

c: The Commerce Commission BBAR does not reflect a simple addition of the building block components due to the treatment of tax and part year effects.

Source: New Zealand Commerce Commission Financial Model, Synergies

Modelling areas

In order to simplify the floor/ceiling cost assessment, Firstgas' transmission network was first broken into a range of modelling areas. These modelling areas were defined as a grouping of delivery points, with the groups established to differentiate sections of the transmission network with:

(a) different pricing arrangements, and noting that there are only a small number of supplementary agreements establishing bespoke prices, which meant that the existing pricing regions established the outer boundary of the modelling areas; and

(b) significantly different usage characteristics, with the result that several current pricing regions were separated into smaller modelling areas, having regard to the nature of the users.

This resulted in the adoption of 29 modelling areas, summarised as follows:

Table 6 Modelling areas

Number	Identifier	DP Group	Specific Delivery Points
1	North Pipeline 1	Drury	Tuakau 2, Harrisville 2, Ramarama, Drury 1
2	North Pipeline 2	Glenbrook	Pukekohe, Kingseat, Waiuku, Glenbrook
3	North Pipeline 3	Auckland	Greater Auckland, Hunua, Hunua (Nova), Hunua 3, Alfriston, Flat Bush
4	North Pipeline 4	Henderson North	Waitoki, Warkworth, Wellsford, Maungaturoto, Marsden 2, Whangarei, Kauri Dairy Factory (DF)
5	Central North 1	Greater Hamilton	Greater Hamilton, Te Kowhai Receipt Point
6	Central North 2	Morrinsville	Te Rapa DF, Horotiu, Kiwitahi 1, Kiwitahi 2, Morrinsville DF, Morrinsville, Tatuanui DF, Waitoa
7	Central North 3	Cambridge	Matangi, Cambridge
8	Bay of Plenty 1	Kinleith	Kihikihi (Te Awamutu), Waikeria, Lichfield DF, Lichfield 2, Tokoroa, Kinleith, Kinleith (Pulp & Paper)
9	Bay of Plenty 2	Okoroire	Putaruru, Tirau DF, Tirau, Okoroire Springs
10	Bay of Plenty 3	Rangiuru	Tauriko, Greater Tauranga, Greater Mt Maunganui, Te Puke, Rangiuru
11	Bay of Plenty 4	Taupo	Reporoa, Broadlands, Taupo
12	Bay of Plenty 5	Rotorua	Rotorua
13	Bay of Plenty 6	Whakatane	Kawerau (Tissue), Kawerau (Pulp & Paper), Kawerau, Te Teko, Edgecumbe DF, Edgecumbe, Whakatane
14	Bay of Plenty 7	Gisborne	Opotiki, Gisborne
15	Frankley Rd	Frankley Rd	Stratford 2, Stratford 3-Bi, TCC Power Station, Ballance (8201), Ballance (9626), Kupe Delivery, Kapuni (Lactose), Kapuni GTP, KGPT Delivery
16	South Pipeline 1	Kaitoke	Matapu, Manaia, Mokoia, Hawera, Hawera (Nova), Patea, Waverley, Waitotara, Wanganui, Kaitoke
17	South Pipeline 2	Marton	Lake Alice, Kakariki, Marton
18	South Pipeline 3	Ashurst	Flockhouse, Oroua Downs, Longburn, Kairanga, Palmerston North, Feilding, Ashurst
19	South Pipeline 4	Pahiatua	Mangatainoka, Pahiatua, Pahiatua DF
20	South Pipeline 5	Hastings	Dannevirke, Takapau, Mangaroa, Hastings, Hastings (Nova)
21	South Pipeline 6	Kuku	Foxton, Levin, Kuku
22	South Pipeline 7	Tawa	Otaki, Te Horo, Greater Kapiti, Pauatahanui 2, Greater Waitangirua, Belmont, Tawa A, Tawa B (Nova)

Number	Identifier	DP Group	Specific Delivery Points
23	Central South Pipeline	Central South	Kaponga, Stratford, Inglewood, Waitara, New Plymouth, Eltham
24	Te Awamutu North Pipeline	Te Awamutu	Pirongia, Te Awamutu DF
25	Maui 1	Maui Other South	Opunake, Pungarehu No 1, Pungarehu No 2, Okato, Oakura
26	Maui 2	Maui Other North	Te Kuiti South, Te Kuiti North, Otorohanga, Ngaruawahia, Huntly Town
27	Maui 3	Huntly	Huntly Power Station
28	Maui 4	Mangorei	Mangorei Power Station
29	Maui 5	Methanex	Ngatimaru Road Delivery, Faull Road, Bertrand Rd/Waitara Valley

Source: Firstgas

Asset values and costs specifically incurred in providing services for each modelling area are directly attributed to that modelling area. Current revenues have also been directly attributed to each modelling area. This has been based on the following approaches:

Table 7 Modelling area-specific costs and assets

Cost type	Category	Method
Operating cost	Compressor fuel	Data collected by compressor station, attributed to relevant modelling area based on GJ.km
	Land management	Data collected network-wide, attributed to modelling area based on pipe length
	Routine and corrective maintenance	Data collected network-wide, attributed to modelling area based on pipe length
	Service interruptions, incidents and emergencies	Data collected network-wide, attributed to modelling area based on pipe length
Assets	Pipelines	Separately identified to Maui pipeline and GTC pipelines, Maui pipeline value attributed by pipe length, GTC pipeline values attributed by estimated ODRC value per modelling area
	Compressor stations	Data collected by compressor station, attributed to relevant modelling area based on GJ.km
	Other assets	Only assets specifically located within, and dedicated to, a modelling area are attributed to that area
Revenues	MPOC revenue	MPOC revenue has been attributed to a modelling area based on the Maui pipeline GJ and GJ.km for gas transported to delivery points within the modelling area
	GTC revenue	GTC CRF and throughput charges have been attributed to a modelling area based on reservation charges and throughput for delivery points within the modelling area
	Supplementary agreements	Where supplementary agreements apply to a delivery point within a modelling area, revenue from that supplementary agreement is attributed to that modelling area

Source: Synergies

Other costs and assets are incurred on a transmission network-wide basis, and the treatment of these costs and assets is discussed below in relation to the assessment of floor and ceiling costs.

Floor and ceiling cost assessment

The ceiling price is designed to ensure that prices are not set above a level at which bypass could theoretically occur, because such a price is *prima facie* likely to be inefficient. The ceiling price is assessed based on the 'stand alone cost' of providing the service, either to an individual customer or to any feasible combination of customers (referred to as the 'combinatorial' stand alone cost test). This combinatorial approach is used, as it is unlikely that a well-informed customer would agree to a price where, either for its services alone or in combination with other services, it would be cheaper for customers to build their own infrastructure.

The floor price is designed to ensure that prices are not set below the level necessary to recover the marginal costs of service provision, as this would require the service provider to incur a loss in providing the service. This would be inefficient because the price of the service would be less than the cost of the additional resources needed to supply it. The floor price is therefore assessed based on the or avoidable cost of providing the customer's service, including both incremental operating cost and any incremental investment required to meet the customer's requirements. Avoidable costs are also considered both on an individual and combinatorial basis.

In addition, if a business is to fully recover the value of its assets without breaching the combinatorial ceiling price for other users, it would be necessary for a customer (or group of customers) to meet the sunk costs associated with any dedicated assets. For convenience, we have referred to this as the 'floor plus' price. However, it should be recognised that, where a business' total revenue is less than required to recover the ODRC value of its assets (as is the case for Firstgas, where the RAB value of assets is less than the estimated ODRC value) it is not essential for each customer (or group of customers) to recover its 'floor plus' costs in order to avoid a breach of the ceiling price for any other group of customers.

In each case, we have focussed on the application of the floor and ceiling limits at a combinatorial level involving logical groupings of customers within the same geographic area, as this is more likely to result in binding price constraints than an assessment of floor and ceiling costs on an individual customer basis.

In practice, this means that for the purpose of evaluating Firstgas' current compliance with the floor and ceiling limits, the following cost and revenue categories have been assessed:

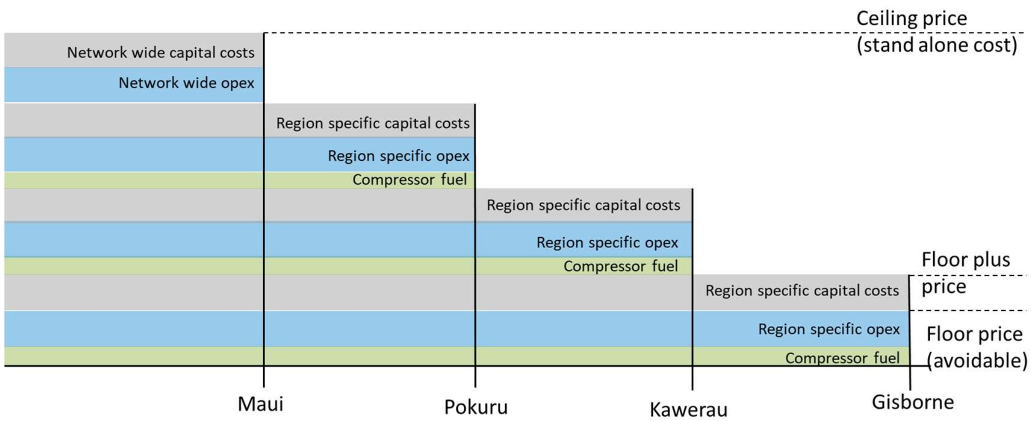
Table 8 Floor and ceiling costs and revenues

Costs	Revenues	Rationale
Floor price		
Target modelling area compressor fuel Target modelling area land management costs Target modelling area routine and corrective maintenance costs Target modelling area service interruptions, incidents and emergencies costs	Revenue derived from delivery points within target modelling area	While the floor price for an individual customer is limited to the avoidable costs of transporting its gas (i.e. compressor fuel), the application of the floor price at a combinatorial level means that revenue derived from delivery points within a modelling area must at least meet the cost of the compressor fuel to deliver gas from the relevant gas field, as well as the area-specific operating costs, in order for it to be economically viable to continue to deliver gas to that area.
Floor plus price		
Floor price for target modelling area Plus return on and of capital for assets within target modelling area, including pipeline assets	Revenue derived from delivery points within target modelling area	Revenue derived from delivery points within a modelling area should preferably also recover the return on and of assets dedicated to delivering gas to those delivery points (although this may not be essential if all ceiling price limits are met)
Ceiling price		
Floor plus price for target modelling area Plus floor plus price for all other modelling areas that gas traverses from the relevant gas field/s to the delivery points in the target modelling areas Plus other 'network-wide' operating costs, estimated on the basis that the target modelling area, plus all other modelling areas that the gas traverses, are provided on a standalone basis Plus return on and of other 'network-wide' assets, estimated on the basis that the target modelling area, plus all other modelling areas that the gas traverses, are provided on a standalone basis	Revenue derived from delivery points within target modelling area Revenue derived from delivery points within all other modelling areas that gas traverses from the relevant gas field/s to the target modelling area	The ceiling price for a modelling region must include all costs (operating costs and return on and of assets) required to transport the gas from the relevant gas field/s to the modelling area. However, application of the combinatorial test means that the revenue from customers within the target modelling area should be combined with the revenue from all other customers that can be served with these assets.

Source: Synergies

The build-up of floor and ceiling costs is also illustrated in the following diagram:

Figure 6 Floor and ceiling costs



Source: Synergies

When estimating the extent of 'network-wide' costs that would be incurred in providing one or more target modelling areas on a standalone basis, it is necessary to recognise that there are significant scale economies in managing a network business such as a transmission pipeline network. Therefore, while it is possible to identify allocation methods that bear some correlation with network-wide costs, it is likely that an allocation of these costs to one or more modelling areas will understate the cost that would be incurred if those areas were provided on a standalone basis. To approximate the extent to which these costs would be incurred on a standalone basis, we have:

- applied a fixed minimum allocation for each cost category, set at 20%;
- allocated the remainder of costs within each category based on a measure of network size, set at the area specific ODRC value.

4.1.2 Results

For the purpose of assessing compliance with the floor and ceiling limits, we have combined our modelling areas into 18 floor and ceiling assessment regions (FCAR) as follows:

Table 9 Floor and ceiling assessment regions (FCAR)

FCAR Number	FCAR Name	Target modelling regions included	Additional modelling regions traversed
1	Henderson North	Henderson North	Drury, Auckland, Maui Other North[1], Methanex, Mangorei, Maui Other South
2	Greater Auckland	Drury, Glenbrook, Auckland	Maui Other North[1], Methanex, Mangorei, Maui Other South
3	Central North	Greater Hamilton, Morrinsville, Cambridge	Maui Other North[1], Methanex, Mangorei, Maui Other South

FCAR Number	FCAR Name	Target modelling regions included	Additional modelling regions traversed
4	BoP 1 - Kinleith	Kinleath	Maui Other North[2], Methanex, Mangorei, Maui Other South
5	BoP 2 - Rangiuru	Okoroire, Rangiuru	Kinleith, Maui Other North[2], Methanex, Mangorei, Maui Other South
6	BoP 3 - Taupo	Taupo	Rotorua, Kinleith, Maui Other North[2], Methanex, Mangorei, Maui Other South
7	BoP 4 - Rotorua	Rotorua	Kinleith, Huntly, Maui Other North[2], Methanex, Mangorei, Maui Other South
8	BoP 5 – Whakatane	Whakatane	Rotorua, Kinleith, Maui Other North[2], Methanex, Mangorei, Maui Other South
9	BoP 6 - Gisborne	Gisborne	Whakatane, Rotorua, Kinleith, Maui Other North[2], Methanex, Mangorei, Maui Other South
10	Frankley Rd	Frankley Rd	Mangorei, Maui Other South
11	South 1 – Kaitoke	Kaitoke	Frankley Rd, Mangorei, Maui Other South
12	South 2 - Marton	Marton	Kaitoke, Frankley Rd, Mangorei, Maui Other South
13	South 3 - Hastings	Ashurst, Pahiatua, Hastings	Kaitoke, Frankley Rd, Mangorei, Maui Other South
14	South 4 - Tawa	Kuku, Tawa	Ashurst, Kaitoke, Frankley Rd, Mangorei, Maui Other South
15	Central South	Central South	Frankley Rd, Mangorei, Maui Other South
16	Te Awamutu	Te Awamutu	Maui Other North, Methanex, Mangorei, Maui Other South
17	Maui 1 - Huntly PS	Huntly	Maui Other North, Methanex, Mangorei, Maui Other South
18	Maui 2 - Methanex	Methanex	Mangorei, Maui Other South

Note: (1) Only includes a km-based allocation of Maui pipeline costs to Rotowaro; (2) Only includes a km-based allocation of Maui pipeline costs to Pokuru

Source: Synergies

Summary results of our evaluation of revenue based on FY23 prices and FY22 demand against floor, floor plus and ceiling costs for each assessment region (calculated using ODRC values) is shown in the following table and graph.

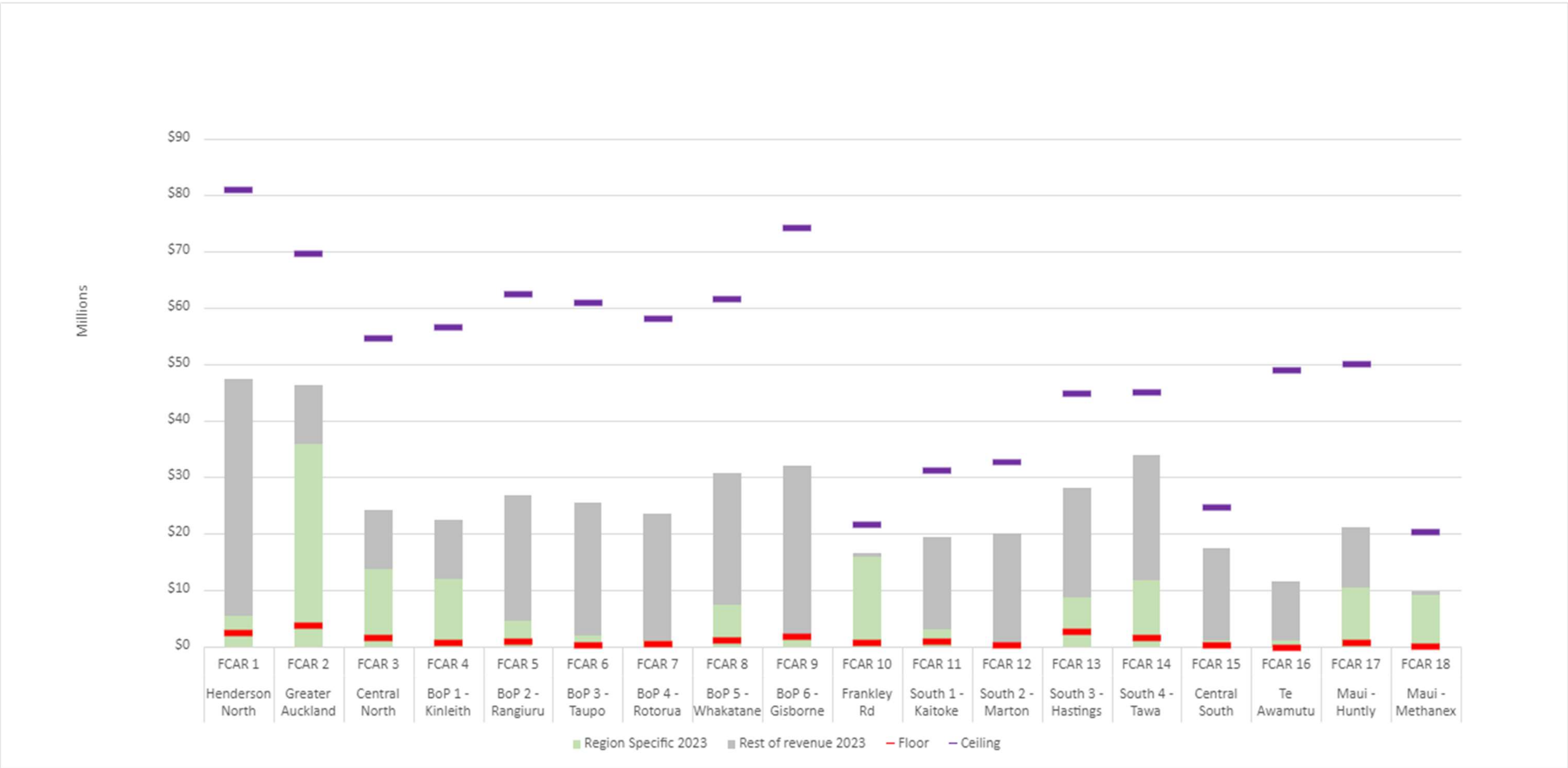
Table 10 Summary of assessment of FY23 prices against floor-ceiling costs

FCAR		Floor Cost	FCAR Specific Revenue (relevant to floor cost)	Ceiling Cost	FCAR Attributable Revenue (relevant to ceiling cost)
1	Henderson North	$2,572,000	$5,385,000	$81,279,000	$47,451,000
2	Greater Auckland	$3,902,000	$35,832,000	$69,870000,	$46,274,000
3	Central North	$1,905,000	$13,739,000	$54,964,000	$24,181,000
4	BoP 1 - Kinleith	$1,040,000	$11,914,000	$56,914,000	$22,357,000
5	BoP 2 - Rangiuru	$1,155,000	$4,449,000	$62,763,000	$26,806,000
6	BoP 3 - Taupo	$597,000	$2,008,000	$61,258,000	$25,444,000
7	BoP 4 - Rotorua	$623000,	$1,079,000	$58,407,000	$23,436,000
8	BoP 5 – Whakatane	$1,384,000	$7,282,000	$61,762,000	$30,718,000
9	BoP 6 - Gisborne	$2,019,000	$1,201,000	$74,328,000	$31,919,000
10	Frankley Rd	$993,000	$15,774,000	$21,898,000	$16,445,000

FCAR		Floor Cost	FCAR Specific Revenue (relevant to floor cost)	Ceiling Cost	FCAR Attributable Revenue (relevant to ceiling cost)
11	South 1 – Kaitoke	$1,127,000	$2,948,000	$31,382,000	$19,393,000
12	South 2 - Marton	$529,000	$637,000	$32,827,000	$20,03000,0
13	South 3 - Hastings	$2,958,000	$8,633,000	$45,180,000	$28,025,000
14	South 4 - Tawa	$1,808,000	$11,748,000	$45,322,000	$33,855,000
15	Central South	$501000,	$1,004,000	$24,808,000	$17,449,000
16	Te Awamutu	$121,000	$1,105,000	$49,289,000	$11,548,000
17	Maui 1 - Huntly PS	$1,008,000	$10,503,000	$50,231,000	$20,945,000
18	Maui 2 - Methanex	$216,000	$9,155,000	$20,478,000	$9,826,000

Source: Synergies

Figure 7 Summary of assessment against floor-ceiling costs FY23



Source: Synergies

This assessment shows that there is only a single FCAR area – the Gisborne area at the eastern extremity of the Bay of Plenty pipeline – that currently fails to meet the assessed floor cost. FY23 prices and FY22 demand result in modelled revenue of $1.2m compared to a floor cost of $2.0m (with the floor cost primarily comprised of routine and corrective maintenance for the pipeline assets in this FCAR). However, it should be noted that this result is based on a simplified allocation of costs to modelling areas, and therefore should be treated as an estimate only. We recommend that Firstgas closely examine the actual costs that it incurs in providing services in this area, to confirm whether the floor cost is being breached, and to what extent.

No FCAR area is assessed as exceeding ceiling price in FY23.

Notably, the Maui pipeline FCAR areas recover revenue well below their ceiling cost. This reflects that the MPOC pricing methodology requires a maximum revenue be established for the Maui pipeline, and that this revenue is recovered by application of a defined standard pricing approach for all gas throughput, including gas that is then further transported on the GTC pipelines. However, as shown by our assessment, this methodology results in prices being established for Maui pipeline direct connect customers that are well below that which is required under an economic ceiling price constraint.

Having said this, we acknowledge that the assessment of ceiling price is also based on a simplified allocation of costs to modelling areas and should be treated as an estimate only. There may be some specific services where the bypass cost for a customer could be less than the ceiling price indicated in this model. For example, the model assumes supply from a group of gas fields in the Taranaki region, however, if a customer located in the Taranaki area is securing supply from a single gas field located close by, its bypass cost may be lower than the ceiling price indicated in the model.

Box 4 Stakeholder consultation – floor and ceiling price limits

Stakeholder questions

1. Is the definition of floor and ceiling prices, and the relevant comparative revenues, adequately explained?
2. Do you have any concerns with the definition of modelling areas and FCAR areas used in assessing floor and ceiling prices?
3. Do you have any concerns with the methodology used to model floor prices and comparative revenue? If so, please explain your concerns.
4. Do you have any concerns with the methodology used to model ceiling prices and comparative revenue? If so, please explain your concerns.
5. Are there any regions where you consider the comparison of FY23 prices against the floor and ceiling price limits to be surprising? In what way?

Stakeholder responses

A number of stakeholders were concerned that the description of the calculation of floor and ceiling prices was not sufficiently well explained, and sought further detail around:

- the logic for defining FCAR areas, and why the existing pricing regions were not used
- the calculation of floor and ceiling prices
- the availability of the floor/ceiling price model or inclusion of a worked example

FCAR areas were used for the purpose of assessing floor and ceiling prices reflecting that the ceiling price should be applied both at the level of an individual customer and any combination of customers (the combinatorial approach). Accordingly, small groupings of customers were modelled, because the ceiling test is more likely to be exceeded for a group of customers within a geographic area than for an individual customer (and if it is exceeded for an individual customer, it will also be likely to be exceeded for the group). In terms of the definition of the FCAR areas, the intent was to apply groupings of customers within a reasonably tightly defined geographic area that would logically be jointly serviced by a hypothetical new entrant. The existing pricing regions were used as the initial starting point for this approach, with modifications to these groupings applied to ensure that they reflected the above principle.

Further illustration of the methodology for calculating floor and ceiling prices has been provided to assist understanding of the approach. The model contains a range of information that is confidential to Firstgas and its customers, and hence is unable to be provided.

Stakeholders also noted the relatively weak relationship between FY23 prices and floor and ceiling prices, and questioned if this suggested that there is room for reviewing allocations across the regions. We agree that the relationship between FY23 prices and floor and ceiling prices is quite weak, but do not consider that there is an economic case for a consistent relationship to be targeted. The use of efficient pricing principles would suggest that the relationship should be based on price elasticity of consumers, so prices should potentially be farthest from the floor for those customers who have the most expensive alternatives.

Stakeholders questioned our highlighting that the MPOC pricing methodology results in prices being established for Maui pipeline direct connect customers that are well below that which is required under an economic ceiling price constraint, noting that this is the case for almost all regions. They were concerned over the inference that Maui pipeline direct connect users are passing a cost burden onto GTC users. In this regard, we reiterate that the concern we were highlighting is that the MPOC imposes a pricing methodology that – by its definition – will result in prices for direct connect users materially below the ceiling price constraint, without opportunity to vary this methodology to reflect willingness to pay outcomes (either for direct connect users or users that connect via GTC pipelines). This is not the case for the GTC pipelines, where the floor and ceiling price constraints apply without further limitation.

4.2 Customer willingness to pay

4.2.1 Approach

In addition to considering how Firstgas' current transmission charges fall within the floor and ceiling limits; we have undertaken an assessment of the 'willingness to pay' transmission charges for different consumer groups.

In this assessment, the term willingness to pay is used in its economic, rather than commercial, context. If prices exceed a consumer's willingness to pay for transmission services, then it will stop using the service, either to switch to a substitute fuel type or service, or because it ceases operation. Where prices are materially below a consumer's willingness to pay, then it can be considered to have a low sensitivity to increases in tariffs. However, where prices are approaching a consumer's willingness to pay, that consumer will have a high sensitivity to increases in transmission charges.

Importantly, willingness to pay is driven by the gas consumer, and in most instances the final gas consumer is not the Shipper (who may be Firstgas' direct customer). Further, for the most part, willingness to pay must be considered in the context of the total supply chain. In other words, customer willingness to pay relates to the delivered cost of gas, and not transmission charges in isolation, with transmission charges generally constituting less than 20% of the delivered cost of gas. Given this small proportion, a wholesale gas pricing response is likely to be required in order to maintain demand from price sensitive customers. Conversely, if other components of the delivered cost of gas are increasing (eg wholesale gas prices, carbon price) there may be only limited opportunity for transmission pricing to promote demand.

Notwithstanding these limitations, the sensitivity of each consumer/consumer class to a change in transmission tariffs will be a function of several factors, which can be summarised being either levers (those factors which maintain or enhance pricing flexibility) or constraints (those factors which constrain pricing).

Constraints on transmission charges can be expected to arise due to the capacity of gas consumers to absorb price increases or to successfully pass an increase on to its customers, which will be influenced by:

- the availability and cost of alternative energy sources;
- the degree of competitiveness of the final market for the product/service of the gas consumer, including whether this is a domestic market (where they may have the opportunity to pass on increased input costs as higher prices, particularly where other market participants bear a similar increase in input costs), or an export market (where they are likely to have little or no ability to increase prices as a result of increased input costs);
- the significance of the delivered cost of natural gas to the consumer's total cost base;
- current transmission pipeline pricing levels and the contribution of transmission charges to the consumer's delivered cost of gas;
- changes in other supply chain costs (e.g. wholesale gas prices, carbon charges) that either offset or compound any changes in transmission tariffs;
- the characteristics of a consumer's demand, having regard to the services consumed and the terms and conditions that they are subject to; and

- the availability of Government funding to encourage customers to switch away from natural gas.

Levers that can be expected to maintain Firstgas' pricing flexibility include:

- the extent to which the consumer is 'tied' to the use of natural gas, due to the characteristics of its demand, or because of sunk investment in its own assets;
- lack of alternative gas transmission infrastructure, including an economic bypass opportunity;
- the high security of gas supply, which may not be able to be matched by other energy sources;
- lack of, or insufficient access to, alternative energy sources; and
- any contractual arrangements for the transmission pipeline, including any sunk costs incurred by consumers through capital contributions (the more a consumer has invested in sunk capital, the more likely it is tied to the transmission pipeline).

An assessment of price sensitivity (or willingness to pay) must be consumer-specific, recognising the potential for wide variation in demand elasticities. Hence, we have considered consumers either individually, or as groupings of consumers with similar characteristics.

Our ability to accurately assess willingness to pay, and hence demand sensitivity is limited, as an accurate assessment requires access to detailed, commercially sensitive information for each consumer. However, the level of precision required to make a reasonably objective assessment of demand sensitivity is not considered to be high. In saying this, as transmission prices increase, more effort may be required in order to ensure that transmission prices do not exceed the customer's willingness to pay.

As a result, our willingness to pay analysis is based on a qualitative assessment of the constraints and levers applicable to each consumer/consumer group, based on publicly available information. Based on this qualitative assessment, we have categorised consumers/consumer groups as having low, medium or high sensitivity to gas transmission charges. Firstgas should consider the consequences of price changes for customers with high sensitivity, as well as larger customers with medium sensitivity particularly as transmission prices continue to increase over time.

In considering the proportion of the delivered gas price relating to transmission charges, this will necessarily depend upon the specific gas supply arrangements in place for each consumer. While the spot price for gas is transparent, this will not necessarily be a good reflection of the price that is paid under contract (as indicated by the emsTradepoint daily prices compared to average prices published by both the MBIE and Gas Industry Company). We have assumed an average wholesale commodity price for gas of $10 to $12.50/GJ, inclusive of carbon price (currently approximately $4.50/GJ), although gas consumers that are classified as energy intensive, trade exposed (EIT) by the NZ Government receive credits against carbon charges substantially reducing the effect of the carbon price, at least in the shorter term[12]. In FY23, transmission charges for consumers on the GTC pipelines typically fall between $1.50-$2.50/GJ, although consumers directly connected to the Maui Pipeline or to Frankley Road pay under $0.60/GJ. At higher gas prices, transmission charges will reflect a lower proportion of the delivered cost of gas.

Both carbon charges and gas transmission charges are expected to increase significantly over the next five years:

- while changes in the carbon price are uncertain, based on the Climate Change Commission's estimates, carbon prices could more than double by 2030 if New Zealand in order to progress towards net zero by 2050; and
- expected increases in Firstgas' maximum allowable revenue, as indicated under the Commerce Commission's 2022 asset stranding model, indicate that average transmission charges will more than double by 2029, even if demand were to be sustained at current levels, due largely to the effect of accelerated depreciation.

[12] Energy intensive, trade exposed (EIT) industries are granted credits against their carbon charges initially at a rate of 90% reducing by 1% pa from 2020 to 2030, then reducing by 2%pa until 2040, then 3%pa thereafter

4.2.2 Summary assessment

A summary of the conclusions from our assessment of willingness to pay, by consumer segment, is presented in the table below.

Table 11 Summary assessment of consumer willingness to pay gas transmission charges

Consumer segment	Significance of gas transmission charges	Gas substitutes		Input cost pass through options	Transmission substitutes	Gas transmission price sensitivity		
		Short term	Long term			Short term (<4 years)	Medium term (4-10 years)	Long term (>10 years)
Petrochemical feedstock	**Moderate** – gas is a major input cost, however major petrochemical producers are located close to gas fields, with gas transmission charges usually only a small proportion of delivered gas cost.	**None** – no viable short-term substitutes	**Depends upon end use** – some, but not all, petrochemical products can use hydrogen as an alternate feedstock	**Low**– petrochemical exporters have prices set on international markets with no opportunity to pass increases in input costs through to higher prices. Domestic suppliers' opportunity to pass through cost increases is uncertain, given a need to maintain parity with import prices for their end product.	**Possible for some gas demand** – as major producers are located close to gas fields, there may be some option for Firstgas transmission substitutes for some demand.	**Part high, part intermediate** – production is likely to be only moderately sensitive to changes in transmission charges until the need for asset renewal investment, at which point producers will be highly sensitive to delivered gas cost, including transmission charge. Producers will be highly price sensitive where bypass is an economic option.	**Part high, part intermediate** - production is likely to be only moderately sensitive to changes in transmission charges until the need for asset renewal investment, at which point producers will be highly sensitive to delivered gas cost, including transmission charge. Gas substitution options may become viable for some petrochemical producers.	**High** – in long term, asset renewal investments will be required, with producers highly sensitive to delivered gas cost. In longer term, gas substitutes will become increasingly economically viable for some petrochemical producers.
Electricity generators	**Moderate** – gas is a major input cost for gas fired generation, gas transmission charges are generally a small proportion of delivered gas cost.	**Not attractive** – other fossil fuels (coal, diesel) can be used, but higher cost and higher emissions. Biomass may be an option for some.	Likely– New technologies to provide reliable peaking capacity may emerge, e.g. batteries, hydrogen, demand response	**High** – where electricity is required to meet peak demand (and other options are not available), gas generators will enter market at a price that fully reflects cost of gas	**Low –** bypass not viable	**Part high, part low** – the use of gas for baseload generation is becoming increasing uneconomic and has a high sensitivity to gas prices. However, generators will not be sensitive to	**Low –** generators will not be sensitive to transmission prices at times when there are no alternate sources of electricity supply to meet peak demand, and while gas demand will fall as baseload demand	**Low/intermediate –** generators will not be sensitive to transmission prices at times when there are no alternate sources of electricity supply to meet peak demand. They will become more price sensitive

Consumer segment	Significance of gas transmission charges	Gas substitutes		Input cost pass through options	Transmission substitutes	Gas transmission price sensitivity		
		Short term	Long term			Short term (<4 years)	Medium term (4-10 years)	Long term (>10 years)
						transmission prices at times when there are no alternate sources of electricity supply to meet peak demand.	decreases, willingness to pay in peak will remain. However, higher peak gas transmission prices may incentivise more investment in renewable generation.	where there are other technologies for reliable peaking capacity, but a longer timeframe may be required for these to become available at sufficient scale.
Dairy producers	**Low** – gas is a modest input cost for dairy, gas transmission is a moderate proportion of delivered gas cost.	**Limited** – generally not possible to substitute without material investment, focus of sustainability investment on coal dependent South Island sites.	**Partial** – investment to move to biomethane and electricity possible at some sites. Required electricity transmission upgrades mean electricity not likely to be viable for many sites.	**Medium** - as an exporter, prices set on international markets and no opportunity to pass increase in input costs through to higher prices. However, increase in processing costs will effectively be passed back to dairy producers under regulatory framework.	**Low –** bypass not viable	**Low** – given modest significance to overall cost structure and criticality of reliable energy supply, dairy producers are likely to be insensitive to transmission costs in short term.	**Low** – given modest significance to overall cost structure and criticality of reliable energy supply, dairy producers likely to be insensitive to transmission costs. Full or partial substitution options will become viable for some sites.	**Intermediate** – given modest significance to overall cost structure and criticality of reliable energy supply, dairy producers likely to be insensitive to transmission costs. For or partial substitution options will become viable for increasing number of sites and if delivered gas price gets too high, higher cost milk producers may exit the market.
Industrial producers – high temperature	**Low** – gas is generally a modest input cost for industrial producers, and gas transmission is a moderate proportion of delivered gas cost.	**Limited or none** – substitutes not currently able to meet requirements for high temperature heat	**Possible –** long term options may emerge (such as hydrogen) but currently economically unviable	**Low or moderate** – exporters have prices set on international markets with no opportunity to pass increase in input costs through to higher prices. Domestic suppliers may have moderate opportunity to pass through cost increases to consumers.	**Low –** bypass not viable	**Low** – given low significance to overall cost structure and criticality of reliable energy supply, these producers likely to be insensitive to transmission costs in short term. Increases in delivered gas price will increase the incentives to make existing processes	**Low** – given low significance to overall cost structure and criticality of reliable energy supply, these producers likely to be insensitive to transmission costs in short term. Increases in delivered gas price will increase the incentives to make existing processes	**Low/intermediate** – given low significance to overall cost structure and criticality of reliable energy supply, these producers likely to be insensitive to transmission costs in short term. Gas substitution likely to become more

Consumer segment	Significance of gas transmission charges	Gas substitutes		Input cost pass through options	Transmission substitutes	Gas transmission price sensitivity		
		Short term	Long term			Short term (<4 years)	Medium term (4-10 years)	Long term (>10 years)
						more efficient and reduce gas usage.	more efficient and reduce gas usage.	economically viable in long term.
Industrial producers – low temperature	**Low** – gas is likely to be a moderate input cost for most process heat users, with gas transmission a moderate proportion of delivered gas costs	**Limited and partial** – In the very short term, LPG is a viable alternative, but attractiveness depends on relative prices and required investment for storage. In the short to medium term, options involving new boiler investment are available, including electricity and, for larger producers, biomass (assuming adequate supply of fuel).	**Likely –** over the medium to long term, asset renewal programs are likely to mean that electricity is an increasingly viable option for many producers, with biomass also increasingly viable for large producers (assuming adequate supply of fuel).	**Moderate** – many industrial low temperature process heat users will be producing goods for the domestic market and likely to have opportunity to pass through increase in cost, but will be constrained by competition (not always facing same input costs)	**Low –** bypass not viable	**Low/intermediate –** given current price relativity with LPG, low impact of transmission on gas price and moderate proportion of production costs, most low temperature industrial users will have low price sensitivity, unless they are able to access GIDI funding to transition away from gas. However, Government and Local Authority users may be more price sensitive given public pressure to reduce carbon emissions.	**Intermediate –** With higher delivered gas prices and new technologies there will be an incentive to substitute for low temperature heat applications, particularly as asset renewal becomes due.	**High –** with increasing carbon and transmission charges, and likely reducing costs of alternate energy options, changeover to electricity or biomass is more likely, particularly as asset renewal becomes increasingly due.
Commercial	**Low** – for commercial users, gas transmission charges can be a small to moderate component of delivered gas costs, but gas will generally be a relatively small cost input.	**Limited** – LPG and electricity (eg heat pumps) provide substitutes for most commercial consumers, with investment, but will usually only replace appliances as they reach their useful life	**Likely** – users likely to transition to electricity in response to sustainability agenda and carbon pricing unless renewable gas becomes viable	**Moderate** – many commercial users will be supplying the domestic market and likely to have opportunity to pass through increase in cost, but will be constrained by competition (not always facing same input costs)	**Low –** bypass not viable	**Low** - Substitution requires investment in new appliances and fit out, not likely to occur until end of appliance life.	**Intermediate** - Increasing substitution to electricity at end of appliance life. New technologies may create opportunities to substitute in some applications for larger commercials consumers.	**Intermediate/high –** with increasing transmission/ distribution cost and carbon charges change over to electricity more likely at end of appliance life.

Consumer segment	Significance of gas transmission charges	Gas substitutes		Input cost pass through options	Transmission substitutes	Gas transmission price sensitivity		
		Short term	**Long term**			**Short term (<4 years)**	**Medium term (4-10 years)**	**Long term (>10 years)**
Residential	**Low -** For residential users connected via distribution systems, gas transmission charges generally a small proportion of gas costs, although the more material distribution charges will be facing similar cost pressures.	**Limited** – LPG and electricity (eg heat pumps) provide substitutes for most residential consumers, with investment, but will usually only replace appliances as they reach their useful life	**Likely** – users likely to transition to electricity in response to sustainability agenda and carbon pricing unless renewable gas becomes viable	Not applicable for residential market as they are the final consumers.	**Low –** bypass not viable	**Low** - Gas take-up by residential customers remains strong. Substitution requires investment in new appliances and fit out, not likely to occur until end of appliance life.	**Intermediate** - Increasing substitution to electricity at end of appliance life.	**Intermediate/high –** with increasing transmission/ distribution cost and carbon charges change over to electricity more likely at end of appliance life.

Source: Synergies

This assessment establishes several common themes:

- a large number of gas consumers have multiple uses of gas at a site (and some may have multiple sites), and each use – and each site – may have different alternate energy options, meaning that there is no single answer to a consumer's willingness to pay for gas transmission;
- in general, gas consumers have a low sensitivity to gas transmission prices in the short term, as transmission prices continue to represent a low to modest proportion of delivered gas prices, and significant investment is typically required to switch fuel sources. There are, however, some larger gas consumers at sites with particularly good alternate energy supply options for low temperature heat, who may be sensitive to gas transmission charges;
- a potential exception is for large petrochemical users located close to gas production, where their high volumes and short transmission distances may mean that transmission bypass is viable, which may make them more sensitive to transmission prices;
- many gas consumers are weighing up opportunities for alternate fuel supplies, driven by a sustainability/climate change agenda, although our consultation with gas consumers indicates that it is unlikely that they will move away from gas until it is clearly economic to do so;
- in the medium term, expected significant increases in transmission charges and increasing carbon charges is likely to increasingly make substitute fuel sources commercially viable, raising consumer sensitivity to transmission charges. In the longer term, technological change may create viable substitute energy sources for high value gas uses, which would further increase price sensitivity to transmission charges.

This assessment is broadly consistent with Concept Consulting's estimates of future gas demand as presented in Figure 3:

- in the short term, there will be a significant decline in gas demand for electricity generation as new renewable capacity comes online and gas generation is increasingly used for peak demand;
- however, for other uses, the short-term decline in gas demand is expected to be modest but gather pace in the medium term beyond five years. This will arise either from a transition to alternate fuels, as industrial equipment and consumer appliances require replacement and alternate fuel sources become increasingly cost

attractive, or from some industrial users' increasing energy costs leading them to close down operations in New Zealand;

- notwithstanding this, there is a range of applications where gas is strongly preferred and is likely to be retained in the longer term. Gas demand is likely to continue at a lower volume, but for use in higher value applications.

This assessment therefore indicates that:

- in the short to medium term, there should be limited need to provide discounts to standard gas transmission charges, as increasing transmission charges are unlikely to drive significant reductions in demand for natural gas within this timeframe;
- there is likely to be a high, and increasing, value placed on gas as a variable source of energy, particularly for electricity generation, indicating that there may be opportunity to charge a premium for providing a more variable gas supply service; and
- in the medium to longer term, demand for natural gas and therefore transmission services will reduce as substitute fuels become more available and commercially viable. It is unlikely that the medium to long term decline in gas use can be avoided by maintaining or reducing transmission prices, given Government policy is aimed at increasing the cost of natural gas in order to incentivise users to move to alternative energy sources. However, constraining the extent of transmission price increases applied to vulnerable demand may help to support overall demand, particularly as opportunities for renewable gases are being developed.

Firstgas has been active in investigating alternative gases for their gas pipeline system. In 2021, studies began into a trial of hydrogen as replacement for natural gas within the Firstgas network, aimed to commence this year. Based on its preliminary studies, the Firstgas group has announced a target of 20% blended hydrogen in their network by 2035, with a move to 100% hydrogen possible by 2050[13]. For 100% hydrogen to become a reality, existing appliances would need either to be converted or be replaced. Firstgas anticipate that most of the equipment would be replaced during its natural retirement cycle if the network were converted to 100% hydrogen.

Firstgas has also been investigating biomethane supply and its use in its transmission and distribution networks. Biomethane has significant benefits over hydrogen in that there is no need to make any changes to the operation of either its transmission or distribution networks or consumers appliances. The main issue for biomethane will be

[13] https://gasischanging.co.nz/assets/uploads/Firstgas-Group_Hydrogen-Feasibility-Study_web_pages_R1204.pdf

the collection of enough feedstock to generate the amount of gas required. This points to either blends of biomethane and hydrogen or using different parts of the networks to deliver different gases.

An issue for the petrochemical plants and some of the larger industrial customers is that hydrogen or hydrogen - natural gas/biomethane blends may not be suitable for their processes. This will need to be considered as Firstgas continues to explore the transmission of renewable gas through its pipeline network.

These movements towards the transmission of alternate resources will support the long-term use of the gas transmission network in the face of increasing carbon charges.

Box 5 Stakeholder consultation – willingness to pay

Stakeholder questions

1. A number of factors have been identified that can be expected to either constrain or maintain a consumer's willingness to pay gas transmission charges. Do you consider these factors to be reasonable? Do you think that there are other factors that need to be considered?
2. The consumer base has been broken into a number of consumer segments, having regard to end use market and available substitution options. Is this categorisation reasonable? Are there other categories that should be separately considered.
3. Have the relevant substitution opportunities for each consumer segment been reasonably identified? Is the timeframe for these opportunities reasonable?
4. Are there any consumer segments where you consider the assessment of gas transmission price sensitivity within the nominated timeframes to be surprising? In what way?
5. The report identifies several common themes from the willingness to pay analysis. Do you have any comments or concerns with these overarching themes?

Stakeholder responses

Stakeholders provided feedback on a range of issues including:

- factors that constrain gas transmission prices, including availability of Government funding to transition away from gas
- factors that enhance flexibility in gas transmission prices, including consideration of security of supply of gas versus alternative energy sources
- specific comments on our assessment of the sensitivity of different consumer groups to changes in gas transmission charges.

These have been reflected as amendments in the final report. However, these changes have not altered our general conclusions and common themes arising from the willingness to pay analysis.

5 Tariff design considerations

5.1 Recommended pricing directions

New Zealand's energy transition will result in fundamental changes for Firstgas, in particular:

- demand for natural gas will significantly decline over time; and
- low emission gases will progressively be developed and injected at locations across the Firstgas transmission system rather than just Taranaki.

In this section we identify the broad pricing directions that will be more appropriate in this future environment.

5.1.1 Standard tariff structures should be developed to more closely align to value of service

The application of standard tariffs can be an effective means of ensuring that customers are treated fairly and make a reasonable contribution to the total costs of the pipeline network. However, the approach to developing these standard tariffs must have regard to the demand environment in which the business is operating. For example:

- in an environment where capacity is scarce and there is potential demand for expansion, standard prices be established so as to effectively ration scarce capacity and provide efficient signals for expansion. In this case, it would be reasonable to set standard tariffs to reflect the cost drivers for developing or expanding the network;
- in an environment where the cost of providing services is well below the aggregate willingness of consumers to pay, it may be reasonable to establish standard tariffs wholly or substantially based on a fully allocated cost of providing the service, if pricing on this basis is unlikely to deter demand.

However, neither of these environments apply to Firstgas transmission. Instead: demand has declined in recent years and is expected to continue to do so; there is ample capacity on most transmission pipelines at present and given declining demand this is expected to continue to be the case. There are concerns that the resulting increases in prices will, over time, exceed some consumers' willingness to pay, leading to demand destruction.

In this environment, it will be increasingly important that standard tariffs are set with regard to the value that the service provides to consumers – that is, their willingness to pay for the service. Developing standard tariffs based wholly or substantially on a fixed cost allocation approach will not provide effective pricing signals, as the vast majority of costs are fixed and/or sunk, and different usage decisions by consumers have little if any direct impact on them. However, this is likely to result in prices for some users, particularly those at the extremities of the network, exceeding their willingness to pay, while prices for centrally located users may remain significantly below their willingness to pay. Further, this will not necessarily result in the development of prices that are perceived to be fair, as users at the extremities of the network will need to pay a high cost for those pipeline sections with only few users, but still would need to make the same proportional contribution to the highly utilised sections as more centrally located customers.

Instead, aligning standard tariff structures to value of service drivers will apply higher prices to those users who place the highest value on the service, and for those users for whom gas transmission provides lower value will assist in keeping standard tariffs within their capacity to pay. In turn, this will assist in maintaining overall transmission demand. Provided that the lower value users are making at least some contribution to fixed costs, higher value users will face lower prices than would be the case if demand were to reduce.

Therefore, we recommend that standard tariff structures and price paths be developed having regard to the value of the service (or the willingness of consumers to pay transmission charges), while also continuing to ensure that they comply with the cost-based floor and ceiling limits. Supplementary agreements may also have a role in tailoring charges where the standard tariffs exceed consumers capacity to pay but ideally should be used in clearly defined circumstances, for example:

- tariffs should only be discounted where this is considered necessary to retain demand;
- any discounting of standard tariffs to retain demand should, where feasible, be accompanied by a commitment for continued usage of the transmission service over a longer term.

Further, if there is a high demand for supplementary agreements to avoid loss in demand, this indicates that the standard tariffs are not effectively aligned with the value of service and may need to be reviewed.

Our assessment in section 4.2 shows that willingness to pay does not appear to be a significant constraint on current transmission charges in the short term, except potentially for the large petrochemical producers in the Taranaki area. This means that Firstgas does not need to immediately adjust standard prices to minimise demand loss.

However, with above CPI price increases in MAR combined with expected falling gas demand, rising transmission prices may begin to constrain demand. As discussed in section 4.2, some types of gas consumers are likely to be more vulnerable than others. Therefore, Firstgas can apply a phased transition to standard price structures that, over time, will increase the relative charge for higher value uses (where price increases are less likely to constrain demand).

While value of service (willingness to pay) is largely a function of each customer's business requirement for gas, there are some broad relationships between willingness to pay and usage characteristics, which can be used to structure Firstgas' standard pricing. The key directions that we consider will promote alignment between standard tariffs and value of service are discussed below.

Box 6 Stakeholder consultation – aligning standard tariffs to value of service

Stakeholder questions

1. The report concludes that all gas consumers will ultimately be better off if gas transmission prices are increasingly set to reflect the value of the service (willingness to pay), rather than cost allocation, in order to maintain demand and some contribution to costs from vulnerable consumers. Do you agree? If not, why not?
2. Do you have concerns with the recommendation that standard tariff structures be developed that, over time, are aimed to more closely align with value of service (provided they remain compliant with floor and ceiling limits)?
3. How important a role do you consider supplementary agreements to have in tailoring charges to retain demand?

Stakeholder response

Stakeholders generally accepted that standard tariff structures need to be developed to reflect the value of service, with supplementary agreements having an important role in tailoring charges to retain demand. It was observed, however, that an increasing requirement to use supplementary agreements is an indicator that the standard tariffs are not effectively aligned to the value of the service and may need to be reviewed. This view has been reflected in the final report.

Stakeholders also reiterated the need for transparency around the use of supplementary agreements to retain demand. Firstgas has confirmed that it maintains clear policy guidelines governing the development of supplementary agreements, which are available on its website. This policy is reviewed periodically to ensure it remains fit-for-purpose. Further, since 2014, all supplementary agreements have been published. We consider that these arrangements provide a high degree of transparency around the circumstances in which supplementary agreements are used, consistent with stakeholder preferences.

Relationship between tariff and transmission distance

At present, natural gas is produced solely from gas fields in the Taranaki region, with delivery points located throughout the transmission system. Increased transmission distance from the Taranaki region is substantially correlated with the cost of network development, given the high fixed pipeline cost associated with increased distance.

However, in the future as renewable gases are developed, these will be injected at other points within the transmission system reflecting the location of the underlying fuel source. Renewable gas producers will contract with gas retailers or gas consumers across the transmission network. A feature of gas transmission is that all gases injected into the network are interchangeable, so it is not necessary, or indeed possible, to physically ship any particular gas in line with the commercial arrangements between the buyer and the seller.

Over time, an increasing volume of gas is likely to be injected into the transmission system from outside the Taranaki area. This will not only result in a blurring of the relationship between the geographic location of a delivery point and the cost of providing the transmission service but also raises the importance of how transmission charges should be differentiated between gas receipt points.

For most gas consumers, transmission distance does not correlate with value of service (and hence willingness to pay). For example, the value of gas used in dairy processing is primarily driven by the end value of its products. While the geographic location of a delivery point will impact the cost and availability of substitute fuel sources, and these options will differ for a user in a remote location than a user in a central location, this is unrelated to the distance that gas travels on the Firstgas transmission system. In other words, the value of the transmission service is unlikely to significantly vary with changes in transmission distance.

This will be increasingly the case as renewable gases are injected at distributed locations across the transmission system. The value of that gas to a consumer will not vary depending upon the geographical location of the gas producer. Similarly, the cost of the transmission system is unlikely to change. Differentiating transmission charges according to the geographic location of receipt and delivery points will instead limit the market for each renewable gas producer and reduce liquidity in the market for renewable gases. A gas swaps market may then emerge in order to enable consumers to minimise their gas transmission charges.

This indicates that there is economic merit in generally applying a flattened relationship between standard tariffs and distance, and for this relationship to flatten further as the injection of renewable gases at distributed locations across the transmission system increases.

A more important aspect of the geographic location of a delivery point may relate to the cost and availability of substitute fuel sources in that area. For example, electricity provides a clear substitute for many gas users in a large urban area such as Auckland. However, in regional areas electricity costs may be prohibitive if it is necessary to extend and expand the electricity transmission network, but biomass may be an effective substitute for larger gas users, particularly in some locations with access to large biomass sources. As a result, there may be benefit in retaining flexibility in the development of standard prices to enable some geographical variation to reflect the cost and availability of substitutes in that area.

From an economic efficiency perspective, there is no requirement for distance to be reflected in prices beyond ensuring that the floor and ceiling price constraints continue to be met for all users. For so long as gas is largely injected into the transmission system from the Taranaki area, from a perceived fairness perspective, it may be desirable to ensure that, on a particular pipeline route (e.g. on the Bay of Plenty pipeline) more distant delivery points continue to pay no less, in $/GJ terms, than those with a shorter delivery distance. However, as over time gas is increasingly injected at distributed points throughout the transmission system, the rationale to apply distance-based differentiation of charges will diminish. A 'postage stamp' approach, where the same transmission charge applies regardless of gas receipt and delivery point, may ultimately be the most efficient pricing approach.

Reflecting these considerations, we recommend that Firstgas pursue a broad pricing direction that:

- for renewable gases, applies a single flat rate across the transmission system (regardless of receipt and delivery point) in order to encourage the sale of renewable gases across the transmission system;
- for natural gas, applies a flattened relationship between the standard tariff and distance, provided that:
  - the floor and ceiling price constraints continue to be met by all users; and
  - while most gas continues to be produced within Taranaki, more distant delivery points on a particular pipeline route continue to pay no less, in $/GJ terms, than those with a shorter distance;

  however, such price adjustments should only be introduced gradually over time, to limit price shocks for centrally located consumers in circumstances where it is not necessary to support demand from more distant consumers; and
- retains flexibility in the development of standard prices to enable some geographical variation to reflect the value of the typical use of gas in that area.

Box 7 Stakeholder consultation – relationship between tariffs and distance

Stakeholder questions

1. Do you agree that, where value of service is generally unrelated to transmission distance, 'flattening' the relationship between transmission distance and price will better align prices to value of service? If not, why not?
2. In order to maintain fairness in charging, the report proposes that, while most gas continues to be produced within Taranaki, more distant delivery points on a particular pipeline route continue to pay no less, in $/GJ terms, than those

with a shorter distance. Do you consider this to be reasonable? Do you think that other constraints should be applied? If so, what other constraints are appropriate?

3. The report concludes that the interest of consumers overall are promoted by de-linking transmission charge and receipt points. Do you agree?
4. How else do you consider that transmission charges should be set for renewable gases injected at locations across the transmission system)?

Stakeholder responses

While stakeholders did not disagree with the proposition that value of service is generally unrelated to distance and that there may be merit in flattening the relationship between tariff and distance, they were cautious about how far this should go for natural gas transmission. There was a view that some distance basis is appropriate to provide signals to new demand that connecting closer to gas sources is economically beneficial.

Concerns were also raised about how quickly such changes could be introduced – the final report highlights that changes should only be introduced over time to limit price shocks for centrally located consumers in circumstances where it is not necessary to support demand from more distant consumers.

There was some stakeholder support for transmission pricing arrangements that supported the introduction of renewable gases into the transmission system, including through use of a flat transmission charge (regardless of receipt and delivery point), possibly at a short term discount to natural gas.

Relationship between tariff and usage requirements

The following table presents a summary of our assessed price sensitivity of different consumer groups to changes in gas transmission charges and their value of availability of gas peaking capacity.

Table 12 Price sensitivity of gas consumers

			Price sensitivity		
User	**Load factor**	**Value of peakiness**	**Short term (<4 years)**	**Medium term (4-10 years)**	**Long term (>10 years)**
Petrochemical producers	Flat	Low	Part intermediate, part high	Part intermediate, part high	High
Electricity generator	Peaky	Very high	Low	Low	Low
Industrial - dairy	Counter cyclical	High	Low	Low	Intermediate
Industrial – high temperature	Intermediate	Intermediate	Low	Low	Part low, part intermediate
Industrial – low temperature	Flat or intermediate	Low or intermediate	Low	Intermediate	High
Commercial/ residential	Peaky	High	Low	Intermediate	Intermediate/ high

Source: Synergies

This shows that there are very significant differences in the price sensitivity of consumers according to the end market in which they operate and their usage requirements, including their requirement for gas peaking capacity.

For electricity generation, renewable generation sources provide a very attractive alternative for baseload electricity generation, with gas quickly transitioning away from providing baseload capacity to peak capacity. In future, gas will only be required for electricity generation where renewable (lower cost) generation is insufficient to meet demand, and electricity prices rise to fully reflect the costs of gas fired peak generation. Accordingly, the use of gas for peak electricity generation can be expected to be both strongly variable, and of particularly high value (noting that at some point, generators may invest in additional renewable generation capacity or in electricity storage assets as an alternate to gas peaking capacity).

Industrial users are less extreme in their usage variability, but many will place a lower value on their gas use, given their options for alternative fuel sources and/or constraints on their ability to pass increased costs through to their end markets. There appears to be a general correlation between price sensitivity and the variability of a consumer's usage, and that for those consumers with a peaky demand, there is typically a high value attributable to their peak demand. Some large industrial gas users are likely to transition to alternative fuel sources for part of their demand but retain access to reticulated gas for some uses or as a backup (variable) fuel source. As is the case for electricity generation, this increasingly peaky demand will be the higher value components of their demand.

In contrast, petrochemical producers have a very flat gas demand profile, and over the medium term are likely to be sensitive to the delivered cost of gas, given its significance to their total production costs.

There is a limited direct relationship between the variability of a consumer's demand and the cost of providing the gas transmission service, in that to meet a peakier demand, greater pipeline capacity is required (i.e. diameter of pipe) and more compression may be necessary to manage the load. However, the relationship between variability and value is likely to be stronger than the relationship between variability and cost, with users gaining a clear value from being able to draw potentially large volumes of gas for short periods on a variable and less predictable basis.

Reflecting these considerations, we recommend that Firstgas pursue a broad pricing direction that differentiates charges according to the value of the gas usage. Options for doing so include either or both:

- Differentiating transmission charges according to customer category. In the short term, the priority would be to consider the transmission charges applicable for electricity generators, who are rapidly moving their demand towards a highly variable, high value use, however other customer classifications could also be applied (eg petrochemical users, large industrial users and commercial/residential users); and/or

- treating usage variability as a proxy of end use value, and applying a higher price for more variable use (and increasing this premium over time, as overall gas demand reduces, but the remaining demand becomes increasingly peaky).

However, such price adjustments should only be introduced gradually over time, to limit price shocks for peaky, or otherwise high value consumers in circumstances where it is not necessary to support demand from other consumers. This is particularly the case as it is difficult to assess the strength of the relationship between demand variability and value based on currently available information. Introducing any changes gradually will enable Firstgas to capture additional information on the demand response of such customers to more gradual increase in charges, to avoid triggering unexpected demand loss.

Box 8 Stakeholder consultation – relationship between tariffs and usage characteristics

Stakeholder questions

1. The report concludes that there is a correlation between usage variability and willingness to pay (value). Do you agree that usage variability can be a reasonable proxy indicator for value? If not, why not?
2. How important to you consider interday (seasonal) or intraday variability to be as a proxy indicator for value?
3. Do you think that there are other usage characteristics that can provide a proxy indicator for value?
4. Do you consider that differentiating transmission charges according to customer category would be a more effective way of targeting value?

Stakeholder responses

While stakeholders did not disagree with the proposition that there is a relationship between value of service and peakiness of demand, they highlighted that the strength of this relationship was unclear and would vary between industry sectors. Accordingly, they urged caution in placing too great a weight on this relationship and highlighted that excessively penalising peaky demand may lead to unexpected changes in consumption patterns, potentially leading to an incentive to discontinue gas use at critical junctures. For example, in electricity generation, this could lead to withholding generation capacity (and further increasing electricity prices), or alternately purchasing of hedges from other generators.

Stakeholders also cautioned against basing assessments of variability on a small number of peaks, as this may not reflect usual usage patterns and value relationships.

We agree that it is difficult to assess the strength of the relationship based on the current analysis, and that any price adjustments targeting more variable demand should only be introduced gradually over time, to limit price shocks for peaky consumers in circumstances where it is not necessary in order to support demand from other consumers, and to allow Firstgas to capture information on the demand response relationship to any increase in charges.

There was a stakeholder's suggestion that another proxy for value that could be considered is consumer willingness to take renewable gas. We consider that this option may have some merit in the longer term but could not practically be implemented in the short term given the very shallow and preliminary nature of the market for renewable gases.

5.1.2 Compliance with cost-based pricing limits

Compliance with the floor and ceiling cost limits, both on an individual and combinatorial basis, is fundamental to ensuring economically efficient transmission charges that are 'subsidy free'. On a practical level, it is also the minimum requirement for the 'fair' treatment of customers.

At present, our modelling indicates that prices in the Bay of Plenty – Gisborne area may not meet the floor price constraint. However, as gas demand continues to contract, it is possible – and even likely - that other geographic areas will emerge as potentially failing the floor price constraint. The Central South and Te Awamutu areas are close to failing the floor price test, but all areas that fail the floor plus price test should be closely monitored.

Where Firstgas has concerns over whether revenues in an area will fail to meet the floor price test (as may currently be the case in the Gisborne area), Firstgas should:

- closely examine the avoidable costs of providing gas in this area, together with incremental benefits that the area offers to the system overall, and adjust prices and/or service offerings for these delivery points to ensure that, at minimum, avoidable operating costs are met; and
- in order to avoid the asset stranding risk associated with further investment in marginal areas, asset renewal capex should be considered on a case by case basis and only implemented if users are prepared to pay a price that recovers these costs.

By closely monitoring the floor price constraint, Firstgas can ensure that, as gas demand reduces, it adjusts the scope of its system coverage to reflect the economic demand for gas transmission services.

While our modelling indicates that Firstgas is not currently breaching its ceiling price for any group of users, Firstgas should monitor revenue against the ceiling price for delivery points in the combined Greater Auckland/Huntly area, to ensure that the ceiling price constraint continues to be met.

Implications of two Codes and MPOC pricing constraints

The pricing methodology specified in Schedule 10 of the MPOC constrains prices in two ways:

- first, it limits the total revenue that can be recovered from MPOC charges to an amount that reflects the return on and of the estimated value of the Maui Pipeline assets[14] and the Maui Pipeline operating costs; and

[14] The MPOC specifies that the assets will be valued at their Optimised Depreciated Replacement Cost.

- then requires that this be applied on a 'cost allocation' basis to all gas transported on the Maui pipeline (with capital charges applied on a $/GJ.km basis and operating costs applied on a $/GJ basis, where GJ refers to the approved nominated quantity of gas).

The first of these constraints aligns with the ceiling price concept, in that the revenues earned from an asset should not exceed the full economic cost of providing the asset. However, the second of these constraints imposes a cost allocation method for determining user charges and requires Firstgas to charge the same tariffs to all delivery points, where an interconnection with a GTC pipeline is treated as a delivery point for pricing purposes.

However, even without this specific pricing methodology, the existence of two separate Codes for the Maui and GTC pipelines requires separate charges to be determined for the Maui and GTC pipelines. This constrains Firstgas' ability to develop standard tariff structures across its fully integrated pipeline system that have regard to floor/ceiling prices, value of service and willingness to pay, as described above.

In particular, the current Code structures require that same price is applied on the Maui pipeline component of Firstgas' transmission system regardless of whether, and the extent to which, gas requires further transportation on a GTC pipeline. The requirement that all users pay the same two part tariff for this central trunk segment of the pipeline reduces the prices applied to consumers who are directly connected to the Maui pipeline, but increases the burden of cost recovery imposed on GTC pipeline users, who must pay prices that recover the cost of the GTC pipeline as well as pay the same two part tariff as a contribution to the Maui pipeline costs. This has the effect that Maui pipeline direct connect customers pay significantly lower transmission charges than GTC customers with a similar gas transmission distance, regardless of the value of the service or their willingness to pay.

Notably, Schedule 10 of the MPOC states that this pricing methodology is intended to reflect 'the standard practice adopted by utilities businesses in New Zealand'.[15] However, our review of pricing principles typically adopted in regulatory regimes (Appendix B) shows that regulatory pricing principles do not usually specify that prices be determined by using a cost allocation approach. Moreover, we have not identified any other regulatory framework that specifies an approach for determining prices applicable to an individual geographic segment of a network business in a similar way.

15 Maui Pipeline Operating Code, Schedule 10.

The development of efficient prices requires an integrated approach to pricing across the Maui and GTC pipelines. It will be necessary to explore the options of how this can most effectively be achieved, and whether removal of Schedule 10 of the MPOC, together with the ability to apply non-standard prices to GTC users would be sufficient, or whether further Code changes would also be required.

Box 9 Stakeholder consultation – compliance with cost-based limits

Stakeholder questions

1. Do you agree that an integrated approach to pricing across the Maui and GTC pipelines will most effectively support the development of efficient prices? If not, why not?
2. Do you consider that there is a benefit in retaining the MPOC pricing methodology? If so, what is the benefit?

Stakeholder responses

Stakeholders had mixed views on the issues around the MPOC. There was some strong support for the view that an integrated approach across the Maui and GTC pipelines is necessary to support the development of efficient prices. Reflecting this view, there was also some strong support that the MPOC pricing methodology should be removed, noting that the original Maui contracts have long expired, and the basis for pricing arrangements in those original contracts no longer applies to the current market circumstances. It was also highlighted that, as the Firstgas MAR increases, the disparity between the MPOC and GTC pricing principles is likely to become more stark.

However, other stakeholders support the continuation of the MPOC pricing methodology, citing its importance in ensuring that MPOC tariffs should only recover costs directly associated with the assets and operation of the Maui Pipeline. In this regard, we reiterate that this principle is consistent with the ceiling price concept, and that there is no suggestion that Maui pipeline charges should be recovering GTC pipeline costs. The most significant constraints on efficient pricing posed by the MPOC is in the specification of the required tariff structure, and the absence of opportunity for supplementary agreements.

Stakeholders supported amendment to the MPOC to introduce the opportunity for negotiation of supplementary agreements.

5.1.3 Reduce perceived barriers to ongoing gas use

In an environment where gas demand is expected to decline over time as climate change objectives are pursued, it will be important for Firstgas to reduce any perceived barriers to continued gas usage, particularly by industrial customers who contribute materially to transmission demand, as this may assist in delaying the loss of gas transmission volumes.

Based on the results of our consultation with customers, options that may assist in reducing perceived barriers to ongoing gas usage include:

- reducing the requirement for customers to commit to capacity. The reducing demand for gas, and the apparent absence of capacity constraints, suggests there is little (if any) need for consumers to reserve capacity in order to ensure that they can secure transmission capacity for their gas demand. While capacity reservation can also be an effective means of addressing Firstgas' revenue risk, the capacity reservation fees as currently applied provide only limited revenue protection for Firstgas. Capacity reservations are only made for a 12-month period, and Firstgas' revenue risk over a 12-month period is largely managed under the regulatory revenue cap[16]. However, while there is ample pipeline capacity, customers continue to be required to reserve capacity in order to avoid being charged much higher transmission overrun charges. As a result, it is perceived by customers that Firstgas is applying commercial constraints on higher gas usage, particularly variable and peak gas usage, where no physical constraints exist;

- reduction in the fixed costs of gas usage. This is linked to the requirement to commit to capacity, where a substantial annual capacity reservation charge is applied to a customer's reserved maximum daily quantity (MDQ);
- increased simplicity in tariff structures and ancillary charges and reduction in the resources required to administer gas transmission arrangements. This includes greater transparency and predictability in gas balancing and cash-out costs.

Box 10 Stakeholder consultation – reduce barriers to gas use

Stakeholder questions

1. Do you consider that the requirement to commit to capacity reservation, and the related overrun fees for usage in excess of reservation, creates a barrier to gas use?
2. Are there other areas where you consider that gas transmission charges could helpfully be simplified?

Stakeholder responses

There was stakeholder support that the requirement to reserve capacity, pay fixed reservation fees and capacity overrun charges, creates an artificially high marginal cost for small peak levels of gas consumption, and potentially leads to uneconomic actions to avoid those charges.

Stakeholders also noted that customers prefer to have a fixed price per GJ of gas delivered, not a changeable price that depends on actual usage in the way that the fixed plus variable structure applies. They also highlighted that high overrun fees can cause them to curtail gas use in excess of reserved capacity.

5.2 Tariff reform assessment criteria

The extent to which a specific pricing structure aligns with the key pricing directions discussed in section 5.1 will determine how effectively it supports efficient and sustainable prices into the future. Reflecting this, we have developed the following criteria for assessing tariff reform options, designed to assess the consistency of a tariff option both with the recommended pricing directions and with Firstgas' pricing objectives. In developing these criteria, we have assumed that, under all pricing structures, Firstgas is able to set prices that allow it to earn the allowable revenue

[16] Capacity reservation charges are fixed income for Firstgas, and reduce the risk of revenue under-recovery, hence limiting the requirement to rely on subsequent revenue cap adjustments. In the absence of capacity reservation charges, there is potential for larger actual under or over recovery of revenue, although over time the revenue cap framework will enable Firstgas to adjust future revenues to pass through the impact of any under/over recovery.

established under the Default Price Path Determination in the short to medium term, but that different price structures will be more or less effective in achieving its other pricing objectives as well as our recommended key pricing directions, thereby supporting gas demand over the longer term. This will ultimately be critical in order that Firstgas can sustainably set tariffs consistent with the Default Price Path Determination over the longer term.

Regardless of the tariff reform option adopted, supplementary agreements may have a role in tailoring charges where the standard tariff exceeds a consumer's capacity to pay, and minimising loss in demand.

Our tariff reform assessment criteria are:

(a) **Enabling prices to be flexibly adjusted to align with cost-based pricing constraints**.

Where Firstgas has concerns over whether revenues in an area will fail to meet the floor price test, Firstgas should closely examine the avoidable costs and incremental benefits of providing gas in this area and adjust prices and/or service offerings for these delivery points to ensure that the floor price is met. Flexibility in adjusting prices and/or service levels within a geographic area will be important to achieve this. This criterion is consistent with our recommendation that prices comply with the floor-ceiling constraints, as discussed in section 5.1.2 and with Firstgas' objectives that prices promote economically efficient outcomes and provide fair outcomes for customers.

(b) **Enabling the application of limited but flexible geographic price differentiation**.

A price structure that enables limited, but flexible, geographic price differentiation reflects that, currently, geographic distance from the Taranaki based production fields is not a significant driver of willingness to pay, and that only limited differentiation is required to ensure floor and ceiling prices are met. However, this becomes more important as renewable gases are increasingly injected into the transmission system at distributed locations outside of Taranaki. This criterion is consistent with the first element of our recommendation that standard prices are developed to reflect value drivers, as discussed in section 5.1.1, and with Firstgas' objectives that prices promote economically efficient outcomes, avoid demand destruction and 'future proof' Firstgas' pricing methodologies.

(c) **Enabling price differentiation for user value**.

This will be best achieved by a price structure that either directly enables differentiation between different value gas uses, or one that enables price differentiation for variable or peak gas transmission on the basis that variable or peaky demand is correlated with higher value gas use. This is consistent with the second element of our recommendation that standard prices are developed to reflect value drivers, as discussed in section 5.1.1. It is also consistent with Firstgas' objectives that prices promote economically efficient outcomes, avoid demand destruction and 'future proof' Firstgas' pricing methodologies.

(d) **Reducing fixed costs and complexity for customers**.

A standard price structure that reduces the requirement for capacity commitment and fixed costs reflects the first two identified barriers to ongoing gas use, as discussed in section 5.1.2, and is consistent with Firstgas' objectives that prices promote fair outcomes for customers and avoid demand destruction. Provided that the revenue cap form of regulation is maintained, removing fixed costs and capacity commitment will not undermine Firstgas' ability to earn the revenue set under the Default Price Path Determination.

Reducing complexity reflects the third barrier to ongoing gas use, as discussed in section 5.1.2, and is consistent with Firstgas' objective to simplify prices wherever possible.

(e) **Ease of implementation**.

Different price reform options will have different implementation issues. The most significant factors that will impact the complexity of implementation issues include whether, and the extent to which:

- changes are required to either, or both, the MPOC and the GTC, with code changes requiring significant customer consultation and, in the case of the MPOC at least, GIC approval;
- changes would require amendment to the operational provisions of either or both Codes, particularly in relation to nomination processes, noting that there may be significant costs to implement required systems changes; and
- significant price changes are likely for some or all customers, with the required consultation arrangements increasing as the magnitude of changes increases (particularly if unfamiliar price structures are proposed) and if the price changes are likely to result in substantial winners and losers amongst the customer base.

As discussed in section 5.1.1, there does not appear to be any immediate imperative to adjust Firstgas' transmission tariffs to avoid demand loss. This means that there is opportunity to implement tariff reform in a phased transition from current pricing levels to the preferred long-term tariff structure. The ability to accommodate a transitioned implementation will therefore be a key consideration for this criterion.

5.3 Evaluation of tariff reform options

5.3.1 Identified tariff reform options

We have identified several broad tariff reform options, including some options raised by customers during our consultation process, as well as options that we have identified as potentially aligned with the recommended pricing directions as summarised in the table below. Note, references to zonal charges are intended to be interpreted at a conceptual level only, and do not refer to the specific zones currently used under the GTC for the assessment of MDQ and overrun charges.

Table 13 Identified tariff reform options

Option	Description
1. Current tariff structures	Continued application of current tariff structures for the Maui and GTC pipelines, with the value of GTC tariff components modified where appropriate to reflect recommended broad pricing directions.
2. Fully variable tariffs for all transmission pipelines	All charges would be applied on a fully variable ($/GJ) basis (using approved nominations for the Maui pipeline and delivery quantity for GTC pipelines).
3. Partial capacity-based tariffs for all transmission pipelines	All charges would include a regionally specified $/GJ/day capacity use charge as well as a $/GJ throughput charge (using nominated quantities for Maui pipeline and actual quantities for GTC pipelines) Capacity charge could either be determined (a) using customer-specified volumes, in which case overrun charges would be necessary to encourage accurate specification (similar to current GTC charge structure) (b) using previous year's maximum volumes, with no requirement to apply overrun charges.
4. Fully variable tariff for all transmission pipelines with load factor multiplier	All charges would be applied on a fully variable ($/GJ) basis (using nominated quantities for Maui pipeline and actual quantities for GTC pipelines) and include the following elements: • a regionally-specified base throughput charge • a load factor multiplier, based on the customers maximum use relative to average use Load factor multipliers could be determined and applied on either a daily or hourly basis.
5. Differentiate charges by consumer segment	Differentiate regionally-specified charges by user segment either defined by: • categorising users according to the nature of the consumer's business. Initially a minimal categorisation of 'electricity generators' and 'other uses' could be applied, with a premium applied to transmission prices for 'electricity generators' reflecting highly variable and high value usage. However additional categorisation of 'other uses' could potentially be considered, breaking this into further categories of petrochemical, large industrial (>10TJ) and residential/commercial • categorising each shipper at each delivery point according to their usage characteristics (eg highly variable large volume, highly variable small volume, low variability). • This would allow a simple $/GJ charging structure to be applied within each group, although the charging structure could reflect any of the other tariff reform options, if preferred.

Source: Synergies

In assessing pricing options, under any change to the current tariff arrangements, we have described and assessed these options assuming an efficient application, that is, assuming that the MPOC (and GTC where required) are changed to enable implementation as described. There is an option for a simpler implementation to be achieved by reducing the extent of change to the MPOC, however in each case this will be at the expense of achieving more efficient long term pricing outcomes.

Further, in developing these tariff reform options, we also considered a range of additional tariff options. However, our initial review did not indicate these options would have enough merit, hence we have not taken them to the evaluation stage. Tariff options that fell into this category included:

- full capacity-based charges, either on a $/GJ/km/day or a regional structure (with region being a proxy for distance). This option implies the use of an overrun charge to make the capacity charge meaningful. This tariff structure was considered likely to exacerbate the concerns with the existing GTC tariff structure, with little benefit in terms of aligning standard prices to value of service.
- declining or inclining block tariffs, as typically used for distribution charges. In gas, the blocks typically decline to reflect economies of scale. Electricity charges also used to typically be declining but in some cases this is reversed to provide a price signal for peaky energy consumption associated with air conditioning and late afternoon/early evening weekday peak demand. This tariff structure is not commonly used in transmission and is likely to have the effect of penalising small customers. It is unlikely to be an effective strategy for aligning standard prices to value of service.
- tranche-based capacity reservation charges, where instead of a single CRF charge, tranches of MDQ could be applied with different overrun charges, enabling users to choose the level of fixed commitment and throughput charging risk that they would prefer. We considered that this approach would substantially increase the complexity of the current GTC charging approach, but with uncertain benefit in terms of improving the alignment of charges to value of service.
- introduction of 'time of use' charges, where all customers are charged a higher price at peak periods. This approach can be attractive either to reflect time of use changes in a supply market (common for electricity generation) or where there are capacity constraints at peak periods, to reflect the cost of expanding capacity. Neither of these circumstances apply to Firstgas' transmission system.
- application of additional peak charges as a variation to current tariff structures, in order to apply higher charges for more variable usage. While this would address one of our the key identified shortcomings of the current tariff structure, in that it doesn't allow differentiation in charges for more variable (higher value) intraday

usage patterns, our initial view is that this would be significantly increase the complexity of the current charging structure and may be practically difficult to implement in a way that did not result in customers perceiving that they were penalised by the application of peak charges in addition to the current overrun charges.

- the tariff structure planned under the previously considered Gas Transmission Access Code (GTAC) framework. However, this tariff structure was based on daily capacity nominations and was designed to incentivise accurate nominations on a daily and hourly basis. We understand that this framework ultimately did not proceed due to its high systems complexity.

These tariff reform options are then evaluated against the assessment criteria identified above.

Box 11 Stakeholder consultation – identified tariff reform options

Stakeholder questions

1. Do you believe that any of the excluded tariff reform options should be considered and assessed in more detail? If so, please explain.
2. Are there other tariff reform options that have not been identified that you believe should be considered?

Stakeholder responses

Stakeholder comments on tariff reform options have been captured in comments below.

5.3.2 Option 1 - current tariff arrangements

Option description

This option reflects a continued evolution of charges under the current tariff structures. Under this option, the current tariff structures and pricing methodologies for each of the Maui and GTC networks would be retained as follows:

- Maui charges would continue to be set based on:
  - $/GJ.km charge on nominated volumes, with the $/GJ.km charge modified over time to continue to recover Maui pipeline capital costs (as allocated by Firstgas from total GTB asset base)
  - $/GJ charge on nominated volumes, with the $/GJ charge modified over time to continue to recover Maui pipeline operating costs (as allocated by Firstgas from total GTB operating costs) from nominated volumes
- GTC charges would continue to be set based on:

- $/GJ charge on GJ/day annual reserved volumes (the capacity reservation fee or CRF), with the charge established on a regional basis, generally increasing with increased distance from Taranaki gas receipt points (note, this charge is set to zero in Frankley Road region)
- $/GJ charge on throughput, with the charge generally common for all regions with the exception of a specific charge for Frankley Road region
- Overrun charge (currently 10x the CRF) for volumes in excess of reserved volumes

- GTC charge components be modified to improve the efficiency of prices:
  - in the short term, ensure charges within all regions align with floor price limit
  - over time:
    - flatten the geographic differentiation between regions; and
    - potentially reduce capacity reservation fees (with a corresponding increase in throughput charges) to lessen the fixed cost of gas usage
- Firstgas would retain the ability to negotiate supplementary agreements with customers on the GTC network if considered necessary in order to avoid loss of demand.

Box 12 Worked example of current tariff structures

We have determined a cost for a number of notional customers on the Maui and GTC pipelines, based on current tariff structures and notional tariff levels. These are then our baseline costs for comparison with alternative tariff structures considered.

GTC pipelines

- Notional Region G1 assumption
  - Current tariff - CRF $300/GJ, TF $0.50/GJ, Overrun charge 10x CRF
- Notional Customer G1.1
  - Reserved quantity – 500 GJ/day
  - Average delivered quantity - 480 GJ/day
  - Total overruns – nil
  - Average price/GJ - $1.36
- Notional Customer G1.2
  - Reserved quantity – 200 GJ/day
  - Average delivered quantity - 220 GJ/day
  - Total overruns – 7,300GJ
  - Average price/GJ - $1.99
- Notional Customer G1.3
  - Reserved quantity – 300 GJ/day
  - Average delivered quantity – 200 GJ/day

- Notional Region G2 assumptions
  - Current tariff - CRF $400/GJ, TF $0.50/GJ, Overrun charge 10x CRF
- Notional Customer G2.1
  - Reserved quantity – 500 GJ/day
  - Average delivered quantity - 380 GJ/day
  - Total overruns – nil
  - Average price/GJ - $1.94
- Notional Customer G2.2
  - Reserved quantity – 200 GJ/day
  - Average delivered quantity – 180 GJ/day
  - Total overruns – nil
  - Average price/GJ - $1.72
- Notional Customer G2.3
  - Reserved quantity – 300 GJ/day
  - Average delivered quantity – 240 GJ/day

- – Total overruns – nil
- – Average price/GJ - $1.73

- – Total overruns – nil
- – Average price/GJ - $1.87

Maui pipeline

- Location 1 (Notional Region M1) assumptions
  - – Current tariff – T1 $0.002/GJ.km, T2 $0.10/GJ
  - – Average distance 100km
- Notional Customer M1.1
  - – Average nominated quantity - 480 GJ/day
  - – Average price/GJ - $0.30
- Notional Customer M1.2
  - – Average nominated quantity - 220 GJ/day
  - – Average price/GJ - $0.30
- Notional Customer M1.3
  - – Average nominated quantity - 200 GJ/day
  - – Average price/GJ - $0.30

- Location 2 (Notional Region M2) assumptions
  - – Current tariff - T1 $0.002/GJ.km, T2 $0.10/GJ
  - – Average distance 300km
- Notional Customer M2.1
  - – Average nominated quantity - 380 GJ/day
  - – Average price/GJ - $0.70
- Notional Customer M2.2
  - – Average nominated quantity - 180 GJ/day
  - – Average price/GJ - $0.70
- Notional Customer M2.3
  - – Average nominated quantity - 240 GJ/day
  - – Average price/GJ - $0.70

(a) Aligns prices to cost-based pricing constraints

Under this option, Firstgas has substantial flexibility in setting prices across the GTC pipelines, with no constraint on setting prices to comply with cost-based pricing constraints.

However, Schedule 10 of the MPOC defines a price methodology for the Maui pipeline, which requires the same two-part tariff to be applied to GTC interconnection points as for direct Maui pipeline connections, and limits Firstgas' flexibility to fully align prices to cost based pricing constraints.

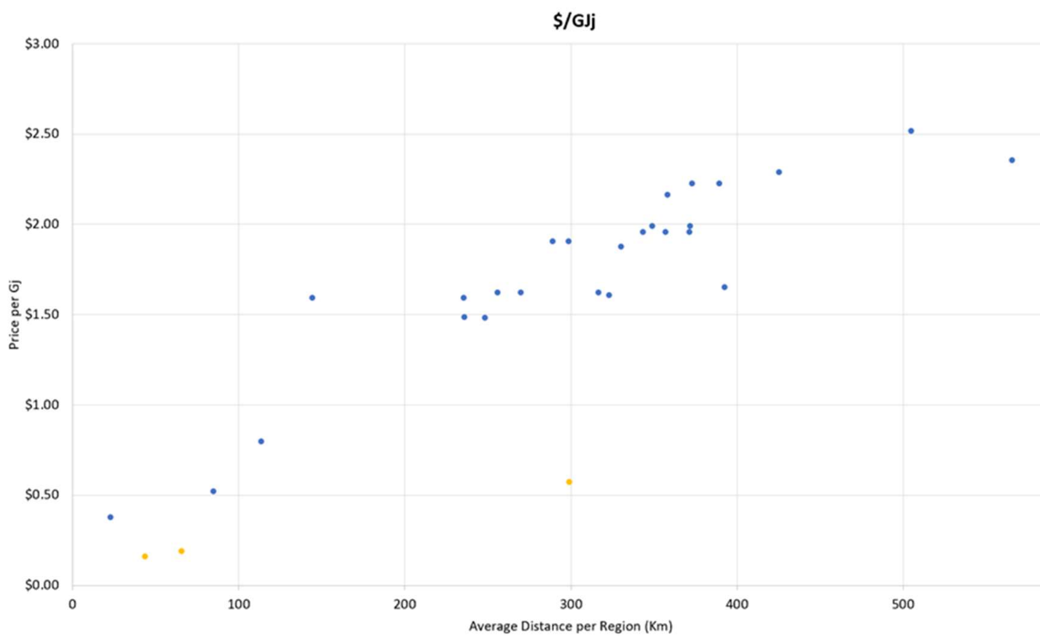
(b) Enables limited and flexible geographic price differentiation

The existing GTC tariff structure, with (apart from for Frankley Road) a common throughput charge and a capacity reservation charge established per price region, provides Firstgas with significant discretion in how it differentiates charges for geographic location, and Firstgas has used this discretion so that prices do not increase directly in proportion to distance (i.e. the tariffs apply a strong 'distance taper').

The existing Maui price structure also applies a 'distance taper', however there is limited discretion in how these tariffs are set, with the MPOC requiring a cost base be established for the Maui pipeline (which the DPP requires to be a subset of Firstgas' total MAR) and applying this to all gas transported on the Maui pipeline via a defined two-part tariff structure.

The graph below shows the average scheduled charge for FY23 (assuming usage is equal to MDQ to exclude the impact of usage variability), for consumers in each modelling area across the transmission system. Yellow points represent connections from the Maui pipeline, while the blue points represent connections from the GTC pipelines. This shows that there is a relatively flat price distance relationship on both the GTC and Maui pipelines, but with charges for delivery points on the Maui pipeline significantly lower than for GTC delivery points of a similar transmission distance.

Figure 8 Price-distance relationship (FY23)



Source: Synergies

For customers who use both the Maui pipeline and the GTC network, Firstgas' high degree of flexibility in setting prices within each pricing region means that it can establish regional prices having regard to the impact of the fixed pricing structure for the Maui pipeline. However, for those customers who are directly connected to the Maui pipeline, this requirement:

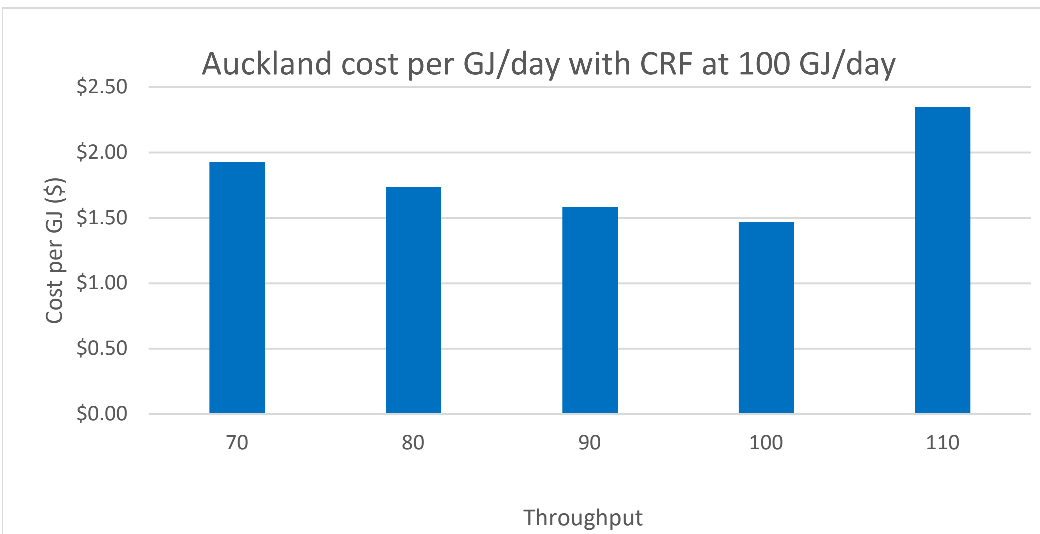
- fixes the charges that can be applied to these customers, regardless of the actual ceiling price constraint (noting directly attributable revenue is well below the ceiling limit) or their willingness to pay, with the result that they pay significantly lower transmission charges for a similar transmission distance than customers connected to the GTC pipeline; and
- fixes the price/distance relationship for these customers.

(c) *Enables price differentiation for user value*

The existing tariff structures do not provide for any price differentiation by consumer category.

The existing GTC tariff structure incorporates a capacity reservation charge based on a customer defined maximum daily quantity (MDQ), a throughput charge per GJ and capacity overrun charge (expressed as a multiple of the equivalent daily capacity reservation charge). The exception to this structure is Frankley Road, where no capacity reservation charge is applied. For regions other than Frankley Road, this provides a lower effective $/GJ charge for those users with stable demand, and a higher effective charge for users with peaky seasonal or daily demand. The resulting profile of charges is illustrated below, with the charges for the Auckland pricing region used to demonstrate the impact.

Figure 9 Price – throughput relationship



Source: Synergies

As a result, the GTC price structure provides an effective mechanism for differentiating prices for users with seasonal or day-to-day variability. However, it does not provide any mechanism for differentiating prices to reflect intraday variability, which is likely to provide high value to some customers – particularly power generators and residential and commercial customers – as well as involve some additional cost associated with higher compression requirements.

The existing Maui price structure requires charges be set based on $/GJ.km and $/GJ and does not enable any price differentiation for usage variability for customers connected directly to the Maui pipeline. Similarly, the price structure for Frankley Road, based purely on $/GJ, does not differentiate price for usage variability.

This is most relevant for the gas power stations – connected to either the Maui pipeline or the Frankley Road pipeline which, operating as peak electricity generators, will have an increasingly peaky and high value demand (both inter and intraday).

(d) Reduces capacity commitment and complexity

In FY23, annual capacity reservation charges reflect around 65% of Firstgas' GTC transmission revenue, and around 45% of Firstgas' total transmission revenues (including Maui pipeline revenues).

The fixed costs for GTC customers can be substantial, for example, in the Greater Auckland region, nearly 70% of total transmission charges are collected from the fixed capacity reservation charge. While a rebalancing of capacity reservation charges and throughput charges may reduce this fixed cost, the current GTC arrangements still require customers to reserve their required annual transmission capacity.

The current arrangements:

- create a significant fixed cost for users;
- create a perception of imposing a commercial constraint on gas usage and a price penalty for higher peaky throughput, notwithstanding that the transmission network is not capacity constrained.

Consultation with customers has also highlighted the complexity of the current pricing arrangements, including as a result of:

- the requirement to reserve MDQ (which for customers with variable usage, requires them to assess the optimal MDQ having regard to the likelihood of under and overruns);
- the requirement to manage gas demand having regard to the nominated MDQ; and
- for retailers, the difficulty in aligning transmission charges (including the various ancillary charges) to their standard retail price structure.

While the different tariff structures on the Maui and GTC pipelines also create some complexity, this was generally considered less significant than the above issues (and less significant than the operational differences between the codes, e.g. the nomination arrangements).

Customers also highlighted complexity associated with gas balancing and cash out arrangements, given the uncertainty and lack of transparency of cash out prices, however this is outside the scope of the transmission pricing review.

These complexities will all be retained under this tariff reform option. While this is less problematic for existing customers who are familiar with these price structures, it may create a barrier for new customers, particularly those wishing to access the GTC pipelines.

(e) Ease of implementation

This tariff reform option retains a high degree of consistency with current tariff structures and does not require any amendment to either the MPOC or GTC, hence will be simple to implement.

Conclusions

The GTC pricing structure is highly flexible in terms of how it can be implemented across the transmission system, enabling both limited and flexible differentiation for geographic location, as well as effectively applying a pricing premium for variability in gas usage. A drawback with this structure is its perceived rigidity and complexity, with its requirement to reserve capacity on an annual basis. Further, as no CRF is applied in the Frankley Road region, no pricing premium for variability is applied in that area, which notably includes peaking power generators.

In contrast, the Maui pricing methodology, while preferred by some customers due to its simplicity, requires the same price be paid by all Maui pipeline users regardless of users' willingness to pay, and as a result provides a lower price for Maui pipeline direct connect customers than could be applied, while still meeting the floor-ceiling limits, and increases the cost burden required to be recovered by GTC pipeline users. This will become increasingly problematic as demand on the transmission system declines.

Box 13 Stakeholder consultation – tariff option 1

Stakeholder questions

1. Do you have any comments or concerns with the evaluation considerations for this tariff option? If so, please explain.

Stakeholder responses

Stakeholders noted that this option is familiar to existing customers, however the complexity of determining how to enter the system (particularly under the GTC) is likely to be a barrier for new customers. This is acknowledged in the final report.

5.3.3 Option 2 - fully variable charges

Option description

This option is intended to remove all fixed charges associated with ongoing gas usage, and only charge consumers according to their actual use of gas.

For the Maui pipeline, charges are already set on a throughput basis ($/GJ and $/GJ.km), but using daily nominated volumes rather than actual volumes. Retention of the daily nominations framework on the Maui pipeline is important from an operational perspective, as this provides critical information for gas balancing across the entire GTB. Pricing based on nominated, rather than actual, throughput is a critical element of this, as it creates an incentive for Shippers to provide accurate nominations.

This option would mean:

- Definition of throughput quantity
  - on the Maui pipeline, prices would continue to be applied to nominated, rather than actual, quantities;
  - on the GTC pipelines, the throughput charge would be based on actual quantities, consistent with the current approach
- Approaches for the structure of the throughput charge are to either:
  - retain the current general pricing approaches under each Code meaning that
    - the Maui charges would retain the existing $/GJ.km and $/GJ price structure
    - the GTC charges would be established regionally, with charges initially set in a way that reflects the current price/distance relationship of the combined CRF and throughput fee for each region (see box for worked example)

    While this would be the simplest option to implement, it embeds a less efficient long term pricing outcome, by requiring a cost allocation, rather than value driven, approach for Maui pipeline charges.
  - adopt a $/GJ.km and $/GJ approach on both Maui and GTC pipelines. This approach is not preferred as it extends the cost allocation currently used for the Maui pipeline approach across GTC. It would also be difficult to define a common structure that fully complies with floor/ceiling limits and does not result in material winners and losers across system.
  - adopt regionally applied $/GJ charges on both Maui and GTC pipelines, with geographic regions defined for the Maui pipeline, with the initial charge for

direct connect customers set in a way that broadly reflects the current price/distance relationship for different offtake points on the Maui pipeline. GTC pipeline interconnections could be treated as separate regions, enabling a more integrated and efficient pricing approach across the transmission system. This option will create greater pricing flexibility for Maui pipeline and address some of the problems with the existing structure, but would result in a more complex implementation.

We have assumed the final option – regionally determined and applied $/GJ charges – as the most efficient application of this option.

- Firstgas would have the ability to negotiate supplementary agreements with customers on the GTC network and the Maui pipeline if considered necessary in order to avoid loss of demand.

Box 14 Worked example for defining regionally based throughput charge

It is assumed that the initial charges applied under this option will generate equivalent regional revenue to the charges applied under the current tariff arrangements, with tariffs subsequently modified over time to improve the efficiency of the tariffs. These worked examples show how an initial equivalent tariff could be determined and then applied, showing the impact on notional customers.

GTC pipelines

- Notional Region G1 assumption
  - Current tariff - CRF $300/GJ, TF $0.50/GJ, Overrun charge 10x CRF
  - Total reserved quantity 1,000 GJ/day
  - Average delivered quantity 900 GJ/day
  - Total overruns 7,300GJ/year
- Notional Region G1 total revenue under current tariff arrangements
  - Total revenue of $524,250 per year
- Equivalent fully variable throughput charge required to achieve this same Region G1 revenue
  - Region G1 fully variable throughput charge $1.60/GJ
- Notional Customer G1.1
  - Average delivered quantity - 480 GJ/day
  - Average price/GJ - $1.60, 18% above base case
- Notional Customer G1.2
  - Average delivered quantity - 220 GJ/day
  - Average price/GJ - $1.60, 20% below base case
- Notional Customer G1.3
  - Average delivered quantity - 200 GJ/day
  - Average price/GJ - $1.60, 8% below base case

- Notional Region G2 assumptions
  - Current tariff - CRF $400/GJ, TF $0.50/GJ, Overrun charge 10x CRF
  - Reserved quantity 1,000 GJ/day
  - Average throughput 800 GJ/day
  - Total overruns, nil
- Notional Region G2 total revenue under current tariff arrangements
  - Total revenue of $546,000 per year
- Equivalent fully variable throughput charge required to achieve this same Region G2 revenue
  - Region G2 fully variable throughput charge $1.87GJ
- Notional Customer G2.1
  - Average delivered quantity - 380 GJ/day
  - Total customer payment - $259,350
  - Average price/GJ - $1.87, 4% below base case
- Notional Customer G2.2
  - Average delivered quantity - 200 GJ/day
  - Average price/GJ - $1.87, 9% above base case
- Notional Customer G2.3
  - Average delivered quantity - 200 GJ/day

<table>
<tr><td></td><td>
– Average price/GJ - $1.87, unchanged from base case
</td></tr>
<tr><td colspan="2"><u>Maui pipeline</u></td></tr>
<tr><td>

Location 1 (Notional Region M1) assumptions
– Current tariff – T1 $0.002/GJ.km, T2 $0.10/GJ
– Average nominated throughput 900GJ/day
– Average distance 100km
Notional Region M1 total revenue under current tariff arrangements
– Total revenue $98,550 per year
Equivalent fully variable throughput charge required to achieve this same Region M1 revenue
– Region M1 fully variable throughput charge $0.30/GJ
All M1 customer revenue and price outcomes are unchanged from base case

</td><td>

Location 2 (Notional Region M2) assumptions
– Current tariff - T1 $0.002/GJ.km, T2 $0.10/GJ
– Average nominated throughput 800GJ/day
– Average distance 300km
Notional Region M2 total revenue under current tariff arrangements
– Total revenue $204,400 per year
Option 2 equivalent fully variable throughput charge required to achieve this same Region M2 revenue
– Region M2 fully variable throughput charge $0.70/GJ
All M2 customer revenue and price outcomes are unchanged from base case

</td></tr>
</table>

(a) *Aligns prices to cost-based pricing constraints*

Under this option, Firstgas has substantial flexibility in setting prices across the GTC pipelines, with no constraint on setting prices to comply with cost-based pricing constraints. By removing the requirements of Schedule 10 of the MPOC, this option increases Firstgas' flexibility to fully align prices to cost based pricing constraints.

(b) *Enables limited and flexible geographic price differentiation*

Under this option, it is assumed regional throughput charges would be set to provide a similar total revenue (by pricing region) as the existing GTC charges. Over time, the prices for the GTC and Maui pipelines may be expected to converge (for similar transmission distances). Any price increases applied for Maui pipeline users will allow price reductions for vulnerable areas within the GTC network (provided that the floor and ceiling price constraints continue to be met).

This option will improve Firstgas' ability to apply limited and flexible price differentiation across the transmission system.

(c) *Enables price differentiation for user value*

This option provides for charges to be established purely on a throughput basis, with no differentiation between consumer categories and no variation for any variability or any other usage characteristics that may align with value. As a result, this structure would not enable any price differentiation for user value on either the Maui or GTC pipelines.

(d) Reduces capacity commitment and complexity

By converting the GTC capacity reservation charge to a throughput charge, this option would eliminate fixed transmission charge for GTC users, resulting in no fixed transmission charges across the GTB.

Compared to the current tariff structure, this option will simplify the pricing arrangements for customers, as there will be no requirement to set an optimised MDQ and manage gas demand relative to this, and transmission charges will more clearly be able to be translated into standard gas retail charges. Stakeholders have emphasised their preference for a stable $/GJ charge to be applied, rather than a pricing structure that causes a varying transmission charge in effective $/GJ terms.

(e) Ease of implementation

This option would require only limited amendments to the GTC to remove the provisions around establishing MDQ, reserving capacity and charging overruns. Potentially, it could be implemented with no change to the GTC at all, by simply reducing capacity reservation fees to zero.

The required changes to the MPOC could also be relatively straightforward, with the removal of the Schedule 10 pricing methodology, and inclusion of provisions enabling the establishment of a regionally defined $/GJ throughput charge, together with the ability to individually negotiate charges with customers if required in order to maintain gas transmission demand.

However, by removing the existing price differentiation for variability on the GTC pipelines, this option would result in material price adjustments for some users, with effective prices increasing for users with flat demand, but decreasing for users with variable demand. The extent of changes to individual customer charges would create winners and losers amongst the customer base and as a result implementation may be challenging.

Conclusions

While this option is an 'easy' way to address some users' concerns about the complexity and rigidity of the GTC pricing structures, it will actually reduce Firstgas' ability to align prices with the value of the service to GTC users by removing any price differentiation for variability. This option improves Firstgas' ability to align prices to users' willingness to pay on the Maui pipeline.

Box 15 Stakeholder consultation – tariff option 2

Stakeholder questions

1. Do you consider that the explanation of this tariff option is clear?
2. Do you believe that any modification to this tariff option would improve its effectiveness? If so, please explain.
3. Do you have any comments or concerns with the evaluation considerations for this tariff option? If so, please explain.

Stakeholder responses

Stakeholders have questioned whether it is necessary to price MPOC to capacity nominations rather than actual volume, or whether small customers could be permitted to pay for gas delivered without the requirement to sell or buy gas to balance their nominations. Operational considerations such as this are beyond the scope of Synergies' review, however we note Firstgas' view that it remains necessary to price MPOC to capacity nominations for operational management purposes, and that significant complexity would be introduced if Firstgas were to introduce two classes of customers with different operational management obligations.

5.3.4 Option 3 - partial capacity-based charge across transmission system

Option description

This option is intended to apply a partial capacity-based charge across the full GTB, with a portion of a customer's charge based on their throughput, and a portion of their charge based on the pipeline capacity required for them reflecting the variability in their throughput. In effect, this would mean that those customers with a more variable usage profile will pay a higher charge per actual GJ used than those customers with a flatter usage profile.

This option would mean:

- Definition of throughput quantity
  - on the Maui pipeline, prices would continue to be applied to nominated, rather than actual, quantities;
  - on the GTC pipelines, the throughput charge would be based on actual quantities, consistent with the current approach
- The throughput charge component would be applied as a $/GJ charge, with the potential for region based differences in the amount of the charge (similar to the approach currently applied on the GTC pipelines)
- The capacity charge would be applied as a $/GJ/day based on required capacity quantity. Approaches for the determination of required capacity are either to:
  - base this on a capacity quantity nominated by the customer, however in order to incentivise customers to appropriately specify capacity quantity a (higher) overrun charge would also need to be applied on throughput above this capacity quantity. This is the approach currently used on the GTC pipelines;

– base this on the maximum capacity used by the customer, which may, for example, be determined as an average of a nominated number of highest usage days in the previous year, or may be set at a nominated percentile of demand. As there would be no requirement for the customer to reserve capacity, there would be no requirement to apply an overrun charge. However, a downside of this is that there would be a year long lag before the price would adjust to any step changes in usage. This could be addressed by allowing a customer to apply for an adjustment to its historic maximum volumes to reflect identified changes in usage.

- The amount of the capacity charge for each region could initially be as the charge required to recover the revenue currently earned by the $/GJ.km tariff (for the Maui pipeline) or the regional CRF (for the GTC pipeline) (see box for worked example). Note, the capacity charge for Frankley Road would need to be separately considered given that only a $/GJ charge is currently applied.
- Firstgas would have the ability to negotiate supplementary agreements with customers on the GTC network and the Maui pipeline if considered necessary in order to avoid loss of demand

Box 16 Worked example for defining partial capacity charge

It is assumed that the initial charges applied under this option will generate equivalent regional revenue to the charges applied under the current tariff arrangements, with tariffs subsequently modified over time to improve the efficiency of the tariffs. These worked examples show how an initial equivalent tariff could be determined and then applied showing the impact on notional G1 and M1 regional customers.

(b) a) Capacity quantity determined by customer specification

- Notional Region G1 assumptions
  - Current tari–f - CRF $300/GJ, TF $0.50/GJ, Overruns 10x CRF
  - Total reserved volume 1,000 GJ/day
  - Total overruns per year 7,300 GJ
- Notional Region G1 revenue under current tariff arrangements
  - Total CRF revenue $300,000 per year
- Notional Region G1 assumptions relevant to option
  - Total customer specified capacity (assumed to be equal to current reserved volume) 1,000 GJ/day
- Option 3(a) equivalent charge for Region G1
  - Daily capacity charge $0.82/GJ/day on specified capacity quantity (equivalent to current CRF)
  - TF continues unchanged

(b) Capacity quantity maximum from previous year

- Notional Region G1 assumptions
  - Current tari–f - CRF $300/GJ, TF $0.50/GJ, Overruns 10xCRF
  - Total reserved volume 1,000 GJ/day
  - Total overruns per year 7,300 GJ
- Notional Region G1 revenue under current tariff arrangements
  - Total CRF and Overrun revenue $360,000 per year
- Notional Region G1 assumptions relevant to option
  - In this case, the capacity charge is applied to each customer's maximum quantity from previous year, not the maximum quantity in aggregate
  - Sum of each customer's maximum quantity 1,150 GJ/day
- Option 3(b) equivalent charge for Region G1

- Overrun charge is applied on volumes above specified capacity quantity at 10x daily capacity charge

- All G1 customer revenue and price outcomes remain unchanged from the base case

- Daily capacity charge $0.86/GJ/day on max capacity quantity (equivalent to current CRF and overrun charge)
- TF continues unchanged
- No overrun charges

- Notional Customer G1.1
  - Maximum prior year volume – 500 GJ/day
  - Average delivered quantity – 480 GJ/day
  - Average price/GJ - $1.39, 3% above base case
- Notional Customer G1.2
  - Maximum prior year volume – 250 GJ/day
  - Average delivered quanti–y - 220 GJ/day
  - Average price/GJ - $1.47, 26% below base case
- Notional Customer G1.3
  - Maximum prior year volume – 400 GJ/day
  - Average delivered quanti–y - 200 GJ/day
  - Average price/GJ - $2.22, 28% above base case

<u>Maui pipeline</u>

a) Capacity quantity determined by customer specification

- Notional Region M1 assumptions
  - Current Tari–f - T1 $0.002/GJ.km, T2 $0.10/GJ
  - Average nominated throughput 900GJ/day
  - Average distance 100km
- Notional Region M1 revenue under current tariff arrangements
  - Total revenue Tariff 1 revenue $65,700 per year
- Notional Region G1 assumptions relevant to option
  - Total customer specified capacity 1,000 GJ/day
  - Total overruns 7,300 per year
- Option 3(a) equivalent charge for Region M1
  - Daily capacity charge $0.15/GJ/day on specified capacity
  - Tariff 2 continues unchanged
  - Overrun charge is applied on volumes above specified capacity quantity at 10x daily capacity charge
- Notional Customer M1.1
  - Customer specified volume – 500 GJ/day
  - Average delivered quantity – 480 GJ/day
  - Overru–s - nil
  - Average price/GJ - $0.26, 15% below base case
- Notional Customer M1.2
  - Customer specified volume – 200 GJ/day
  - Average delivered quanti–y - 220 GJ/day
  - Overruns – 7,300 GJ

b) Capacity quantity maximum from previous year

- Notional Region M1 assumptions
  - Current Tari–f - T1 $0.002/GJ.km, T2 $0.10/GJ
  - Average nominated throughput 900GJ/day
  - Average distance 100km
- Notional Region M1 revenue under current tariff arrangements
  - Total revenue Tariff 1 revenue $65,700 per year
- Notional Region G1 assumptions relevant to option
  - Sum of each customer's maximum quantity 1,150 GJ/day
- Option 3(b) equivalent charge for Region M1
  - Daily capacity charge $0.16/GJ/day on max capacity quantity
  - Tariff 2 continues unchanged
  - No overrun charges
- Notional Customer M2.1
  - Maximum prior year volume – 500 GJ/day
  - Average delivered quantity – 480 GJ/day
  - Average price/GJ - $0.26, 12% below base case
- Notional Customer M2.2
  - Maximum prior year volume – 250 GJ/day
  - Average delivered quantity – 220 GJ/day
  - Average price/GJ - $0.28, 7% below base case
- Notional Customer M2.3
  - Maximum prior year volume – 400 GJ/day
  - Average delivered quanti–y - 200 GJ/day

  - Average price/GJ - $0.37, 24% above base case
- Notional Customer M1.3
  - Customer specified volume – 300 GJ/day
  - Average delivered quantiy - 200 GJ/day
  - Overruns - nil
  - Average price/GJ - $0.33, 8% above base case

  - Average price/GJ - $0.41, 38% above base case

(a) *Aligns prices to cost based pricing constraints*

Under this option, Firstgas would have substantial flexibility in setting prices to apply on a regional basis across the transmission system, with no constraint on setting prices to comply with cost-based pricing constraints.

(b) *Enables limited and flexible geographic price differentiation*

Under this option, it is assumed GTC zonal charges would initially be set to provide a similar total revenue (by pricing region) as the existing GTC charges. A similar level of discretion would be allowed for Maui prices. Over time, the prices for the GTC and Maui pipelines may be expected to converge (for similar transmission distances). Any price increases applied for Maui pipeline users will allow price reductions for vulnerable areas within the GTC network (provided that the floor and ceiling price constraints continue to be met).

This option will improve Firstgas' ability to apply limited and flexible price differentiation across the transmission system.

(c) *Enables price differentiation for user value*

This option will enable the application of price differentiation for variability on the Maui pipeline, in a similar way as currently is applied on the GTC system. As a result, it provides a structure for differentiating prices for seasonal or day-to-day variability but does not provide a mechanism for differentiating prices to reflect intraday variability, which is likely to provide high value to some customers – particularly power generators – as well as involve some additional cost associated with higher compression requirements.

Under sub-option (a), there is a risk that high overrun charges may exceed the value of the service to customers, and as a result may disincentives peak gas use. This is particularly of concern for Maui pipeline and Frankley Road customers that do not currently reserve capacity or pay overrun fees, with the behavioural consequence of applying significant capacity overrun fees to these customers difficult to predict. This could, for example incentivise generators to purchase hedges instead of paying overrun charges in dry years.

(d) Reduces capacity commitment and complexity

This option will impose on Maui users' a new requirement for a fixed element of charges.

Under sub-option (a), it would also require Maui users to annually specify an optimised quantity of required capacity and pay overrun charges where this quantity is exceeded. By extending the application of the GTC pricing arrangements, which are perceived by customers to be more rigid and complex, this option may to increase the administration requirement for Maui pipeline customers.

However, under sub-option (b), the requirement for any users to specify and reserve an optimum amount of capacity will be removed. Similarly, there will be no requirement to pay overrun charges with the reserved capacity is exceeded. Instead, capacity charges will automatically be established based on the prior year's maximum capacity use (with an opportunity for this to be reviewed where a customer can demonstrate a change in their business operations which will significantly impact gas usage). This will significantly simplify administrative complexity for GTC users and will avoid a material increase in administrative complexity for Maui pipeline users.

Either option is likely to impose material complexity for electricity generators, whose demand varies significantly from year to year depending on hydrological variability (and in particular, whether it is a wet or dry year), with only limited predictability. Not only will this complicate their assessment of optimal reserved capacity under sub-option (a), it will also limit the usefulness of historic peak usage as a predictor of current year peak usage under sub-option (b).

Stakeholders have highlighted the difficulty that this tariff structure creates for shippers in passing transmission tariffs onto customers, as it results in a varying effective $/GJ transmission charge.

(e) Ease of implementation

Sub-option (a), requiring customer specification of capacity quantity and an overrun charging arrangement, will require significant amendment to the MPOC to implement and may not be readily achievable without significant changes to the operational aspects of the Code. Further, the extent of changes to individual customer charges may create challenging implementation issues.

However, sub-option (b), where capacity quantities are set based on prior year actual throughput, should not require material changes to the operational aspects of the MPOC. It will also enable operational simplification of the GTC, by removing provisions around capacity reservations and overruns.

Conclusions

A partial capacity reservation charge structure is preferable to a fully variable charge in terms of its ability to reflect the value of the transmission service to users and to promote economically efficient pricing.

The current GTC structure, involving reservation of an optimum amount of capacity, and payment of overrun charges where this is exceeded, is not generally preferred by customers due to its perceived rigidity and complexity. Extension of this pricing structure to the Maui pipeline may be difficult to implement, given the nature of the changes that would be required to the MPOC and potential customer resistance to the change.

However, a variation to this where capacity charges are established based on a customer's previous year's usage offers a significant increase in simplicity.

Box 17 Stakeholder consultation – tariff option 3

Stakeholder questions

1. Do you consider that the explanation of this tariff option is clear?
2. Do you believe that any modification to this tariff option would improve its effectiveness? If so, please explain.
3. Do you have any comments or concerns with the evaluation considerations for this tariff option? If so, please explain.

Stakeholder responses

Stakeholders generally considered that explanation of this option was clear.

However, the difficulty of predicting usage for electricity generators, who are subject to significant changes in demand due to hydrological variability, was emphasised. Under the variation to this option, where capacity charges are based on a customer's previous usage, it was emphasised that such charges should not be based on a small number of peaks. Instead, they should be assessed based on a longer series of peaks, for example using the 75th percentile of demand, in order to ensure they reflect more normal demand patterns.

5.3.5 Option 4 – fully variable charge with regional load factor multiplier

Option description

This option allows the tariff to be applied on a fully variable basis but includes an adjustment to a customer's tariff to reflect the variability in their throughput either on a daily or hourly basis.

This option would require:

- throughput charges determined on a regional basis for both the Maui and GTC pipelines, applied as discussed under option 2; and
- a load factor (daily:annual, hourly:daily) multiplier applied to the throughput charges.

A daily:annual load factor would be defined as maximum daily use over average daily use over the year, in which case a more variable daily demand will be reflected as a higher daily:annual load factor.

The same would approach could be applied to hourly variations within a day, with hourly:daily load factor defined as maximum hourly use over average hourly use in a day, and where a more variable hourly demand is reflected as a higher hourly load factor.

The two load factor multipliers are designed deal with different types of peakiness for which there is different value attached to the different types of variability. The two factors can then be amalgamated into a single load factor multiplier, either by multiplying the two factors (which effectively creates a hourly:annual load factor) or by applying chosen weights to the daily and hourly load factor multipliers.

In its simplest application, the customer's resulting actual load factor would be multiplied by a base throughput charge to determine the actual throughput charge for that customer. However, it is possible to scale down (or up) the load factor multiplier in order to reduce (or strengthen) the price premium applied for variable use. This would be particularly likely to be required if using an hourly:annual load factor, as some customers are likely to generate very high load factors on this basis.

The boxes below present a worked example of the application of load factor multipliers.

Box 18 Worked example for defining and applying load factor multipliers (unscaled)

It is assumed that the initial charges applied under this option will generate equivalent regional revenue to the charges applied under the current tariff arrangements, with tariffs subsequently modified over time to improve the efficiency of the tariffs. These worked examples show how an initial equivalent tariff could be determined and then applied showing the impact on notional G1 regional customers.

Defining load factor multiplier

1. Calculating load factors

a) Daily:annual load factor

- Load factor determined based on actual usage for the previous year
- Region daily usage assumptions
  - Total region
    - Sum of each customer's max historic throughput 1150 GJ/day
    - Total average daily throughput 900GJ/day
    - System daily:annual load factor 1.28
  - Customer 1
    - Maximum volume 500 GJ/day

b) Hourly:daily load factor

- Load factor determined based on actual usage for the day within the previous year with the peak hourly usage
- Region hourly usage assumptions
  - Total region
    - Sum of each customer's max historic throughput 70 GJ/hour
    - Total average hourly throughput 48GJ/hour
    - System hourly:daily load factor 1.461
  - Customer 1

- Average volume 480 GJ/day
- Customer daily load factor 1.042
- Customer 2
  - Maximum volume 250 GJ/day
  - Average volume 220 GJ/day
  - Customer daily load factor 1.136
- Customer 3
  - Maximum volume 400 GJ/day
  - Average volume 200 GJ/day
  - Customer daily load factor 2.00

- Total volume for peak day 500GJ, with average hourly throughput 20.8GJ/hour
- Maximum hourly volume 22GJ
- Customer hourly load factor 1.056
- Customer 2
  - Total volume for peak day 250GJ, with average hourly throughput 10.4GJ/hour
  - Maximum hourly volume 25GJ
  - Customer hourly load factor 2.400
- Customer 3
  - Total volume for peak day 400GJ, with average hourly throughput 16.7GJ/hour
  - Maximum hourly volume 22GJ
  - Customer hourly load factor 1.380

2. Combining and scaling load factors

a) Daily:annual load factor only

- Load factor multiplier could be applied using only daily load factor
- Applicable daily:annual load factors:
  - System – 1.278
  - Customer 1 – 1.042
  - Customer 2 – 1.136
  - Customer 3 – 2.000
- The power of load factor pricing premium could be reduced by applying a scaling factor to LF-1 eg scaling to 75% would give:
  - System – 1.208
  - Customer 1 – 1.031
  - Customer 2 – 1.102
  - Customer 3 – 1.750

b) Hourly:annual load factor

- Load factor multiplier could be applied by multiplying daily and hourly load factors to create hourly:annual load factor
- Applicable hourly:annual load factors:
  - System – 1.867
  - Customer 1 – 1.100
  - Customer 2 – 2.727
  - Customer 3 – 2.760
- The power of load factor pricing premium could be reduced by applying a scaling factor to LF-1, although a greater scaling factor would be appropriate given magnifying effect of hourly:annual load factor eg scaling to 25% would give:
  - System – 1.217
  - Customer 1 – 1.025
  - Customer 2 – 1.432
  - Customer 3 – 1.440

c) Weighted load factor

- Load factor multiplier could be applied by weighting daily and hourly load factors
- For example, if a 33:67 weighting was applied to hourly and daily load factors, the applicable weighted load factors would be:
  - System – 1.338
  - Customer 1 – 1.046
  - Customer 2 – 1.553
  - Customer 3 – 1.795
- Again, the power of load factor pricing premium could be reduced by applying a scaling factor to LF-1 eg scaling to 75% would give:
  - System – 1.254
  - Customer 1 – 1.035
  - Customer 2 – 1.415
  - Customer 3 – 1.597

3. Identifying equivalent base throughput charge

- Notional G1 Region current tariff assumptions
  - Current tariff – CRF $300/GJ, TF $0.50/GJ, Overrun charge 10x CRF
  - Total reserved volumes 1,000 GJ/day
- Location 1 (Notional Region M1) assumptions
  - Current tariff – T1 $0.002/GJ.km, T2 $0.10/GJ
  - Average nominated throughput 900GJ/day
  - Average distance 100km

- Average daily throughput 900 GJ/day
- Total overruns 7,300/year

- Notional Region G1 total revenue under current tariff arrangements
  - Total revenue of $524,250 per year
- Equivalent fully variable throughput charge required to achieve this same Region G1 revenue
  - Region G1 fully variable throughput charge $1.60/GJ

- Notional Region M1 total revenue under current tariff arrangements
  - Total revenue $98,550 per year
- Equivalent fully variable throughput charge required to achieve this same Region M1 revenue
  - Region M1 fully variable throughput charge $0.30/GJ

a) Scaled daily:annual load factor

- Equivalent G1 base throughput charge
  - At scaled system load factor multiplier of 1.208 – $1.60
  - At load factor of 1.000 - $1.32
- Equivalent M1 base throughput charge
  - At scaled system load factor multiplier of 1.208 - $0.30
  - At load factor of 1.000 - $0.25

b) Scaled hourly:annual load factor

- Equivalent G1 base throughput charge
  - At scaled system load factor multiplier of 1.217 – $1.60
  - At load factor of 1.000 - $1.31
- Equivalent M1 base throughput charge
  - At scaled system load factor multiplier of 1.217 - $0.30
  - At load factor of 1.000 - $0.25

c) Scaled weighted load factor

- Equivalent G1 base throughput charge
  - At scaled system load factor multiplier of 1.254 – $1.60
  - At load factor of 1.000 - $1.27
- Equivalent M1 base throughput charge
  - At scaled system load factor multiplier of 1.254 - $0.30
  - At load factor of 1.000 - $0.24

4. Applying load factor multiplier

a) Scaled daily:annual load factor

- Customer 1
  - Customer scaled load factor multiplier (from above) 1.031
  - Base G1 region variable charge $1.32/GJ
  - Actual G1 region variable charge $1.36/GJ, unchanged from the base case
  - Base M1 region variable charge $0.25/GJ
  - Actual M1 region variable charge $0.26/GJ, 15% below base case
- Customer 2
  - Customer scaled load factor multiplier (from above) 1.102
  - Base G1 region variable charge $1.32/GJ
  - Actual G1 region variable charge $1.46/GJ, 27% below the base case

b) Scaled hourly:annual load factor

- Customer 1
  - Customer scaled load factor multiplier (from above) 1.025
  - Base G1 region variable charge $1.31/GJ
  - Actual G1 region variable charge $1.34/GJ, 1% below the base case
  - Base M1 region variable charge $0.25/GJ
  - Actual M1 region variable charge $0.25/GJ, 16% below base case
- Customer 2
  - Customer scaled load factor multiplier (from above) 1.432
  - Base G1 region variable charge $1.31/GJ
  - Actual G1 region variable charge $1.88/GJ, 6% below the base case

c) Scaled weighted load factor

- Customer 1
  - Customer scaled load factor multiplier (from above) 1.035
  - Base G1 region variable charge $1.27/GJ
  - Actual G1 region variable charge $1.32/GJ, 3% below the base case
  - Base M1 region variable charge $0.24/GJ
  - Actual M1 region variable charge $0.25/GJ, 17% below base case
- Customer 2
  - Customer scaled load factor multiplier (from above) 1.415
  - Base G1 region variable charge $1.27/GJ
  - Actual G1 region variable charge $1.80/GJ, 10% below the base case

– Base M1 region variable charge $0.25/GJ – Actual M1 region variable charge $0.27/GJ, 9% below base case	– Base M1 region variable charge $0.25/GJ – Actual M1 region variable charge $0.35/GJ, 18% above base case	– Base M1 region variable charge $0.24/GJ – Actual M1 region variable charge $0.34/GJ, 13% above base case
• Customer 3 – Customer scaled load factor multiplier (from above) 1.750 – Base G1 region variable charge $1.32/GJ – Actual G1 region variable charge $2.31/GJ, 33% above the base case – Base M1 region variable charge $0.25/GJ – Actual M1 region variable charge $0.43/GJ, 45% above base case	• Customer 3 – Customer scaled load factor multiplier (from above) 1.440 – Base G1 region variable charge $1.31/GJ – Actual G1 region variable charge $1.89/GJ, 9% above the base case – Base M1 region variable charge $0.25/GJ – Actual M1 region variable charge $0.36/GJ, 18% above base case	• Customer 3 – Customer scaled load factor multiplier (from above) 1.597 – Base G1 region variable charge $1.27/GJ – Actual G1 region variable charge $2.03/GJ, 17% above the base case – Base M1 region variable charge $0.24/GJ – Actual M1 region variable charge $0.38/GJ, 27% above base case
Note, there is a minor difference in total revenue under options 4(b) and 4(c) as the combination of individual customer hourly and daily load factors, when aggregated, does not create an identical result to the combination of system hourly and daily load factors.		

This option would require a mechanism to assess the daily and, potentially, hourly load factors for each consumer. In practice, from Firstgas' perspective, this would need to be identified by Shipper and by delivery point (or agreed grouping of delivery points), given Firstgas' lack of visibility of individual consumer use at a given delivery point. Shippers would then be required to allocate these charges to their customers at each delivery point (or agreed grouping of delivery points).

The simplest mechanism to determine daily and hourly load factors would be to apply the previous year's actual load factor. While a true-up mechanism could be applied at the end of each year, this is likely to significantly add complexity with only limited additional benefit unless there is a reasonable expectation of a significant change in load factor and total gas usage from year to year.

For most customers, this could be predicted if there was a planned significant change in business operations leading to a planned significant change in gas usage. However, this would be more difficult to predict for electricity generators, whose volume and variability will vary from year to year depending on weather conditions. For example, in a wet year, renewable generation is likely to have high availability, meaning gas peaking generators will be used more intermittently, leading to lower gas usage but a higher load factor. However, in a dry year, with lower renewable generation availability, higher usage of gas peaking stations and lower load factor can be expected. A mechanism to address this would likely be required.

This option may also require a maximum hourly quantity (MHQ) or MDQ above which Firstgas is not obliged to supply and/or some sort of charge (e.g. peak flow charge) if it was considered necessary to deter excessive demand on a short-term basis.

Firstgas would have the ability to negotiate supplementary agreements with customers across both the GTC and Maui networks if considered necessary in order to avoid loss of demand.

(a) Aligns prices to cost based pricing constraints

Under this option, Firstgas has substantial flexibility in setting prices across the GTC pipelines, with no constraint on setting prices to comply with cost-based pricing constraints.

(b) Enables limited and flexible geographic price differentiation

Under this option, Firstgas would have discretion as to how regional throughput charges are established across both the Maui and GTC pipelines. This would allow Firstgas the ability to reduce the disparity between transmission charges for Maui pipeline customers compared to GTC customers. As a result, this option enhances Firstgas' ability to apply limited and flexible price differentiation for distance (except where necessary to reflect cost-based price constraints). However, this option could result in significant price adjustments for Maui users, depending on the extent of price change applied, and the timeframe over which it is introduced.

(c) Enables price differentiation for user value

This option will result in all standard charges being differentiated based on a user's consumption variability (potentially including both intra and inter day variability) as a proxy for value.

The application of a load factor multiplier will result in some price adjustments for users on the GTC pipeline as the outcome of a standard load factor multiplier will differ from the current CRF/throughput charge arrangement. However, it may be possible to design the load factor multiplier to initially broadly replicate the effect of the regionally-based CRF and throughput charging system, with alignment in the load factor multipliers (if desired) able to occur over a defined transitional period.

However, the more significant change will be on the Maui pipeline and on the Frankley Road pipeline, where no variability-based differentiation currently occurs, and for electricity generators, which have an increasingly variable gas demand. It would be appropriate to implement price differentiation for variability for these customers over a transitional period.

(d) *Reduces capacity commitment and complexity*

By eliminating the application of capacity reservation charges for GTC users, this option will remove fixed transmission charge for all GTB customers.

This option may be perceived by GTC customers as a simpler, lower fixed cost way of differentiating prices for variability, as there will be no requirement to establish an optimised capacity reservation quantity and manage gas demand relative to it. Instead, load factor pricing adjustments will be automatically determined and applied (based on the previous year's usage). Further this option will result in a single pricing framework across the entire Firstgas pipeline network (although there will remain operational differences between the MPOC and GTC).

However, the load factor multiplier is likely to be difficult for shippers to translate to individual customers, except where the customer is directly connected to the transmission pipeline. It will also be complex for shippers to confirm that they are being charged the correct amounts for every delivery point, and to ensure that those amounts are being appropriately reflected in their charges to customers.

(e) *Ease of implementation*

This option would create significant operational issues that would need to be managed, particularly if hourly load factors were to be considered.

Currently, only large users have time of use meters that allow measurement of hourly quantities. This option would create significant complexity where there are multiple consumers served from a single delivery point, as there is no current mechanism for allocating hourly use. It would also require retailers to assess how to pass transmission charges through to their customers, who will contribute differently to the overall variability of throughput at that delivery point. This would be particularly complex for distribution networks connected to a delivery point. In practice, this means that it is not practically viable to implement hourly load factor pricing, except to large industrial users.

This tariff reform option would also require significant amendment to both the MPOC and the GTC to implement.

Finally, the extent of changes for many individual customers charges may create substantial implementation issues and would require extensive customer consultation. There may be significant resistance from some customers, given the opportunities within this option for their prices to materially increase, particularly where they have highly variable usage. It may be necessary to include a long-term price path commitment aimed at constraining the potential impact for these users.

Conclusions

This option provides a conceptually simple and effective way of achieving the desired pricing outcomes across both pipeline systems, in terms of aligning standard prices with both cost-based floor and ceiling limits, and drivers of value of service. It also has the benefit of relative simplicity in application from a customer's perspective. However, there will be significant complexity in the implementation of this option, with both operational implications and a requirement for substantial changes to both gas codes. This option will also create ongoing complexity for shippers in translating and applying gas transmission charges to their customers. Further, there may be resistance to this option from some customers, who will perceive that it creates a significant opportunity for their prices to rise at a faster rate than for other customers.

Box 19 Stakeholder consultation – tariff option 4

Stakeholder questions

1. Do you consider that the explanation of this tariff option is clear?
2. Do you believe that any modification to this tariff option would improve its effectiveness? If so, please explain.
3. Do you have any comments or concerns with the evaluation considerations for this tariff option? If so, please explain.

Stakeholder responses

Stakeholders highlighted the expected practical complexity of this option on an ongoing basis, in terms of translating gas transmission charges through to customers at each delivery point, as well as to confirm that the correct amounts are being charged at each delivery point.

5.3.6 Option 5 - differentiation by consumer category

Under this option, prices would be separately established for identified categories of gas users who have materially different usage requirements and/or a materially different value of gas use.

The simplest approach is to define user categories according to the nature of the consumer's business. As a first priority, we anticipate that a differentiated charge could be applied for electricity generation, given the transition to using gas for peak capacity, with the result that the gas demand has become highly variable and high value when used. However, differentiated charges could also be applied for other categories of consumers, where they have significant differences in their value of use if differentiating prices on this basis becomes important to support demand. Additional categories may be petrochemical producers, major industrial users (>10TJ) and commercial/residential users.

A benefit of differentiating charges by consumer category is that there is less requirement for the tariff structure to adjust charges to reflect drivers of value.

Therefore, a simpler change to current tariff structures can be adopted, such as a regionally determined $/GJ charge for each consumer category.

However, it would also be possible to adopt a more significant change in structure, such as load factor pricing, for one or more consumer segments, in order to better target value drivers. Limiting the use of load factor pricing to segments involving electricity generators and/or large industrial users would significantly lessen the implementation issues identified with that option, as there would be a limited number of users affected, all with time of use meters already installed.

A variation to this option is to define gas user categories according to the characteristics of their use, rather than according to the nature of the consumer's business. For example, groups could be defined by shipper and by delivery point according to:

- Group A including those users with the highest variability in terms of absolute GJ, given their volume changes have implications for the operation across the transmission network;
- Group B including those users with lower variability in absolute terms, but with high seasonal or intraday peaking requirements as a ratio to average demand;
- Group C including those users with lower variability and incorporating shippers to delivery points not captured in the above groups.;
- Additional groups could be defined if greater differentiation within Groups A and B is considered desirable, or to capture specific sub-groups, such as renewable gases.

Charges for all groups could be applied on a simple $/GJ basis, but with differentiation of charges between these groups developed using similar principles as described under the load factor pricing option. Where a shipper's usage at a delivery point changed, it could apply to be moved to a different group.

Regardless of approach adopted, we consider that this option would best be implemented on an integrated basis across both the Maui and GTC pipelines (at least for electricity generators), meaning that the pricing restrictions in the MPOC would need to be removed.

Firstgas would maintain the ability to negotiate supplementary agreements with customers on both the Maui pipeline and GTC network if considered necessary to avoid loss of demand.

(a) Aligns prices to cost-based pricing constraints

Under this option, Firstgas would have substantial flexibility in setting prices across both the Maui and GTC pipelines, provided that they complied with the floor/ceiling pricing constraints.

(b) Enables limited and flexible geographic price differentiation

This option would allow Firstgas discretion as to how it sets prices across both the Maui and GTC pipelines, provided that they comply with floor/ceiling constraints. Accordingly, Firstgas could reduce the disparity between transmission charges for Maui pipeline customers compared to GTC customers, if this were considered appropriate. As a result, this option enhances Firstgas' ability to apply limited and flexible price differentiation for distance (except where necessary to reflect cost-based price constraints). However, this option could result in significant price adjustments for some users, depending on the extent of price change applied, and the timeframe over which it is introduced.

(c) Enables price differentiation for user value

This option would enable Firstgas to set transmission prices for categories of users that better reflects their value of use (where those categories are defined either by the nature of the consumer's business or by the demand characteristics for a shipper at a given delivery point).

If groups were defined by the nature of the consumer's business, this could be achieved by:

- applying a different simple $/GJ throughput charge to each consumer category, although this may require Firstgas to adopt numerous consumer categories, to enable it to set transmission charges reflective of the different value placed on the service by different types of users; or
- adopting a tariff structure that adjusts charges for usage variability, which may support the use of a more limited number of consumer categories, potentially limited to electricity generators, large industrial customers (>10TJ) and others.

However, if groups were initially defined according to their usage variability characteristics, a simple $/GJ throughput charge could then be applied to each group, reflecting the different value associated with usage.

(d) Reduces capacity commitment and complexity

The extent to which this option reduces capacity commitment and fixed costs will depend upon the tariff structure applied to each consumer category.

(e) Ease of implementation

This tariff reform option would require amendment to both the MPOC and GTC to implement tariffs for specific gas user classes.

Also, by introducing a new tariff for electricity generators, this option could potentially result in significant price adjustments for these users, although this can be transitioned over time.

Where user classes are defined by the nature of the consumer's business, it is likely to be challenging to implement tariff differentiation, particularly as the number of consumer categories increases. This relates to both establishing a basis for the extent of price differentiation (given different usage requirements within all categories), as well as complexities of identifying different consumer loads for charging purposes, especially for smaller consumers or those connected via distribution networks.

However, where user classes are defined according to usage characteristics at a delivery point, this allows price differentiation to be considered in a more structured way according to load factor impacts (as described in option 4). It also will provide a simpler approach to identifying the appropriate charges to be applied to different shippers and different distribution points.

Conclusions

This option provides a mechanism to establish tariffs in a way that reflects the value of the service to customers with different usage requirements, applying a simpler tariff structure.

Box 20 Stakeholder consultation – tariff option 5

Stakeholder questions

1. Do you consider that the explanation of this tariff option is clear?
2. Do you believe that any modification to this tariff option would improve its effectiveness? If so, please explain.
3. Do you have any comments or concerns with the evaluation considerations for this tariff option? If so, please explain.

Stakeholder responses

One stakeholder proposed an alternate way to categorise gas user groups according to usage characteristics by shipper and by delivery point rather than by the nature of the consumer's business. This has been included in the final report as an alternative approach for tariff option 5.

5.3.7 Evaluation summary

The following table presents a summary of the evaluation of each of the potential tariff reforms.

Table 14 Evaluation summary – tariff reform options

Criteria	1. Current tariff structure	2. Fully variable tariffs	3(a). Partial capacity charge – customer specify	3(b). Partial capacity charge – historic usage	4. Variable with load factor multiplier	5. Customer differentiation of charges
Cost-based limits	Partly meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria
Limits differentiation for distance	Partly meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria	Fully meets criteria
Applies differentiation for user value	Meets criteria in limited way	Does not meet criteria	Partly meets criteria	Partly meets criteria	Fully meets criteria	Fully meets criteria
Reduced fixed cost and complexity	Meets criteria in limited way	Fully meets criteria	Does not meet criteria	Substantially meets criteria	Substantially meets criteria	Fully meets criteria
Ease of implementation	Fully meets criteria	Partly meets criteria	Meets criteria in limited way	Partly meets criteria	Does not meet criteria	Partly meets criteria

Legend:

- Fully meets criteria
- Substantially meets criteria
- Partly meets criteria
- Meets criteria in limited way
- Does not meet criteria

This evaluation summary shows that, if the implementation issues for the regional load factor charge were able to be resolved, this option will provide for the most effective long term standard pricing structures, having regard to the principles of economic efficiency, the expected demand environment, and Firstgas' pricing objectives, particularly if hourly load factor charging is included. However, practical issues mean that this is not reasonably able to be implemented for all but large industrial users, and even for those users, this option is likely to cause practical complexity.

Applying customer differentiation of charges may enable Firstgas to implement the required long term pricing directions with less disruption to customers and less implementation risk, and would allow a simple $/GJ tariff structure to be applied for each group.

The groups could be defined either according to the nature of the consumer's business, or with reference to the usage characteristics of each shipper at each delivery point. The latter approach may result in less complexity around defining the appropriate charging category to apply for delivery points serving multiple consumers, as well as for shippers passing transmission charges onto their customers. It may also be more acceptable to consumers and shippers if the charging groups are based on quantifiable data, rather than just at the discretion of Firstgas.

Box 21 Stakeholder consultation – summary evaluation of tariff options

Stakeholder questions

1. Do you have any concerns with the comparative evaluation of tariff options. If so, please explain.
2. What tariff option, or combination of tariff options, do you think will provide the most effective long term pricing structure for Firstgas?

Stakeholder responses

Stakeholders generally prefer Firstgas to apply a simple $/GJ throughput charge structure. While a number of stakeholders note their preference for option 2, some stakeholders acknowledge its shortcomings, with a single $/GJ variable charge applied to all users giving no opportunity to align prices to value. We note that this key shortcoming can be addressed if this is combined with option 5, with one stakeholder identifying a simple $/GJ charge applied to usage-based groupings of gas users as its preferred approach.

6 Implementation considerations

Based on our recommended pricing directions, together with our identification and evaluation of specific tariff reform options, we have identified both near term and longer-term opportunities for Firstgas to consider.

Near term opportunities are those that can readily be implemented in the short term, relying on existing pricing and operational frameworks and without the need for any Code amendments. Longer term opportunities are those that require more detailed analysis, or which may involve review and required amendment of either or both the MPOC and GTC.

6.1 Near term opportunities

We recommend that Firstgas consider the following near-term opportunities to modify its pricing structures:

Alignment with floor prices

As discussed in greater detail in section 4.1.2, Firstgas should undertake a detailed assessment of the actual incremental cost of service delivery in the Gisborne area (and in other areas where revenue is close to the estimated floor price) and assess whether, and to what extent, price adjustments are required so that prices meet the floor price constraint. This will improve the efficiency of Firstgas' current prices by ensuring that all consumers pay charges that cover the incremental cost of providing services to them, both on an individual and a combinatorial basis.

Pricing for renewable gas

Firstgas should consider developing a pricing policy and methodology for renewable gas. This would allow Firstgas to clearly and consistently apply a pricing methodology that is suited to a broadly distributed set of receipt points, and which assists in supporting the development of the renewable gas market. In developing this policy, Firstgas should consider the merits of:

- using 'postage stamp' based pricing that does not distinguish prices based on the geographical location of the producer to promote the development of renewable gas supplies; and
- applying a discounted transmission charge to assist in the development of the market for renewable gas, but incorporating a mechanism to reduce the size of the discount as the market matures.

In the short term, Firstgas can implement this pricing policy through the use of supplementary agreements, given the limited number of expected applications. Over time, this can be incorporated into Firstgas' standard pricing schedules.

Identify preferred long-term price structure

We have concluded in section 4.2.2 that, in the short to medium term, there should be limited need to provide discounts to standard gas transmission charges, as increasing transmission charges are unlikely to drive significant reductions in demand for natural gas within this timeframe. However, over time, expectations for declining demand across much of Firstgas' consumer base means that Firstgas does need to consider what pricing structure will best enable it to implement more efficient prices that better align with value and minimise the risk that increasing transmission charges further hasten such decline.

In this context, we consider that it is important that, in the short term, Firstgas establishes its preferred long-term price structure. From this, Firstgas can take actions that progressively move towards this outcome.

This report identifies and evaluates a number of tariff reform options and highlights a subset with the greatest potential benefit in promoting the efficiency of Firstgas' prices. However, further evaluation of the practical implications of these price options should be undertaken, including:

- If considering tariff option 5, further assessment of the preferred methodology for grouping gas users for the purpose of specifying different tariff classes, considering:
  - the pros and cons of defining tariff groups based on the nature of the consumer's business, or the nature of each shipper's usage at each delivery point;
  - if segments were to be defined according to the nature of each shipper's usage at each delivery point, quantitative analysis of demand to delivery points across the transmission system, and indicative identification of the criteria to be used to define each group;
- For any tariff options being further considered, development of indicative price specifications and modelling to enable an understanding of the impact of different tariff options by shipper and by delivery point;
- Assessing implementation issues including:
  - Evaluation of implementation risks, including whether there is opportunity to implement the tariff option in a staged manner to mitigate implementation risks; and

  - Understand what Code changes are required to enable the tariff option to be implemented
- Further stakeholder consultation on Firstgas' preferred option/s.

Modify existing price structures

Under the GTC, Firstgas has considerable flexibility in the way that it sets transmission prices. Even without Code changes, Firstgas has the opportunity to modify the balance between its fixed and variable charges and can modify the extent of charges that are applied to overruns.

However, it is important that any changes made to these price structures in the short term are aligned with Firstgas' preferred long term price structure. Accordingly, we do not recommend significant changes to these existing price structures until Firstgas has established its preferred long term price structure (discussed above). Once this preferred long term price structure is determined, Firstgas could then consider progressively implementing modifications to its existing prices to transition towards that structure.

For example:

- if Firstgas were to decide to implement a form of customer categorisation and charge differentiation, together with a simple $/GJ tariff structure, it could commence by progressively increasing the variable component of GTC pipeline charges (and reducing the capacity reservation component), and potentially also reducing the capacity overrun charge;
- if Firstgas were to decide to apply a flattening of the geographic profile of charges and developed a transition plan towards this, it could commence the implementation of this transition plan through progressive amendment of GTC pipeline charges.

6.2 Longer term opportunities

We recommend that Firstgas also consider the following opportunities, which may need to be progressed over a longer time frame.

Seek removal of MPOC constraints on efficient pricing

Firstgas should consider the need for a review of the MPOC in order to:

- seek removal of the Schedule 10 pricing methodology requirements, which limit Firstgas' ability to set efficient prices across its transmission network; and

- at the same time, include in the MPOC an ability to negotiate non-standard prices as part of supplementary agreements.

While it is likely that amendments to both the MPOC and the GTC will be required to implement Firstgas' preferred long term price structure, it may take some time to finalise this, having regard to the need for further analysis and stakeholder consultation. As a result, there may be merit in progressing Code changes in two separate steps.

Seek to modify Codes to enable implementation of preferred long term price structures

Once Firstgas has established its preferred long term price structures, it should commence the process of seeking amendment to the MPOC and GTC, where required, to enable it to implement this.

Develop price reform implementation plan

As noted above, in the short to medium term, there should be limited need for Firstgas to provide discounts to standard gas transmission charges, as increasing transmission charges are unlikely to drive significant reductions in demand for natural gas within this timeframe. This means that Firstgas has time to progressively implement its preferred long term price structure to minimise price shocks to customers, and to evaluate any unexpected effects on demand.

Reflecting this, Firstgas should consider developing a price reform implementation plan that incorporates:

- Identify sequence of steps involved, including any priority elements of reform – for example, in section 5.1.1, we identified that a short term priority would be to consider the transmission charges applicable for electricity generators, who are rapidly moving their demand towards a highly variable, high value use;

- Develop indicative price paths, which show how prices can progressively be adjusted to reflect the recommended pricing directions. These indicative price paths can then be used as a guide for Firstgas' annual price reviews, however Firstgas should retain the ability to deviate from these price paths in response to any unexpected effects on demand.

A. Firstgas current pricing arrangements

A.1 Maui Pipeline

The table sets out the fees and charges in the Maui Pipeline Operating Code.

Table 15 Shippers fees and charges

Fee/Charge	Description	Calculation method	Comments
Throughput charges			
AQ Fee	Authorised Quantity is a capacity reservation	AQ Fee = AQ * Tariff 1	Capacity reservation charge to reflect the primary driver of pipeline costs Not used by Shippers because the Maui Pipeline does not have overrun charges and capacity is not capacity constrained
Tariff 1	notionally covers capital related costs of the Maui pipeline	T1 charge = Q *GJ * km * T1 price	Reflects the two main cost drivers
Tariff 2	Covers the forecast operating costs of the Maui Pipeline	T2 charge = Nominated Q* T2 price	Reflects secondary driver of pipeline costs
Negative mismatch	Gas sold to a Shipper that does not inject as much gas as is delivered	Mismatch charge = Mismatch * mismatch price	Pricing signal to ensure Shippers supply the gas that they want delivered

Table 16 Welded Party Fees and charges

Fee/Charge	Description	Calculation method	Comments
Incentives Pool Debit			
Daily Operating Welded Point Imbalances	Notional charge (Incentives Pool Debit (IPD) for difference between aggregate daily nominations and actual metered quantities at Welded Points	IPD = GJ of difference above Daily Operating Imbalance Limit IPD charge = IPD * Incentive Debit Pool Price	If there is no claimant, no charge will be levied Rationale for this charge unclear
Excess Peak flow	Notional charge (IPD) for hourly flow exceeding the Peaking Limit at Welded Points	IPD = GJ of hourly flow above Peaking Limit IPD charge = IPD * Incentive Debit Pool Price	If there is no claimant, no charge will be levied Rationale for this charge unclear
Cash-Out purchase	Charge for accumulating operational Imbalances at Welded Points	Cash-Out cost = Cash out Quantity * Cash-Out Buy Price	Rationale for this charge unclear

A.2 GTC Pipeline

This table sets out the eight charges for Shippers on the GTC. Charges for Welded Parties arise because of the interaction between the Maui and non-Maui Pipelines and are included as part of the Balancing and Peaking Pool payments.

Table 17 Welded Party Fees and charges

Fee/Charge	Description	Calculation method	Comments
Capacity Reservation Charge	Reserves Capacity for a year	CRC = CRF * reserved capacity (GJ/day) also MDQ	Reflects the primary driver of pipeline costs
Throughput Charge	Charges for quantities of gas actually delivered	TC = Through put * TF	Reflects secondary driver of pipeline costs
Overrun Authorisation Charge	Fee for obtaining authorisation to over run	Overrun quantity to be authorised * CRF	Needed to ensure Shippers book sufficient capacity
Authorised Overrun Charge	Fee for an overrun that has been authorised	Actual overrun quantity * CRF * 8	Needed to ensure Shippers book sufficient capacity
Unauthorised Overrun Charge	Fee for an overrun that has not been authorised	Actual overrun quantity * CRF * 10	Needed to ensure Shippers book sufficient capacity
Alternative Transmissions Services Charge	Charges for providing an Alternative Transmission Service in the event of the part of GTC pipeline not being able to provide the contracted service	To be determined at the time	An interesting provision for contingency situations
Correction Charges	Charged for administration associated with correcting calculation of transmission charges	Hours of administration *$100	
Balancing Gas charges/ BPP	Charges for accumulating a gas imbalance	Complex methodology involving a Balance and Peaking Pool and the Balancing arrangements on the Maui Pipeline	Seems to be much more complex than is necessary, given the common ownership of the Maui and non-Maui Pipelines

B. Regulatory pricing frameworks

We have reviewed a sample of regulatory pricing frameworks across the energy, water and transport sectors in New Zealand, Australia and the UK to assess how they incorporate the principles of efficient pricing design. The approaches are summarised in the table below. This shows that regulatory pricing frameworks are typically structured to reflect the principles for efficient pricing, as described in section 3.2.

Table 18 Regulatory pricing frameworks summary

Jurisdiction/ sector	Regime/Regulator	Key elements of pricing principles
Energy		
New Zealand - electricity	Electricity (transmission/distribution)	Prices should be subsidy-free (i.e. should fall between incremental (floor) and stand-alone (ceiling) cost limits) Prices should reflect the impact of network use and service levels on economic cost Where prices that signal economic costs would not meet target revenues, the shortfall should be recovered by prices that least distort network use Prices should respond to customer requirements and enable negotiation
Australia - electricity	National Electricity Rules – AER	*For distribution networks:* Prices should, in aggregate, enable the full recovery of the efficient cost of providing the service Prices are to be established between floor and ceiling price limits Prices are to be based on the long run marginal cost of providing the service. Mark-ups to marginal cost (to enable full cost recovery by the service provider) should minimise the distortions to efficient pricing signals In setting prices, the service provider must consider the extent to which retail customers can mitigate the impact of changes in tariffs through their decisions about usage of services. The structure of each tariff must also be reasonably capable of: (1) being understood by retail customers that are or may be assigned to that tariff (including in relation to how decisions about usage of services or controls may affect the amounts paid by those customers) or (2) being directly or indirectly incorporated by retailers in contract terms offered to those customers *For transmission networks,* Transmission networks are subject to a prescriptive tariff structure and cost attribution methodology in relation to the provision of prescribed transmission services under a revenue cap control. The Transmission Network Service Provider must have separate prices for the following sub-categories of prescribed transmission service: (1) prescribed transmission use of system services (prescribed TUOS services) – locational component (2) prescribed TUOS services – non-locational component (3) prescribed common transmission services (4) prescribed entry services (5) prescribed exit services.

Jurisdiction/ sector	Regime/Regulator	Key elements of pricing principles
		The annual service revenue requirement for prescribed TUOS services (supplied at transmission connection points) is to be allocated between a locational and non-locational component either: (1) 50% to each component; or (2 an alternative allocation to each component, that is based on a reasonable estimate of future network utilisation and the likely need for future transmission investment, and that has the objective of providing more efficient locational signals to market participants and end users Prices for recovering the locational component of prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network by transmission customers and for which network investment is most likely to be contemplated. Locational prices are charged on a fixed demand ($/kw) basis. The non-locational TUOS and prescribed common transmission services must use postage stamp prices (on a demand and/or volumetric basis) and the prescribed entry and exit services must use fixed dollar annual charges.
	National Gas Rules – AER	Prices should, in aggregate, enable the full recovery of the efficient cost of providing the service Prices are to be established between floor and ceiling price limits Prices are to have regard to the marginal cost of providing the service. Mark-ups to marginal cost (to enable full cost recovery by the service provider) should minimise the distortions to efficient pricing signals
UK – gas and electricity	Electricity and gas - OFGEM	Revenue cap regulation is applied Pricing rules are established for some services. Assessment is primarily based on the impact of the *change* in price, rather than an *in-principle* statement of pricing objectives.
Transport		
New Zealand - rail	n/a	
Australia - rail	National Access Regime - ACCC	Prices should, in aggregate, enable the full recovery of the efficient cost of providing the service Prices are to be established between floor and ceiling price limits Price discrimination is permitted to maximise demand Limits on price discrimination can be applied within the same end market
	Queensland Access Regime – QCA	Prices should, in aggregate, enable the full recovery of the efficient cost of providing the service Prices are to be established between floor and ceiling price limits Price discrimination is permitted to maximise demand Limits on price discrimination can be applied within the same end market
	WA Rail Access Regime - ERA WA	Prices to be established between floor and ceiling price limits Price discrimination is permitted to maximise demand Limits on price discrimination can be applied within the same end market Prices should enable the full recovery of any costs of network expansion to meet customer requirements
Water		
New Zealand	n/a	
Australia	Bulk water - ACCC	Prices should promote the economically efficient use of water infrastructure assets

Jurisdiction/ sector	Regime/Regulator	Key elements of pricing principles
		Prices should ensure sufficient revenue streams to allow efficient delivery of the required services Prices should reflect the principles of user pays
	Bulk water - QCA	Prices should enable the full recovery of the efficient cost of providing the service Prices should signal the efficient use of services Prices should signal the costs associated with augmentation of water supply infrastructure
UK	Bulk water – OFWAT	Revenue cap regulation is applied, with pricing rules established for some services Prices should promote key objectives, including fairness and affordability; environmental protection; stability and predictability; and transparency and customer-focussed service Prices should reflect the long term run cost of delivering the services Differentiation between small and large users of the same services can only occur to reflect cost impacts