Regulatory options for New Zealand's gas transmission system

22 December 2022

Building a better working world

RELEASE NOTICE

Ernst & Young was engaged on the instructions of the Gas Industry Co. ("Client") to deliver a report describing options for the economic regulation of the gas transmission network to support the development of the Gas Transition Plan (GTP), in accordance with the engagement letter dated 26 October 2022.

The results of Ernst & Young's work, including the assumptions and qualifications made in preparing the report, are set out in Ernst & Young's report dated 22 December 2022 ("Report"). The Report should be read in its entirety including the transmittal letter, this notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

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We do not imply, and it should not be construed that we have verified any of the information provided to us, or that our enquiries could have identified any matter that a more extensive examination might disclose.

22 December 2022

Caitlin Tromop van Dalen
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New Zealand

Dear Caitlin,

Regulatory options for New Zealand's gas transmission system

We are pleased to present our report *Regulatory options for New Zealand's gas transmission system* as per the terms agreed in our engagement letter dated 26 October 2022.

Purpose of our report and restrictions on its use

This report was prepared on your instructions solely for the purpose of supporting the Gas Industry Co. (GIC) to conduct research for the Gas Transition Plan (GTP) into the role of economic regulation of gas transmission infrastructure in New Zealand's decarbonisation journey. The report should not be relied upon for any other purpose. In carrying out our work and preparing our report, we have worked solely on the instructions of GIC and for GIC's purposes.

Our report may not have considered issues relevant to any third parties. Any use such third parties may choose to make of our report is entirely at their own risk and we shall have no responsibility whatsoever in relation to any such use. We disclaim all responsibility to any other party for any loss or liability that the other party may suffer or incur arising from or relating to or in any way connected with the contents of this report, the provision of this report to the other party or reliance upon this report by the other party.

Scope of our work

To support GIC in conducting research for the GTP this report has provided:

- An outline of the current regulatory settings for gas transmission in New Zealand
- A set of criteria for ensuring the regulatory framework supports the gas transition
- An overview of economic regulation options for gas transmission networks including price cap, revenue cap, hybrid regulation and deregulation
- An insight into how other jurisdictions such as Australia, the United Kingdom and California are approaching the gas transition
- A review of economic regulation and transitions in adjacent industries such as telecommunications and postal services
- A final assessment of regulatory options for New Zealand's gas transition
- Appendices outlining the regulatory settings applied to gas transmission in Australia, the United Kingdom and Europe.

In preparing this report we have considered and relied upon information from a range of sources believed to be reliable and accurate. We have not been informed that any information obtained from public sources was false. Responsibility for its accuracy and completeness does not rest with Ernst & Young Limited.

Our work has been limited in scope and time and we stress that a more detailed report may reveal material issues that this report has not.

If you would like to clarify any aspect of this report or discuss other related matters, then please do not hesitate to contact us.

Yours sincerely

Paul Melville
Partner

Executive summary

The New Zealand energy system is currently undergoing a transformation as the country seeks to reach a net zero carbon economy by 2050, as required in the *Climate Change Response Act 2019*. Part of the transition includes decreasing reliance on fossil fuels, including natural gas.

At the time of writing this report, the *Gas Transition Plan*[1] is being developed to establish transition pathways for the fossil gas sector in line with the emissions budgets, provide a framework to inform and engage with stakeholders about the challenges and opportunities for the sector and establish a strategic view on the potential role for renewable gases. The *Gas Transition Plan Terms of Reference* sets out five desired outcomes for the overall transition for fossil gas out to 2035:

- **Sustainability:** Aotearoa New Zealand avoids making decisions that further lock in our reliance on fossil fuels
- **Energy Security:** Security of supply is maintained through the transition, as fossil gas continues to be progressively displaced by renewable, lower emissions, alternatives
- **Energy Equity:** adverse and unexpected effects on fossil gas consumers are prevented or mitigated and consumers retain access to affordable, reliable and abundant energy. This includes minimising the broader effects on prices paid by consumers, as well as pricing of inputs for businesses as we transition
- **Emission Reductions:** Aotearoa New Zealand prioritises reducing emissions in the most economically efficient way. The pace of emissions reductions will need to support Aotearoa New Zealand's emissions budgets and 2050 emissions targets
- **Energy Conservation and Efficiency:** energy conservation and efficiency play a key role in the overall transition.

This report has been written to support the development of the *Gas Transition Plan* on issues relating specifically to the gas transmission network and the impact that changing gas demand will have on its economic regulation. We have not considered the economic regulation of the gas distribution networks in this report.

The gas transmission network is owned by First Gas and takes gas from over 15 producing fields in Taranaki and transports it to gas distribution networks, industrial facilities, and electricity generators around the North Island. There is no gas transmission network in the South Island.

The gas transmission is subject to economic regulation under Part 4 of the *Commerce Act 1986*. This defines the revenue that the gas transmission business (GTB) can receive to cover its capital and operating costs. The revenue comes almost entirely from pipeline charges, paid by shippers and interconnected parties, on both a fixed and volume basis. These costs are then passed through to consumers.

To date, the revenue cap model defined by the price-quality path under Part 4 regulation has been suitable for recovering costs of running and investing in the gas transmission network. This is because demand for gas has generally been stable with no significant long-term changes in gas supply or consumption.

As New Zealand transitions to a net zero economy, the demand for fossil gas is set to decrease. He Pou a Rangi, the Climate Change Commission[2], suggested in its final advice that under the Demonstration Path, demand for fossil gas could decrease from around 191.7 PJ in 2020 to 26.1 PJ in 2050, an 86% decrease. Under current regulatory settings, a reduction in gas throughput

[1] MBIE, Terms of Reference – Gas Transition Plan

[2] Climate Change Commission, Figure 8.7, Ināia tonu nei: a low emissions future for Aotearoa (2022)

increases the risk for the gas transmission network owner to under recover the costs of their investment and/or will require significant increases in transmission prices paid by consumers. These outcomes are not aligned with the desired outcomes of the *Gas Transition Plan*.

In this report, we examine the potential economic regulation options, such as price cap and revenue cap models and deregulation, that could be applied to the New Zealand gas transmission network to ensure it aligns with the desired outcomes set in the *Gas Transition Plan Terms of Reference*. We also consider the performance of different regulatory options in relation to the purpose of monopoly regulation and Part 4 of the *Commerce Act 1986*, the effort to implement regulatory change and potential impacts on the GTB.

The findings in this report are based on a literature review of regulatory models used in Australia, the United Kingdom and other jurisdictions around the world, as well as various studies on how to manage infrastructure returns during the gas transition. We have also drawn on existing work in New Zealand and similar transitions in adjacent industries, such as telecommunications. Our analysis is focused on a scenario where fossil gas throughput is declining and is not displaced at scale by an alternative renewable gas.

This report seeks to examine potential options available to the gas transmission regulators and does not seek to recommend specific regulatory changes that should be implemented in New Zealand. More detailed analysis on potential options will be required to determine a way forward.

Our high-level assessment suggests that, in a future where gas volumes through the transmission network will decline, there is no clear evidence that an alternative regulatory option, different to the current revenue cap model, would be better suited to align the gas transmission network with the outcomes set in the *Gas Transition Plan*.

Each regulatory option could play a role in the gas transition depending on which outcomes are most important for the gas transition. For example, if protecting consumers from gas price shocks has a relatively higher importance than the other criteria, then the price cap model is likely to be better because the price is set from the outset and has limited ability to increase in response to falling gas throughput. However, declining gas throughput results in declining units of gas that the GTB can charge for. This creates the risk that the business will under recover their revenue and may not be able to recover their costs. A revenue cap model decreases this risk for the business as prices may better encourage continued investment, particularly in safety and reliability, but will have a more limited ability to protect consumers from price shocks. Trade-offs will be required in whichever option is used.

Instead of changing the regulatory option applied to transmission networks, how the incentives and mechanisms within the regulatory option are set and how directive the regulator chooses to be will likely make the most impact.

Research into gas transitions in other jurisdictions suggests that the design of incentives and potentially more directive mechanisms within each regulatory option are important for encouraging the desired behaviours from the GTB, other industry players and end consumers.

Designing components within the regulatory regime to better align the gas transmission network operation with a future where fossil gas throughput is expected to decrease is already being used in New Zealand. For example, the *Default Price-Quality Path 3 (DPP3)* process resulted in shortening the expected economic lives of assets to ensure costs of investing in these assets are recouped earlier and reduces risk of asset stranding. This change increases the depreciation allowance for the regulatory period, bringing revenue forward and maintaining the incentive to invest. The regulatory period was also shortened to four years so that the impact of relevant Government policy decisions can be realised sooner in the next DPP.

There are numerous avenues that could be considered to influence the right behaviours but would require more analysis to fully understand the costs and benefits. For example, the regulator could choose to be more directive in the role it desires the GTB to play in the gas transition by reducing the revenue allowance associated with funding new connections through the *Asset Management Plan* (AMP) allowances. Currently, the GTB has capital expenditure allocated in the AMP to fund new connections for customers seeking to connect to the network. If the business does not fund new connections, then the connecting customer would be required to fund the connection themselves. This additional cost for the customer would act as a disincentive to connecting and consequently avoid the additional gas use associated with the new connection. This approach may also have implications for competition in the gas market (which is an objective within the Gas Policy Statement) so further analysis of the costs and benefits would be required before implementation.

An important consideration for the regulatory framework applied to the gas transmission network is whether the GTB should be able to have full return of capital and return on capital from consumers (as it does currently), via other avenues (such as the compensation options being considered in Australia), or not at all. This is important because the regulated asset base (RAB) is fundamental in revenue setting. The ability for utility owners to have a return on capital and return of capital sits at the heart of the 'regulatory compact' for economic regulation – a fair return on capital in return for equitable service.

The regulator could choose to decrease the weighting that the RAB has on the revenue or price setting. For example, revenue/price could be set at a level that only recovers the GTBs operating costs, plus some return, or only a portion of the return of capital. This could keep prices to end consumers at a reasonable level and protect consumers from price shocks. However, changes to the ability of the GTB to have return on and return of capital would change the owner's business risk and undermine the regulatory compact. In most cases compensation has been required if a decrease in return of the RAB is mandated by the regulator.

Finally, the regulator could choose to use the pricing principles or a more directive mechanism to incentivise certain behaviours. This could be targeted at certain classes of customers or regions to encourage switching away from fossil gas or switching to renewable gas. However, this would again put the operator's revenue at risk and therefore could undermine the fair return and regulatory compact with the owner.

Detailed analysis into these potential levers is required to ensure the right behaviours are incentivised and that unintended consequences are avoided.

We also identified that deregulation may play a role in the gas transition but likely only in a staged approach.

A similar approach could be used as used in the copper to fibre transition where parts of the network are deregulated over time as the critical mass of consumers transition to alternative energy sources. Safeguards and careful deregulation design would be required to protect consumers from adverse effects.

The gas transmission network can play its role in enabling the gas transition and decarbonising New Zealand's energy use

In this research, we set out to understand whether changing the regulatory framework that sets the revenue and/or price settings for the gas transmission network would better enable the network to support the gas transition in light of declining gas throughput. Our high-level assessment suggests that there is no clear evidence that an alternative regulatory option would be better suited to align the gas transmission network with the outcomes set in the *Gas Transition Plan*. Instead, how the incentives and mechanisms within the regulatory option are set and how directive the regulator chooses to be will likely make the most impact.

Contents

1. Context of this report

The New Zealand energy system is currently undergoing a transformation as the country seeks to reach the net zero carbon economy by 2050, as required in the *Climate Change Response Act 2019*. Part of that transition includes the decreasing reliance on fossil fuels, including natural gas. To give effect to this target, the *Emissions Reduction Plan 2022* set out within *Action 11.3.1: Manage the phase-out of fossil gas* states the need for a Gas Transition Plan.[3]

The purpose of the *Gas Transition Plan*[4] is to establish realistic, but ambitious, transition pathways for the fossil gas sector in line with the emissions budgets, provide a framework to inform and engage with stakeholders about the challenges and opportunities for the sector and establish a strategic view on the potential role for renewable gases.

The *Gas Transition Plan Terms of Reference* sets out five desired outcomes for the overall transition for fossil gas out to 2035:

- **Sustainability:** Aotearoa New Zealand avoids making decisions that further lock in our reliance on fossil fuels
- **Energy Security:** security of supply is maintained through the transition, as fossil gas continues to be progressively displaced by renewable, lower emissions, alternatives
- **Energy Equity:** adverse and unexpected effects on fossil gas consumers are prevented or mitigated and consumers retain access to affordable, reliable and abundant energy. This includes minimising the broader effects on prices paid by consumers, as well as pricing of inputs for businesses as we transition
- **Emission Reductions:** Aotearoa New Zealand prioritises reducing emissions in the most economically efficient way. The pace of emissions reductions will need to support Aotearoa New Zealand's emissions budgets and 2050 emissions targets
- **Energy Conservation and Efficiency:** energy conservation and efficiency play a key role in the overall transition.

As the industry co-regulator, the Gas Industry Company is responsible for developing the *Gas Transition Plan*, in partnership with the Ministry for Business, Innovation and Employment. The purpose of this report is to support the development of, and stakeholder engagement with, the *Gas Transition Plan* on issues relating specifically to the gas transmission network and the impact that changing gas demand will have on its economic regulation.

This report will examine the potential economic regulation options that could be applied to the New Zealand gas transmission network. This report focuses on revenue for the transmission network owner/operator and the return of capital investments in a future where throughput on the gas transmission network is declining/has declined (return of capital and return on capital). This report does not explicitly examine price setting options (which would be covered in a transmission pricing methodology and is not part of this report). This report also does not examine regulatory settings for the gas distribution networks.

Currently, gas pipeline businesses are regulated by the Commerce Commission, under Part 4 of the *Commerce Act*. Part of the regulatory framework defines the revenue that the GTB can receive to cover its capital and operating costs. The revenue comes almost entirely from pipeline charges, paid by shippers and interconnected parties, on both a fixed and volume basis. These costs are then passed through to consumers, most of whom are residential, through their arrangements with gas suppliers. Gas producers do not pay for access to the gas transmission network. The pipelines are

[3] Ministry for the Environment, Emissions Reduction Plan, Chapter 11 Energy and Industry (2021).
[4] MBIE, Terms of Reference – Gas Transition Plan.

open access with terms and conditions of access set out in the *Maui Pipeline Operating Code* and the *Gas Transmission Code*. Pricing is set annually through the *Transmission Pricing Methodology*.

To date, the current regulatory framework has been suitable for recovering costs of running and investing in the gas transmission network. Demand for gas has generally been stable with no significant long-term changes in gas supply/consumption.

As New Zealand transitions a to net zero economy, the demand for natural gas is set to decrease. He Pou a Rangi, the Climate Change Commission[5], suggested in its final advice that under the Demonstration Path, demand for gas could decrease from around 191.7 PJ in 2020 to 26.1 PJ in 2050, an 86% decrease. Under current regulatory settings, a reduction in gas throughput increases the risk for the gas transmission network owner to under recover the costs of their investment.

A future with reduced gas throughput is one example of the range of possible futures for the gas transmission network. The Gas Industry Company has defined a set of scenarios to use within the Gas Transition Plan. These scenarios are not discussed in detail here. For this report, we have assumed that if natural gas is displaced at scale with an alternative gas, such as hydrogen or biogas, and the current infrastructure is able to be used, then it is likely that there will be little merit in moving from the existing regulatory framework.

[5] Climate Change Commission, Figure 8.7, Ināia tonu nei: a low emissions future for Aotearoa (2022).

2. Current regulatory settings for gas transmission networks in New Zealand

The New Zealand gas transmission infrastructure is owned by First Gas and takes gas from over 15 producing fields in Taranaki and transports it to gas distribution networks, industrial facilities, and electricity generators around the North Island.[6] This includes the First Gas transmission pipeline and the Maui pipeline, and there is no gas transmission network in the South Island.[7] This section discusses the current regulatory settings for the gas transmission network. Table 1 provides a summary of the contents of this section.

Table 1: Summary of New Zealand gas transmission network regulation

Economic Regulating Authority	Legal framework	Regulatory Framework	Regulatory Period	Main elements to determine revenue cap
Commerce Commission	Part 4 of the Commerce Act	Revenue cap with a wash-up mechanism	4 years (previously 5 years)	The building blocks of allowable revenue: return on capital, depreciation, Opex, tax, revaluations

As monopoly infrastructure, the New Zealand gas transmission network is regulated by the Commerce Commission under Part 4 of the *Commerce Act*. The purpose of monopoly regulation by the Commerce Commission is to benefit consumers in the long-term so that suppliers:

- have incentives to innovate and to invest, including in replacement, upgraded, and new assets
- have incentives to improve efficiency and provide services at a quality that reflects consumer demands
- share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices
- are limited in their ability to extract excessive profits.[8]

Under the *Commerce Act*, GTBs are regulated through price-quality regulation in the form of default and customised price paths. The default price path (DPP) is used to set the maximum allowable revenue (MAR) a GTB can earn from its customers which means the overarching New Zealand regulatory framework for the gas transmission network is a revenue cap. The Commerce Commission also has the ability to set a customised price-quality path (CPP) to better suit the specific needs of a GTB and its customers, but a CPP is only set if it requested by a GTB and approved by the Commerce Commission. For example, if a GTB wanted to make expenditure at a level higher than is allowed for in the DPP they may desire a CPP. There are currently no CPPs in place in New Zealand.[9]

DPPs are set for GTBs for the length of the regulatory period (currently four years) and determine the maximum annual revenue net of pass-through and recoverable costs that they are allowed to earn, and the minimum quality standards they must maintain. In New Zealand, DPPs are set for all

[6] Working Group Future Working Group, NZ Gas Infrastructure Future, Findings Report (2021).

[7] First Gas, Our Network.

[8] Commerce Act Part 4, s 52A.

[9] Commerce Commission, Gas pipelines customized price-path.

gas pipeline businesses (distribution and transmission) that are regulated under Part 4 of the Commerce Act using the building blocks of allowable revenue (BBAR).[10]

From 1 October 2022 to 30 September 2026 (the current regulatory control period) GTBs are subject to the revenue cap specified in the *Gas Transmission Services Default Price-Quality Path Determination 2022*, otherwise known as DPP3.[11] The allowable revenue that GTBs can earn is dependent on the value of the regulatory asset base (RAB) and allowable rate of return as set by the Commerce Commission in the price path. Most of the inputs for setting the price-quality path are set out in the Input Methodologies (IMs) that are also developed by the Commerce Commission, however Capex and Opex are determined based on the DPP and not the IMs.

First determined in 2010, the IMs are the rules and processes that provide certainty about how the Commerce Commission will regulate gas transmission pipelines under Part 4 of the Commerce Act and must be applied when the Commerce Commission is setting price-quality paths and determining information disclosure (ID) requirements.[12] The IMs outline how the Commerce Commission values and depreciates assets, allocates Capex and Opex, shares risk, treats tax and outlines how GTBs are compensated for their investments. They must be reviewed at least every 7 years under Part 4, with a review currently being undertaken and due for completion in February 2023. A summary of the IMs from the 2012 determination that were consolidated in April 2018 is provided in Table 2.

Table 2: Summary of input methodologies in the 2012 determination (consolidated in 2018)[13]

Summary of Input methodologies	
Cost allocation	Operating expenditure (service interruptions, incidents and emergencies, routine and corrective maintenance and inspection, compressor fuel, land management and associated activity, system operations, network support, business support)
	Capital expenditure (connections, system growth, asset replacement and renewal, relocations, reliability, safety and environment)
Asset valuation	RAB values and roll forward
	Total depreciation
	Total revaluation
Taxation	Regulatory tax allowance
	Tax losses
	Depreciation temporary differences
	Notional deductible interest
Cost of capital	Estimating the weighted average cost of capital
	Fixed WACC parameters
	Estimating risk-free rate
	Estimating average debt premium
	Estimating the 67th percentile estimate of WACC
	Publication of estimates
	Application of cost of capital methodology
	Methodology for estimating term credit spread differential
	Term credit spread difference
	Interpretation of terms relating to term credit spread differential
Reconsideration of the default price-quality path	Catastrophic Event
	Change event
	Error event
	Major transaction
	When price-quality paths may be reconsidered
	Amending price-quality path after reconsideration

[10] Commerce Commission, Introduction to the DPP for stakeholders (2018).
[11] Commerce Commission, Gas Transmission Services Default Price-Quality Path Determination 2022.
[12] Commerce Commission, 2023 Input Methodologies Review.
[13] Commerce Commission, Gas Transmission Services Input Methodologies Determination 2012.

Treatment of periods that are not 12 month periods	-
Availability of Information	-

Most of the GTB allowed revenue is defined using the BBAR methodology to define a Maximum Allowable Revenue (MAR) for each year. However certain costs are considered outside the control of the GTB and are allowed to be recovered in addition to the MAR. These 'pass through' and recoverable costs include items such as compressor fuel, balancing gas costs, rates and levies are added to the MAR to give the total revenue to be recovered each year.

The DPP allows for revenue stability for the GTB operator by allowing over recovery of revenue or under recovery up to 20% of revenue to be washed up to future years. This means that if the GTB operator over recovers revenue in any year the allowable revenue in 2 years' time will be reduced by the amount of the over recovery and vice versa for under recovery. This ensures that returns remain in line with the risk profile of long life, high Capex assets.

The Commerce Commission also requires certain information disclosure from pipeline businesses. In line with this requirement, GTBs share an Asset Management Plan (AMP) that sets out their planned asset investment and maintenance to meet future consumer demand. This document is updated annually and outlines Capex and Opex forecasts moving forward. Importantly, this information includes regulatory asset base categories, network expenditure, non-network expenditure and customer connection costs, which can significantly impact the Opex and Capex values used in the building blocks, and the setting of the MAR.[14]

Therefore, the overall form of revenue regulation in New Zealand for the gas transmission network is a revenue cap (set through the DPP) with an annual wash-up mechanism, and ID requirements. This revenue cap limits the maximum revenue a GTB can make for a year. In comparison, gas distribution businesses (GDBs) are subject to a maximum average price cap, otherwise known as a weighted average price cap.[15]

Under revenue cap regulation the customers take on most of the regulatory period demand risk (i.e., the risk of demand being significantly lower or higher than expected will impact prices). The GTB is still exposed to some level of demand risk under the revenue cap as they can recover no more than a 20% reduction in revenue compared to forecast under the wash-up mechanism. Part of a GTB's forecast revenue is based on prices multiplied by forecast quantity and so the annual wash-up mechanism ensures revenues are not over or under recovered relative to the revenue cap. [16] The Commerce Commission believes the revenue cap is the most suitable regulatory option because GTBs are highly exposed to volatility in demand due to external factors, and the revenue cap places the within-period demand risk with the party who can best manage this risk.

In the *2016 Input methodologies review*[17], the overall form of regulatory control for GTBs was under discussion and changed from a 'lagged' revenue cap to a 'pure' revenue cap with an annual wash-up mechanism. The IMs had previously allowed the Commerce Commission to choose between a weighted average price cap and a lagged revenue cap for GTBs. As outlined in *Topic paper 1*[18] on the form of control, the Commerce Commission made this change because the use of lagged quantities had allowed for windfall gains and losses by GTBs, potentially creating inappropriate incentives for GTBs to underinvest in their networks to prevent a windfall loss. The Commerce Commission believed that not exposing GTBs to demand risk they will be able to better invest in the network and allow for more stable prices, which is in the long-term interests of consumers. Allowing

[14] First Gas, Asset Management Plan Update 2022.

[15] Commerce Commission, DPPs for gas pipelines from October 2022 Final Reasons paper.

[16] Commerce Commission, DPPs for gas pipelines from October 2022 Final Reasons paper.

[17] Commerce Commission, Input methodologies review: decisions summary paper (2016).

[18] Commerce Commission, Input methodologies review decisions (2016), Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower.

for an annual wash-up mechanism also incentivises GTBs to offer more innovative tariffs and allows for the introduction of capacity auction-based pricing to better utilise pipeline capacity[19].

2.1 Building Blocks of Allowable Revenue (BBAR)

As mentioned above, price-quality regulation by the Commerce Commission uses a BBAR method to align the financial interests of GTBs and their customers by incentivising GTB cost reduction. This alignment of incentives is achieved over regulatory control periods, where the maximum revenues for delivering transmission services over the period (currently DPP3) are outlined at the beginning of the period and provide an opportunity for the GTB to earn its allowed revenues. These allowed revenues are designed to mimic what the GTB would earn if the market was competitive (and not a monopoly). When GTBs reduce their costs in an efficient manner they receive higher profits under the revenue cap and the efficiencies can be shared with customers in the next DPP reset through reduced revenues.[20]

As outlined in DPP3[21], the starting prices allowed in the first year of the regulatory period and the rate of change in revenue from year to year are the two main components of the overall revenue cap. The starting price in the first year of the regulatory period is the maximum allowable revenue (MAR) net of pass through and recoverable costs which is calculated using the building blocks of allowable revenue (BBAR). Therefore, the starting price is based on current and projected profitability and not revenue rolled over from the previous regulatory period.

Figure 1 depicts the building blocks of allowable revenue (BBAR) used to calculate the MAR. These building blocks are set equal to forecast costs to allow GTBs to earn the revenue required to meet their costs and make a fair return on their investments. The methodology for determining the value of the building blocks is provided by the IMs (outlined above) and DPP reset decisions.

The BBAR values for each year of the regulatory period can fluctuate year to year and are smoothed out to produce a price path referred to as the MAR. The MAR values for the second to the fourth year of the regulatory period are calculated by applying the CPI-x (rate of change) formula to the previous year's MAR and therefore the present value of BBAR should equal the present value of MAR.

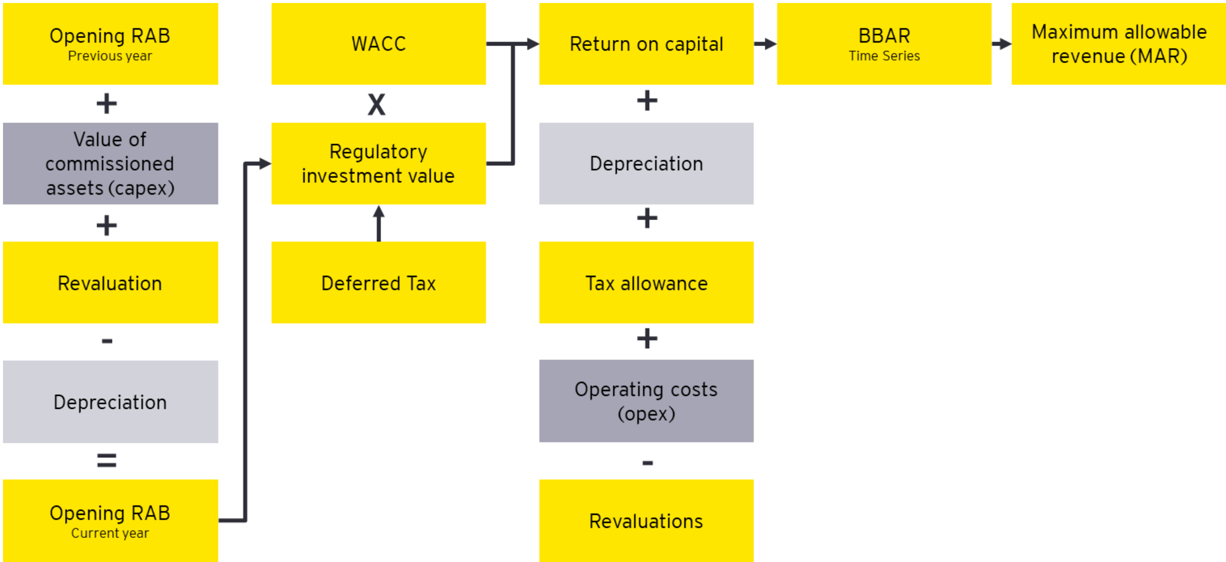
The choice of x-factor in the rate of change formula does not impact the present value of the revenue the GTB can earn over the regulatory period. This is because it determines the timing of the MAR that the GTB can earn over the period, rather than the present value. In DPP3, the WACC rate and the allowed Capex and Opex levels have a larger influence on the change in starting price compared the previous regulatory period. The biggest influences on the BBAR are the RAB (which influences depreciation and return on capital calculations) and Opex figures.

[19] Capacity allocation was a significant issue in the gas transmission system prior to the retirement of the Otahuhu B power in 2015. Most parts of the gas transmission system now have adequate capacity for current demand.

[20] Commerce Commission, DPPs for gas pipelines from October 2022 Final Reasons paper.

[21] Commerce Commission, DPPs for gas pipelines from October 2022 Final Reasons paper.

Figure 1 Building blocks of New Zealand economic regulation[22]



The regulatory asset base (RAB) is the value of the GTB network assets which depreciate over time and are indexed to account for inflation. The Commerce Commission discussed their approach to RAB indexation and inflation risk in *Topic Paper 1*[23] from the 2016 IM review. The paper addressed issues raised by gas pipeline businesses, including that the Commerce Commission approach to indexing exposes them to inflation risk. However, the Commerce Commission believes their approach creates a price path with a real return on capital and the revaluation of the RAB compensates for any inflation over the regulatory period. While there is potential for forecasting errors, there is no alternative approach that provides inflation protection to the RAB. The indexation of the RAB means that if inflation is higher than forecast, the RAB is revalued higher by an equal amount, and vice versa, with the expected revaluation gain deducted from the MAR. This means that the price path includes a real return on capital with compensation for inflation over time. If the RAB was unindexed the impact on the revenue path would be higher revenues in the earlier part of the asset's life, with lower revenues later in the asset's life when compared to an indexed RAB.[24]

Table 3 outlines the building blocks that make up the allowable revenue for DPP3 and the figures are taken from the Commerce Commission's financial model[25]. The BBAR is calculated using the following formula which adjusts costs to be at the end of each year in the regulatory period (period-end terms):

BBAR = return on capital + depreciation + Opex x TFmid + (regulatory tax allowance) x TFtax – other regulated income x TFmid

Where TFmid = 1.0302 and TFtax = 1.0302

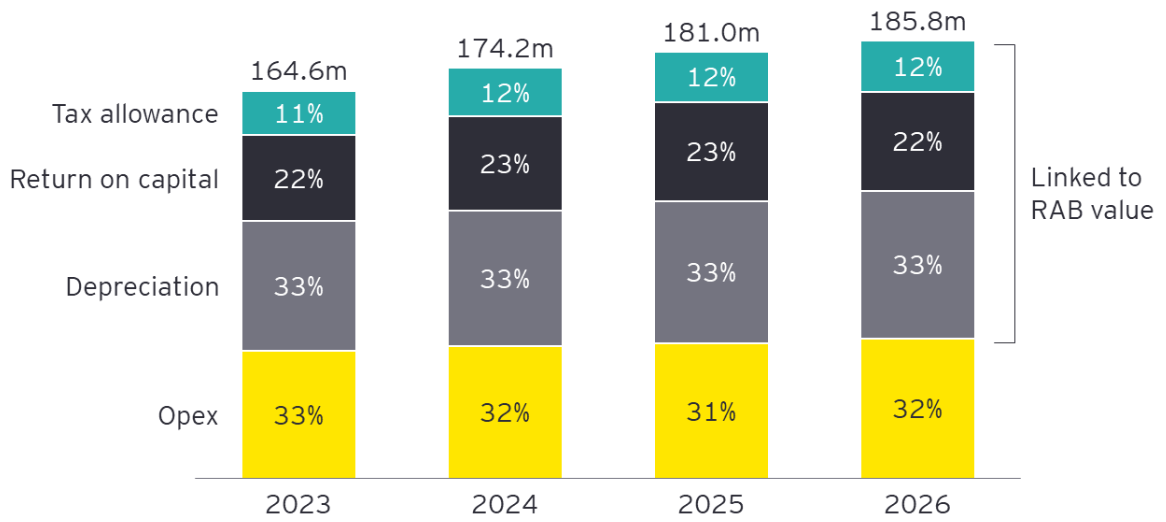
[22] Commerce Commission, Figure E1, Default price-quality paths for gas pipeline businesses from 1 October 2022: Final reasons paper.
[23] Commerce Commission, Input methodologies review decisions (2016), Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower.
[24] Australian Energy Regulator, Why do we index the regulatory asset base?
[25] Commerce Commission, Gas DPP3 final - Financial model - 31 May 2022.

Table 3: Key components of the BBAR for DPP3

BBAR before tax in BBAR period-end terms, direct simple calculation				
	2023 ('000)	2024 ('000)	2025 ('000)	2026 ('000)
Return on capital	36,039	39,518	41,438	41,466
Depreciation	54,142	56,778	59,531	62,016
Opex	53,513	55,336	56,654	58,465
Regulatory tax allowance	18,705	20,263	21,042	21,482
BBAR (calculated as per the formula above)	164,576	174,181	181,009	185,840

As shown in Figure 2, when these values are converted to a percentage of the BBAR it is evident that depreciation (which is calculated from the RAB) is the largest portion of the BBAR, followed closely by operating expenditure. Return on capital is also a significant component within the BBAR, which is linked to the value of the RAB. Finally, the regulated tax allowance is calculated from the pre-tax revenue minus Opex and depreciation so is therefore also heavily influenced by the RAB value.

Figure 2: Building blocks for DPP3 as a percentage of the BBAR



While we have simplified the calculation, the design of the methodology is such that the RAB value contributes significantly to all but the Opex building block. As the assets are long lived and require significant upfront investment, it has been appropriate that return on capital and return of capital should be fundamental to the methodology. As a result, there is little linkage between revenue and gas throughput. This is where the challenge arises for the GTBs, as the revenue required to cover both capital and operating costs may need to be more strongly linked to gas throughput if we are to maintain the 'regulatory compact' in a future with declining gas throughput.

Under the current regulatory framework, the RAB is unlikely to change materially due to decreased gas throughput, therefore regardless of whether gas throughput declines. This is because the existing infrastructure, and the required maintenance, renewal and refurbishment, will be required as the network is in service. If, however, gas throughput declines to the point where parts of the network can be decommissioned, then this would decrease the RAB and the related revenue requirements.

Underlying operating costs will more likely be correlated to decreased gas throughput (and any network decommissioning), however, the net direction of the change of costs is uncertain. For example, costs relating to typical network operations are likely to be largely fixed as long as the network is in service. The effects of decreased gas throughput on service interruptions, incidents, emergencies and maintenance and the costs required to respond to those needs are uncertain.

As the design of the BBAR methodology does not allow allowable revenues to materially decrease in line with the decline in gas throughput, then recovery of revenue will need to be spread over a smaller volume of gas throughput. This is likely to result in prices to end consumers increasing on a unit throughput basis. We expect that there will be different price impacts on different customer groups (such as residential, commercial and industrial) but these impacts have not been explored in detail in this report.

2.2 DPP3 decisions relating to the gas transition

A review into the DPP for GTBs was completed on 31 May 2022 and is known as DPP3. This reset considered how New Zealand's transition to a net zero emissions economy by 2050 could impact the setting of the revenue cap and made changes to the price path and revenue cap as a result. The most significant changes were the reducing of the regulatory period from five to four years and the shortening of the economic lives of new and existing assets. Table 4 summarises the changes made to the price path as a result of DPP3 decision-making. Key considerations when making these changes were:

- Whether the length of the regulatory period should be changed
- Whether expenditure allowance levels should be altered
- The cost of investigating whether to add some low or no carbon gas to natural gas
- Whether some of the capital costs of providing natural gas pipeline services should not be assumed to require recovery from natural gas consumers as the pipelines may have a future use – and value – conveying other gases (such as hydrogen)
- Whether the Commerce Commission should change the remaining asset lives to reflect their remaining economic lives rather than physical lives
- The extent to which prices to consumers of gas pipeline services should rise as a result of an uncertain future.[26]

Table 4: How declining demand for natural gas influenced DPP3 decisions[27]

DPP3 Decision	Summary of Decision
Shortened the average lives of new and existing assets to calculate depreciation	Shortened asset lives to better reflect the remaining economic lives of the networks, which increases the depreciation allowance for the regulatory period, bringing revenue forward and maintaining the incentive to invest. This allows GTBs to

[26] Commerce Commission, DPPs for gas pipelines from October 2022 Final Reasons paper.
[27] Commerce Commission, DPPs for gas pipelines from October 2022 Final Reasons paper.

	recover their investment and receive a normal rate of return within the estimated timeframe remaining for natural gas use.
Shortened the regulatory period to four years	Shortened the period so that the impact of relevant Government policy decisions can be realised sooner in the next DPP.
Did not change the overall regulatory setting from the revenue cap	A change to the overall regulatory framework was considered but not actioned. This was because at this time a change would not result in better outcomes for consumers or a reduction in compliance costs, regulatory costs or complexity. The Commerce Commission believes the revenue cap places the within-period demand risk with the best party to manage it and promotes the purpose of Part 4.
Set Capex based on historical figures and Opex based on forecasts	Capex and Opex allowances were set to support sufficient network maintenance and growth but also protect customers from unnecessary investment. GTBs forecast Capex is limited to a projection of historical average real Capex. Allowances include Capex for asset replacement/renewal and new customer connections. Opex is set in line with forecasts in Asset Management Plans but is capped based on Commerce Commission forecasts. Base, step and trend Opex modelling is used to test GTB forecasts and check they are reasonable. Opex is treated differently to Capex as it is generally easier to predict.
Allow Opex to research transitioning to blended gases	Research expenditure allowed for to acknowledge the need to consider and plan for an uncertain gas future.
Provided expenditure event and risk reopeners	Reopeners provided to allow GTBs to get additional funding to respond to growth or risks that were unforeseen at the beginning of the regulatory period.
Smoothing price increases of GTBs to prevent excessive profits	Smoothing of price increases to limit the impact of DPP3 decisions that could have resulted in a significant initial price increase for consumers in the first year if not smoothed.

3. Criteria for ensuring the regulatory framework supports the gas transition

The regulatory framework that is applied to the revenue setting for GTBs will significantly influence the role that the transmission network has in enabling the desired outcomes described in the *Gas Transition Plan Terms of Reference*. To assess the suitability of different regulatory settings for the New Zealand gas transmission network, we have developed a set of assessment criteria that cover the key outcomes that the Gas Transition Plan is trying to achieve, the impacts on the industry and the applicability or effort required to transition to a different regulatory option.

The assessment criteria are summarised below in Table 5. For this report, the criteria directly relating to the outcomes set in the Gas Transition Plan have the highest weighting. These criteria follow the three areas of the energy trilemma: sustainability, equity, reliability.

These criteria are further supported by objectives set out in the *Gas Policy Statement 2008*. Note that for both the *Gas Transition Plan* and the *Gas Policy Statement*, the outcomes and objectives set are for the whole gas industry and therefore the gas transmission network will have varying levels of contribution towards meeting these objectives.

We have also included additional criteria that are not directly related to the outcomes within the *Gas Transition Plan* or *Gas Policy Statement*. These criteria relate to the practicality of adopting a different regulatory approach.

Table 5: Assessment criteria for regulatory options

Assessment criteria	Weighting
1. Enabling New Zealand's decarbonisation through sustainability, emissions reductions, energy conservation and efficiency	High
2. Ensuring energy security and reliability for consumers throughout the transition	High
3. Ensuring energy equity for consumers throughout the transition	High
4. Alignment with the purpose of monopoly regulation	Med
5. Effort required to implement regulatory change	Med
6. Implications for the gas transmission business	Low

The following sections provide more detail on the criteria, how they relate to the *Gas Transition Plan*, Gas Policy Statements, and the relevant assessment considerations.

3.1 Enabling New Zealand's decarbonisation through sustainability, emissions reductions, energy conservation and efficiency

As the purpose of the *Gas Transition Plan* is to support the decarbonisation of New Zealand's energy system, the first criteria that regulatory options are assessed against are the ability for the regulation to influence behaviour that is line with a low carbon future. Specifically, the *Gas Transition Plan*, and therefore any regulatory changes recommended within it, needs to ensure the following outcomes, as stated in the *Terms of Reference*:

- **Sustainability:** Aotearoa New Zealand avoids making decisions that further lock in our reliance on fossil fuels

- **Emissions Reductions:** Aotearoa New Zealand prioritises reducing emissions in the most economically efficient way. The pace of emissions reductions will need to support Aotearoa New Zealand's emissions budgets and 2050 emissions targets

- **Energy Conservation and Efficiency:** energy conservation and efficiency play a key role in the overall transition.

Meeting these outcomes would also help meet the objectives set out in the *Gas Policy Statement 2008*:

- (11.c) Incentives for investment in gas processing facilities, transmission and distribution, energy efficiency and demand-side management are maintained or enhanced

- (12.a) Energy and other resources used to deliver gas to consumers are used efficiently

- (12.e) The gas sector contributes to achieving the Government's climate change objectives as set out in the *New Zealand Energy Strategy*, or any other document the Minister of Energy may specify from time to time, by minimising gas losses and promoting demand-side management and energy efficiency.

To meet the objectives, the regulatory options considered for the gas transmission network were assessed against the following criteria:

Table 6: Sub-criteria for 'Enabling New Zealand's decarbonisation through sustainability, emissions reductions, energy conservation and efficiency'

Sub-criteria	Description
Encourages decarbonisation	Does not incentivise over investing in the network such that it encourages consumers that can economically decarbonise via other energy sources to remain on fossil fuels.
Maintains green gas option	Does not incentivise under investing in the network to the point where alternative renewable gases may not be able to use the network.

3.2 Ensuring energy security and reliability for consumers throughout the transition

Ensuring energy security is another key element required for a successful transition away from fossil fuels. The *Gas Transition Plan*, and therefore any regulatory changes recommended within it, needs to ensure "that security of supply is maintained through the transition, as fossil gas continues to be progressively displaced by renewable, lower emissions, alternatives."

Meeting this outcome would also help meet the objectives set out in the *Gas Policy Statement 2008*:

- (11.e) Risks relating to security of supply, including transport arrangements, are properly and efficiently managed by all parties

- (11.f) Consistency with the Government's gas safety regime is maintained

- (12.d) The quality of gas services where those services include a trade-off between quality and price, as far as possible, reflect customers' preferences.

Providing reliable energy supply includes the ability to do so safely. Within the *Gas Policy Statement* 2008 there is an objective for different parts of the gas industry to ensure that "consistency with the Government's gas safety regime is maintained". Safety will to an extent be addressed by monopoly regulation as part of the quality requirements and other safety related legislation which set minimum operating standards (e.g. *Gas (Safety and Measurement) Regulations 2010*, *Worksafe New Zealand Act 2013*). However, to operate safely the GTB must have sufficient operating and capital allowance to do so and therefore economic regulation needs to allow for these costs.

To meet these objectives, the regulatory options considered for the gas transmission network were assessed against the following criteria:

Table 7: Sub-criteria for 'Ensuring energy security and reliability for consumers throughout the transition'

Sub-criteria	Description
Maintains appropriate asset life	Does not incentivise under investing in the network such that parts of the network reach end of life or are decommissioned early, before fossil gas reliant customers are able to economically decarbonise via other fuels
Maintains reliability and security	Does not incentivise under investing in network such that reliability and/or security standards for end consumers are compromised
Maintains safety	Does not incentivise under investing in processes or resources such that safety standards for industry employees and end consumers are compromised

3.3 Ensuring energy equity for consumers throughout the transition

Ensuring energy equity is another key element required for a successful transition away from fossil fuels. The *Gas Transition Plan*, and therefore any regulatory changes recommended within it, needs to ensure that "adverse and unexpected effects on fossil gas consumers are prevented or mitigated and consumers retain access to affordable, reliable and abundant energy. This includes minimising the broader effects on prices paid by consumers, as well as pricing of inputs for businesses as we transition."

Meeting this outcome would also help to meet the objectives set out in the *Gas Policy Statement 2008*:

- (11.d) Delivered gas costs and prices are subject to sustained downward pressure
- (12.c) The full costs of producing and transporting gas are signalled to consumers.

The regulation of revenue and pricing can impact pricing to consumers in two ways. Firstly, economic regulation sets the revenue and price of transmission service passed through to gas users. Changes to pricing driven by the model design may impact different consumers differently and impact energy equity.

Secondly, regulation can also impact the way shippers access gas transmission services and the way they are charged for those services. Current settings ensure open access and control exercise of monopoly power by the GTB operator. However, other regimes may not offer these protections and therefore could impact energy equity through exercise of monopoly power.

Consideration of impacts of the regulatory options on the wider gas market can also help to meet the objectives set out in the *Gas Policy Statement 2008*:

- (11.b) Barriers to competition in the gas industry are minimised
- (12.b) Competition is facilitated in upstream and downstream gas markets by minimising barriers to access to essential infrastructure to the long-term benefit of end users.

To meet these objectives, the regulatory option used for the gas transmission network needs to be assessed against the following:

Table 8: Sub-criteria for 'Ensuring energy equity for consumers throughout the transition'

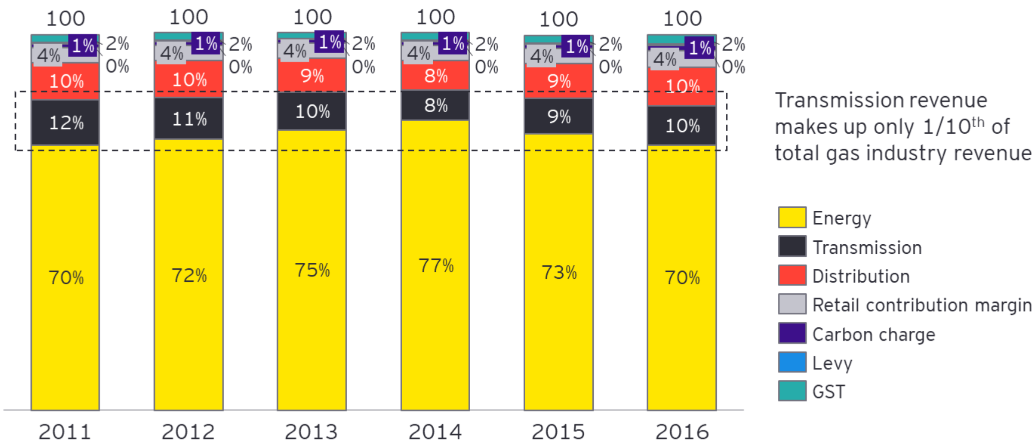
Sub-criteria	Description
Maintains affordability	Incentivises downwards pressure on transmission prices to the end consumer, or at a minimum, does not incentivise upwards pressure on transmission prices
Maintains equitable access	Contributes to downwards pressure on gas prices to the end consumer by maintaining sufficient access to the network at reasonable cost

It is worth noting here that keeping prices for end consumers at a reasonable level is important not only for ensuring energy equity, but also for enabling the gas transmission network to continue operating throughout the transition. If consumers who need gas are not willing or able to pay the price to use gas, then this revenue to the gas transmission network is unable to be recovered and limits the network's ability to play its role in the transition. By ensuring energy equity during the transition, or specifically, setting the price of gas transmission services at a level that consumers are willing to pay, the transmission business can continue to provide these services.

Figure 3 shows the historical estimated total revenue breakdown for New Zealand's gas industry. It illustrates that transmission revenue has historically contributed to only a tenth of the total revenue collected from consumers (though this proportion could increase or decrease depending on the nature of the consumer). Therefore, when considering consumer willingness to pay and energy equity, transmission costs need to be considered within the wider context of other gas costs (e.g. energy being the largest proportion and rising carbon costs) and how this proportion might change throughout the transition.

We do not go into detail in this report on the price responsiveness and price setting for different consumer groups.

Figure 3: New Zealand gas industry estimated total revenue breakdown 2011-2016[28]



3.4 Alignment with the purpose of monopoly regulation

The Commerce Commission regulates markets where there is little or no competition (e.g. monopoly markets). This is to ensure the price and quality of goods and services provided are for the long-term benefit of consumers, consistent with benefits that might be gained in competitive markets.

[28] Gas Industry Company, The New Zealand Gas Story, 2017.

Part 4 of the *Commerce Act* sets out the goods and services that are subject to regulation and the legislative rules governing that regulation. Gas pipeline services (transmission and distribution) are included under Part 4.

At present, there is no indication that the gas transmission network will not be a monopoly moving forward, and therefore it is likely that the Commerce Commission will continue to regulate the price-quality of gas pipeline services. Given that the monopoly is considered to exist, the Commerce Commission would have to ensure that the benefits of regulation continue to outweigh the costs of regulation.

Therefore, assessing the compatibility of potential alternative gas pipeline revenue recovery options within the context of monopoly regulation is an important consideration. The only option that would not meet this criterion would be the deregulation of the gas transmission network in the absence of an economic alternative (i.e. competition).

It is important to note that the Commerce Commission is currently reviewing the regulatory rules for energy networks, including gas pipeline businesses, therefore how gas pipeline services are regulated under Part 4 (such as the IMs) might change. The Commerce Commission have indicated that they expect to publish a gas issues paper for consultation in late 2022, laying out their emerging views on long-term demand risks for gas pipeline businesses.

The Commerce Commission also has an approach for regulated industries with assets that have decreasing or declined utilisation going forward. This approach is currently being applied to the copper telecommunications network in New Zealand and is discussed in more detail later in this report.

To meet these objectives, the regulatory option used for the gas transmission network was assessed against the following:

Table 9: Sub-criteria for 'Alignment with the purpose of monopoly regulation'

Sub-criteria	Description
Consistency with monopoly regulation	Allows regulation of monopoly power consistent with existing frameworks under the Commerce Act (but may require regulatory change)

3.5 Effort to implement regulatory change

One of the assessment criteria being considered is the effort to implement regulatory change. Any regulatory change will require time and effort to implement and may face barriers or additional obstacles based on the nature of the regulatory change and how different it is to the status quo.

Factors that regulatory options will be considered against include:

Table 10: Sub-criteria for 'Effort to implement regulatory change'

Sub-criteria	Description
Need for legislative change	Whether the current regulatory instruments such as Part 4 of the Commerce Act and the IMs are suitable for enabling the regulatory option
Need for new capabilities/capacity	Whether a similar regulatory change or model has already been implemented in New Zealand and can be replicated for the gas transmission network. If not, the additional effort and resources required to set up and transition the regulatory option (for example requiring the Commerce Commission or Gas Industry Co. to build new capability)

Implementation timeframe	The timeframe in which the regulation can be implemented considering the requirements for public consultation and Cabinet approvals
Additional barriers	Additional barriers or opportunities such as social license (e.g. if adverse outcomes are more likely or if similar models have been used for other industries with negative effects) or interdependencies with other regulation (e.g. environmental) that need to be considered

3.6 Implications for gas transmission business

How the GTB responds to the signals or incentives set by the regulatory regime will be critical for realising the desired outcomes set in the *Gas Transition Plan*. Therefore, having an understanding of the potential costs, benefits and consequences that each regulatory option could have on gas transmission is important, particularly where they relate to revenue and the ability to recover the operating and capital costs of investing in and running the gas transmission network.

Each regulatory option will be assessed against the following:

Table 11: Sub-criteria for 'Implications for gas transmission business'

Sub-criteria	Description
Maintains capital return	Whether the revenue model enables the GTB to gain return of capital, and reduces the risk of stranded assets
Maintains asset risk profile	Whether the revenue model has a similar level of revenue risk to the existing model
Implementation effort	The effort required to transition to and operationalise the new regime
Maintains existing compliance effort	Whether there is significant additional ongoing effort required to maintain compliance

4. Overview of economic regulation options for gas transmission networks

There are several models for economic regulation that are applied to gas transmission networks globally. We have undertaken a review of regulations across the European Union (EU), Australia and the United Kingdom (UK) to understand the options available that could be applied in New Zealand. Details of these regulatory models are provided in in the appendices.

Table 12 summarises the main methods of regulating utility prices and revenue and jurisdictions where they apply.

Table 12: Summary of economic regulation options

Type of regulation	Example Jurisdictions
Price cap regulation	Austria Albania
Revenue cap regulation (For the purposes of this report, includes rate of return and cost-plus variants)	New Zealand Australia (Appendix A) UK (Appendix B) Parts of the EU (Appendix C)
Hybrid forms of regulation	Portugal Italy
Deregulation	Nova Energy Distribution networks in NZ

4.1 Description of regulatory options

4.1.1 Price cap regulation

In its simplest form, price cap regulation requires the GTB to price their services no higher than the specified maximum price for the regulatory period. The intention behind a price cap is to incentivise the GTB to reduce their costs to maximise their returns as the GTBs profitability depends on their ability to keep costs below the level of revenue allowed by the price cap.

Under a price cap, the regulator sets an initial maximum price (often based on costs, efficiency savings, and/or asset value) which alters over time in line with a price index such as CPI and is set in advance by the regulator. Therefore, the maximum price rises in line with the index but falls at a rate (x) that is set by the regulator to reflect potential costs savings due to increased efficiency. The value of x and the cap are reviewed every few years to reflect changes in demand and costs.[29]

In practice, price cap regulation is more complex, especially if a utility has multiple products or services on offer that are either separated out or bundled together under one cap. Additional mechanisms can be built into the cap, such as for service quality and performance, to retain the desired incentives and drive certain behaviours.

An example of price cap regulation is the weighted average price cap previously applied to electricity distribution businesses (EDBs). [30] This price cap exposed EDBs to changes in demand as they could experience revenue losses when demand dropped, and EDBs that charged below the price cap did not get to recover their revenue losses in later years. This method is considered to disincentivise GTBs to invest in efficiency measures and can encourage regulated entities to underinvest in services if it is not accompanied by relevant service level and performance requirements.

[29] Infrastructure regulation and market reform, Principles of price cap regulation.
[30] Commerce Commission, Revenue cap for electricity distribution businesses and COVID-19 related impacts (2020).

4.1.2 Revenue cap regulation

Revenue cap regulation provides a maximum level of revenue that can be recovered over the regulatory period. In setting the revenue cap, regulators often consider the costs that need to be covered and the rate of return that the GTB requires on their investment. Providing the GTB with certainty about the level of revenue they can recover over time encourages them to invest and maintain the gas network. It is also a form of incentive regulation as it uses rewards and penalties to incentivise certain GTB behaviours, and the GTB is often incentivised to keep their costs as efficient as possible to maximise their profit under the revenue cap.

Like the price cap, revenue cap regulation can also use an adjustment for inflation and productivity. Providing a revenue cap that is independent of changes in demand encourages businesses to invest in and maintain their networks (linking to higher capital expenditure). This means that revenue stability is achieved for the GTB rather than price stability for customers.

Rate of return regulation is sometimes considered a regulatory form on its own but is closely aligned with revenue and price cap regulation. For instance, rate of return calculations inform the setting of some revenue caps depending on the jurisdiction and therefore this report has chosen to use price and revenue cap as the overall forms of regulation. Rate of return is considered a more 'traditional' form of economic regulation and is a form of cost-plus regulation. It would allow a GTB to recover the cost of providing transmission services including an allowable rate of return on the RAB and is traditionally calculated based on cost and demand estimates.[31]

The Commerce Commission currently uses revenue cap regulation for GTBs and it is a key component of the price-quality path. Refer to section 2.1 for an explanation of how the revenue cap is calculated.

4.1.3 Hybrid forms of regulation

Most jurisdictions in different regulated industries apply hybrid approaches to regulation and it is very difficult to observe a jurisdiction that applies a single dominant approach.[32] Therefore, many jurisdictions use a form of regulation that is a hybrid between revenue cap, price cap and other forms of regulation. For instance, a hybrid price cap could be set to incentivise the GTB to raise profits by lowering costs of production. However, the regulatory setting could state that if profits rise above an agreed amount, then they are immediately adjusted downwards to share some of the additional profit with users and this restricts the level of supernormal profits that can be earned by regulated transmission businesses.[33]

Examples of hybrid regulation are found in Portugal and Italy. Portugal uses price cap regulation for Opex and rate of return regulation for Capex. Italy uses cost-plus regulation for Capex and price cap regulation for Opex.[34]

4.1.4 Deregulation

Deregulation is the removal of regulatory settings for price and revenue for the GTB. By removing the limits on price and revenue, the GTB would be incentivised to adopt a model where prices are set at a level that recovers capital and operating costs and provides a reasonable profit.

The purpose of regulation is to ensure monopoly industries do not overcharge users for services and therefore it is likely that deregulation is not an ideal option in an environment where gas transmission remains a monopoly. However, there could be a future scenario where the benefits of regulation do not outweigh the costs of regulation and deregulation becomes a favourable option.

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[31] Chris Decker for Ofgem, Characteristics of alternative price control frameworks: an overview (2009).

[32] Chris Decker for Ofgem, Characteristics of alternative price control frameworks: an overview (2009).

[33] Janice A. Beecher, Economic regulation of utility infrastructure (2013).

[34] Council of European Energy Regulators, Regulatory Frameworks Report 2021.

As outlined in Appendix B, some pipelines in Australia are under Part 23 regulation which means they are essentially unregulated and are free to set their own prices. The decision to not regulate a pipeline in Australia is made after considering market power, costs and benefits.

4.2 Comparison of key features of each regulatory option

Table 13 provides a summary of the key features of each regulatory option in terms of asset value, capital investment, Opex and controllable/uncontrollable costs in the context of reduced gas throughput. Hybrid forms of regulation will adopt characteristics from both price and revenue cap regulation and will vary greatly by jurisdiction. For this reason, we have excluded it from the table below.

It is worth noting that the links to asset value, capital expenditure, operational expenditure and controllable/uncontrollable costs are very similar for price and revenue caps. The main differences arise in the way a jurisdiction chooses to calculate their price and/or revenue ceiling. For instance, how they use the regulatory asset base (RAB) or what operational and capital costs they include.

Table 13: Summary of key features of economic regulatory options

	Price cap regulation	Revenue cap regulation	Deregulation
Asset value (RAB value)	Asset value is often used to determine the price ceiling and therefore a higher RAB could lead to the setting of a higher price cap. There is a link to asset value however, within the RPI-x formula used to capture the impact of inflation on prices in subsequent years after the initial price cap is set. The link to asset value is not as mechanistic as within the building blocks formulas that are used to calculate revenue ceilings.	RAB value helps to determine the value of depreciation and the rate of return that is often factored into the allowed revenue calculation. Therefore, a higher RAB often leads to the setting of a higher revenue cap. This calculation is dependent on the economic life of the asset, the method of depreciation, and which assets are considered as part of the asset base in a jurisdiction.	In monopoly infrastructure there is a risk of the GTB overcapitalising and having an asset base that is not necessary, requires high prices to receive the necessary return, and has a high risk of asset stranding in an uncertain future. In contrast, in the absence of regulation there is a risk that the asset base is not sufficient to provide the quantity or quality of service required and this negatively impacts customers. This reduces the risk of asset stranding in an uncertain future.
Capital expenditure (Capex)	This method incentivises efficient capital expenditure after the setting of the price cap to increase profit. However, this has to be balanced with levels of capital investment that ensure the asset base supports the levels of demand required to make the revenue required to cover costs. As demand x price = revenue, less connections means less gas usage and lower revenue. If demand is lower than forecast there is a risk that the GTB could not recoup their costs.	Revenue caps incentivise capital investment to increase the RAB which increases the allowed revenue. However, this is balanced with incentives to keep capital investment at an efficient level to make a profit under the revenue cap. This reduces unnecessary capital investment as the number of new connections/increased demand does not determine the revenue received as the GTB can alter the prices charged to customers to receive the allowed revenue.	For deregulated monopoly infrastructure there is a risk that the GTB will under or over invest in the absence of incentives to guide behaviour. If they over invest there is a risk of asset stranding in a reduced gas future but if they underinvest there is a risk the assets will not be able to support future demand and the quality of service provided will be negatively impacted.

	Price cap regulation	Revenue cap regulation	Deregulation
Operational expenditure (Opex)	Operating expenditure is a component of most price cap calculations and is often forecast from previous expenditure. Under a price cap, the GTBs are incentivised to maximise operational savings to increase their profit under the already set price cap.	Operating expenditure is a component of most revenue cap calculations and is often determined based on forecasts of previous expenditure or forecasts of demand. As an incentive-based form of regulation, the GTB are still incentivised to keep their operating costs down so they can increase their profits under the cap.	The GTB is likely to factor their forecast Opex into prices so that they recoup their costs. There is less incentive to be efficient and reduce costs than under regulation if transmission remains a monopoly. Reduced pressure to be cost efficient may push up prices for consumers.
Controllable and uncontrollable costs	If uncontrollable costs for the regulatory period are higher than expected and/or not considered within the price cap, the GTB is at risk of a loss as it cannot increase its prices to cover this rise. Price caps incentivise cost efficiency for controllable costs that are considered when setting the price cap. However, depending on the jurisdiction and settings there may be provisions to allow for uncontrollable costs to lower this risk.	If uncontrollable costs for the regulatory period are higher than expected and/or not considered within the revenue cap, the GTB is at risk of a loss as it cannot increase its prices to cover this rise. Revenue caps incentivise cost efficiency for controllable costs that are considered when calculating the revenue cap. Some revenue cap regulatory methods allow adjustments to be made during the regulatory period for specified uncertainties which influence uncontrollable costs, or the cost may be considered in a later period or through other mechanisms to allow the GTB to recoup the cost.	The GTB is likely to consider both controllable costs and possible uncontrollable costs when setting access prices. There is still a risk that the prices they set will not be enough to cover their uncontrollable costs for the period. This may lead to higher prices in later periods which are passed on to consumers. Alternatively, the GTB could overestimate uncontrollable costs and charge unfair prices to customers to cover this risk, especially when there is a lack of competition.
Link to throughput	Declining gas throughput and declining demand for gas could lead to reduced revenue for GTBs under price cap regulation if not accounted for when setting the cap as GTBs are not able to increase their prices above the cap to account for reduced demand.	Declining gas throughput, if not properly forecast when setting the revenue cap could lead to increased prices for consumers when demand is lower than expected. This is because GTBs can increase their prices to make their allowed revenue under the cap.	For deregulated monology gas transmission infrastructure many GTB costs are fixed regardless of throughput. The absence of regulation allows the GTB to set their own prices and self-regulate. This would likely result in inflated prices as there is less demand for gas and a reduced customer base to spread fixed costs across. GTBs are able to determine their own profit margin.

5. Addressing the gas transition in other jurisdictions

To support our understanding of how different regulatory options could be applied to the New Zealand gas transmission network in a future less reliant on natural gas, we also conducted a review of research completed in other jurisdictions on the gas transition.

In the following sections, we outline some of the key findings from Australia, the UK and California, and how they might be relevant to the New Zealand context.

5.1 AER Review into regulating gas pipelines under uncertainty[35]

The Australian Energy Regulator (AER) has undertaken a review of Australia's energy system to understand how to support the transition from a centralised, fossil fuel-based system to a decentralised, renewables-based system. Like New Zealand, Australia intends to reach net zero emissions by 2050 and is considering how their gas networks should adapt to make this transition possible.

The review explores how declining natural gas use could impact gas transmission and distribution businesses as well as customers. Declining demand for gas means that access prices will increase because there are less customers to share network costs with. As there would be fewer customers in a declining gas future, the customers that remain using gas would have to take on the burden of paying for the long-term asset costs of those customers who left the network before contributing enough revenue to pay off the capital investment incurred on their behalf. If customer prices rise it could also lead to further decline in demand because customers cannot afford, or will not pay, the increased prices.

The AER Review considered potential future options for the regulation of gas pipelines in Australia in an environment of uncertainty caused by these unknown levels of demand for future gas pipeline services. Gas demand in future years could decline rapidly, remain at current levels, or grow, and the regulatory environment needs to be able to adapt to these possible scenarios. Due to the similarities between the regulatory regimes used in Australia and New Zealand, there is merit in exploring in more detail whether these options could be applied in New Zealand. The potential regulatory changes outlined in the report are summarised in Table 14.

[35] AER Information Paper, Regulating gas pipelines under uncertainty (2021).

Table 14: Summary of potential options[36]

Potential options	Description
Option 1: Adjusting regulatory depreciation	This potential option would bring forward the cost recovery of the efficient investments that GTBs have made, increasing certainty that these costs can be recovered and reducing stranded asset risk and increased prices that would drive customers away. Bringing forward cost recovery involves accelerating regulatory depreciation through the shortening of the depreciation period (asset life) or increasing the depreciation rate. This increases the prices charged to customers and the revenue required by the GTB for the regulatory period. Shortening the asset lives for new pipeline assets could help preserve the current incentives for the GTB to make new investments. However, shortening the lives of existing assets could do the opposite and disincentivise the GTB to make new investments. In New Zealand, this is similar to the change made in DPP3 which shortened the average lives of new and existing assets to better reflect the remaining economic lives of the networks, which increases the depreciation allowance for the regulatory period, bringing revenue forward and maintaining the incentive to invest.
Option 2: Compensating for stranded asset risk	This option involves the AER providing ex-ante (based on forecast) compensation to the GTBs in the form of a cash payment for expected stranded asset losses. This could be calculated based on the probability of the loss occurring, the value of the stranded assets or the extent to which other methods could be used to reduce stranded asset risk. The benefit of this compensation is that it may incentivise efficient investment by the GTBs as they have more confidence in recovering their efficient costs. The possible downside of compensation is that it is difficult to estimate fairly, and asset stranding is unpredictable in an uncertain environment.
Option 3: Removing capital base indexation	This option involves removing indexation of the RAB to increase the speed of the cost recovery of investments. If this occurs, the return on capital provided to the GTBs will be based on the nominal rate of return meaning a greater proportion of revenue is covered sooner and customer prices increase in the short-term. The benefit of this approach is that in an uncertain future removing indexation means revenues are higher in the short term and lower in the future when there may be fewer customers. The potential downfall of the approach is that removing the RAB means the network charges faced by customers would not be in line with inflation. This means RAB values and real prices would be hard to predict as inflation can change unexpectedly.

[36] AER Information Paper, Regulating gas pipelines under uncertainty (2021).

Potential options	Description
Option 4: Sharing costs under capital redundancy provisions	Under this potential option, the GTBs and customers could negotiate the allocation of the stranded asset risk by using capital redundancy provisions in the National Gas Rules (NGR). The NGR allows an access arrangement to share the costs resulting from a decline in demand for services between the GTB and its customers. It also states that a full access arrangement can include a mechanism that removes assets that stop contributing to service delivery from the capital asset base. The benefit of this approach is that it can reduce stranded asset risk by providing a level of certainty, can be more flexible in the face of uncertainty, and is more consultative and transparent with customers. The potential downsides of this approach are that an asset may need to be under-utilized or obsolete to be declared redundant and removed from the RAB. Therefore, the option may only be appropriate for underutilization of specific assets rather than the whole network. The option may also mean the GTBs forgo the recovery of some costs from customers which is a disincentive to share costs. The option would take significant time to implement as it has to be included in an access arrangement in one regulatory period and can only be used in the subsequent access period.
Option 5: Revaluation of asset base	This option involves reflecting changing demand conditions in the RAB through periodic revaluation rather than changing network prices due to demand changes. This means that if in the future demand is lower than expected, the RAB would be valued downwards. However, if future demand is higher, the RAB could be valued upwards. The benefits of this approach are that it would place risk with the GTBs and keep prices stable for customers (maintaining their confidence). However, the downsides of this approach are that it requires legislative change and a new component added to the building blocks.
Option 6: Introducing exit fees	This option involves imposing exit fees on customers who disconnect from a gas network. This could help to reduce the level of unrecovered cost related to their connections that remains in the RAB if they have not stayed on the and reduce price rises for remaining customers. Exit fees could be calculated as the difference between the incremental revenue that the customer contributes at the time of investment and the actual incremental revenue the customer paid during their connection period. The benefit of this approach is that it promotes equity amongst pipeline customers, but the downside of the option is that it makes it difficult for customers to switch to alternative energy sources and is not in line with decarbonisation policies.

Potential options	Description
Option 7: Increasing fixed charges	Gas access prices in Australia are normally comprised of fixed charges and demand-based charges that fluctuate based on the volume of gas used. If gas consumers reduce their use of gas, they would pay less in variable charges which means that regulated GTBs may under-recover their investment costs (stranded asset risk). Therefore, using a price structure where costs are recovered through increased fixed charges rather than variable charges means gas charges are not reliant on gas consumption levels and can help reduce stranded asset risk. The benefit of this option is that it equitably applies across the GTB customer base. The downside of this approach is that it is dependent on the user base remaining the same and not declining, as is likely to happen in the future.
Option 8: Maintaining status quo	The potential need to adapt the regulatory settings depends on the perceived stranded asset risk. If this risk is not material, it may not require regulatory action as it may not change the behaviour of GTBs. The benefit of maintaining the current settings is that existing customers do not need to pay more to address declining gas use in the future, however the downsides are that ignoring stranded asset risk may result in a lack of efficient network investments and means the safety, reliability and affordability of gas in the future is not ensured.

5.2 AEMC information paper on extending the regulatory frameworks to hydrogen and renewable gases[37]

The Australian Energy Market Commission (AEMC) has undertaken a review into regulatory frameworks to understand whether these frameworks are compatible with renewable gases and hydrogen. The AEMC have recommended changes to the national gas regulatory frameworks in the form of draft recommendations and rules so the sector can support decarbonisation agendas by evolving to more renewable gases.

The review identified that changes would need to be made to the NGR and NGL so the regulatory framework used in Australia can be more appropriately applied to other covered gases. These changes are required to facilitate investment by GTBs to ensure reliable gas supply for customers by changing interconnection rules and transparency mechanisms, promoting access to and efficient use of regulated pipelines, and the implications for non-covered pipelines in Australia.

In line with these improvements, the AEMC made final policy recommendations which are outlined in Table 15. These recommendations are relevant to New Zealand due to the regulatory similarities between the two jurisdictions.

[37] Australian Energy Market Commission, Review into extending the regulatory frameworks to hydrogen and renewable gases 2022.

Table 15: Summary of AEMC regulatory recommendations based on extending regulatory frameworks to other gases[38]

AEMC recommendations	
1	Change the pipeline interconnection rules so that the right to connect requires the connection to provide safe and reliable gas to customers.
2	Change the pipeline interconnection recovery rules to reflect that a new connector can recover the metering and monitoring costs from connecting parties to promote efficient connections and investment in the pipelines by GTBs.
3	Require GTBs to publish information on the type of gas the pipeline is transporting, limits on the blending of gas that apply to the pipeline and any plans to transition to other covered gases.
4	Amend the arbitration rules for non-scheme pipelines to recognise that access prices should reflect the costs of complying with regulations such as the mandated transition to another gas.
5	Change Rule 82 of the NGR for scheme pipelines to require regulators to treat government grants (provided for the purpose of transitioning to other gases) as user capital contributions to ensure customers do not cover the cost of assets funded by these grants.
6	Change Rule 82 of the NGR to require regulators to treat some or all of concessional finance (below market rate financing by government) as a capital contribution where assessed as necessary to ensure consumers are not paying for assets that have been funded in this manner.

5.3 UK Climate Change Commission research into the future regulation of the UK gas grid[39]

Like Australia, the UK has been considering the consequences of decarbonisation on future regulation of the gas transmission network. A 2016 report into *Future Regulation of the UK Gas Grid* considered the impacts and implications of future scenarios impacting the UK. These scenarios are similar to, if not the same as, the future gas scenarios being considered in New Zealand and include:

- The re-purposing of gas networks to supply hydrogen (or other renewable gases) instead of natural gas
- Decommissioning parts of the gas network due to replacement by electric energy alternatives
- A mixture of possible scenarios requiring a varied response such as some re-purposing and some decommissioning of assets.

Table 16 provides an overview of the demand scenarios considered in the report and the possible impact of these scenarios on the regulatory environment in the UK.

[38] Australian Energy Market Commission, Review into extending the regulatory frameworks to hydrogen and renewable gases 2022.
[39] Frontier Economics for the Committee on Climate Change, Future regulation of the UK gas grid - Impacts and institutional implications of UK gas grid future scenarios 2016.

Table 16: Overview of future demand scenarios and impact on economic model in the UK

Future demand scenarios	Explanation of scenario	Impact of scenarios on network charges and the regulatory framework
Scenario 1: Central	In Scenario 1 there is a continued role for most of the gas network, including both transmission and distribution, to service the gas demand that remains by 2050.	If this 'central' scenario occurs, the current regulatory model should be sufficient in its current form because majority of the gas transmission network is still required to service the forecast demand by 2050. However, some decommissioning of assets will need to occur by 2050. It is assumed that some network costs will decline by 2050 due to some asset decommissioning because a portion of overheads, maintenance and other Capex and replacement costs are reliant on network length.
Scenario 2: Low Gas	In Scenario 2, there is a low level of gas demand by 2050, and an assumption that there will be switching to more energy efficient (low carbon) heating options which will enable gas networks to decommission large parts of the network by 2050.	Despite a fall in network investment, there would be an increase in prices which would increase gas bills by more than 50% by 2050 and is caused almost solely by a significant decline in gas demand. It is expected that maintenance, overhead and other Capex costs for the distribution networks would fall in line with the reduction in the network's length due to a significant portion of distribution networks being decommissioned. Therefore, it is assumed that investments in expanding the distribution network would drop to zero by 2028 and there is a very high risk of asset stranding.
Scenario 3: National Hydrogen	An alternative scenario in which a portion of the gas network is transitioned to carrying hydrogen instead of natural gas from approximately 2025.	In this scenario, the gas distribution networks will include new regulated costs that result from transitioning to hydrogen and require costs to build up the infrastructure required for this transition. The network tariffs would likely increase slightly in the short term because of higher network revenue requirements to cover this expenditure but would fall in the longer term by around 30% because of lower revenue requirements and higher gas or hydrogen demand depending on the mix. There is no transmission network decommissioning in this scenario and therefore other transmission costs such as maintenance, overheads, other Capex and replacement would increase proportionately to the increase in network capacity. However, there are likely to be efficiency improvements over time as are currently provided for in regulatory frameworks.

Future demand scenarios	Explanation of scenario	Impact of scenarios on network charges and the regulatory framework
Scenario 4: Patchwork Hydrogen	This scenario accounts for a regional switchover to hydrogen in only parts of England.	In this scenario customers in different regions would face different costs relative to the gas used in that region. The cost implications for networks are similar to the first scenario because a high proportion of the network is required to decommission assets. Therefore, some decommissioning of assets will need to occur, and some network costs will decline by 2050 because a portion of overheads, maintenance and other Capex and replacement costs are dependent on the length of the network which reduces as a result of decommissioning.

5.4 California's approach to managing the gas transition

Like New Zealand and other countries mentioned in this report, California is facing an uncertain gas future where assets could be stranded as gas use declines because of increasing electrification to reach decarbonisation goals. An Environmental Defense Fund (EDF) report into *Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California* considers how California could manage the shift away from reliance on gas while managing the impact on gas assets and customers. A section of the report discusses potential ways to mitigate the impact of stranded assets in California and is a valuable discussion that can also be applied to other jurisdictions such as New Zealand.

Table 17 outlines the potential options for mitigating risk and the impact of stranded assets. Interestingly, there are similarities between these options and the potential options identified in the AER Review on *Regulating gas pipelines under uncertainty*.

Table 17: Potential options for mitigating risk and the impact of stranded assets[40]

Potential option	Description
Strategic targeting of electrification efforts	As California strategically targets electrification across the state, electrification is likely to increase, and relevant strategies will need to consider stranded asset risk. This could involve coordinating electric and gas utilities to minimise the stranded asset risk. For instance, explicitly targeting electrification to maximise customer benefit, minimise costs and effectively manage stranded asset risk.
Developing pathways to pay for early retirement	If gas infrastructure assets are no longer required due to electrification, then alternative financing strategies will need to be utilised to mitigate the stranded asset risk and the associated negative financial implications. The potential pathways identified in the report were securitisation, accelerated depreciation, changes to return on equity and disallowance of recovery. These pathways are described in more detail in Table 18.
Decommissioning	It is important to plan for the costs associated with decommissioning gas transmission assets if the assets cannot be repurposed for continue operation i.e. by using the pipeline infrastructure for other covered gases. The decommissioning costs include both the cost of physical decommissioning and the cost to the customers remaining on the network. This cost could be incurred after the useful life of the assets or brought

[40] Environmental Defense Fund, Managing the transition (2019).

	forward and spread over the useful life, which is more beneficial for customers remaining on the network.
Alternative uses of existing assets	Stranded asset risks and costs can be avoided by using the existing gas transmission infrastructure for other, more sustainable, gases such as biomethane and hydrogen. This would reduce the asset stranding risk as the useful life of existing assets would not be reduced in a decarbonised future.

There were several options highlighted in the report as potential ways to pay for the early retirement of gas infrastructure assets. These potential options - securitisation, accelerated depreciation, changes to return on equity and disallowance of recovery - are outlined in more detail in Table 18 below.

Table 18: Summary of potential ways to pay for early retirement of assets[41]

Potential option	Description
Securitisation	This option involves recovering stranded asset costs by issuing ratepayer backed bonds that are related to the remaining value of the existing asset. When issued the gas assets would no longer earn a rate of return (as they are removed from the RAB), and the customer saves the difference between the cost of capital and the bond interest rate. It means that capital cost of the asset is recovered up front and provides an opportunity for GTBs to make new investments better aligned to decarbonisation objectives.
Accelerated depreciation	Accelerated depreciation involves removing an asset from the RAB before the end of its expected useful life and results in a short-term increase in customer charges but a long-term reduction in the magnitude and duration of the stranded asset risk. Shortening the economic life of the asset brings the depreciation costs forwards. This accelerated depreciation method of addressing stranded asset risk has already been employed by the Commerce Commission in the DPP3 reset and has also been acknowledged in the previously discussed AER Report into potential option in an uncertain gas future. This shows that multiple jurisdictions see it as a legitimate option for reducing stranded asset risk.
Changes to return on equity	This potential option involves changing the return on equity that is allowed for a gas infrastructure asset and reduces the potential stranded asset value by reducing the remaining asset value. It would be possible for California to reduce the GTBs return on equity so that future gas investments are less attractive and would aid decarbonisation agendas.
Disallowance of recovery	The regulator could prevent GTBs from recovering the cost of all or some of the stranded asset leaving them solely responsible for the associated costs, foregone revenue and potential write off value. This option leaves the most risk with the GTB out of all the identified options in the report and is most common in situations where the GTB has not acted efficiently. This was not identified as a viable option by the EDF but could be varied to suit a specific future scenario. For example, if GTBs were required to stop investing in gas from a certain point to suit net zero and decarbonisation agendas. In the New Zealand context, disallowance of recovery would not encourage continued investment in gas transmission infrastructure meaning that in a

[41] Environmental Defense Fund, Managing the transition (2019).

	declining gas future, those customers who remain reliant on gas for various reasons could be disadvantaged.

As well as discussing how to manage the stranded asset risk, the report proposed possible ways to plan and manage for future gas investment in an uncertain gas environment. Some continued investment is needed to maintain the transmission network and provide a certain level of safety and service quality. However, it is difficult to know what level of investment is required and efficient in an uncertain future.

The report provides the example of a bright line test to determine which customers should be responsible for paying for what share of the new investment costs and when this responsibility is no longer relevant, so it can be discharged from the cost burden. Other approaches could be providing more investment certainty by giving a timeframe for the gas transition in the form of mandates and targets or tying the investment recovery period to the relevant climate policy so that costs cannot be recovered after a certain date.

6. Economic regulation and transitions in adjacent industries

Other regulated industries in New Zealand have experienced transitions where regulated service delivery has been phased down/out and asset owners have had to adapt their operations. While the contexts in which these transitions have occurred differ from that of the gas transition required for decarbonisation, there are potentially insights that can be applied to the gas transition. In this section, we explore the applicability of learnings from the postal industry and telecommunications industry.

6.1 Telecommunications: Copper to fibre transition in New Zealand

A similar transition scenario that may provide applicable insights for the gas transmission network transition is in the telecommunications industry, where the copper network is being phased out as customers shift to the fibre network and mobile services.

Historically, telecommunications services in New Zealand have been delivered via the copper network. In 2011, the Government announced its ultra-fast broadband (UFB) initiative, which sought to build a nationwide fibre network by the end of 2022 to deliver improved broadband services to New Zealanders. As more New Zealanders transfer to the fibre network and the growing mobile networks, demand on the copper networks is set to decrease over time. This decrease in demand is like that expected on the gas transmission network.[42]

The copper line network is owned and operated by Chorus. Chorus is also responsible for rolling out the bulk of the ultra-fast fibre network build and managing a significant proportion of the fibre network. Other local fibre companies exist, including Enable Networks in Christchurch, Ultra-Fast Fibre in the central North Island, and Northpower in Northland.

The *Telecommunications Act 2001* provides the underlying economic regulatory settings for communications markets in New Zealand. From 2020, Chorus became subject to 'utility style' regulation for its fibre network. Utility style regulation refers to the price-quality and information disclosure regulation that is typically applied to utilities under Part 4 of the *Commerce Act*. In this instance, the regime was introduced into the *Telecommunications Act* but replicated Part 4 of the *Commerce Act* wherever applicable.

Initially, it was expected that the utility style regulation would apply to both fibre and copper networks. However, it was later decided that the copper networks would be excluded from the new regulation because prices had already been set and resetting the price path would add confusion to the industry.

In terms of the transition and the phase out of copper, Chorus is adopting a 'grandfathering approach' where existing copper regulation will continue to apply until sufficient fibre roll out exists. The copper network will be deregulated and withdrawn incrementally by geographical area. Table 19 below illustrates how this will occur.

[42] Ministry for Business, Innovation and Employment, Announcements on the future of communications regulation 2018.

Table 19: Chorus regulatory framework for copper and fibre networks (2022)[43]

<table>
<tr><th>Areas where fibre is available (~87% of population)</th><th>Areas where fibre is not available (~13% of population)</th></tr>
<tr><td>Fibre network in Chorus areas:
► Regulated asset base for fibre access services with revenue cap set by the Commerce Commission
► First regulatory period 2022-2024
► Commission can review the revenue cap model from 2025.</td><td rowspan="2">Copper network:
► Remains regulated and TSO applies
► Copper pricing capped at 2019 levels with adjustments for inflation
► Commerce Commission required to review copper regulatory settings no longer than 2025.</td></tr>
<tr><td>Copper network:
► The copper network in these areas become deregulated and the Telecommunications Service Obligation (TSO) removed
► Chorus can choose to withdraw copper services with six months' notice to consumers, subject to the Copper Withdrawal Code[44], which sets out the minimum requirements Chorus must meet before it can stop providing wholesale copper phone and broadband services
► The TSO Deed recognises that additional funding may be sought for commercially non-viable customers.</td></tr>
</table>

A gradual deregulation and decommissioning process that is aligned with decreased, geographical throughput could be applied to the gas transmission network. This would allow the GTB to set prices that would allow them to gain a return on capital and make a profit in areas where most consumers have already decarbonised via an alternative fuel.

However, there are a few challenges with directly comparing the copper network transition and gas transmission network transition.

The first challenge in comparing the two transitions is that Chorus is the sole owner of the copper network and is majority owner of the fibre network. This means that for the most part, Chorus' loss in copper customers, and consequently copper revenue, translates to a gain in fibre customer, and consequently fibre revenue. To an extent, this could act as an incentive for Chorus to accelerate the transition away from copper and to its fibre networks so that it can decommission its copper network sooner, saving on operating and capital costs required for its upkeep.

This is different to the gas transmission network because it is unlikely that most gas transmission users would transition to another service that is largely offered by the GTB. It's likely instead, that many users would shift to energy sources that use other forms of transport, such as electricity. Therefore, the key difference between Chorus and the GTB is that Chorus can retain a large proportion of its customer base, whereas the GTB is likely to lose a significant proportion of its

43 Chorus, Annual Report FY22.
44 Commerce Commission, Copper Withdrawal Code 2022.

customer base. A reduction in customer base, and consequential reduction in revenue, means that the GTB also does not have the incentive to transition customers away more quickly.

The second challenge is that within the telecommunications industry, it may be easier to understand the point in which a geographical area is ready for its copper lines to be deregulated and decommissioned because the service offerings provided by the fibre and/or mobile networks are almost direct substitutes to that of the copper networks and it is relatively easy and low cost for almost all consumers to switch over once there is sufficient availability.

In the gas context, the wide-ranging needs and uses of gas and the consequent switching costs can make this switching point less clear. For example, some geographical areas will include residential, commercial, and industrial gas end users. In the case where the electricity network capacity is improved in the area, a significant proportion of these end users may be able to switch their gas use to electricity, with some technology investment. However, there may still be some commercial and some industrial users that cannot easily switch to electricity (e.g. high temperature process heat users). If, in this case, the build out of the electricity network was viewed in the same light as the build out of the fibre network, and the local gas transmission network was deregulated and decommissioned, then these remaining gas users could face very high gas costs and may need to exit the market.

6.2 New Zealand Post: Deregulation

An example of deregulation in New Zealand that may provide insights for the gas transmission network transition is in the postal industry. Until 1998, under the *Postal Services Act 1987*, New Zealand Post (NZ Post) had sole right to deliver standard letters around New Zealand. In 1998, the *Postal Services Act* was enacted to remove NZ Post's monopoly on the standard letter post.[45]

By the time that the *Postal Services Act* was introduced, the only monopoly that existed was in standard letter delivery. Other aspects of the postal service, such as for delivering letters weighing more than 200 grams and international mail, were already operating in a competitive market. This Act enabled other postal operators, upon registration, to compete in the previously monopolised sector of the postal market.

The purpose of removing the monopoly on the standard letter delivery service was to:[46]

- Lower prices for customers over time
- Improve service performance and efficiency for New Zealand post
- Encourage new entrants and services to the market
- Increase customer choice.

The deregulation of the postal industry and consequential transition period is different to that of the gas transition because at the time of deregulation, delivery volumes were increasing as opposed to decreasing. This meant that after deregulation, NZ Post was incentivised to maintain or grow its letter delivery throughput through improving its business activities. This is different to the gas network, where deregulation is more likely to be a result of demand declining significantly and a decline in gas transmission utilisation.

The key learning to take from the NZ Post example is that the removal of their monopoly position was signalled well in advance, providing them time to prepare business plans that could be enacted as soon as the Act was put in place. In a similar sense, the GTB would be required to adapt their business activities to ensure they can deliver a service that allows them to make a profit.

[45] New Zealand Post, History of NZ Post.
[46] New Zealand Government, Proposed Postal De-regulation, 1997.

NZ Post had been preparing for competition in the market since it became a state-owned enterprise in 1987. The impact of deregulation was already a scenario that had been included in its business plans. In the ten years between corporatisation and the removal of the monopoly, key drivers such as increasing competition in other postal services and a desire to exceed customer expectations had led to NZ Post making significant efficiency gains and service improvements.

The risk of deregulation would be that the gas transmission network is withdrawn from service too early, or prices increase too materially, creating negative impacts for gas consumers that may not have alternative low carbon options available to them. An approach like NZ Post's Deed of Understanding could protect consumers from any shocks that could result from deregulation.

During the transition period immediately after the removal of the monopoly, New Zealand Post was still required to deliver services that ensured continuity and stability under a Deed of Understanding. In return for maintenance of these services levels, New Zealand Post continued to be designated as the country's official postal administration to the Universal Postal Union (the international organisation of postal operators) for at least five years. New Zealand Post also retained the exclusive right to issue "official" New Zealand postage stamps.

7. Assessment of regulatory options for New Zealand's gas transition

The potential regulatory options that could be applied to New Zealand's gas transmission network vary in their ability to create outcomes aligned with the *Gas Transition Plan*. In this section, we discuss how the different regulatory options identified and learnings from other contexts can impact how aligned the long-term plan for the gas transmission plan is with the *Gas Transition plan*, and the different trade-offs and actions that may be required.

Table 20, later in this section, summarises the regulatory options considered in this study and how they perform against each of the assessment criteria discussed in Section 3.

Our high-level assessment suggests that, in a future where gas volumes through the transmission network will decline, there is no clear evidence that an alternative regulatory option would be better suited to align the gas transmission network with the outcomes in the Gas Transition Plan. Instead, how the incentives and mechanisms within the regulatory option are set, and how directive the regulator chooses to be, will likely make the most impact.

Each regulatory option could play a role in the gas transition depending on which outcomes are prioritised

The high-level assessment of the different regulatory options highlights the varying advantages and disadvantages of each option, depending on which criteria are most important for the gas transition.

For example, if protecting consumers from gas price shocks has a relatively higher importance than the other criteria, then the price cap model is likely to be better because the price is set from the outset and has limited ability to increase in response to falling gas throughput. The prices can also be set sufficiently high to encourage consumers to switch to a lower carbon fuel where it is economic or if the regulator chose to be more directive, could be used to incentivise specific groups of consumers to decarbonise. Conversely, in the revenue cap model, prices may start at a reasonable level for consumers, but may need to increase if gas throughput decreases to ensure the revenue is recouped. A hybrid approach can adopt some of the price stability characteristics of the price cap model.

While the price cap model might protect consumers from increasing prices, declining gas throughput results in declining units of gas that the GTB can charge for. This creates the risk that the GTB will under recover their revenue and may not be able to recover their costs. This risk exists in some form for the revenue cap model, where large, annual increases in prices may lead to end consumers being forced to exit the market prematurely and unexpectedly, leading to under recovery of revenue in a given year. However, the revenue wash up largely protects the GTB from this effect (as long as under recovery is less than 20% of revenues).

Trade-offs will be required in whichever option is used. Without additional controls, GTBs under the price cap model may also have incentives that directly oppose the aims of decarbonisation. Because revenue does not have a cap and is broadly a product of gas volume and price, and connections, a GTB under a price cap model is incentivised to increase gas volumes and new connections to grow their revenue. Similarly, under the revenue cap model, because revenue is closely related to the value of the RAB, a GTB has an incentive to overinvest in the network to increase their RAB and therefore revenue. The positive effect of overinvestment is that it is likely that reliability is improved if investment is in the right place.

Based on the assessment, deregulation is unlikely to be a viable option on its own, however may play a role in a future where the network is eventually decommissioned. We discuss this option later in this section.

How a regulatory option is enforced is likely to have a bigger impact on the gas transition

On balance, the assessment suggests that there may not be much additional value for New Zealand's gas transition in moving away from the existing revenue cap model used for the gas transmission network in a future of declining gas throughput. However, we know that in its current state the regulatory settings may not sufficiently incentivise behaviours that are aligned with the Gas Transition Plan outcomes. The discussion below is based on our high-level assessment only. Detailed analysis will be required to ascertain any changes that could be made to the regulatory framework.

Research into gas transitions in other jurisdictions suggests that the design and directiveness of the mechanisms and incentives within each regulatory option are important for encouraging the desired behaviours from the GTBs, other industry players and end consumers. Current incentives tend to be targeted towards cost efficiency and prudent investment in the network that does not result in unreasonable prices for users – however with a future of declining gas throughput the balance of these incentives may need to change.

Designing components within the regulatory regime to better align the gas transmission network operation with a future where fossil gas throughput is expected to decline is already being used in New Zealand. As discussed in Section 2.2, the DPP3 process resulted in shortening the expected economic lives of assets to ensure costs of investing in these assets are recouped earlier and reduces risk of asset stranding. This change increases the depreciation allowance for the regulatory period, bringing revenue forward and maintaining the incentive to invest. The regulatory period was also shortened to four years so that the impact of relevant Government policy decisions can be realised sooner in the next DPP.

There are other avenues that could be considered to influence the right behaviours but would require more analysis to fully understand the costs and benefits.

For example, both the price cap and revenue cap options tend to use the RAB as a significant driver of price or revenue setting, which will create challenges for revenue recovery in a future with declined gas throughput or smaller consumer base. In either option, the regulator could choose to decrease the weighting that the RAB has on the revenue or price setting. For example, revenue/price could be set at a level that only recovers the GTB's operating costs, plus some return, or only a portion of the return of capital. This could keep prices to end consumers at a reasonable level and protect consumers from price shocks. However, maintaining prices to end consumers could impact the GTB's ability to recover the full cost of their capital investment.

While we do not explore price setting for different consumer groups in detail in this report, it is important to note that reasonable price levels are important not only for ensuring energy equity, but also to ensure that consumers that continue to be reliant on gas are willing to pay for the services provided by the GTB and the wider gas industry. If the remaining consumers are not willing or able to pay to use gas throughout the transition, then the GTB is unable to receive the revenue it requires to continue operating.

An important consideration for the regulatory framework applied to the gas transmission network is whether the GTB should be able to have full return of capital and return on capital from consumers (as it does currently), via other avenues (such as the compensation options being considered in Australia), or not at all. This is important because the regulated asset base (RAB) is fundamental in revenue setting. The ability for utility owners to have a return on capital and return of capital sits at the heart of the 'regulatory compact' for economic regulation – a fair return on capital in return for equitable service.

If the model allows the GTB to continue to obtain a return of capital, then it is likely that it would keep investing in the network, particularly to ensure safety and reliability. If, on the other hand, the GTB is not able to gain a return of capital, then it is less likely to reinvest in the network. The level of ongoing investment in the network required will be dependent on the expectation on whether gas throughput will decline to the point of decommissioning or whether the network will be expected to operate on an ongoing basis, leaving the option for alternative gases. These are long-term strategic considerations that need to be signalled to the market.

Another example could be for the regulator to reduce the revenue allowance associated with funding new connections through the AMP allowances. Currently, the GTB receives revenue so that it can fund new connections for customers seeking to connect to the network. If the GTB does not fund new connections, then the connecting customer would be required to fund the connection themselves. This additional cost for the customer would act as a disincentive to connecting and consequently avoid additional gas use associated with the new connection. This intervention would require the regulator to choose to be more directive in how it desires the GTB to participate in the gas transition. This approach may also have implications for competition in the gas market (which is an objective within the *Gas Policy Statement*) so further analysis of the costs and benefits would be required before implementing.

Finally, the regulator could choose to use the pricing principles or more directive mechanism to incentivise certain behaviours. This could be targeted at certain classes of customers or regions to encourage switching away from fossil gas or switching to renewable gas. However, this would again put the operator's revenue at risk and therefore could undermine the fair return and regulatory compact with the owner.

Detailed analysis into these potential levers is required to ensure the right behaviours are incentivised and that unintended consequences are avoided.

Deregulation may play a role in the gas transition

There is also the consideration of whether some areas of the transmission network should continue to be covered by regulation during the transition. As used in the copper to fibre transition, a staged deregulation approach could be applied, where parts of the network are deregulated over time as the critical mass of consumers transition to alternative energy sources.

Careful consideration will be required in defining the circumstances in which a geographical region is ready for the deregulation of its gas transmission assets, as the end consumers of gas have widely varying needs (from residential heating to hard-to-abate industries) and varying ability to switch to alternatives.

To further protect consumers from any disruption caused by deregulation, regulators can choose to develop a minimum service requirement for a period immediately after deregulation.

The gas transmission network can play its role in enabling the gas transition and decarbonising New Zealand's energy use

The *Gas Transition Plan* seeks to ensure that the gas industry, and specifically, the gas transition network, are aligned with five desired outcomes: sustainability, emissions reductions, energy conservation and efficiency, reliability and equity. These outcomes are overlayed with the context of declining fossil gas throughput and the potential for the introduction of renewable gases.

In this research, we set out to understand whether changing the regulatory framework that sets the revenue and/or price settings for the gas transmission network would better enable the network to support the gas transition in light of declining gas throughput. Our high-level assessment suggests that there is no clear evidence that an alternative regulatory option would be better suited to align the gas transmission network with the outcomes set in the *Gas Transition Plan*. Instead, how the incentives and mechanisms within the regulatory option are set and how directive the regulator chooses to be will likely make the most impact.

Table 20: Summary of regulatory option assessment

Rating ● Positive impact ◕ Somewhat positive impact ◑ Neutral ◔ Somewhat negative impact ○ Negative impact

Assessment criteria	Regulatory options			
	Price cap / incentive regulation	**Revenue cap / incentive regulation**	**Hybrid forms of regulation**	**Deregulation**
Enabling NZ's decarbonisation through sustainability, emissions reductions, energy conservation and efficiency				
Encourages decarbonisation	○	◑	◕	○
Maintains green gas option	◑	◑	◕	○
Comments	• More likely to incentivise demand growth to increase revenue • More likely to overinvest in network	• Where RAB is used as a determinant for revenue, then may choose to overinvest to increase asset base	• Gain share/pain share could disincentivise overinvestment and be used to incentivise support for green gas	• Motivated to increase profit which requires increased revenue and/or decreased costs • Increased revenue through more demand
Ensuring energy security and reliability for consumers throughout the transition				
Maintains appropriate asset life	◔	●	◑	○
Maintains reliability and security	◔	●	◑	○
Maintains safety	◑	●	◑	◑
Comments	• Motivated to reduce costs • Will spend enough to meet quality requirements	• Link to RAB value incentivises spend on maintaining asset life	• Motivated to reduce costs • Will spend enough to meet quality requirements	• Motivated to reduce costs • Quality requirements not regulated • Quality driven by costs and license to operate • May choose to decommission early
Ensuring energy equity for consumers throughout the transition				
Maintains affordability	●	◔	◑	○
Maintains equitable access	●	●	●	○
Comments	• More likely to provide more stable prices for end consumers	• May lead to steep and material price increases for end consumers	• More likely to provide more stable prices for end consumers with share efficiencies	• More likely keep costs low and efficient operations • May charge prices higher than stipulated by previous regulation
Alignment with the purpose of monopoly regulation				
Consistency with Monopoly Regulation	●	●	●	○
Comments	• Administered by regulator	• Administered by regulator	• Administered by regulator	• No regulator required • Could only be applied in places where there are limited monopolistic powers or where benefits of regulation are outweighed by costs
Effort to implement regulatory change				
Need for legislative change	◑	●	◑	●
Need for new capabilities/ capacity	○	●	○	◑
Implementation timeframe	○	●	○	●
Additional barriers	●	●	◑	◑
Comments	• Some NZ experience due to previous weighted average price cap for electricity distribution businesses • Greater risk to regulator on getting pricing right for recovery and equity	• Current model	• Largely based on price cap model so limited regulatory reform needed • Consultation required on implementation form	• Transition to deregulation may be required but can adopt learnings from other industries • No legislative change but further consumer protections may be required
Implications for gas transmission business				
Maintains capital return	◔	●	●	◔
Maintains asset risk profile	◔	●	●	◔
Implementation effort	◔	●	◔	●
Maintains existing compliance effort	◔	●	◔	●
Comments	• Falling demand may cause under-recovery of investments	• Current model • Falling demand may cause under-recovery of investments if price increase is material and disruptive, and customer base rapidly declines	• Falling demand may cause under-recovery of investments akin to price cap model	• Significant strategic and operational shift • Enables business to ensure profitability

Appendix A Glossary

Term	Description
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BBAR	Building blocks of allowable revenue
Capex	Capital expenditure
CESS	Capital expenditure sharing schemes
CPP	Customised price path
DPP	Default price path
DPP3	Third default price-quality path
EDB	Electricity distribution business
EDF	Environmental Defense Fund
ERA	Economic Regulation Authority
GDB	Gas distribution business
GEMA	Gas and Electricity Markets Authority
GTB	Gas transmission business
ID	Information Disclosure
IM	Input methodology
MAR	Maximum allowable revenue
NCC	National Competition Council
NGGT	National Grid Gas Transmission
NGL	National Gas Law
NGR	National Gas Rules
Ofgem	Office of Gas and Electricity Markets
Opex	Operating expenditure
RAB	Regulatory asset base
RIIO	Revenue = Incentives + Innovation + Outputs
RIIO-2	Network price controls 2021-2028 (UK)
Totex	Total expenditure (capital and operating expenditure)
WACC	Weighted average cost of capital

Appendix B Regulatory settings used in Australia

Australia's gas pipelines are privately owned by a range of different parties. Regulation of Australian gas transmission networks varies between Tasmania/Western Australia and all other states and territories due to the presence of two different regulators – the Australian Energy Regulator (AER) and the Economic Regulation Authority (ERA). Table 21 provides a summary of the regulatory settings used for gas transmission in Australia and distinguishes between these two jurisdictions.

Table 21 Summary of gas transmission regulation in Australia

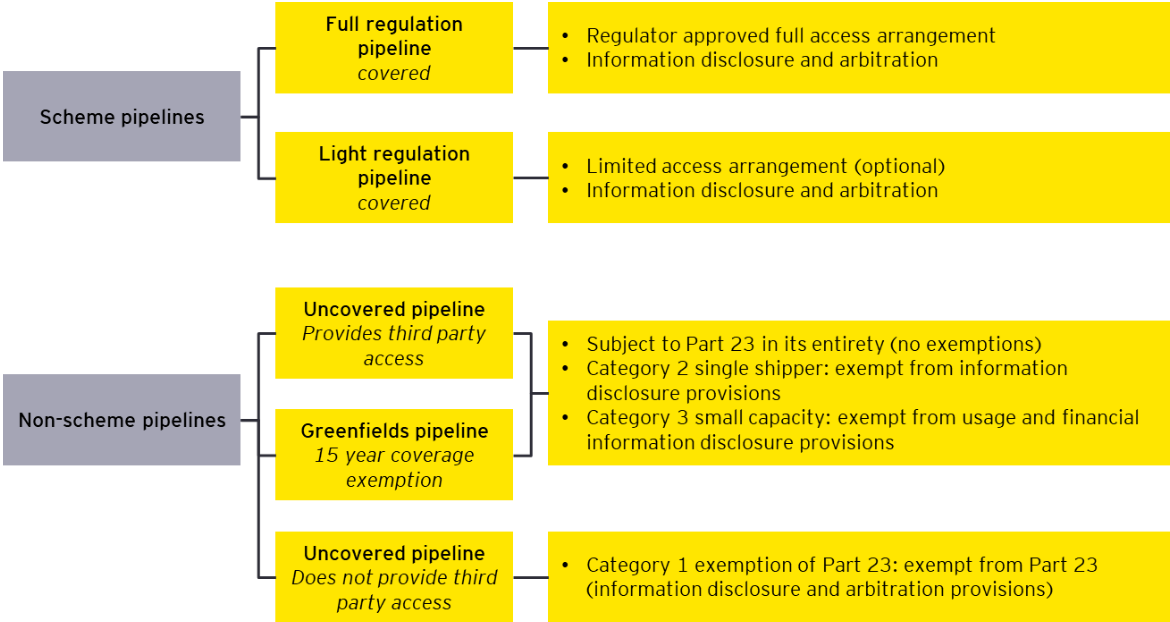
<table>
<tr><th>Country / Jurisdiction</th><th>Authority/s</th><th>Legal framework</th><th>Regulatory System</th><th>Regulatory Period</th><th>Main elements to determine</th></tr>
<tr><td>Tasmania and Western Australia</td><td>Economic Regulation Authority (ERA)</td><td>National Gas Access (WA) Act 2009 enacts the NGL and NGR</td><td rowspan="2">Network revenue allowance (revenue cap) used to set reference tariff (access prices) / incentive schemes</td><td rowspan="2">5 years</td><td rowspan="2">Efficient operating and maintenance costs, asset depreciation costs, taxation costs, commercial return</td></tr>
<tr><td>All states and territories except Tasmania and Western Australia</td><td>Australian Energy Regulator (AER)</td><td>National Gas Law (NGL) and National Gas Rules (NGR)</td></tr>
</table>

The National Competition Council (NCC) makes decisions on the classification of natural gas pipelines and the form of regulation applied to a covered pipeline. The type of regulation that applies to each pipeline depends on whether the pipeline is a natural monopoly, whether regulation would promote competition and whether regulation would be cost-effective.[47]

This form of pipeline classification between scheme and non-scheme pipelines is summarised in Figure 4 and shows that only full regulation pipelines have regulator approved access arrangements while light regulation pipelines have optional limited access arrangements. Both forms of regulation require information disclosure and allow for arbitration by the regulator where necessary.

[47] Australian Energy Regulator, State of the energy market 2022.

Figure 4: Summary of pipeline classification[48]



The Australian Energy regulator (AER) regulates the gas pipelines in all states and territories except Tasmania and Western Australia where the Economic Regulation Authority (ERA) is responsible for economic regulation. The *National Gas Law* (NGL) and *National Gas Rules* (NGR) provide a framework for the regulation of gas pipeline services by both regulators. The *National Gas Access (WA) Act 2009* implements a modified version of the NGL in Western Australia.[49] Therefore, both regulators approve access arrangements in their jurisdictions in line with the NGL and NGR.

Part 9 of the NGR outlines price and revenue regulation. In line with this legislation, a regulators role in gas pipeline regulation varies depending on the type of regulation applying to a pipeline. the type of regulation applied depends on:

- whether pipeline access is likely to promote a material increase in competition in another market; and
- whether full or light regulation is suitable depending on market power, and the costs and benefits of regulation.[50]

A.1.1 Full regulation pipelines[51]

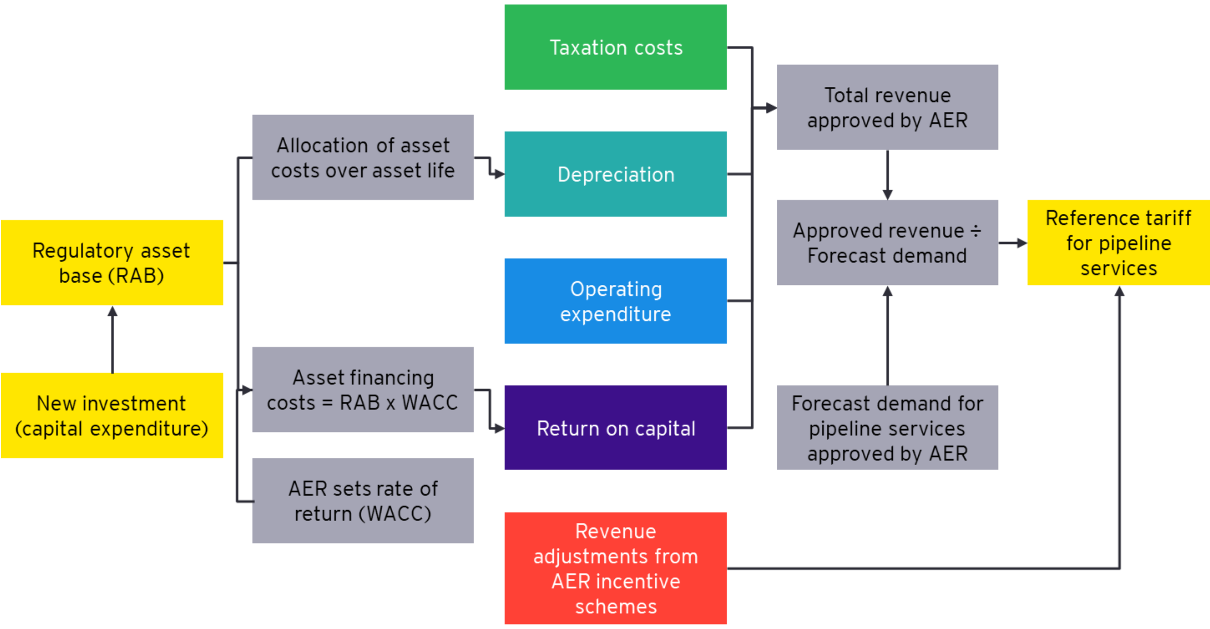
Full regulation gas pipelines in Australia must periodically submit a regulatory proposal called a 'full access arrangement' to the relevant regulator for approval under section 2 of the NGL. The proposal outlines the GTBs forecast revenue and expenditure requirements over the coming access arrangement period (5 years) and an access price that is based on forecast demand. The relevant regulator then assesses the proposal and decides whether the forecasts and access price are reasonable and efficient and can ask for more information if it believes the proposal to be unreasonable. The regulator can amend the revenue proposed by a GTB to ensure the approved cost forecasts are efficient and fair for customers in line with the purpose of regulation.

Like New Zealand, the regulator uses a building block approach to assess the business's efficient costs and revenue requirements set out in the proposal and their final decision sets prices (known

[48] AEMC, Regulatory classification of gas pipelines.
[49] ERA, Gas Access Arrangement Guideline (2022).
[50] AEMC, Regulating gas pipelines.
[51] Australian Energy Regulator, State of the energy market 2022.

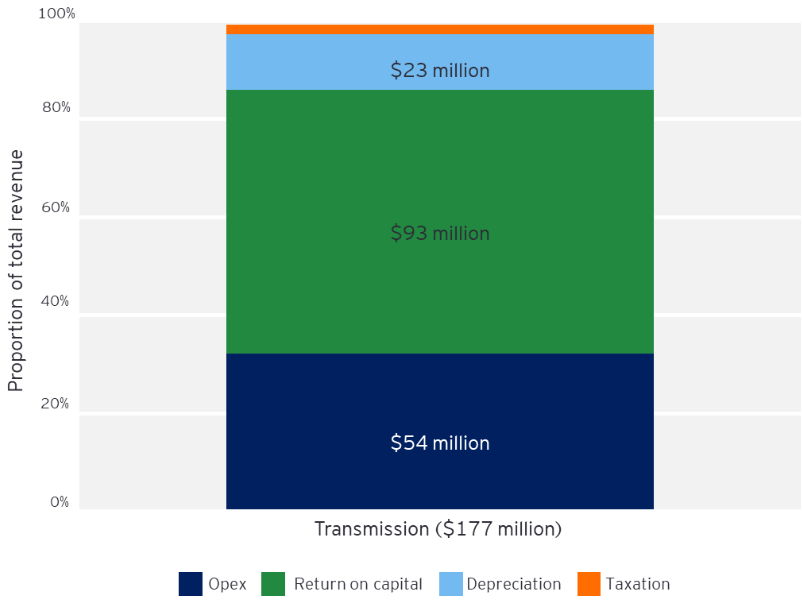
as reference tariffs in Australia) for pipeline services.[52] Figure 5 shows the range of building blocks used by the regulator to forecast how much revenue a GTB will need to earn to cover its return on capital, efficient operating and maintenance costs, asset depreciation costs and taxation.

Figure 5 AER building block approach to setting reference tariff[53]



To gain an insight into the influence each building block has on revenue, Figure 6 below provides the pipeline revenue composition for gas transmission decisions by the AER based on Opex, return on capital, depreciation and taxation. It shows that the biggest proportion of revenue is decided by return on capital ($93 million) followed by Opex ($54 million).

Figure 6: Composition of average annual average gas transmission revenues[54]



Note: CPI adjusted to June 2022 dollars. Gas pipeline businesses also receive bonuses or penalties that impact on annual network revenues but these are not material and not considered in this figure.

[52] Australian Energy Regulator, State of the energy market 2022.
[53] Australian Energy Regulator, Figure 5.4, State of the energy market 2022.
[54] Australian Energy Regulator, Figure 5.5, State of the energy market 2022.

The NGR allow GTBs to earn extra revenue if they outperform their efficiency targets, but they can also incur penalties for underperformance. This means that GTBs who keep their actual costs below the regulatory forecast can increase their profit and the efficiency gains can be shared with customers through lower access prices.[55] This is a similar incentive scheme to the efficiency incentives in the New Zealand revenue cap.

Although not explicitly mandated in the NGR, the relevant regulator can also approve the use of capital expenditure sharing schemes (CESS) to incentivise GTBs to efficiently maintain and operate their network assets. The CESS allows GTBs to earn a bonus when they keep new capital investment below forecast levels, and some of these savings are passed on to customers through lower pipeline charges in later access periods. There is a risk with this scheme that GTBs will inflate their investment forecasts to receive this benefit, but this can be mitigated by the relevant regulator analysing investments proposed by the GTBs.[56] These are similar to incentives employed in New Zealand and the UK.

A.1.2 Light regulation pipelines[57]

The light regulation of pipelines comprises of commercial negotiation supported by mandatory information disclosure and requires GTBs to publish access prices and other terms and conditions on their website. Light regulation pipelines can voluntarily propose limited access arrangements to the regulator for approval, otherwise no access arrangement is necessary. Light regulation does not involve setting allowed revenues using a building block methodology.

The pipelines cannot act in any way that could negatively impact customers, such as through price discrimination, or negatively impact competition in other markets, in line with the purpose of regulation set out in the NGR. If a party cannot negotiate fair access to a pipeline, the relevant regulator can step in to arbitrate the dispute and monitor GTB compliance with price disclosure obligations. This form of 'light' regulation is different to New Zealand's fully regulated pipelines.

A.1.3 Pipelines under Part 23 regulation[58]

Pipelines under Part 23 regulation are essentially unregulated and can set their own prices. The regulator sets, monitors and enforces guidelines on the disclosure of financial and non-financial information. The purpose of these guidelines is to make it easier for customers to negotiate access at a fair and reasonable price. In the event of a dispute under Part 23, the regulator can appoint arbitrators. This is the only example of deregulation of GTBs explored in this report and provides an example of how deregulation can be used in the right context.

[55] Australian Energy Regulator, State of the energy market 2022.

[56] Australian Energy Regulator, State of the energy market 2022.

[57] Australian Energy Regulator, State of the energy market 2022.

[58] Australian Energy Regulator, State of the energy market 2022.

Appendix C Regulatory settings used in the United Kingdom

This section discusses the regulatory settings currently used in the UK. Table 22 summarises the regulatory settings currently used in the UK with further explanation provided below.

Table 22 Summary of UK regulation[59]

Country	Authority	Legal framework	Regulatory System	Regulatory Period	Main elements to determine revenue cap
UK	Office of Gas and Electricity Markets (Ofgem) who is governed by the Gas and Electricity Markets Authority (GEMA)	Gas Act 1986, utilities Act 2000, Competition Act 1998, Enterprise Act 2002 and measures set out in a number of Energy Acts	Revenue cap based on rate of return with incentive-based regulation	Five years	Bottom-up Capex and Opex benchmarking/analysis complemented by Totex benchmarking, efficiency considerations, RAB, WACC RPI, real price effects and performance against incentive regimes

The Office of Gas and Electricity Markets (Ofgem) regulates the gas transmission system in the UK using the RIIO framework, which stands for 'Revenue = Incentives + Innovation + Outputs'. This framework is used to set the allowed revenues, which are the maximum amount the owner of the gas transmission system in the UK, National Grid, can earn in a year from customers – a similar framework to New Zealand. Therefore, the UK uses revenue cap regulation with rate of return and incentive-based components. The main elements for determining the allowed revenues include bottom-up Capex and Opex benchmarking/analysis complemented by Totex benchmarking, efficiency considerations, RAB, WACC RPI, real price effects and performance against incentive regimes.[60]

The RIIO framework uses ex ante (based on forecasts) price control to set the efficient outputs that GTBs are required to deliver and the revenue that they are allowed to earn for the duration of the regulatory period. The framework also considers output incentives, efficiency incentives and uncertainty mechanisms for revenue adjustment during the price control period.[61] The key components of the RIIO model are outlined in Table 23 and Figure 7 below.

Table 23: Components of the RIIO framework[62]

Component	Description
Outputs of the pipeline networks	These outputs outline what the network expenditure is expected to deliver based on categories such as customer satisfaction, reliability and availability, safe services, connection terms, environmental impact and social obligations.
Business Plans	These business plans describe what the GTB will do and how it has projected its revenue requirements. The business plan for the

[59] Council of European Energy Regulators, Regulatory Frameworks Report 2021.

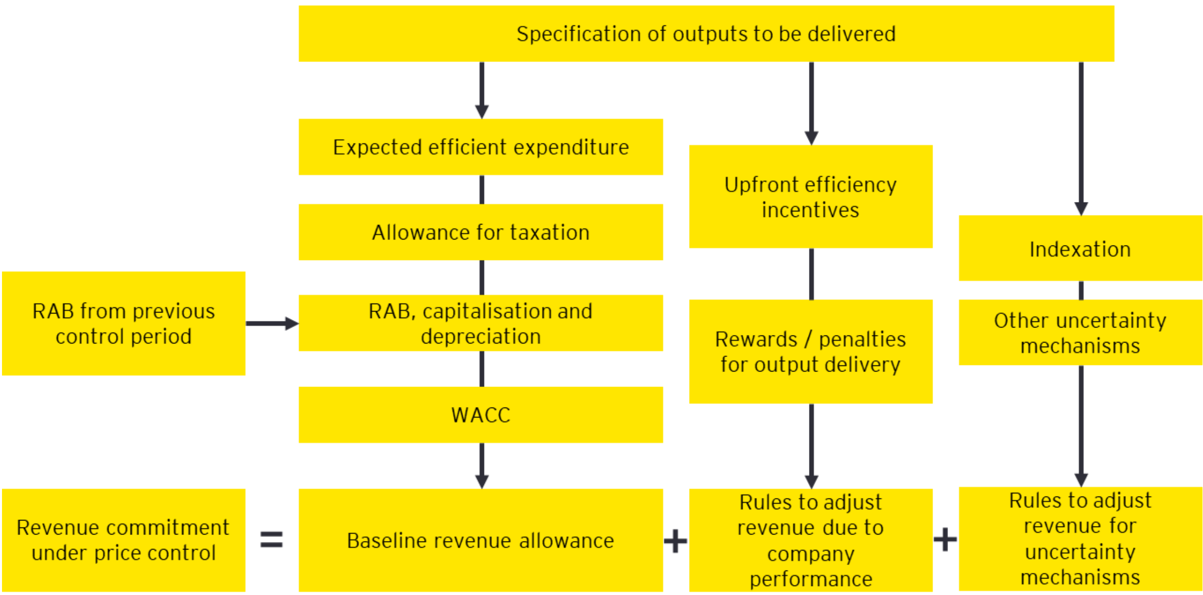
[60] Council of European Energy Regulators, Regulatory Frameworks Report 2021.

[61] Ofgem, Handbook for implementing the RIIO model 2010.

[62] Pöyry, Overview of the RIIO Framework 2017.

Component	Description
	regulatory period (also known as 'price control' period), is reviewed and assessed by Ofgem. These plans are similar to the Asset Management Plans used in New Zealand.
Ex ante price control	The price control sets the allowed revenue at the start of the regulatory period (i.e. ex ante) which provides incentives for GTBs to be efficient when considering their long-term costs. The allowed revenue is calculated using the building block approach and considers a return on asset base, depreciation, opex and tax.
Incentive and uncertainty mechanisms	Mechanisms that create adjustments to the allowed revenue during the price-control period because of improvements in efficiency or performance standard.
Innovation incentives	Incentives that encourage behaviour change and service or performance quality provided by GTB and can be used to further decarbonisation goals and agendas.

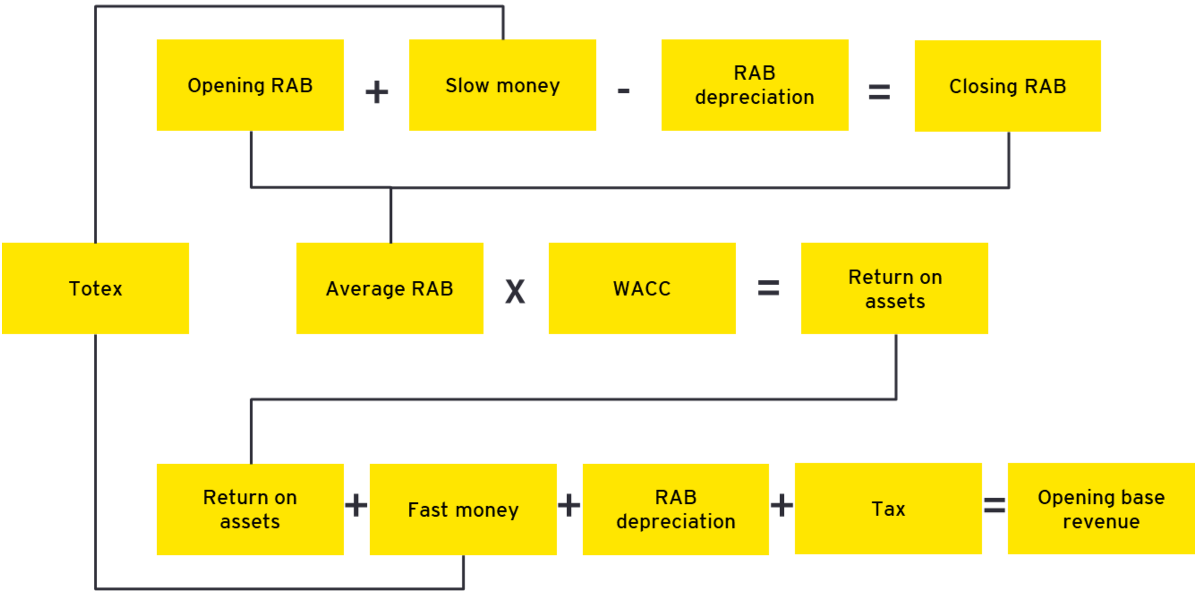
Figure 7: Summary of the RIIO framework to determine the revenue commitment under the price control[63]



A major component of the maximum revenue allowance is the baseline revenue allowance which is set through a building block approach. A summary of the components of the UK building blocks of opening base revenue (a part of the maximum revenue calculation shown in Figure 7) is provided in Figure 8 below.

[63] Pöyry, Figure 12, Overview of the RIIO Framework 2017.

Figure 8 Building blocks of UK baseline allowed revenue[64]



Before the start of each regulatory period, a final determination (currently RIIO-2) is made that sets out how the baseline allowed revenue a GTB can earn for the period is calculated, how well the ongoing efficiency incentives are working, any specific rewards or penalties that are linked to outputs and the ongoing nature of any uncertainty mechanisms.

The UK is currently in the RIIO-2 control period which spans the period 1 April 2021 to 31 March 2026 and is therefore a five year regulatory period.[65] Like New Zealand's recent DPP3 decisions, the *RIIO-2 network price controls* were specifically designed to prepare GTBs to deliver net zero at the lowest cost to consumers, while still maintaining world-class levels of system reliability and customer service, and ensuring no consumer is left behind. The decisions in RIIO-2 that apply specifically to National Grid Gas Transmission (NGGT) are outlined in the *NGGT Annex* to the final determinations.[66] For instance, in RIIO-2 Ofgem introduced a net zero re-opener across all gas transmission networks to allow for any necessary net zero related changes to the price control within the RIIO-2 regulatory period, subject to a materiality threshold.

The key differentiator between the RIIO framework and more standard rate of change building block approaches is the treatment of expenditure. Additions to the asset base are not reflected as capital expenditure and are treated as a portion (the capitalisation rate) of the total expenditure of the GTB and are known as 'slow money'. The capitalisation rate reflects the expected Opex-Capex split and determines what proportion of Totex is added to the RAB. The Totex is the sum of the forecast Opex and Capex incurred in that year, with residual Totex (fast money) recovered in the year it is incurred. The WACC, depreciation and capitalisation rate are set for the whole regulatory period and the WACC is the main determinant of the return on assets.[67]

The revenue allowance is adjusted annually to get the maximum revenue allowance according to the actual performance of the GTB and impacts tariff calculations (charges to use the network). These adjustments consider inflation, capital investment, non-controllable/pass through operating and maintenance costs, and other mechanisms and incentives.[68]

[64] Pöyry, Figure 13, Overview of the RIIO Framework 2017.
[65] National Grid, How we're regulated.
[66] Ofgem, RIIO-2 Final Determinations - GTTB Annex 2021.
[67] Pöyry, Overview of the RIIO Framework 2017.
[68] Ofgem, RIIO-2 Final Determinations - Core Document 2021.

GTBs are subject to efficiency and output incentives as part of the RIIO framework and are incentivised to beat their allowed costs through a sharing mechanism that allows them to keep a share of the underspend or bear a proportion of any overspend and is similar to the efficiency incentives under the revenue cap in New Zealand. The revealed actual costs are then used to set benchmarks for following price control periods to continue to incentivise efficiency.

GTBs are also subject to quality regulation measures like New Zealand and must meet certain performance outputs. If a GTB does not meet these performance benchmarks they can receive penalties, claw back of revenue or enforcement action. In the latest regulatory period RIIO-2, there are output incentives related to meeting the need of consumers and network users, maintaining a safe and resilient network and delivering an environmentally sustainable network.

The RIIO framework uses uncertainty mechanisms to address the unpredictability of market conditions, which is important in the face of an uncertain gas future. GTBs propose expenditure that they think should be subject to uncertainty mechanisms in their business plans and could include mechanisms such as volume drivers, indexation, pass-through, re-openers, triggers and more. [69] These mechanisms allow the price control arrangements to respond to unexpected changes to the gas industry environment, such as declining throughput.

[69] Ofgem, RIIO-2 Final Determinations – Core Document 2021.

Appendix D Regulatory settings used in Europe

The Council of European Energy Regulators (CEER) published a 'Report on Regulatory Frameworks for European Energy Networks 2021'. Table 24 below provides a summary of the gas transmission regulatory settings used across Europe. Overall, incentive methods are used in nine European countries, price/revenue caps are used by 26 countries and rate of return regulation is used in five countries.

Table 24: Summary of regulatory settings used in Europe[70]

Country	Authority	Legal framework	Regulatory System	Regulatory Period	Main elements used to determine price/revenue regulation
Austria	E-control	Gas Act 2011	Incentive regulation - price cap	4 years. Current RP: 2021-24	Efficiency scores, increase in WACC for taking full volume risk, indexed historic depreciated costs to determine RAB
Belgium	CREG	NC TAR, Belgian law, CREG approved tariff methodology	Incentive regulation / revenue cap	4 years. Current RP: 2020-23	Non- controllable and controllable costs, depreciation costs, taxes and fair margin
France	Commission de Régulation de l'Énergie	French law (code de l'énergie) and CRE tariff decisions	Incentive regulation / revenue cap	4 years. Current RP: 2020-24	Non-controllable and controllable costs, depreciation costs, taxes, fair margin
Germany	Bundesnetzagentur (BNetzA)	EnWG, ARegV, GasNEV	Incentive regulation / revenue cap	5 years. Current RP: 2018-22	Non-controllable and controllable costs, Totex efficiency benchmark, general inflation and sectoral productivity factor, volatile costs
Netherlands	Authority for Consumers and Markets (ACM)	Gaswet (Gas Act)	Incentive regulation / revenue cap	3-5 years. Current RP: 2017-21	Totex, CPI, cost efficiency benchmark, productivity change, WACC, RAB
Northern Ireland	Northern Ireland Authority for Utility Regulation	Gas (NI) Order 1996	Mixture	5 years. Current RP: 2017-22	Review of historic and forecast Opex, productivity, WACC, inflation
Czech Republic	Energy Regulatory Office (ERO)	Act No. 458/2000 on the Conditions of Business and State Administration in Energy Industries and on Changes to	Incentive regulation/ revenue cap, price cap	5 years. Current RP: 2021-25	Eligible costs, eligible depreciation and amortisation, RAB, WACC

[70] Council of European Energy Regulators, Regulatory Frameworks Report 2021.

Country	Authority	Legal framework	Regulatory System	Regulatory Period	Main elements used to determine price/revenue regulation
		Certain Laws (the Energy Act), Public notice no. 195/2015 on price control in gas sector			
Estonia	Konkurentsiamet	Natural Gas Act	Rate of return	No period	Variable costs, operating costs, depreciation of RAB, justified return on RAB
Finland	Energy Authority (Energiavirasto)	Electricity Market Act (588/2013), Natural Gas Market Act (587/2017) and Act on the supervision of the electricity and natural gas market (590/2013)	Revenue cap	Current regulatory framework is set for two RPs (2016-19 and 2020-23)	Efficiency, quality, innovation and investment incentives, WACC, return on RAB
Greece	Regulatory Authority for Energy (RAE)	Law 4001/2011	Cost-plus	4 years. Current RP: 2019-22.	Opex (non-controllable and controllable costs), depreciation, RAB (assets and approved investment plans, working capital), WACC
Hungary	Hungarian Energy and Public Utility Regulatory Authority (MEKH)	Act 40 of 2008 on natural gas Commission Regulation 2017/460 (NC TAR)	Incentive regulation	4 years. Current RP: Jan 2017- Sept 2021 (longer than four years due to the change from Jan-Dec RPs to Oct-Sep RPs)	Allowed revenue is composed of Opex, Capex, depreciation (all adjusted to account for inflation), efficiency improvement factor for Opex (CPI-X)
Ireland	Commission for Regulation of Utilities (CRU)	Under Section 10A of the Gas Act 1976 as amended CRU sets the tariffs and the allowed revenue for the TSO	Incentive regulation / revenue cap	5 years. Current RP: 2017-22	Review of historic and forecast Opex, review of historic and forecast Capex, value of assets in TSO's RAB, Rate of Return, inflation, depreciation, reporting and incentives.
Italy	Italian Regulatory Authority for Energy, Networks and Environment (ARERA)	ARERA Res. 114/2019/R/gas	Cost-plus for CAPEX. Price cap for OPEX	4 years. Current RP: 2020-23	Opex (updated with price cap), return on net RAB, additional return for incentives, depreciation, fuel gas, losses, unaccounted for gas.
Latvia	Public Utilities Commission	Energy Law, Law on Regulators of Public Utilities, Methodology for the Calculation of the Tariffs on the Natural Gas Transmission System Services, Methodology for the Calculation of the	Revenue cap	3 years	Opex and Capex (depreciation and return on capital)

Country	Authority	Legal framework	Regulatory System	Regulatory Period	Main elements used to determine price/revenue regulation
		Tariffs on the Natural Gas Distribution System Service			
Lithuania	National Energy Regulatory Council (NERC)	The Law on Natural Gas of the Republic of Lithuania	Revenue cap	5 years. Current RP: 2019-23	Totex, RAB, WACC, technical losses, efficiency benchmark
Luxembourg	Institut Luxembourgeois de Régulation (ILR)	Law modified 1 August 2007 relative to the organisation of the natural gas market, ILR/G20/21	Revenue cap / incentive regulation	4 years. Current RP: 2021-24	Remuneration on RAB, depreciation, controllable Opex, non-controllable Opex
Norway	N/a	Act on common rules for the internal market for gas with underlying regulations.	Under development	Under development	Under development
Poland	The President of the Energy Regulatory Office (URE)	Energy Law Act and regulations of the Minister of Energy	Revenue cap	Calendar year	Justified operating expenditures, depreciation, local taxes and other fees, cost of gas losses and return on capital employed
Portugal	Entidade Reguladora dos Serviços Energéticos (ERSE)	Decree-Law No. 62/2020 of 28 August	Price cap (OPEX) and rate of return (CAPEX)	4 years. Current RP: 2020-23	Non-controllable and controllable costs, RAB, WACC, efficiency benchmark, inflation mechanism for attenuation of tariff adjustments
Romania	National Regulatory Authority for Energy (ANRE)	Energy and Gas Law 123/2012, ANRE Order 217/2018 for distribution activity and Order 41/2019 for transmission activity	Incentive regulation - revenue cap	Generally 5 years. Current RP (TSO): Oct 2019-Sept 2024	Non-controllable (pass-through) and controllable costs, efficiency factor, general inflation rentability of RAB (RAB * Rate of return), depreciation, technological consumption
Slovakia	Regulatory Office for Network Industries (URSO)	Act No. 250/2012 Coll. On Regulation in Network Industries, Act No. 251/2012 Coll. On Energy Industry, URSO Decree No. 223/2016 Coll. (gas), URSO Decree No. 18/2017 Coll. (electricity)	Benchmarking	5 years. Current RP: 2017-21, extended until 2022	Analysis of entry-exit tariffs in other Member States of the EU
Slovenia	Energy Agency	Act on the methodology for determining the regulatory framework of the natural gas transmission system operator	Incentive regulation/revenue cap	3 years. Current RP: 2019-21	Controllable Opex (general productivity), uncontrollable Opex, Capex (depreciation, regulated return on assets), consumption, incentives

Country	Authority	Legal framework	Regulatory System	Regulatory Period	Main elements used to determine price/revenue regulation
Spain	Comisión Nacional de los Mercados y la Competencia (CNMC)	Law 34/1998 of the Hydrocarbons sector, circulars 2/2019, 9/2019, 4/2020 and 8/2020	Incentive regulation	6 years. Current RP: 2021-26 (gas years, i.e. from 1 Oct-30 Sept). Gas year 2021: 1 Jan-30 Sept 2021	Investment and Opex reference values, RAB, rate of return, regulatory lifetime of assets, incentives
Sweden	Swedish Energy Markets Inspectorate	Naturgaslagen (Gas Act)	Revenue cap	4 years. Current RP: 2019-22	Totex (divided into Capex, non-controllable Opex and controllable Opex). General efficiency target of reducing 1% of controllable Opex annually
Albania	Ministry of Infrastructure and Energy	Law on Natural Gas Sector	Price cap	Yearly. Current RP: 1 January-31 December 2021	Opex and Capex, general inflation (only for electricity), revenue requirement adjustment
Georgia	Georgian national energy and water supply regulatory commission (GNERC)	Georgian law on energy, tariff calculation methodologies and investment appraisal rules approved by GNERC	Cost-plus / incentive-based regulation	3 years. Current RP: 2020-22	Capex, Opex, cost of normative losses, correction component and service quality component
North Macedonia	Energy and Water Services Regulatory Commission of Republic of North Macedonia (ERC)	Law on Energy and regulatory acts	Revenue cap	5 years. Current RP: 2017-21	Opex and Capex
Ukraine	National Energy and Utilities Regulatory Commission (NEURC)	The Laws of Ukraine "On the natural gas market", "On the natural monopolies", NEURC Resolutions of 30 September 2015 # 2517 and of 25 February 2016 # 236	Incentive regulation	5 years. Current RP: 2020-24	Allowed revenue is composed of Opex considering efficiency factors, Capex, depreciation adjusted to inflation rates

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