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Default price-quality paths for gas pipeline businesses from 1 October 2022

Final Reasons Paper

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Associated documents

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28 February 2013	ISBN 878-1-869452-20-9	Setting default price-quality paths for suppliers of gas pipeline services
28 February 2013	ISBN 978-1-869453-11-4	[2013] NZCC 4 Gas Distribution Services Default Price-Quality Path Determination 2013
27 March 2014	ISBN 978-1-869453-60-2	[2013] NZCC 5 Gas Transmission Services Default Price-Quality Path Determination 2013 (consolidating all amendments as of March 2014)
29 May 2017	ISSN 1178-2560	[2017] NZCC 15 Gas Distribution Services Default Price-Quality Path Determination 2017 (29 May 2017)
29 May 2017	ISSN 1178-2560	[2017] NZCC 14 Gas Transmission Services Default Price-Quality Path Determination 2017 (29 May 2017)
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3 April 2018	ISSN 1178-2560	Gas Distribution Services Input Methodologies Determination 2012 (consolidating all amendments as of 3 April 2018)
3 April 2018	ISSN 1178-2560	Gas Transmission Services Input Methodologies Determination 2012 (consolidating all amendments as of 3 April 2018)
4 August 2021	ISBN 978-1-869459-15-4	Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper
10 February 2022	ISBN 978-1-869459-78-9	Default price-quality paths for gas pipeline businesses from 1 October 2022 – draft reasons paper
10 February 2022	ISBN 978-1-869459-79-6	Proposed amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths – Draft reasons paper
25 March 2022	ISBN 978-1-869459-93-2	Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths – weighted average cost of capital - reasons paper
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30 May 2022	ISSN 1178-2560	Gas Distribution Services Input Methodologies Amendment Determination (No.2) 2022 – 30 May 2022
30 May 2022	ISSN 1178-2560	Gas Transmission Services Input Methodologies Amendment Determination (No.2) 2022 – 30 May 2022
30 May 2022	ISSN 1178-2560	Gas Distribution Information Disclosure Amendment Determination 2022 – 30 May 2022

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31 May 2022	ISSN 1178-2560	Gas Transmission Services Default Price-Quality Path Determination 2022 – 31 May 2022

Commerce Commission
Wellington, New Zealand

Contents

Glossary

Acronym	Definition
$ 2021	Expenditure is expressed on a Disclosure Year 2021 year-end basis for each supplier
2050 target	New Zealand's target to achieve net zero emissions of greenhouse gases by 2050
AIS	Asset Information System
AMP	Asset Management Plan
BAU	Business-as-usual
BBAR	Building Blocks Allowable Revenue
BBM	Building Blocks Method
capex	Capital expenditure
CCC	Climate Change Commission
CCRA	Climate Change Response Act 2002
Concept	Concept Consulting Ltd
CPI	Consumer Price Index
CPP	Customised price-quality path
CPRG	Constant Price Revenue Growth
DPP	Default price-quality path
DPP1	Default price-quality path for the first regulatory period (1 October 2013 – 30 September 2017)
DPP2	Default price-quality path for the second regulatory period (1 October 2017 – 30 September 2022)
DPP3	Default price-quality path for the third regulatory period (1 October 2022 – 30 September 2026)
DPP4	Default price-quality path for the fourth regulatory period (the regulatory period from 1 October 2026)
DYxx	Disclosure Year 20xx
EDB	Electricity Distribution Businesses
EDB DPP3	Default price-quality path for the third regulatory period (1 April 2020 – 31 March 2024) for Electricity Distribution Businesses
ERP	Emissions Reduction Plan May 2022
ERP Part 1	First stage of the Emissions Reduction Plan
FCM	Financial Capital Maintenance
First Gas	First Gas Limited, parent entity which covers both their transmission and distribution businesses
First Gas Distribution	The distribution business of First Gas Limited
First Gas Transmission	The transmission business of First Gas Limited
GAAP	Generally Accepted Accounting Practice
Gas IMs	Input Methodologies for gas pipeline services
GDB	Gas Distribution Business
GDS	Gas Distribution Services
GIC	Gas Industry Company
GPB	Gas Pipeline Business

Acronym	Definition
GTAC	Gas Transmission Access Code
GTB	Gas Transmission Business
GTS	Gas Transmission Services
ICP	Installation Control Point
ID	Information Disclosure
IFRS	International Financial Reporting Standards
IMs	Input Methodologies
IM Review	Statutory Input Methodologies Review
IRIS	Incremental Rolling Incentive Scheme
LCI	Labour Cost Index
MAR	Maximum Allowable Revenue
MBIE	The Ministry of Business, Innovation and Employment
MEUG	Major Electricity Users' Group
MGUG	Major Gas Users' Group
NPV	Net Present Value
NZ ETS	New Zealand Emissions Trading Scheme
NZIER	The New Zealand Institute of Economic Research
NZ IFRS	The New Zealand International Financial Reporting Standards
OFGEM	The Office of Gas and Electricity Markets
opex	Operating expenditure
Part 4	Part 4 of the Commerce Act 1986
PE	Polyethylene
PPI	Producer Price Index
PQ	Price Quality
RAB	Regulatory Asset Base
RBNZ	Reserve Bank of New Zealand
RFI	Request for Information
SaaS	Software as a Service
Stranding risk	risk of economic network stranding
RTE	Response Time to Emergencies
TAMRP	Tax Adjusted Market Risk Premium
the Act	Commerce Act 1986
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap
X-factor	The rate of change in prices. If prices are increasing, then the value of x will be negative when applying a CPI-X approach

Gas DPP3 Decisions at a glance

Change relative to draft decision	Unchanged from draft	Update or change to input	Change of policy or implementation

#	Policy measure
Price path	
P1	Set starting prices on the basis of current and projected profitability of each Gas Pipeline Business (**GPB**) using a building blocks allowable revenue (**BBAR**) model.
P2	Set change in annual prices for each GPB (**X-factor**).
P3	Applied a revenue cap with a wash-up mechanism for the Gas Transmission Business (**GTB**) as the form of control.
P4	Applied a weighted average price cap (**WAPC**) for Gas Distribution Businesses (**GDBs**) as the form of control.
P5	Used GDBs' Installation Control Point (**ICP**) and gas demand growth forecasts to forecast Constant Price Revenue Growth (**CPRG**).
Transitioning to net zero	
U1	Set a regulatory period of four years.
U2	Introduced via a Gas IM amendment a capital expenditure (**capex**) capacity event reopener for projects and programmes that: - were unforeseen at the time of publishing supplier expenditure forecasts that we based the DPP3 allowances on; or - that were foreseen for later regulatory periods, but changes in circumstances mean that the project or programme is brought forward into the current regulatory period.
U3	Introduced via a Gas IM amendment a capex and operating expenditure (**opex**) risk event reopener for projects and programmes that: - were unforeseen at the time of publishing supplier expenditure forecasts that we based the DPP3 allowances on; or - that were foreseen for later regulatory periods, but changes in circumstances mean that the project or programme is brought forward into the current regulatory period; and - in the case of opex the proposed operating expenditure is cost-effective when compared to capex for the same purpose.
U4	Introduced via a Gas IM amendment a mechanism to allow us to adjust asset lives when calculating depreciation for a DPP when doing so would better reflect the economic asset lives and promote the purpose of Part 4 (**Part 4**) of the Commerce Act 1986 (**the Act**).
U5	Shortened asset lives in DPP3 to reflect the remaining expected economic lives of the networks. This mitigates economic network stranding risks. Our final decision puts weight on a wider range of possible future scenarios than the draft and considers the potential residual value of the pipelines when they are no longer used to convey natural gas.
Operating expenditure	
O1	Used GPB's forecasts of opex to set our opex allowance, subject to a cap based on our estimate of forecast opex using a base, step, and trend approach.
O2	Used revised actual opex from DPP2 Year 4 (Disclosure Year 2021) as the opex base value.
O3	Modelled and provided for step changes in opex for First Gas Transmission and GasNet.

Change relative to draft decision

Unchanged from draft	Update or change to input	Change of policy or implementation

#	Change	Policy measure
O4	Unchanged from draft	Inflated opex using a weighted average of all-industries Labour Cost Index (**LCI**) (60%) and Producer Price Index (**PPI**) (40%).
O5	Unchanged from draft	Applied an opex partial productivity factor of 0%.
O6	Unchanged from draft	Used GPB's own projections of ICP growth.
O7	Unchanged from draft	Scaled base opex for forecast of network length and ICP growth based on historical relationship of network length to ICP growth.
O8	Update or change to input	Updated elasticity factor based on the most recent available Australian and New Zealand gas supplier data.
Capital expenditure		
C1	Unchanged from draft	Used a top-down historical network real capex projection approach to limit network capex forecast allowances.
C2	Unchanged from draft	Allowed GPB non-network capex following high level scrutiny of forecasts and Asset Management Plan (**AMP**) material.
C3	Unchanged from draft	Allowed GDB consumer connection capex as this aligns with our CPRG forecast.
C4	Unchanged from draft	Not added margins to historical network capital expenditure projections.
C5	Unchanged from draft	Obtained nominal capex series by inflating real $2021 capex using New Zealand Institute of Economic Research (**NZIER**) forecast of all-industries PPI.
Other inputs to the financial model		
M1	Update or change to input	Weighted average cost of capital (**WACC**) of 6.14%. The WACC figure reflects the four-year average risk-free rate observed in December 2021- February 2022 in line with the four-year regulatory period.
M2	Unchanged from draft	Increased via a Gas IM amendment the tax-adjusted market risk premium (**TAMRP**) from 7.0 to 7.5%.
M3	Unchanged from draft	Based Consumer Price Index (**CPI**) forecasts on Reserve Bank of New Zealand's forecasts of inflation as per IMs.
M4	Unchanged from draft	Included an allowance for disposed assets based on historical levels.
M5	Unchanged from draft	Included an allowance for other regulated income based on historical levels.
Quality Standards		
QS1	Unchanged from draft	Retained response time to emergencies (**RTE**) standard for GPBs.
QS2	Unchanged from draft	Retained major interruptions standard for the GTB.
QS3	Unchanged from draft	Did not introduce new quality standards for GPBs.
Compliance reporting		
CO1	Unchanged from draft	Retained substance and content of price-path and quality compliance reporting requirements for GPBs.
CO2	Unchanged from draft	Did not introduce new price-path and quality compliance reporting requirements for GPBs.
CO3	Change of policy or implementation	Aligned timing of ex-post compliance reporting for price-path and quality standards with Information Disclosure (**ID**).
CO4	Change of policy or implementation	Specified compliance reporting requirements via s 53N notices rather than within DPP determinations.
Other		
X1	Unchanged from draft	Retained cut-off date for Customised price-quality path (**CPP**) application of 23 October 2024 to allow sufficient time for any potential CPP decisions to be finalised before we commence the DPP4 reset process.

Executive Summary

Purpose

X1 This paper sets out the default price-quality paths we have set for gas pipelines businesses (**GPBs**) for the third regulatory period (1 October 2022 – 30 September 2026) (**DPP3**) in respect of gas pipeline services.

X2 These price-quality paths determine the maximum revenues GPBs can recover from their consumers and the minimum quality standards they must meet when supplying gas pipeline services. The DPP3 settings will take effect from 1 October 2022.

X3 We thank parties who provided their views through submissions and cross-submissions.[1] These views have informed our decisions.

Starting prices and annual changes in prices

X4 Our DPP3 decisions have resulted in the starting prices and annual changes in prices shown in Table X1.

Table X1: Starting prices and rates of change ($ nominal)

Gas Pipeline Business	Starting prices (Maximum allowable revenue in 2022/23 ($m))	Rate of change (relative to CPI)
GasNet	4.852	CPI + 5.5%
Powerco	57.633	CPI + 5.0%
Vector	58.317	CPI + 0%
First Gas Distribution	28.566	CPI + 10.0%
First Gas Transmission	147.227	CPI + 8.5%
Industry total	**296.595**	

X5 We have not used an alternative rate of change for Vector as we have for other GPBs because the price impact from applying a single starting price adjustment for the first year of DPP3 ending 2023 would not have exceeded 10% real.

X6 Our decisions will result in a nominal increase in household gas bills of about 3.8% per year on average for each of the four years of DPP3. For a medium annual household gas bill of about $1,246, this will be an increase of around $48 per year for each of the four years of DPP3. These bill impacts are less than our draft decision

[1] Submissions can be found on the Commerce Commission website

which was an increase in household gas bills of about 4.5% per year on average or around $55 per year. The impact on individual households, as well as commercial and major industrial consumers will depend on their particular circumstances and arrangements with natural gas suppliers.

Context for our decision

X7 The Government has committed to net zero emissions by 2050 (**2050 target**) which requires all greenhouse gases, other than biogenic methane, to reach zero on a net accounting emissions basis by 2050.[2,3] The Government has recently published its emissions reduction plan (**ERP**) which sets New Zealand on a pathway to meeting the 2050 target.[4] The Government's plan includes phasing out the use of fossil fuels, including natural gas, whilst ensuring energy is accessible, affordable, secure, and supports economic development, and there is an equitable transition.

X8 As natural gas demand declines so too will the number of users on gas pipeline networks. This has implications, in particular, the remaining economic life of the networks to convey natural gas is likely to be shorter than previously expected.

X9 However, natural gas remains an essential energy source for many homes and businesses and it will likely take years for users to migrate to lower emission alternatives. Further investment is still required to ensure the networks continue to provide safe and reliable supply of natural gas until they are no longer needed.

X10 GPBs, in their Asset Management Plans (**AMP**s) estimate that the level of investment in operating expenditure (**opex**) and capital expenditure (**capex**) required to be approximately $2 billion in the next ten years alone. We have assessed the amount that should be allowed in DPP3. The forecast amounts of opex and capex that will be required in future periods will be considered in future price-path resets.

X11 While delivered volumes of natural gas will likely decline over time, the rate at which it will do so, and by when the service is likely to phase out, is unclear at this point.

Our decision package and how it benefits consumers of gas pipeline services

X12 Our package of decisions seeks to promote the long-term benefit of consumers of gas pipeline services by promoting outcomes that are consistent with outcomes in competitive markets. In reaching our decisions we recognise that natural gas is an important energy source for a range of consumers and is likely to continue to play a role for some time as New Zealand transitions to a net zero economy. Consumers

[2] Climate Change Response Act, s 5Q(1)(a)

[3] Ministry for the Environment "Emissions reduction plan discussion document" (October 2021), p. 9.

[4] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan" (16 May 2022)

who continue to use natural gas should be able to do so with confidence that their supply will be safe and reliable.

X13 Key decisions we have made as part of DPP3 include:

X13.1 smoothing price increases over the regulatory period to minimise the impact of price rises on consumers of gas pipeline services;

X13.2 setting the length of the regulatory period at four years to enable us to review price-quality settings at the earliest opportunity after further government energy policy initiatives are scheduled to be announced;

X13.3 shortening asset lives to better reflect the expected remaining economic lives of the networks;

X13.4 setting capex and opex allowances that are sufficient to maintain networks and support short-term growth while protecting consumers from paying for investment that may not be needed in the long-term;

X13.5 allowing some opex for the investigation of blended gases in networks, recognising that this could benefit consumers of gas pipeline services; and

X13.6 providing expenditure reopeners for GPBs to seek additional funding for unforeseen growth or risks that affect safe and reliable gas supply.

X14 Gas is currently used by approximately 300,000 consumers to run businesses, heat water and homes, and to cook. Meeting this demand and potential demand from new consumers requires significant continued investment to build and maintain large infrastructure assets. These investments are recovered over time from the consumers who benefit from those services. Recognising that natural gas will continue to play a role as an energy source for some time, we have sought to promote the section 52A purpose by:

X14.1 maintaining appropriate incentives for GPBs to invest in gas pipelines to deliver safe and reliable services for consumers;

X14.2 minimising the risk of inefficient investment; and

X14.3 smoothing price increases for consumers of gas pipeline services and limiting the ability of GPBs to earn excessive profits.

We have set a four-year regulatory period to allow the regulatory settings to be adjusted earlier in response to energy policy developments over DPP3

X15 DPP3 covers the four-year period from 1 October 2022 to 30 September 2026. By setting a shorter regulatory period we can consider new developments affecting the gas sector sooner when making our decisions for the default price-quality path for the fourth regulatory period (from 1 October 2026) (**DPP4**).

X16 The ERP published on 16 May 2022 sets out some of the key expected developments over DPP3:

X16.1 a gas transition plan by the end of 2023 which will set out a transition pathway for the fossil gas industry, explore opportunities for renewable gases and ensure an equitable transition;

X16.2 an energy strategy by the end of 2024 which aims to address strategic challenges in the energy sector and signal pathways away from fossil fuels; and

X16.3 the second ERP in 2024 outlining policies and strategies for meeting the second emissions budget (2026-2030).

We have shortened asset lives to better reflect their expected economic lives

X17 Prior to this DPP, our approach to asset lives assumed that GPBs will provide services for decades to come, and their assets will have economic lives approximating their physical lives. But with expectations for declining demand, the Government wanting to phase out the use of natural gas, and the potential for network closure, gas pipeline assets will now have a shorter expected economic life conveying natural gas than previously assumed.

X18 Accordingly, we have shortened the regulatory asset lives of the network to better match the period during which the network is still expected to convey natural gas. This means the period over which GPBs' investments in assets is to be recovered is shorter than previously assumed, which increases the allowance for depreciation in DPP3. This has the effect of better maintaining incentives for GPBs to invest in their networks while there is still demand for natural gas. We consider this to be in consumers' long-term interests, and have smoothed price increases over time to help reduce the impact on consumers.

X19 Going forward, through information disclosure, this will allow GPBs to adjust asset lives for new and existing assets to better reflect their expected economic lives in future DPP resets and allow recovery of asset-related costs under the building blocks method (**BBM**) over a shorter, and more realistic, timeframe. This means that consumers of gas pipeline services should avoid larger price increases in future resets. To minimise price shocks to consumers in DPP3 we have smoothed the price increases occurring in DPP3 and have deferred some of the increase in prices to DPP4 (although we will need to assess the prices afresh for DPP4).

We have limited expenditure to reflect the future transition away from natural gas while allowing for short-term growth and sufficient funds to adequately maintain networks

X20 To recognise the long-term outlook for gas is in decline, we have been cautious in setting capex allowances. We have done this by limiting capex to historical levels rather than allowing the forecasts provided by the GPBs. We consider this allows sufficient capex for GPBs to deliver a safe and reliable supply of gas and asks GPBs to be prudent and prioritise their expenditure to deliver what is needed.

X21 We have allowed capex for system growth and consumer connection during DPP3. We are satisfied that gas distribution businesses' (**GDBs**) capital contribution policies reflects expectations of a future decline in the use of piped natural gas.

X22 We have set opex allowances that are largely consistent with GPB forecasts but are capped for each year based on our own forecasts of future opex. Our forecasts use a base, step, and trend modelling approach as they did in the draft. We consider the allowances we have set should provide sufficient funds to maintain natural gas networks and ensure that consumers continue to receive safe and reliable supply.

X23 Table X2 provides the resulting opex and capex expenditure allowances for each GPB.

Table X2: Expenditure allowances for the four-year DPP (real $000)

Gas Pipeline Business	Opex	Capex	Total
GasNet	9,454	3,309	12,763
Powerco	73,585	67,271	140,856
Vector	56,271	23,064	79,336
First Gas Distribution	39,970	47,170	87,140
First Gas Transmission	198,196	142,898	341,094
Industry Total	**377,477**	**283,712**	**661,188**

X24 Figures X1 and X2 present our DPP3 opex and capex allowances for all GPBs compared with DPP3 draft allowances, DPP2 allowance settings, GPB 2021 AMP forecasts and historical actual expenditure.

Figure X1: Historical and allowed operating expenditure (real $000)

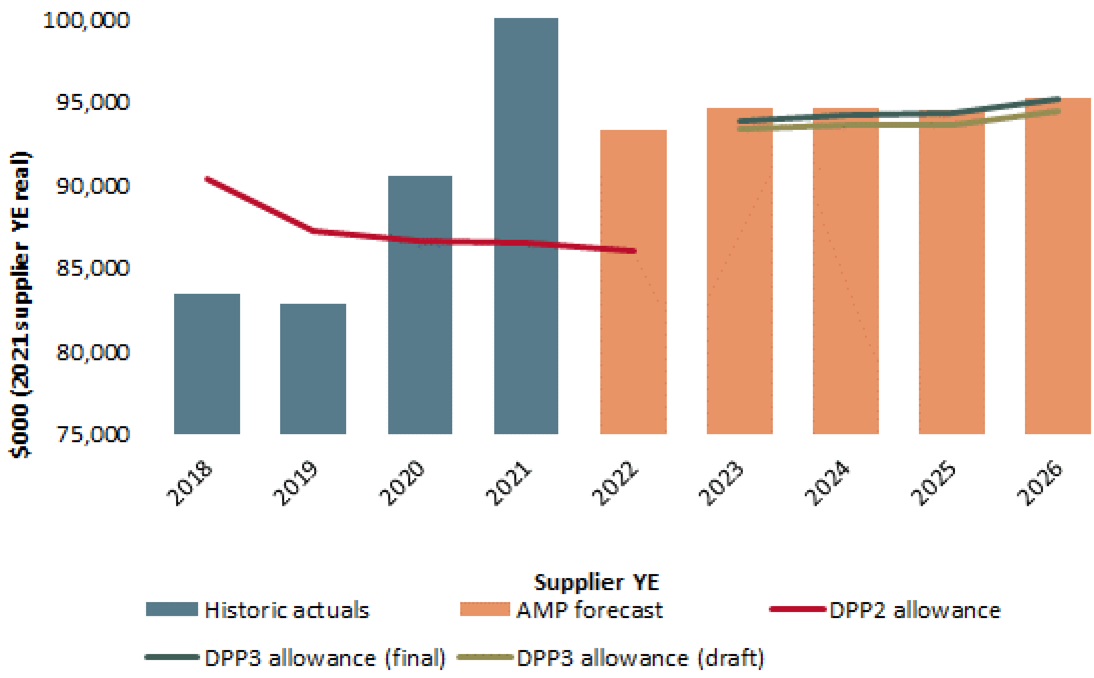
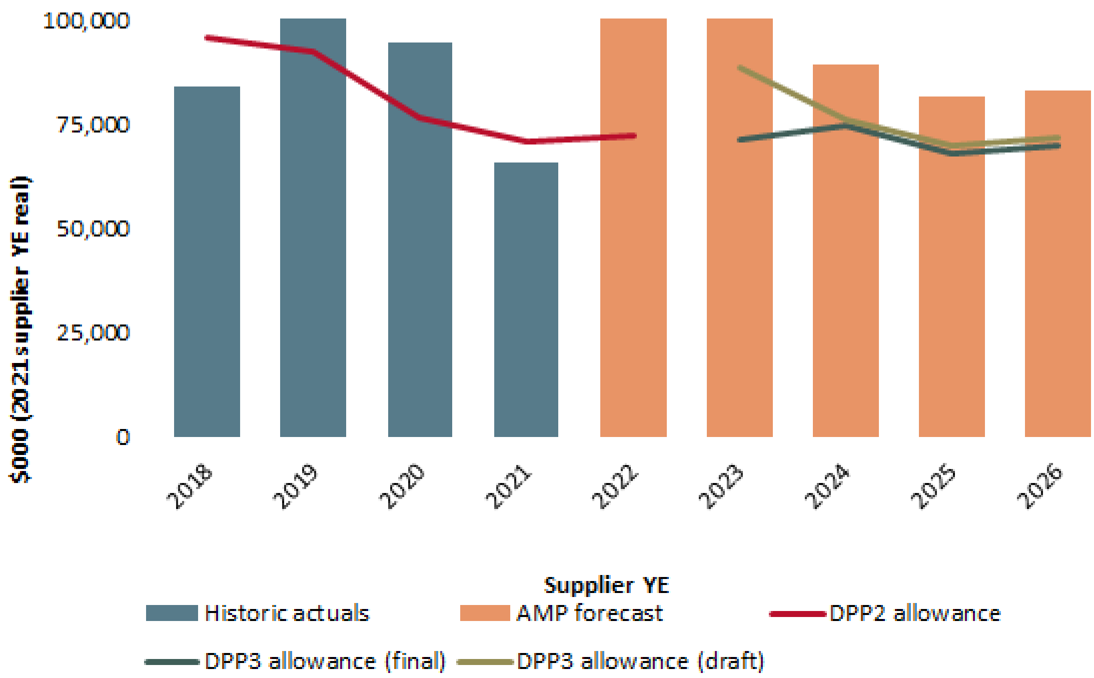


Figure X2: Historical and allowed capital expenditure (real $000)



X25 Finally, to provide some flexibility for GPBs to respond to unforeseen events during DPP3, we have introduced two reopeners for capex and one reopener for opex, for capacity events and risk events. These apply to individual projects or programmes relating to customer connection, system growth, asset relocations capex and to asset replacement and renewals capex.

We have smoothed prices over DPP3 to minimise price rises for consumers of gas pipeline services

X26 Any price increases can be difficult for consumers of gas pipeline services to absorb. Our DPP3 decisions would have resulted in significant price increases for consumers if we had applied a one-off starting price adjustment.

X27 Table X3 shows the price increases if we had applied a one-off starting price adjustment in Year 1 of DPP3 and no annual real price increases in the subsequent years of DPP3.

X28 Instead, we have:

X28.1 applied alternative rates of change for GPBs where a one-off starting price adjustment results in a price increase greater than 10%; and

X28.2 limited annual real price increases to 10% per annum for the initial starting price adjustment between DPP2 and DPP3 and for the remaining three years of DPP3.

X29 This means that for all GPBs other than Vector, we have smoothed the price rises for consumers over the DPP3 regulatory period. Vector's customers will experience a one-off increase in prices for the distribution component of their bills, which will then increase by inflation only over the remainder of DPP3

Table X3: Implied real price increases due to one-off starting price adjustment

Gas Pipeline Business	Implied starting price ($m)	Implied real price increase for year 1 of DPP3
GasNet	5.256	14.3%
Powerco	62.036	13.0%
Vector	58.317	7.7%
First Gas Distribution	33.030	27.2%
First Gas Transmission	166.427	22.6%

Future developments affecting gas pipelines

X30 We have set this DPP at a time when it is clear the long-term future of natural gas is in decline, but the rate of this decline is not yet clear. Considering this, we have made our decision based on the best information available at this time, including the ERP released on 16 May 2022.

X31 We recognise there are likely to be future developments that we will need to take account of when we come to set the next DPP in four years' time, including:

X31.1 Announcements on energy policy relating to the natural gas sector including the Government's proposed gas transition plan due by the end of 2023 and the energy strategy due by the end of 2024.

X31.2 Technical and commercial developments, for example, there is considerable activity in developing options for alternative low-emission gases, such as hydrogen, including as potential replacements for natural gas.

X31.2.1 Our DPP3 decision reflects an expenditure allowance to investigate blending low levels of, for example, hydrogen with natural gas. These innovations could extend the economic lives of the pipelines for delivering natural gas.

X31.2.2 The conveyance of other gases as alternatives to natural gas is outside the scope of Part 4 of the Commerce Act 1986 (**Part 4**). However, if the pipelines can be used for an alternative gas, this would increase the residual value of the pipelines when they are no longer used for the conveyance of natural gas. Our DPP3 decision considers this as one possible scenario.

X32 Our DPP3 decisions, including in relation to the length of asset lives used in our Building Blocks Model (**BBM**) to calculate depreciation, apply for the regulatory period which ends in 2026. In the IM Review we can look more holistically at the overall BBM framework. The outcome of the IM Review is not something we can predict now. It is possible that we will modify the IMs to provide more flexibility in terms of the application of the BBM for gas pipelines. However, the timing of the IM Review, which must be completed by the end of 2023, may mean that we are unable to fully consider the plans and strategies that are being developed that are relevant to the gas sector. It is open to us to review the IMs at any time and we could undertake a more focused review prior to the next Gas DPP in 2026.

1. Introduction

Purpose of this paper

1.1 This paper sets out the default price-quality paths (**DPP**) that we have put in place from 1 October 2022 for the gas pipeline services provided by gas pipeline businesses (**GPBs**) which consist of:

1.1.1 the natural gas transmission business (GTB), First Gas Transmission;

1.1.2 four natural gas distribution businesses (**GDBs**) namely, First Gas Distribution, GasNet, Powerco and Vector.

1.2 The current DPPs for both the GTB and the GDBs expire on 30 September 2022.

How we have structured this paper

1.3 Table 1.1 details the structure of the chapters and attachments in this paper.

Table 1.1: Structure of this paper

Section	Title	Description of content
Chapter 1	**Introduction**	Sets out the purpose of this paper, what it covers and how it is structured. Explains the consultation process we have followed in arriving at our decisions.
Chapter 2	**Framework for setting the default price-quality path**	Describes the high-level framework we have applied in making our decisions for the default price-quality path for the third regulatory period from 1 October 2022 to 30 September 2026 (**DPP3**).
Chapter 3	**Context for our decisions**	Summarises the context for setting the gas DPP including the transition to a net-zero economy and the phasing out of fossil fuels like natural gas.
Chapter 4	**Summary of our decisions**	Provides an overview of our decisions and describes our approach to the price-path and the price-path we have set. Summarises how we are managing uncertainties in the DPP.
Chapter 5	**Our decisions on expenditure allowances**	Summarises our decisions on our expenditure forecasting approach, allowances for operating expenditure (**opex**) and capital expenditure (**capex**).
Chapter 6	**Recognising shorter asset lives to address stranding risk**	Summarises our decision to shorten asset lives to better reflect the expected remaining economic life of the natural gas pipelines. This mitigates the risk of economic stranding.
Chapter 7	**Our decisions on quality standards**	Summarises our decisions on quality standards.
Attachment A (Supporting information for Chapter 5)	**Forecasting operating expenditure**	Provides further details of, and explanations for our approach to setting opex allowances, our modelling assumptions and the opex allowances we have set for GPBs.

Section	Title	Description of content
Attachment B (Supporting information for Chapter 5)	**Forecasting capital expenditure**	Provides further details of, and explanations for our approach to setting capex allowances, our modelling assumptions and the capex allowances we have set for GPBs.
Attachment C (Supporting information for Chapter 6)	**Analytical supplement – Recognising shorter asset lives to address economic network stranding risk in DPP3**	Provides supplementary information on our analytical approach to considering the problem posed by altered expectations of gas asset lifetimes and the risk of network stranding faced by GPBs.
Attachment D (Supporting information for Chapter 6)	**Modelling supplement – Recognising shorter asset lives to address economic network stranding risk in DPP3**	Provides supplementary information on the long-term modelling that has informed our judgement on the action required in DPP3 to better reflect economic asset lives of GPB assets.
Attachment E (Supporting information for Chapter 4)	**Price-setting features**	Provides further details of, and explanations for how we set the price path for GPBs and the key parameters related to price-setting (form of control, approach to setting starting prices, length of regulatory period, Constant Price Revenue Growth (**CPRG**) and rate of change of revenue through the period).
Attachment F (Supporting information for Chapter 4)	**Forecasts of other inputs to the financial model**	Provides further details of, and explanations for the estimate of the Weighted Average Cost of Capital (**WACC)**, Consumer Price Index (**CPI**), and the approach we have taken and decisions we have made on asset disposals and other regulated income.
Attachment G	**Assessing compliance with the price-quality path**	Provides further details of, and explanations for how GPBs will report on and demonstrate compliance with the price-quality path over the regulatory period.

Materials accompanying this paper

1.4 We have published the following documents alongside this paper:[5]

1.4.1 The gas distribution services (**GDS**) DPP determination and gas transmission services (**GTS**) DPP determination that give legal effect to our decisions.

1.4.2 Section 53N notices for the GDB and GTB that set out compliance reporting requirements.

1.4.3 The models we have used in determining the starting prices.

1.4.4 An external report by Concept Consulting Ltd. (**Concept**) that we commissioned on gas demand forecasts that we have relied on to reach our price-path decisions.

5 Commerce Commission webpage : 2022 gas default price-quality path.

Previously published papers

1.5 On 25 March 2022, we published our decisions and supporting reasons on amendments to the cost of capital Gas Input Methodologies for gas pipeline services (**Gas IMs**) to:

1.5.1 increase the value of the tax adjusted market risk premium (**TAMRP**) used in the WACC calculation; and

1.5.2 to allow WACC estimates that reflect both a four-year and a five-year regulatory period.[6]

1.6 On 1 April 2022, we published a cost of capital determination incorporating these changes which set the WACC estimates used in DPP3.[7]

1.7 On 30 May 2022 we published:

1.7.1 a Gas Input Methodologies amendments reasons paper outlining how we have amended the Gas IMs that are necessary to implement our DPP3 decisions for GPBs; and

1.7.2 amendments to the Gas IMs determinations and information disclosure (**ID**) determinations for gas pipeline services.

The process we have followed

1.8 This paper is the conclusion of our process to reset DPP3 that commenced in 2021. Submissions and cross-submissions received during our consultations are available on our website.[8]

1.9 Table 1.2 sets out the key process steps for both the Gas IM amendments and the DPP decisions during the Gas DPP3 reset process.

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6 Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths - weighted average cost of capital" (25 March 2022).

7 Commerce Commission "Cost of capital determination for gas pipeline businesses 2022-2026/2022-2027 default price-quality path" (1 April 2022).

8 Commerce Commission webpage : 2022 gas default price-quality path.

Table 1.2: Key process steps

Date	Key publication or event
20 April 2021	Open letter published to seek views on emerging issues for electricity networks, natural gas networks and airports as they relate to our responsibilities under Part 4 of the Commerce Act 1986 (**the Act**).[9] We used submissions on the open letter to help identify some of the issues for consideration when resetting the DPP.[10]
4 August 2021	Process and issues paper for Gas DPP3 published.[11]
30 August 2021	Submissions on the process and issues paper.[12]
13 September 2021	Cross-submissions on the process and issues paper.[13]
8 December 2021	Notification of draft decision on regulatory period to advise stakeholders of our draft decision to set a four-year regulatory period for DPP3.[14]
4 February 2022	Notice of intention for potential amendments to Gas IMs to advise stakeholders of the scope of potential amendments to targeted aspects of the Gas IMs.[15]
10 February 2022	DPP3 Draft decision published.[16] DPP3 Draft IM Amendments published.[17]
24 February 2022	Submissions on draft decision on Cost of Capital Input Methodologies amendments (as the Gas IMs require us to estimate the WACC for our DPP3 final decision by 31 March 2022, the Cost of Capital IM amendments were on a faster track than the other IM amendments).[18]
8 March 2022	Cross-submissions on draft decision on Cost of Capital IM amendments.[19]

9 Commerce Commission "Open Letter - ensuring our energy and airports regulation is fit for purpose" (29 April 2021).

10 Commerce Commission "Open letter on priorities for Energy and Airports Summary of key themes from submissions (12 October 2021).

11 Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021).

12 Commerce Commission website submissions on process and issues paper (2021).

13 Commerce Commission website cross-submissions on process and issues paper (2021).

14 Commerce Commission "Notice of our draft decision to set a four-year regulatory period for our reset of price-quality paths for gas pipeline businesses" (8 December 2021).

15 Commerce Commission “Notice of Intention – potential amendments to IM for gas pipeline services” (4 February 2022).

16 Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 Draft reasons paper (10 February 2022).

17 Commerce Commission “Proposed amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths – Draft reasons paper” (10 February 2022).

18 Commerce Commission website submissions on draft decision on Cost of Capital IM Amendments (2022).

19 Commerce Commission website cross submission on draft decision on Coast of Capital IM Amendments (2022). “Gas pipelines default price-quality path.

Date	Key publication or event
14 March 2022	Submissions on: - DPP3 draft decision - Draft decision on remaining Gas IM amendments.[20]
25 March 2022	Final decision on Cost of Capital IM amendments published.[21]
28 March 2022	Cross-submissions on: - DPP3 draft decision - Draft decision on remaining Gas IM amendments.[22]
30 May 2022	Final decision on remaining Gas IM amendments published.[23]
31 May 2022	Final DPP3 decision published.[24] (DPP3 price-quality paths will take effect from 1 October 2022).

1.10 As we explained in our reasons paper for the amendments to the Gas IMs:[25]

1.10.1 all submissions were carefully considered and were important in informing our final decisions;

1.10.2 when setting the timing of our key process steps we were also conscious of the need to complete the DPP3 reset by 31 May 2022, so that the DPP3 price-quality path would commence on 1 October 2022 once the DPP2 price-quality path ended on 30 September 2022;

1.10.3 we consider that in the overall context of our process the period of time we allowed for submissions and cross-submissions on our draft DPP3 decisions was reasonable; and

1.10.4 we considered whether or not further consultation was required as a result of the information in the emission reduction plan (**ERP**), but concluded that this was unnecessary.

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20 Commerce Commission website submissions on draft decisions for DPP3 and DPP3 IM Amendments (2022).

21 Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths - weighted average cost of capital" (2022)l.

22 Commerce Commission website cross-submissions on draft decisions for DPP3 and DPP3 IM Amendments.

23 Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths - reasons paper" (30 May 2022).

24 This paper.

25 Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths -reasons paper" (30 May 2022).

Further inquiries and feedback on process

1.11 Inquiries on the final determination and its associated published documents should be addressed to:

Matthew Clark (Manager, Transpower & Gas)
c/o infrastructure.regulation@comcom.govt.nz

Feedback on process for setting DPP3

1.12 We will invite feedback on the process we have followed to set DPP3, and on ways this process could be improved in future. Further details on how to provide feedback will be notified shortly.

2. Framework for setting the default price-quality path

Purpose of this chapter

2.1 This chapter describes the high-level framework we have applied in setting DPP3. To explain this, we discuss:

2.1.1 the requirements for setting DPPs under Part 4 of the Act;

2.1.2 the overarching objectives in the Act that are relevant when setting a DPP;

2.1.3 the relevant Gas IMs; and

2.1.4 our framework for making decisions for DPP3 which includes three key longstanding economic principles of Part 4 regulation.

2.2 This chapter does not discuss our framework for considering changes to the Gas IMs for GPBs and the reasons for the IMs changes. This is discussed in our Gas IM Amendments Reasons Paper published on 30 May 2022.[26]

Requirements for setting Default Price-Quality Paths under Part 4 of the Commerce Act 1986

2.3 Under Part 4, GPBs are subject to two forms of regulation in respect of their supply of gas pipeline services:

2.3.1 ID regulation, under which GPBs are required to publicly disclose information relevant to their performance;[27] and

2.3.2 default/customised price-quality regulation, under which price-quality paths set the maximum prices or revenues that GPBs can charge. They also set standards for the quality of the services that each GPB must meet.[28] This ensures that GPBs do not have incentives to reduce quality to maximise profits under their price-quality paths.

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[26] Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths. reasons paper" (30 May 2022).

[27] Commerce Act, s 52B and s 55C.

[28] Commerce Act, s 52B, 53M and s 55D.

2.4 To set a DPP, Part 4 specifies a number of requirements and obligations we must follow:

2.4.1 the regulatory rules and processes, referred to as Input Methodologies (**IMs**), which we are required to apply when determining the prices and quality standards applying to the supply of natural gas pipeline services;[29]

2.4.2 what the determinations used to set DPPs must specify;[30]

2.4.3 the content and timing of DPPs;[31] and

2.4.4 requirements when resetting DPPs.[32]

2.5 We must consider the Part 4 purpose and what DPP regulation is intended to achieve when making our decisions. We discuss these objectives and how we are required to use them to set DPPs in the next section of this chapter.

Overarching objectives in Part 4 that are relevant when setting a Default Price-Quality Path

Purpose of Part 4

2.6 Part 4 provides for the regulation of the price and quality of goods or services in markets where there is little or no competition, and little or no likelihood of a substantial increase in competition.[33]

2.7 Section 52A of the Act sets out the purpose of Part 4 regulation in respect of the regulated goods or services:

> (1) The purpose of this Part is to promote the long-term benefit of consumers in markets referred to in s 52A by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services—
>
> (a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and
>
> (b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and

[29] Commerce Act, s 52S(b)(ii).

[30] Commerce Act, s 53O.

[31] Commerce Act, s 53M.

[32] Commerce Act, s 53P.

[33] Commerce Act, s 52. The process and criteria for deregulating gas pipelines is set out in s 55A(5) and (6).

(c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and

(d) are limited in their ability to extract excessive profits.

2.8 Our decisions for DPP3 must therefore promote the long-term benefit of consumers of natural gas pipeline services. Section 52A guides us that this is to be achieved by promoting outcomes that are consistent with outcomes produced by competitive markets and gives us four outcomes to pursue that are considered consistent with those of competitive markets.

2.9 As defined in the Act, a consumer "means a person that consumes or acquires regulated goods or services".[34] This includes both the direct acquirers of the gas pipelines services and those persons that indirectly consume those services via the purchase of natural gas.

2.10 In practice, when setting a DPP, it is important to note:

2.10.1 we do not focus on replicating all the potential outcomes or mechanisms of workably competitive markets, but on promoting the s 52A outcomes;

2.10.2 none of the objectives listed in s 52A(1)(a) to (d) are paramount, and they are not separate and distinct from each other, nor from s 52A(1) as a whole. Rather, we must balance the s 52A(1)(a) to (d) outcomes, and exercise judgement in doing so;[35] and

2.10.3 when exercising our judgement, we are guided by what best promotes the long-term benefit of consumers of gas pipeline services.[36]

2.11 In certain instances, our ability to exercise judgement will be constrained, because we must make our decisions according to specific legal requirements. For example, we must apply:

2.11.1 the Gas IMs, which were determined because they promote the outcomes in s 52A and certainty for suppliers and consumers in relation to the rules, requirements, and processes that apply to the regulation, or proposed regulation; and

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34 Commerce Act,, s 52C.

35 *Wellington International Airport Ltd & others v Commerce Commission [2013] NZHC 3289, para 684.*

36 *Wellington International Airport Ltd & others v Commerce Commission [2013] NZHC 3289, paras 165, 222, 684, 686 and 761.*

2.11.2 the mandatory requirements in the Act. For example, s 53M(4) provides that a regulatory period must be five years, while s 53M(5) provides that we may set a shorter period if we consider that it would better meet the purposes of Part 4, but the term may not be less than four years.

Purpose of default/customised price-quality regulation

2.12 Section 53K of the Act sets out the purpose of default/customised price-quality regulation:

> The purpose of default/customised price-quality regulation is to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances.

2.13 We have taken this purpose to mean that:

2.13.1 DPPs are to be set in a relatively low-cost way, and are not intended to meet all the circumstances that a GPB may face; and

2.13.2 customised price-quality paths (**CPPs**) are intended to be tailored to meet the particular circumstances of an individual GPB.

2.14 To meet the relatively low-cost purpose of DPP regulation, we must take into account the efficiency, complexity, and costs of the DPP regime as a whole when resetting the DPP. What this means in practice will vary over time and between sectors.

2.15 We have developed a combination of low-cost principles, including applying the same or substantially similar treatment to all suppliers on a DPP where this is workable.[37] These include:

2.15.1 setting starting prices and quality standards or incentives with reference to historical levels of expenditure and performance;

2.15.2 where possible, using existing information disclosed under ID regulation, including suppliers' own asset management plan (**AMP**) forecasts; and

2.15.3 limiting the circumstances in which we will reopen or amend a DPP during the regulatory period.

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[37] Gas Distribution Services Default Price-Quality Path Determination 2013 [2013] NZCC 4; Gas Transmission Services Default Price-Quality Path Determination 2013 [2013] NZCC 5; Electricity Distribution Services Default Price-Quality Path Determination 2015 [2014] NZCC 33; Gas Transmission Services Default Price-Quality Path determination 2017 [2017] NZCC 14; Gas Distribution Services Default Price-Quality Path determination 2017 [2017] NZCC 15; and Electricity Distribution Services Default Price-Quality Path Determination 2020 [2019] NZCC 21.

2.16 Our application of the low-cost principles is subject to our specific obligations under the IMs and the Act.

Interaction of climate change policy with the Section 52A purpose

2.17 New Zealand is targeting zero greenhouse gases (excluding biogenic methane for which there are separate provisions) on a net accounting emissions basis by 2050 (**2050 target**), as set out in s 5Q of the Climate Change Response Act 2002 (**CCRA**). The Government must publish the emissions budget for the first three emissions budget periods by 31 May 2022. Each emissions budget period is five years, except for the first period, which runs from 2022 to 2025. [38]

2.18 The CCRA established He Pou a Rangi (the Climate Change Commission (**CCC**)), whose role is to advise the Government on how to reach its climate goals. The CCC has published its final advice to the Government on its first three emissions budgets and directions for its emissions reduction plan 2022 to 2025.[39] The purpose of the recommendations in the advice is to propose a means by which the Government can put New Zealand on track to achieve the 2050 target.

2.19 The Government published its first three emissions budgets limiting the emissions New Zealand can produce for the next 15 years on 9 May 2022 and its emissions reduction plan (**ERP**) that outlines the policies and strategies New Zealand will take to meet the first emissions budget on 16 May 2022. [40,41]

2.20 Section 5ZN of the CCRA provides:

> If they think fit, a person or body may, in exercising or performing a public function, power, or duty conferred on that person or body by or under law, take into account—
>
> (a) the 2050 target; or
>
> (b) an emissions budget; or
>
> (c) an emissions reduction plan.

2.21 The purpose of s 5ZN is to allow the 2050 target and emissions budgets to influence broader Government decision making where they are relevant.

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[38] Climate Change Response Act 2002, s 5X(3).

[39] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021),

[40] Emissions budgets announcement.

[41] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022).

2.22 The legislative history shows that Parliament made a deliberate decision to make climate change a permitted but not a mandatory consideration, and in this context contemplated that climate change mitigation would be taken into account only where consistent with the other legal requirements applying to a decision.[42]

2.23 Parliament left it to decision-makers (acting reasonably) to determine whether and how to take climate change mitigation into account.

2.24 We are required to exercise our powers within the scope of our legislative framework, and to make decisions to promote the Part 4 purpose contained in s 52A of the Act.

2.25 It follows that we must determine whether and how to take the s 5ZN factors of the CCRA into account, but we cannot do so in a way that compromises our overriding statutory duty to promote the Part 4 purpose.

2.26 How we take account of the matters set out in s 5ZN within this constraint is a matter for our expert judgement based on the available evidence.

2.27 We agree with the view expressed by Chapman Tripp (for Vector) that the 2050 target is "part of the factual matrix" and a relevant consideration when applying the s 52A purpose statement.[43]

2.28 We do not agree with the view expressed by Chapman Tripp (for Vector) that Parliament intended to elevate the s 5ZN(a)-(c) factors "as considerations of equal weight to the factors" in s 52A(1)(a)-(d).

2.29 The suggestion that the s 5ZN(a)-(c) factors can be placed "alongside" the outcomes in s 52A(1)(a)-(d) does not reflect the way that the latter purpose statement operates. The Part 4 regime is focused on creating the conditions that will promote outcomes consistent with those in competitive markets, such that regulated suppliers have the incentives listed in s 52A(1)(a)-(d), with the ultimate aim of promoting the long-term benefit of consumers. Those incentives are not objectives in themselves.

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42 The section as introduced expressly provided that climate change mitigation was a relevant consideration "subject to other requirements that apply by or under law". The section was largely rewritten in the select committee, but the committee did not intend by removing this proviso to allow s 5ZN to override existing legal requirements: the Ministry for the Environment advised in its Departmental Report at 110 that making it a mandatory consideration was inappropriate in circumstances "where considering the target or an emissions budget would be inconsistent with the specific statutory requirements that apply to a decision under its own enactment.".

43 Chapman Tripp (on behalf of Vector) Legal Advice "submission on Gas DPP process and issues paper" (1 September 2021).

2.30 Rather, s 5ZN allows us to take those considerations into account in the context of fulfilling our statutory purpose, which is to promote the long-term benefit of consumers of natural gas pipeline services by promoting outcomes consistent with those in workably competitive markets. However, we cannot have regard to the factors in s 5ZN, where doing so would detract from the Part 4 purpose.

2.31 Matters that arise from climate change policy might also be relevant to our DPP3 decisions in the ordinary course outside of the ambit of s 5ZN. If climate change legislation imposed obligations on regulated businesses and we considered this to be relevant to our decisions or part of the relevant factual context, we would take this into account in setting DPP3 based on ordinary administrative law principles.

2.32 As work on the DPP3 reset commenced in mid-2021 and the DPPs must be finalised by the end of May 2022 for the price-quality paths to apply from 1 October 2022, we substantively completed our analysis and consultation for DPP3 in advance of the publication of the emissions budgets on 9 May 2022 and the emissions reduction plan on 16 May 2022.

2.33 When we were completing our analysis and consulting we took account of the 2050 target. We have also considered the emissions budgets and the emissions reduction plan in the limited time between its publication on 9 May 2022 and 16 May 2022, and the date of our decisions. We consider that this new information is consistent with the information we relied on for our draft decisions and that there is nothing in them that suggests that we need to take a different approach for DPP3.

Input methodologies

2.34 To make the DPP3 decisions, we must apply the following key Gas IMs:

2.34.1 Specification of Price;

2.34.2 Cost Allocation;

2.34.3 Asset Valuation;

2.34.4 Treatment of Taxation.[44]

[44] These IMs are set out in the Gas Distribution Services Input Methodologies Determination 2012 (Consolidated April 2018) and the Gas Transmission Services Input Methodologies Determination 2012 (Consolidated April 2018).

2.35 We must also apply the Cost of Capital IM when we estimate the WACC that will apply to DPP3. We are required to estimate the WACC no later than six months before the start of a regulatory period (in this case by 31 March 2022) and do so via a separate process.

2.36 As part of the DPP3 reset, we made several Gas IM amendments that:

2.36.1 have enabled us to shorten asset lives so that they better reflect the remaining expected economic lives of the GPBs networks;

2.36.2 have enabled us to estimate a WACC that reflects a four-year regulatory period; and

2.36.3 updated the estimate of the tax adjusted market risk premium which is used in the WACC estimation.[45]

2.37 As we are required to apply the Gas IMs that are in place when we make our decisions the decisions in this paper apply the Gas IMs as amended.

The framework we have applied for making decisions on DPP3

A building blocks approach to price-quality (and information disclosure) regulation

2.38 Our price-quality (**PQ**) regulation under Part 4 is based on a building blocks method (**BBM**).

2.39 BBM creates financial incentives which align regulated suppliers' interests with those of their customers in reducing costs and becoming more efficient. This alignment of incentives is achieved over regulatory control periods, where the maximum revenues (or prices) for delivering the regulated services over the regulatory control period are specified up front.

2.40 Setting the maximum revenues (or prices) in this way provides an ex ante opportunity for the regulated provider to earn its allowed return. The allowed return under a BBM approach is the best estimate of the return that an efficient firm has an ex ante opportunity to earn in a workably competitive market (sometimes referred to as a 'normal return'). Where regulated suppliers outperform their allowed returns by becoming more efficient they enjoy the benefit of these efficiencies (in the form of higher profits) with the efficiencies shared with consumers at the next reset in the form of reduced revenues (or prices).

[45] Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths. reasons paper" (30 May 2022).

2.41 BBM is also used as part of ID regulation to underpin the assessment of returns which helps us and other interested parties in assessing whether the outcomes in s 52A are being met.

2.42 We have developed a decision-making framework and set of economic principles over time to support our decision-making under Part 4 when we determine the values of the specific building blocks under the IMs.

2.43 As discussed below, these have been consulted on and used as part of prior processes and help provide consistency and transparency in our decisions.

2.44 However, we recognise that issues may arise over time and that we need to be open to modifying or changing our approaches where this would better promote the purpose of Part 4.

2.45 While we recognise the uncertainty in the gas sector and that demand for piped natural gas in New Zealand is likely to decline and eventually be phased out (as discussed in Chapter 3), we still consider that our existing approaches to PQ regulation described above would likely best give effect to the purpose of Part 4 in the current context.

Decision-making framework for DPP3

2.46 Our decision-making framework for DPP3 applied the same approaches we used for the last DPP reset unless making changes would:

2.46.1 better promote the purpose of Part 4; [46]

2.46.2 better promote the purpose of DPP regulation; [47] or

2.46.3 reduce unnecessary complexity and compliance costs.

2.47 As we consider the Part 4 purpose to be the most important consideration for our decisions, we do not make a change on the basis of the other criteria in paragraph 2.46 where we consider that doing so would detract from that purpose.

2.48 This approach, which was adapted from the 2016 IM Review framework, was applied when we reset the DPPs for GPBs in 2017 and for Electricity Distribution Businesses (**EDBs**) in 2019. We consider this helps ensure consistency with the low-cost purpose of the DPP.[48]

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46 Commerce Act, s 52A.

47 Commerce Act, s 53K.

48 Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2017 – Final reasons paper" (31 May 2017), paras 2.19-2.22.

Economic principles

2.49 We have three key and longstanding economic principles that we have regard to in setting DPPs under Part 4. We consider that these are useful analytical principles that can help us reach decisions that promote the Part 4 purpose. They can also help promote regulatory predictability by signalling to stakeholders how we are likely to approach relevant decisions. However, if the principles cease to be consistent with the Part 4 purpose in a specific situation we will not continue to apply them.

2.50 *Real financial capital maintenance* (**FCM**): we provide regulated suppliers with the ex ante expectation of earning their risk-adjusted cost of capital (a 'normal return'). This provides regulated suppliers with the opportunity to maintain their financial capital in real terms over timeframes longer than a single regulatory period. However, price-quality regulation does not guarantee a normal return over the lifetime of a regulated supplier's assets. The decarbonisation of the energy sector (which we discuss in Chapter 3) provides additional challenges and uncertainty to the business of conveying natural gas by pipeline, and the returns on and of capital from doing so. Our approach in setting this DPP within that more challenging and uncertain context is discussed in Chapter 4 and Chapter 6.

2.51 *Allocation of risk*: ideally, we allocate particular risks to regulated suppliers or consumers depending on who is best placed to manage the risk. In order to determine the regulatory settings in price-quality regulation that will give effect to the FCM principle, we consider the allocation of risk. We aim to allocate risks to the party best placed to manage them. Managing risks includes:

2.51.1 actions to influence the probability of occurrence where possible;

2.51.2 actions to mitigate the costs of occurrence; and

2.51.3 the ability to absorb the impact where it cannot be mitigated.

2.52 Regulated suppliers have various risk management tools at their disposal, including insurance, investment in network strengthening/resilience, hedging, contracting arrangements and delaying certain decisions eg, when to make large investments. Once the risks are allocated between regulated suppliers and consumers, we compensate regulated suppliers and consumers accordingly through the price-quality path we set.

2.53 *Asymmetric consequences of over- and under- investment*: we apply FCM recognising that usually there are asymmetric consequences to consumers of regulated energy services, over the long-term, of under-investment. This principle is particularly relevant when considering the consequences to regulated suppliers' incentives to invest if our WACC estimate is too high or too low. As such, the application of this principle is an important factor in our decision under the Part 4 IMs on whether a WACC uplift is justified.[49] Since the WACC uplift is determined under the Part 4 IMs, the relevance of this principle in the context of a DPP reset is limited.

2.54 We elaborated on each of these principles and how they should be applied in the context of price-quality regulation in our 2016 IM Review framework paper.[50]

Our role to consider or support a transition to alternative gases is limited

2.55 Under the current legislative framework our scope to consider or support a transition to alternative gases is limited.

2.56 More particularly, since s 52A does not reference decarbonisation or mitigating climate change as outcomes to be promoted, and the s 52A purpose must remain paramount, we cannot take these factors into account in a way that would compromise the s 52A purpose.

2.57 The scope of the regulated service also limits the extent to which the optionality of alternative gases can be supported through a DPP.

2.58 The purpose of subpart 10 of Part 4 is to regulate "gas pipeline services" used for the conveyance of natural gas. Section 55A states that, unless the context otherwise requires, "gas pipeline services" means "the conveyance of natural gas by pipeline, including the assumption of responsibility for losses of natural gas".

2.59 While 'natural gas' is not a defined term under the Act our view is that natural gas as that term is used in s 55A does not include hydrogen gas and biogas (clean gases). In our view, when Parliament enacted Part 4 and extended regulation to gas pipeline services, it did not have in mind the use of those networks for conveying anything other than conventional natural gas (fossil gas), and thus intended "natural gas" to bear its technical and ordinary meaning to capture the kind of gas that was then (and is now) being conveyed through the GPBs' networks.

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[49] Commerce Commission "Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services: Reasons paper" (30 October 2014), Chapter 3.

[50] Commerce Commission "Input methodologies review decisions: Framework for the IM review" (20 December 2016), p 38-49.

2.60 We note the arguments from some submitters that biogas has a similar chemical structure to natural gas and that it is substitutable for natural gas and that we should include clean gases under the regulated service.[51] However, Part 4 does not regulate infrastructure but a service, and the service of conveyance of natural gas by pipeline cannot be equated with the (currently non-existent) market for the conveyance of clean gases by pipeline.

2.61 Goods or services may only be regulated under Part 4 where (a) they are supplied in a market where there is little or no competition or prospect of competition, (b) there is scope for the exercise of substantial market power, and (c) the benefits of regulation outweigh the costs (s 52G). As a number of submitters have noted the Act incorporates a mechanism for the Commission to inquire into these matters and report to the Minister, who can then after following a specific statutory process recommend regulation of new goods or services by order in council (ss 52E to 52O).[52]

2.62 Where changing circumstances suggests that regulation should be extended to new goods or services, then the legislation contemplates that this should be considered and implemented through the statutory enquiry process (or direct amendment). To treat "natural gas" as including clean gases would cut across the envisaged statutory process.

2.63 Our view, therefore, is that the conveyance of clean gases by pipeline cannot be considered a gas pipeline service for purpose of Part 4.

2.64 We consider that a blend of biogas or hydrogen with natural gas where natural gas is the most significant component could be considered 'natural gas'. The threshold at which a mixture would cease to be regulated is difficult to determine, but we consider that a blend of natural gas and other gas that does not require pipeline or appliance conversion is a reasonable threshold for consideration under Part 4.

2.65 Consistent with our position we have asked the Ministry of Business, Innovation and Employment (**MBIE**) to explore the definition of gas pipeline services in s 55A, including the position of clean gases.

2.66 The scope of the regulated services has significant implications for the GPBs cost of investigating and developing potential unregulated services such as the conveyance of clean gas.

51 First Gas "DPP3 Draft Decision submission" (16 March 2022), p.26 para 6.1.

52 MGUG Gas DPP3 Draft Decision cross submission (28 March 2022), p.2 paraX4 and p.4 para 9.

2.67 Under the current BBM approach and IMs we cannot approve opex or capex in relation to unregulated services, nor do we think that this would be appropriate. Assets totally unrelated to the regulated service further cannot be included in the regulatory asset base (**RAB**). Also, where GPBs use assets that are currently used to deliver regulated services to investigate and develop potential unregulated services, the cost allocation IMs will apply.

2.68 Accordingly, while GPBs can still carry out investigations and invest in the conveyance of alternative gas, except to the extent that it entails relatively low levels of blending such that it can still be considered natural gas, the cost would be part of establishing a new service and cannot be recovered through charges from consumers of gas pipeline services.

2.69 We can consider the prospective continued use of the regulated assets to provide unregulated services (including where these services may become regulated in the future) under current legislative settings. In particular, to the extent there is the potential for repurposing the regulated assets to convey clean gases, the pipeline assets may have a residual value which should reduce how much capital cost should be recovered from consumers of natural gas pipeline services (chapter 6).

3. Context for our decisions

Purpose of this chapter

3.1 This chapter summarises the context for setting the gas DPP, in particular, that New Zealand is transitioning to a net zero emissions economy with Government plans to phase out the use of fossil fuels such as natural gas, and the possible implications for GPB pipelines.

New Zealand's transition to a net zero carbon emissions economy

3.2 New Zealand is in a period of transition towards a net zero emissions economy by 2050. As part of this transition the Government has signalled it wants to phase out the use of fossil fuels such as natural gas, whilst ensuring energy is accessible, affordable, secure, and supports economic development and there is an equitable transition.[53] No end date has been indicated for this phase out, but demand for natural gas is likely to decline and eventually be phased out.

3.3 As well as the Government's decarbonisation policies a number of other factors are likely to affect the future use of, and declining demand for, natural gas:

3.3.1 declining gas demand in some consumer segments may reduce demand in other consumer segments if it reduces economies of scale and/or results in costs being shared among a smaller number of consumers of gas pipeline services;

3.3.2 rising awareness of climate change amongst mass market consumers may discourage new consumers from connecting to the gas network and may prompt existing users to move away from gas in particular if they need to replace appliances and alternate energy options are considered to be economic;

3.3.3 growing pressure to operate in environmentally sustainable ways may similarly influence businesses' energy choices, again actual switching depends on the availability and attractiveness of alternatives;

3.3.4 potentially rising costs of developing new or additional natural gas reservoirs, and increasing difficulty of securing long-term contracts, may discourage the development of gas fields that is required to maintain production at current levels;

[53] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan" (16 May 2022), p.48.

3.3.5 possible uncertainty over gas supply, and potentially rising costs of wholesale gas due to higher costs of production, may discourage consumers from committing to the future use of gas;

3.3.6 natural gas may have an important role as a transitional energy source and/or as a potential supplement to renewable but intermittent energy sources; and

3.3.7 the pace of development of alternative gases and the extent to which they will be viable substitutes for natural gas, will also affect future demand for natural gas.

3.4 This expected decline in the use of natural gas has implications for the pipeline networks which were built to convey natural gas from Taranaki to the locations where it is used. These implications include:

3.4.1 declining throughput;

3.4.2 uncertainty over the pace of demand decline and when the conveyance of natural gas may be phased out;

3.4.3 the need for ongoing investment to maintain service to those consumers who continue to use natural gas and seek to do so for some time yet; and

3.4.4 potential repurposing of pipelines to convey gases other than natural gas.

3.5 The expected decline in the use of natural gas, and the likely implications for the natural gas pipeline services we regulate, has been a factor in the key decisions we have made, including in particular:

3.5.1 the length of regulatory period;

3.5.2 the level of expenditure allowances;

3.5.3 the cost of investigating whether to add some low or no carbon gas to natural gas (which at low levels of blending we would still consider to be natural gas, as discussed in Chapter 2);

3.5.4 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);

3.5.5 whether we should amend the remaining asset lives to reflect their remaining economic lives rather than physical lives; and

3.5.6 the extent to which prices to consumers of gas pipeline services should rise as a result.

Existing Government policies for the transition towards a net zero economy

Climate change targets

3.6 In 2019, the Government made a legislative commitment to achieve net zero emissions by 2050. This target requires all greenhouse gases, other than biogenic methane, to reach net zero by 2050.[54] This commitment extends previous government targets under the Kyoto Protocol in 1998 and the 2015 Paris Climate Agreement and which were reflected in the Climate Change Response Act 2002 before 2019.

3.7 The net zero target refers to net accounting emissions reaching zero, ie, the target takes into account the emissions of greenhouse gases into the atmosphere offset against the removals of greenhouse gases from the atmosphere, across the whole economy.[55] Net accounting emissions also includes offshore mitigation (emissions reductions and removals, or allowances from emissions trading schemes that originate from outside New Zealand) although emissions budgets must be met, as far as possible, through domestic emissions reductions and domestic removals. [56,57] Offshore mitigation may be used if there has been a specified significant change of circumstance.[58]

The NZ Emissions Trading Scheme

3.8 The New Zealand Emissions Trading Scheme (**NZ ETS**) plays an important role in driving emissions reductions in New Zealand. The NZ ETS places a price on emissions of greenhouse gases. All sectors of New Zealand's economy, apart from agriculture, pay for their emissions through the NZ ETS. Businesses in the NZ ETS are required to buy units to cover their emissions. This helps businesses participating in the NZ ETS to consider emissions in their decision making and provides an incentive for them to reduce their emissions.[59]

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[54] Climate Change Response Act 2002, s 5Q(1)(a) and Ministry for the Environment "Emissions reduction plan discussion document" (October 2021), p. 9.

[55] Ministry for the Environment webpage on greenhouse gas emissions targets and reporting (27 May 2021).

[56] Climate Change Response Act 2002, s 4.

[57] Climate Change Response Act 2002, s 5Z(1).

[58] Climate Change Response Act 2002, s 5Z(2).

[59] Ministry for the Environment webpage on NZETS.

3.9 The Government notes that a rising carbon price "discourages fossil fuel use and encourages investment in energy efficiency and fuel switching".[60] The scheme has already resulted in rising carbon prices, which businesses which emit (and absorb) carbon will need to factor into their decision-making.[61]

Ban on offshore exploration

3.10 In 2018, the Government decided there would be no further offshore oil and natural gas exploration permits granted, limiting potential natural gas supplies and restricting investment in the production of natural gas in New Zealand.

Advice from the Climate Change Commission

3.11 In May 2021, the CCC delivered its advice to the Government outlining how New Zealand can reach its emissions reduction targets under the CCRA.[62] The CCC highlighted that emissions from energy, industry and buildings contribute around 44% of long-lived greenhouse emissions in Aotearoa. The CCC's view was that to reduce these emissions, Aotearoa must decarbonise how it produces and uses energy, transforming to an energy system that is low emissions, affordable and secure.[63]

3.12 The CCC stressed that the most urgent area for action is for the Government to develop a comprehensive energy strategy to ensure actions to decarbonise are considered across the whole energy system. The CCC noted that to transform energy production and use requires investment and certainty to allow businesses and individuals to plan and respond.[64]

3.13 To meet the 2050 target of net zero long-lived gases, the CCC noted that Aotearoa needs to transition away from fossil fuels. Instead, the country will need to rely more heavily on renewable electricity and low-emissions fuels like bioenergy and hydrogen, while also improving energy efficiency.[65]

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[60] Ministry for the Environment "Transitioning to a low-emissions and climate-resilient future – Aotearoa New. Zealand's Long-term Low-Emissions Development Strategy" (4 November 2021), p. 49.

[61] Ministry for the Environment NZETS Auction Noticeboard.

[62] Climate Change Response Act, s 5X (1) to (3) and 5ZD.

[63] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021), p. 274, 276.

[64] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021), p. 276.

[65] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021), p. 277.

3.14 The CCC recommended that the Government commit to delivering a strategy to decarbonise the energy system and ensure the electricity sector is ready to meet future needs, including:[66]

3.14.1 developing and implementing a national energy strategy to decarbonise the system. The strategy would need to cover:

3.14.1.1 setting a target so that 50% of all energy consumed comes from renewable sources by 31 December 2035. Consideration should also be given to replacing the target for 100% renewable electricity with achieving 95% - 98% renewable electricity by 2030;

3.14.1.2 how to ensure access to affordable, secure, low-emissions electricity for residential, commercial, and industrial consumers of gas pipeline services; and

3.14.1.3 creating a plan for managing the diminishing role of fossil gas across the energy system, covering the associated consequences for network infrastructure and workforce during the transition;

3.14.2 supporting development and deployment of low-emissions fuel options such as bioenergy and hydrogen;

3.14.3 determining how to eliminate fossil gas use in residential, commercial and public buildings. Actions should include:

3.14.3.1 setting a date to end the expansion of pipeline connections in order to safeguard consumers from the costs of locking in new fossil gas infrastructure;

3.14.3.2 evaluating the role of low-emission gases as an alternative use of pipeline infrastructure; and

3.14.3.3 determining how to transition existing fossil gas users towards low-emissions alternatives.

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[66] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021), pp 286-287.

3.15 The CCC also recommended:

3.15.1 the Government commit to outlining a plan for actions required to decarbonise the industrial sector;

3.15.2 upgrading existing buildings and constructing new buildings that are low emissions.

3.16 The CCC noted that setting a renewable energy target can signal that emissions reductions are required across the full energy system, including the transition away from fossil fuels in heat and electricity.[67]

3.17 While highlighting the importance fossil gas plays in the current energy system, the CCC stated that the use of fossil gas will need to decrease as we move towards net zero emissions. The CCC noted the concerns raised regarding the consequences of any changes in the availability of gas on energy affordability and reliability.

3.18 To get on a low emissions path, the CCC stated that Aotearoa needed to:[68]

3.18.1 avoid locking in new fossil gas assets; and

3.18.2 phase down how much fossil gas is used in existing residential, commercial and public buildings.

3.19 While recommending the transition away from fossil gas, the CCC highlighted that the diminishing role of fossil gas across the energy system will need to be carefully managed and sequenced as there may be consequences for network infrastructure and the workforce.[69]

3.20 The CCC noted the view of some submitters of the possibility that low emissions gases, such as hydrogen or biogas, could be blended into fossil gas to lower its emissions intensity.[70]

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[67] Climate Change Commission “Ināia tonu nei: a low emissions future for Aotearoa 2022-2025” (2021), p. 278.

[68] Climate Change Commission “Ināia tonu nei: a low emissions future for Aotearoa 2022-2025” (2021), p. 285.

[69] Climate Change Commission “Ināia tonu nei: a low emissions future for Aotearoa 2022-2025” (2021), p. 69.

[70] Climate Change Commission “Ināia tonu nei: a low emissions future for Aotearoa 2022-2025” (2021), p. 285.

3.21 The CCC's position, based on existing evidence, was that the possible future availability of low emissions gases was insufficient reason to warrant continued expansion of gas network infrastructure. The CCC stated that until there is substantial evidence that blending or fully converting the gas network to low emissions will not increase costs to consumers, expansion of the fossil gas network to serve residential, commercial and public buildings should not be permitted.[71]

3.22 While the NZ ETS will play a role in deterring expansion of fossil gas infrastructure, the CCC's view was that other measures are also needed to safeguard consumers – until such time as it can be demonstrated that the transition to low emissions gases would benefit consumers and substantially reduce emissions in a way that aligns with emissions budgets and targets. The CCC noted two potential measures:

3.22.1 placing a moratorium on new fossil gas connections; and/or

3.22.2 setting a date after which no new fossil gas connections would be permitted in residential, public and commercial building.

Emissions budgets and the emissions reduction plan

3.23 The Government has considered advice from the CCC and in response published:

3.23.1 on 9 May 2022, the first three emissions budgets which cover the period from 1 January 2022 to 31 December 2035;[72] and

3.23.2 on 16 May 2022, the ERP that outlines the policies and strategies New Zealand will take to meet its first emissions budget.[73]

3.24 We have set DPP3 based on information available at the time, this includes the Government's long-term low-emissions development strategy published on 4 November 2021 and the ERP published on 16 May 2022.[74,75]

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[71] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021), p. 285.

[72] Emissions budgets announcement.

[73] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022).

[74] Ministry for the Environment "Transitioning to a low-emissions and climate-resilient future – Aotearoa New Zealand's Long-term Low-Emissions Development Strategy" (4 November 2021).

[75] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022).

3.25 The long-term low-emissions development strategy for the purposes of the Paris Agreement included the first part of the ERP (**ERP Part 1**), by setting out New Zealand's national circumstances and contextualising the detailed policies and strategies which were published in the full ERP on 16 May 2022.[76]

3.26 ERP Part 1 set out the Government's long-term vision, as well as how sectors and systems across the economy will contribute to the vision. The ERP Part 1 described:

3.26.1 the current reality in New Zealand;

3.26.2 how the ERP fits into the country's wider climate response; and

3.26.3 the long-term strategic direction for each sector and system across the economy which set the scene for the detailed policies and strategies that followed in the ERP published recently.

3.27 The energy and industry sector plan outlined in ERP Part 1 clearly signalled the direction of travel for gas. It stated that the key components to manage the transition to low emissions include:

3.27.1 managing the phase-out of fossil fuels, including by:

3.27.1.1 ensuring reliable energy supply for industry as well as residential and other consumers of gas pipeline services;

3.27.1.2 supporting the phase-down of domestic fossil fuel production following the ending of new permits for offshore oil and gas exploration; and

3.27.1.3 ensuring a just transition for affected businesses, employees and communities;

3.27.2 encouraging investment in new renewable electricity generation and infrastructure, and large-scale energy storage;

3.27.3 assisting New Zealanders to engage in the energy system through household and local technology solutions, including efficient management of energy resources;

3.27.4 increasing the availability and use of low-emissions energy sources such as bioenergy and hydrogen; and

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[76] Ministry for the Environment "Transitioning to a low-emissions and climate-resilient future – Aotearoa New Zealand's Long-term Low-Emissions Development Strategy" (4 November 2021), p. 15.

3.27.5 supporting the pathway for transition for other sectors, such as transport, building and construction.[77]

3.28 The ERP expanded on the key policies and strategies outlined in ERP Part 1 for each sector, and set out focus areas and corresponding actions.

3.29 The ERP, under its sector plan for energy and industry, describes five focus areas and corresponding actions within each focus area to drive emissions reductions. [78] The focus areas are to:

3.29.1 use energy efficiently and manage demand for energy;

3.29.2 ensure the electricity system is ready to meet future needs;

3.29.3 reduce our reliance on fossil fuels and support the switch to low-emissions fuels;

3.29.4 reduce emissions and energy use in industry; and

3.29.5 set strategic approaches and targets to guide us to 2050.

3.30 The third focus area is of most direct consequence for natural gas. [79] It has two stated actions:

3.30.1 to manage the phase-out of fossil gas (ie, natural gas); and

3.30.2 to develop low-emissions fuels, including hydrogen.

3.31 The ERP notes that the phase-out of fossil gas presents short-term and long-term challenges, including balancing capital investment with declining fossil gas use, fossil gas affordability and the risk of stranded network assets. It notes that the Government is working to address these challenges and set out a pathway for the fossil gas sector.[80]

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[77] Ministry for the Environment "Transitioning to a low-emissions and climate-resilient future – Aotearoa New Zealand's Long-term Low-Emissions Development Strategy" (4 November 2021), p. 48-49.

[78] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), p. 208-221.

[79] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), p.215-216.

[80] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), p.216.

3.32 The ERP includes a number of key initiatives it seeks to progess. These include the Government developing a gas transition plan by the end of 2023 which will set out a transition pathway for the fossil gas industry, explore opportunities for renewable gases and ensure an equitable transition. [81]

3.33 The gas transition plan will be an input to the energy strategy which will be developed by the end of 2024. The energy strategy aims to address strategic challenges in the energy sector and signal pathways away from fossil fuels. [82]

3.34 At this time, the Government has not yet articulated:

3.34.1 the rate at which it wants to phase out the use of fossil fuels, including natural gas;

3.34.2 when it considers the phase-out should be completed by; and

3.34.3 how it more precisely intends to balance the phase out of fossil fuels, with its other energy objectives which are to ensure:

3.34.3.1 Energy will be accessible and affordable and will support the wellbeing of all New Zealanders.

3.34.3.2 Energy supply will be secure, reliable and resilient, including in the face of global shocks.

3.34.3.3 Energy systems will support economic development and an equitable transition to a low-emissions economy.

3.35 The default price-quality path for the fourth regulatory period beginning on 1 October 2026 (**DPP4**) provides the next opportunity to comprehensively consider the implications of any new relevant Government policy that becomes available after this decision on DPP3. Any such new policy released prior to the completion of the Part 4 IM Review in 2023 may be reflected in the IM Review.

Factors affecting the demand for natural gas

3.36 The demand for natural gas is expected to decline given the transition to renewable energy. However, the rate at which use decreases is uncertain and there is no clarity as to when use may be phased out.

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[81] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), Action 11.3.1 on p.216.

[82] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), Action 11.5.2 on p. 221.

3.37 In the very near term, natural gas production and use may increase.

3.37.1 Concept Consulting Ltd (**Concept**) forecasts natural gas production to increase in 2023 and 2024 to levels not seen in any year since 2002.[83]

3.37.2 GPBs are forecasting an increase in the number of residential and small connections over DPP3.

3.38 Any increase in gas use is likely to be shortlived, however, with gas use expected to begin declining shortly thereafter, although the rate of decline is uncertain and will likely vary between different groups of consumers of gas pipeline services. Concept forecasts, a decline in use of natural gas over the period to 2026 particularly due to falling gas demand for power generation.[84] Concept forecasts:

3.38.1 for residential, commercial, and agricultural users, the use of natural gas reflects the outcome of decisions by many thousands of consumers. There are unlikely to be sudden shifts in the level of annual use of natural gas for these users because decisions to switch energy source typically involve capital expenditure for appliances and modifications to premises. Concept's middle case assumes relatively flat demand for this segment until 2025, and a 40% reduction by 2035;

3.38.2 natural gas use by larger industrial users is likely to decline 'fairly slowly' over the period from 2022 through to 2035; and

3.38.3 use for power generation is likely to experience a significant drop. While electricity demand growth may lead to increased use of natural gas in the short-term, Concept assesses that in the long-term, a larger share of power generation is likely to come from renewable sources.

3.39 Different parts of the natural gas network face a more uncertain future than others.[85] For example, natural gas is used in industrial heating, the production of industrial products (largely for export), and to support electricity demand peaks. It is likely that some consumers of natural gas will find it more difficult to switch their consumption of natural gas to alternatives than other users. This includes users with high process heat requirements and some residential users such as tenants and users who are unable or unwilling to replace existing appliances.

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[83] Concept Consulting "Gas supply and demand projections" (24 March 2022), p.20.

[84] Concept Consulting Ltd, "Gas demand and supply projections – 2021 to 2035" , Figure 19 and p. 19-22.

[85] Vivid Economics (for First Gas and Powerco) "Gas infrastructure futures in a net zero New Zealand" (2018), p.5.

3.40 When the use of natural gas may be phased out is also uncertain and a number of forecasts assume gas use continues to or beyond 2050.

3.40.1 The Gas Industry Company (**GIC**) notes that while there are differences in forecasts of the energy sector, "all see significantly reduced demand for natural gas in New Zealand as the transition progresses, and some natural gas remaining in the energy mix in 2050".[86]

3.40.2 The New Zealand National Infrastructure Strategy notes the electricity sector will still produce carbon emissions in 2050 as gas-fired generation may still be needed to provide electricity when our wind, solar, geothermal and hydro generation can not meet demand; and there might also be some industrial processes, like steel and cement production, that require very high temperatures and switching to electricity would be overly costly under current policy settings.[87]

Sequence of demand decline amongst consumer groups

3.41 Demand for natural gas can be impacted by large customers, businesses or industries shutting down and the uncertainty about if and when they might exit.

3.42 The GIC highlighted the importance of Methanex to the New Zealand natural gas market, noting that if Methanex was to cease operations, a large and stable proportion of natural gas demand would leave with it.[88] The GIC noted that Methanex plays a key role in supporting natural gas production investment, helping to ensure natural gas availability to support electricity generation and major users. We consider that Methanex's departure could accelerate a decline in demand due to a loss of confidence in supply.

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[86] "Gas Industry Company Limited "Market Settings Investigation – Report to the Minister of Energy and Resources (30 September 2021), p. 27.

[87] New Zealand Infrastructure Commission, "Rautaki Hanganga o Aotearoa: New Zealand Infrastructure Strategy 2022 – 2052" (2022),p.56, section 6.1.1.

[88] Gas Industry Company Limited "Gas Market industry Settings Investigation Consultation Paper (24 June 2021), p.36-37.

3.43 Similarly, the CCC highlighted the role of Methanex in the transition away from fossil gas. The CCC observed that:[89]

3.43.1 as a large user of fossil gas, Methanex's demand incentivises fossil gas producers to continue production to supply all users; and

3.43.2 Methanex can also provide flexibility by reducing its demand and methanol production when there is an interruption in supply or in dry years when the hydro lakes are low.

3.44 The CCC also noted that its demonstration path modelling stages the closure of Methanex to 2040. It noted that its assumption was compatible with modelled fossil gas supply but assumed continued investment to enhance extraction from onshore and offshore fields.[90]

3.45 The CCC's advice to the Government also noted that the speed with which Aotearoa reduces fossil gas use for generating electricity needs to be carefully managed to ensure electricity remains reliable and affordable.[91] The CCC observed that:

3.45.1 Removing fossil gas too quickly from the system could increase electricity prices and reduce reliability. This could have significant consequences for the electrification of transport and low- to medium-temperature process heat.

3.45.2 There are currently fewer options for moving away from fossil gas for industries that need high temperature process heat and rely on fossil gas as a feedstock for products like urea.

3.45.3 There are solutions for moving away from using fossil gas in residential heating and cooking, such as heat pumps and induction stove tops. Biogas and hydrogen may also offer opportunities. There is an upfront cost to replacing fossil gas appliances, boilers and infrastructure. This cost can be minimised by replacing appliances with low-emissions alternatives when they reach the end of their useful life.

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[89] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021), Box 5.2, p. 69.

[90] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021), p.135.

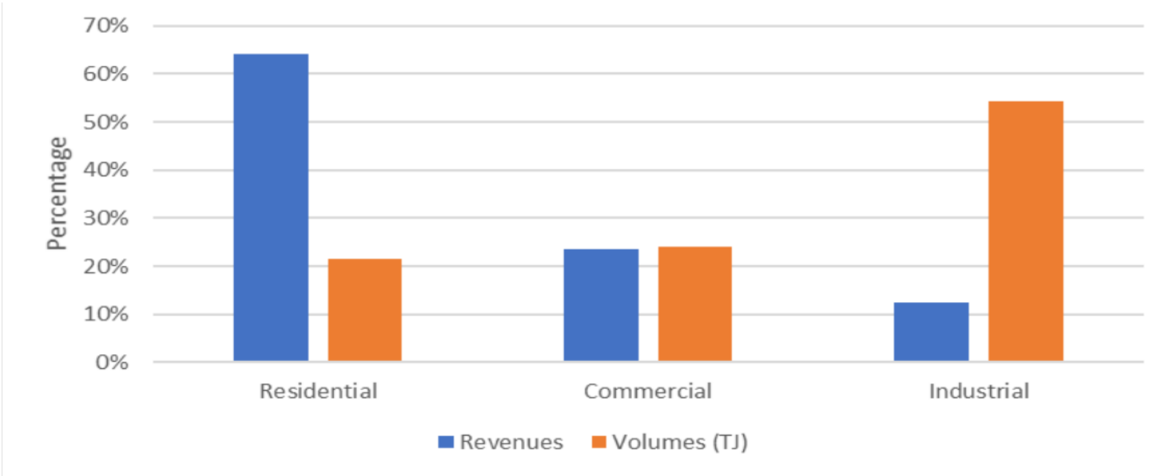
[91] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021), Box 5.2, p69.

3.46 The CCC concluded that as the use of fossil fuels is phased down, the diminishing role of fossil gas across the energy system will need to be carefully managed and sequenced as there may be consequences for network infrastructure and the workforce.[92]

3.47 The GIC noted that several industry participants raised concerns about the long-term viability of a domestic natural gas market at such a reduced scale.[93]

3.48 The prices paid for gas varies between consumer groups. Residential and small business consumers contribute a higher proportion of the costs of running the gas pipeline businesses despite using relatively less gas as shown in Figure 3.1.[94] Larger gas users pay less, particularly towards the gas distribution networks since they use relatively little of those networks.

Figure 3.1: Proportion of revenues and volumes by consumer group (combined total for Powerco, First Gas & Vector)



Source: Vector's 2020 GDB Information Disclosure - Schedule 8 (Billed Quantities by Price Component); Firstgas, Final GDB Information Disclosure 2019 - Schedule 8 (Billed Quantities by Price Component); PowerCo, Gas Distribuion Services - Annual Information Disclosure Statement 2019 - Schedule 8 (Billed Quantities by Price Component).

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92 Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa 2022-2025" (2021),Box 5.2, p69.

93 Gas Industry Company Limited "Gas Market industry Settings Investigation Consultation Paper (24 June 2021), p.36-37.

94 First Gas Group Climate Change Commission Draft Advice Submission (26 March 2021), Attachment 3 (Oakley Greenwood Response to Climate Change Commission Advice), p. 45, Figure 22.

3.49 If, as expected, the demand for natural gas falls, then the GPBs will, in the short term, seek to recover their largely fixed costs by increasing the prices charged to the consumers who are willing to pay higher prices to continue to use gas. This may include, for example, some commercial consumers and residential consumers. Over time, however, as more consumers leave, further price increases will be required, and more consumers may leave, accelerating the decline in gas usage and potentially leading to the closure of the natural gas pipelines. In time, reducing gas demand seems likely to result in an overall decrease in revenues. We note that both the CCC and the Government have stressed the need for an orderly transition of the energy system, balancing reducing emissions with other concerns such as affordability, accessibility and security.

Consumer climate change awareness and sentiment

3.50 Some consumers of gas pipeline services may consider switching away from natural gas and fossil fuels, independent of government climate change and energy policies. This could be due to growing climate change awareness and electricity potentially becoming more price competitive compared with natural gas. However, switching energy sources is not a costless exercise and may require consumers to buy new appliances.

3.51 Currently, there is limited knowledge of consumer preferences and attitudes toward natural gas, and we do not know what consumer preferences will be in the future. Consumer preferences will likely depend on the opportunity for substitution away from natural gas to other energy sources, including alternative gases, and the cost of doing so.

3.52 There is growing social pressure on businesses and other natural gas users to invest and operate in a way that is environmentally sustainable. This could, if suitable alternatives are available, prompt increased efforts by gas users to decarbonise and lead to a decrease in demand for natural gas.

Supply uncertainty in the natural gas sector

3.53 GIC notes it is often stated that there is sufficient 'gas in the ground' to meet mass market, industrial and power generation demand for the next decade.[95] Updated analysis by Concept in 2022 continues to support the view that "there is sufficient gas in New Zealand's existing fields to meet the demands from high-value gas users for the very long-term". However, Concept notes that to produce existing reserves and maintain production levels so as to meet this demand:[96]

3.53.1 will require significant investment (Concept cite GIC 2020 estimates of $300-$500 million of investment every three to five years); and

3.53.2 may also require longer term contracts to purchase gas. Methanex has traditionally entered such agreements but if Methanex exits, other users may need to enter into such contracts.

3.54 According to the GIC, there is higher risk for investment in gas development and production in New Zealand than previously has been the case, and a higher risk premium is being attached to investment to compensate.[97] The GIC considers this leads to a real risk that insufficient investment will be committed to ensure that New Zealand natural gas reserves will come to market and that security of supply for both electricity generation and major users could be compromised during the transition to 2030 and beyond. This excludes the potential option of importing natural gas from Australia or elsewhere.

3.55 Upcoming Government decisions or interventions in the natural gas sector and changes to consumer preferences may accelerate or slow the decline of natural gas supply. These decisions may also affect NZ ETS prices, carbon credit policies, and energy pricing differentials that will impact the natural gas sector.

Substitution of natural gas with alternative gases

3.56 The development of hydrogen or biomethane as substitutes for natural gas is at a very early stage and is highly uncertain. There are economic and technical barriers for large-scale production for both hydrogen and biomethane, and the role of gas pipelines to convey such gases in New Zealand has not yet been established.

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95 Gas Industry Company Limited "Market Settings Investigation – Report to the Minister of Energy and Resources (30 September 2021), p.2-3.

96 Gas Industry Company "Gas supply and demand projections" (24 March 2022), p.28-9.

97 Gas Industry Company Limited "Market Settings Investigation – Report to the Minister of Energy and Resources (30 September 2021), p.37.

3.57 The global gas industry has been signalling for some time now that new low carbon emission 'clean' gas solutions (biogas and hydrogen) may eventually replace natural gas.[98] The Government's recent ERP includes a focus area of replacing fossil fuels with low-emissions fuels such as bioenergy and hydrogen. The development of a roadmap for hydrogen in Aotearoa is an early step.[99] Low-emission fuels and gases have a role to play in the transition to net zero however the pace at which this transition can occur is highly uncertain.

3.58 The prospect of repurposing existing gas pipelines to carry low or no carbon gases provides long-term potential for the use of existing gas networks even if natural gas use is phased out.

3.59 GPBs, the Government, the GIC and the Gas Infrastructure Future Working Group continue to explore the implications of different scenarios for the long-term future of natural gas pipeline businesses.

3.60 The Gas Infrastructure Future Working Group assessed two very different scenarios for future natural gas use in New Zealand in its findings report from August 2021:[100]

3.60.1 the wind-down scenario – where all natural gas consumption is phased out and natural gas infrastructure is decommissioned in a safe and reliable way; and

3.60.2 the repurposing scenario – where, for some uses, natural gas consumption transitions from natural gas to green alternatives such as hydrogen or biogas.

3.61 More recently, the Gas Infrastructure Future Working Group has been looking at steps to facilitate repurposing, including developments elsewhere, including Australia.

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98 David Williams "The burning questions about gas" (21 October 2021).

99 Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), p.216.

100 Gas Infrastructure Future Working Group "NZ Gas Infrastructure Future – Findings Report" (13 August 2021), p. 10. The group is made up of representatives from Vector, First Gas, and Powerco, with observers from the GIC, the Ministry of Business, Innovation and Employment, the Commerce Commission, the Electricity Authority and the Major Gas Users Group.

Hydrogen

3.62 Hydrogen's potential as a substitute for natural gas is uncertain at this stage because there are technical and economic issues around its generation, storage, transportation and end use.

3.63 There is a considerable amount of research being undertaken internationally on the potential use of hydrogen. In New Zealand, First Gas has been studying the possibility that its gas pipelines may be re-purposed for 'clean' gas use and recently published a report on the feasibility of hydrogen as a future conveyance gas.[101]

3.64 First Gas sees hydrogen as a viable solution to the Government's net-zero carbon emissions target by 2050. The First Gas hydrogen feasibility report identifies what it thinks are the likely technical and economic challenges in converting its pipelines to convey hydrogen, first as a blended gas and then moving to 100% hydrogen.

3.65 First Gas sees hydrogen blending with natural gas commencing in 2030 expecting to be at 20% hydrogen blended by 2035. First Gas in its submission on our draft decision, updated that across both hydrogen and biogas blending it broadly expects to be at an average of 5% blended gases in late 2027, increasing to 10% blended gases by late 2032.[102]

3.66 The Government has indicated that it will develop a hydrogen roadmap for New Zealand by 2023. To inform the roadmap, Castalia has produced a scenarios report considering the role green hydrogen, ie, hydrogen produced using renewable electricity, could play in the transition to a net zero economy.[103] The Castalia report explored possible use cases of green hydrogen in 2050 under two pathways, ie, a business-as-usual (**BAU**) pathway without specific policy interventions and one with policy interventions.

3.67 Castalia's modelling suggested that green hydrogen may account for around eight percent of New Zealand's total energy demand by 2050 and that it is possible that this demand will increase over time as hydrogen technologies become more developed.[104]

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[101] First Gas Group" Bringing Zero Carbon Gas to Aotearoa – Hydrogen Feasibility Study – Summary Report.

[102] First Gas "DPP3 Draft Decision submission" (16 March 2022) p.28.

[103] Castalia "New Zealand Hydrogen Scenarios – Report to MBIE" (April 2022).

[104] Castalia "New Zealand Hydrogen Scenarios – Report to MBIE" (April 2022), p.7

3.68 The Castalia report identified four sectors where hydrogen technology and applications of hydrogen could be used:[105]

3.68.1 The transport sector is likely to be the largest source of demand of hydrogen in New Zealand and will likely come from heavy-duty vehicles like heavy trucks, coach buses and speciality vehicles. Demand in aviation is likely to occur and some demand may also emerge in marine and rail, though the technologies for these three applications are still in development.

3.68.2 Hydrogen could provide an option for rapid demand response in electricity systems as production can be ramped up and down quickly. Hydrogen storage may be viable to mitigate dry year risk.

3.68.3 There is only limited scope to replace industrial feedstocks with hydrogen. Fertiliser production may use hydrogen as a feedstock if costs come down and technology advances. If emissions are to be eliminated from steelmaking, hydrogen is likely to play a significant role. Combusted hydrogen could be used mainly for high temperature process heat applications. Use of combusted hydrogen in domestic and commerical applications is likely to be small as there are other competing energy sources like electricity and biogas.

3.68.4 Hydrogen could be used to support decarbonisation efforts in export markets, particularly in countries like Japan, Korea and Singapore. Although New Zealand-produced hydrogen is likely to be cost-competitive and it has a competitive advantage over other countries in the short-term, New Zealand has to act quickly and could miss out if it lags behind other countries who are already ahead in establishing a hydrogen export industry. [106]

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[105] Castalia “New Zealand Hydrogen Scenarios – Report to MBIE” (April 2022), p.8-9.

[106] Castalia “New Zealand Hydrogen Scenarios – Report to MBIE” (April 2022), p. 68-69

3.69 Under a BAU pathway, Castalia noted that:

3.69.1 Hydrogen uptake has demand from around 2030 and that demand depends on the relative competitiveness of hydrogen technology and uses Castalia expected demand to be in the transport sector for heavy vehicles, support of the electricity system and for export. It is not clear if hydrogen would be lower cost than other energy sources or carriers for combustion use cases.[107]

3.69.2 The production pathway for hydrogen will depend on plant utilisation, electricity costs and distance from market. The paper noted that both a centralised and decentralised production approach could be used and distribution via gas pipelines is likely to be cost competitive although costs are difficult to estimate.[108]

3.70 Castalia noted that policy interventions could bring forward hydrogen uptake or preserve infrastructure options. It said that preserving existing infrastructure, such as gas pipelines, may provide options that avoid additional sunk costs or enable a wider range of decarbonisation technologies. Viable options to preserve natural gas pipelines include introducing blends of hydrogen.[109]

3.71 A March 2022 Concept report analysed the cost effectiveness of reticulated green hydrogen for industrial boiler process heat, space heating and water heating.[110] The Concept report concluded that direct use of electricity was significantly more cost-effective than green hydrogen for all three energy end-use applications. In its January 2019 study on the potential economics of hydrogen technologies in New Zealand, Concept found that hydrogen could be economic for some niche applications, but for the majority of New Zealand's energy needs, hydrogen is unlikely to become cost-competitive with alternative low carbon options, particularly direct use of electricity.[111]

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[107] Castalia "New Zealand Hydrogen Scenarios – Report to MBIE" (April 2022), p.10 – 14

[108] Castalia "New Zealand Hydrogen Scenarios – Report to MBIE" (April 2022), p.10.

[109] Castalia "New Zealand Hydrogen Scenarios – Report to MBIE" (April 2022), p.15, 77.

[110] Concept Consulting Limited "Green Gas Report" (2022 unpublished).

[111] Concept Consulting webpage summary on "H2 in NZ - A study of the potential economics of hydrogen technologies in New Zealand" (January 2019).

Biomethane

3.72 A recent joint study between Beca, First Gas, Fonterra and the Energy Efficiency & Conservation Authority outlined an initial pathway for the use of biogas and biomethane. Biogas can be refined into biomethane which makes it a direct substitute for natural gas and able to be integrated with existing assets used to transport and use natural gas.[112] Expected NZ ETS price increases will increase the competitiveness of biofuels like biomethane since NZ ETS units are not required to be paid if it is used.

3.73 However, estimated quantities of available biomethane in New Zealand are significantly less than the quantities required to replace existing use of natural gas. Beca estimate that by 2050, up to 13 PJ of biomethane can be made available which if realised, could potentially replace only 7% of our 2020 natural gas consumption. We note from the Beca report that there are still many steps to realising this biomethane potential.[113]

[112] Beca "Biogas and Biomethane in NZ : Unlocking New Zealand's Renewable Natural Gas Potential" (July 2021), p.7.

[113] Beca "Biogas and Biomethane in NZ : Unlocking New Zealand's Renewable Natural Gas Potential" (July 2021), p.81.

4. Summary of our decisions

Purpose of this chapter

4.1 This chapter summarises the decisions we have made in setting DPP3 for the GPBs. The chapter covers:

4.1.1 an overview of our decisions;

4.1.2 our approach to determining price-paths for the GPBs;

4.1.3 the price-path we have set for each GPB; and

4.1.4 the key drivers for how we have set starting prices.

Overview of our decisions

4.2 In reaching our decisions we have been guided by the Part 4 purpose. We must promote the long-term interests of consumers of gas pipeline services by promoting outcomes consistent with competitive market outcomes such that the objectives listed in s 52(a) to (d) are achieved. In making our decisions to best promote the Part 4 purpose we have sought to:

4.2.1 maintain incentives for GPBs to continue investing in natural gas pipelines to deliver safe and reliable services for consumers;

4.2.2 minimise the risk of inefficient investment; and

4.2.3 smooth price increases for consumers of gas pipeline services and limit GPBs' ability to earn excessive profits.

4.3 Table 4.1 summarises the key decisions we have made and how these decisions promote the Part 4 purpose.

Table 4.1: Summary of key decisions

Decision	Benefit delivered
Reset starting prices based on current and projected profitability	To set the starting prices for GPBs in DPP3 we have retained the building blocks approach we used in DPP2. We have updated the building block model to reflect current and updated information on including costs, demand, the value of the RAB and WACC. This approach incentivises GPBs to continue to provide safe and reliable services at the quality consumers demand and helps protect consumers from paying more than is necessary to do so (Chapter 4, Attachment E and Chapter 6).
Operating expenditure allowances set based on a comparison of GPBs' AMP forecasts with our base, step, and trend modelling approach	We have capped the opex allowances at the lesser of GPB's AMP forecast, or our estimates from modelling opex using a base, step, and trend modelling approach. Our base, step, and trend modelling used the Disclosure Year 2021 (**DY21**) actual opex, which is the most recently available and reasonable ex ante estimate of efficient opex and have adjusted this to account for recurring and non-recurring expenditure. This is detailed in Attachment A. Our modelling allowed us to model known factors that affect opex trends such as network length, Installation Control Point (**ICP**) growth and cost step changes that are supported by supplier information.
Capital expenditure allowances set using a top-down approach based on GPB's own forecasts and capped at 100% of the historical average spend. Introduced capex allowance reopeners	We have set capital expenditure allowances using a top-down approach based on GPBs' own forecasts of capex but capped by their average historical levels of capex spend. In contrast to DPP2, capex allowance for DPP3 does not include a margin to the historical capex. Our objective is to incentivise GPBs to identify and prioritise prudent and efficient expenditure to maintain a safe and reliable network. Given the uncertainty over the future demand for natural gas pipelines we have introduced capacity and risk event re-openers to provide GPBs with some flexibility to seek an additional expenditure allowance in circumstances where capital contributions are not appropriate (Chapter 5 and Attachment B). We have also introduced a risk event reopener for additional asset replacement and renewals capex where the GPB has identified an unexpected material deterioration of an asset (or assets), or that an unexpected event has occurred. An opex reopener is available where opex is demonstrably more cost-effective than capex for the risk event reopener. The purpose of the reopeners is to mitigate the risk that DPP expenditure allowances will be insufficient to address network capacity issues or mitigate a risk that was unknown at the time the DPP was set.
The expected average asset lives for new and existing assets has reduced. The effect of this is to increase the depreciation allowance in DPP3	We have shortened the average lives of new and existing assets to better reflect the remaining economic lives of the networks. This mitigates the risk of economic stranding by increasing the depreciation allowance for DPP3, bringing revenues forward to maintain incentives to invest (Chapter 6) GPBs will record higher depreciation in ID for each year of DPP3, and this will reduce the RAB we will use to set prices in DPP4. Consumers of gas pipeline services will benefit from continuing investment in the network and GPBs have a reasonable opportunity to recover their

Decision	Benefit delivered
continued...	investment together with a normal rate of return within a timeframe which reflects the best information we have on how long the GPBs may continue to convey natural gas. In making our decision on remaining economic lives we have had regard to a range of scenarios for how long it may take to phase out the use of natural gas as well as the potential for the pipelines to have a residual value if they can be used to convey other gases (eg, hydrogen).
Retaining the current form of control settings	We have retained existing settings for form of control. GDBs are subject to a weighted average price cap which incentivises investment by GDBs to maintain their customer base (Attachment E). The GTB is subject to a revenue cap with a wash-up mechanism (Attachment E). Our view is that changing the current form of control settings is not likely to result in better outcomes for consumers of gas pipeline services or reduce compliance costs, other regulatory costs, or complexity.
Shortening the regulatory period to four years	The shorter regulatory period will allow us to consider the effects of Government policy decisions and relevant market changes sooner in the next DPP. (Attachment E).
Forecasting demand using GDB data	We have used GDBs' ICP and demand forecasts to model growth during DPP3. This ensures that there is consistency between our capex allowances and the Weighted Average Price Cap (**WAPC**) settings, and offsets the impact of upward bias in GDB growth forecasting. GDBs hold the most information about their existing customers, new customer enquiries, and the willingness to pay for new connections. GDBs are forecasting with the best available information (Chapter 5 and Attachment E).

Our approach to determining price-paths for the Gas Pipeline Businesses

4.4 The DPP must specify allowable revenues and quality standards for each GPB for the regulatory period, as set out in s 53M of the Act. The revenue limits are set before accounting for pass-through costs and recoverable costs. The two main components of these limits are:

4.4.1 the 'starting price' allowed in the first year of the regulatory period; and

4.4.2 the 'rate of change' in revenue allowed relative to the CPI, that is used to adjust the revenue allowed in later parts of the regulatory period.

4.5 The decision on whether the default price-path limits maximum prices or revenues depends on the form of control specified in the IMs.

4.5.1 The GDBs will be subject to a limit on their maximum average price ('weighted average price cap').

4.5.2 The GTB will be subject to a limit on their maximum revenue ('revenue cap').

4.6 The Act also requires us to set the regulatory period over which the price-path applies. We have set a four-year regulatory period.

4.7 A four-year regulatory period will allow us to consider changes in the natural gas sector and set a new price-quality path sooner than if we set a five-year regulatory period. We consider that a four-year regulatory period promotes the purpose of Part 4 better than a five-year term, given the current context for natural gas pipelines, including that further material government climate and energy policy announcments are expected during DPP3. Attachment E discusses this further.

4.8 We have set starting prices based on current and projected profitability. As an alternative, the Act allows revenues to be set by 'rolling over' the revenues which apply at the end of the preceding regulatory period. In our process and issues paper, we sought views from stakeholders on our approach to setting starting prices.[114] Stakeholders supported an approach based on current and projected profitability, highlighting that:

4.8.1 the outlook for the sector has changed considerably since the previous DPP reset; and

[114] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 Process and Issues paper (4 August 2021), para 5.17.

4.8.2 resetting the price path to reflect current circumstances would mean the price path is more likely to be fit for purpose.

4.9 We have concluded that using current and projected profitability better reflects the current and projected circumstances of the GPBs than the alternative of rolling over prices. Attachment F provides further detail on our approach to setting price-paths for the GPBs.

Our proposed price paths for gas pipeline businesses

4.10 We have determined starting prices, and annual rates of change in prices for the subsequent years of DPP3, based on the current and projected profitability for each GPB. This approach results in a series of annual maximum allowable revenues (**MAR**) for each GPB.

4.11 The four-year time series of MAR for each GPB is set out in Table 4.2. The starting prices are the maximum allowable revenues in the first year of the regulatory period.

4.12 Table 4.3 shows the starting prices and the rates of change we have determined for each GPB. Table 4.3 highlights that we have used alternative rates of change to smooth price increases across the regulatory period. We explain how we have set alternative rates of change from paragraph 4.32.

Table 4.2: Maximum Allowable Revenues in each year of the regulatory period ($m, nominal)

Gas Pipeline Business	2021/2022 forecast MAR	2022/2023	2023/2024	2024/2025	2025/2026
GasNet - Draft	4.384	4.839	5.284	5.681	6.093
GasNet - Final	4.384	4.852	5.339	5.752	6.175
Powerco - Draft	51.436	58.875	66.648	74.245	82.475
Powerco - Final	51.436	57.633	64.169	69.924	75.899
Vector - Draft	50.702	56.856	62.771	68.231	73.989
Vector - Final	50.702	58.317	61.646	63.816	65.846
First Gas Distribution - Draft	24.646	28.250	32.036	35.765	39.831
First Gas Distribution - Final	24.646	28.566	32.919	37.149	41.782
First Gas Transmission - Draft	131.623	148.762	167.033	187.411	210.275
First Gas Transmission - Final	131.623	147.227	163.455	180.939	200.246

Table 4.3: Starting prices (excluding pass-through and recoverable costs) and rate of change ($m nominal)

Gas Pipeline Business	Starting prices ($ m)	Price Increase from 2021/2022	Rate of change
GasNet - Draft	4.839	CPI + 5.1%	CPI + 5.1%
GasNet - Final	4.852	CPI + 5.5%	CPI + 5.5%
Powerco - Draft	58.875	CPI + 7.5%	CPI + 7.5%
Powerco - Final	57.633	CPI + 5.0%	CPI + 5.0%
Vector - Draft	56.856	CPI + 5.2%	CPI + 5.2%
Vector - Final	58.317	CPI + 7.7%	CPI + 0%
First Gas Distribution - Draft	28.250	CPI + 10.0%	CPI + 10.0%
First Gas Distribution - Final	28.566	CPI + 10.0%	CPI + 10.0%
First Gas Transmission - Draft	148.762	CPI + 10.0%	CPI + 10.0%
First Gas Transmission - Final	147.227	CPI + 8.5%	CPI + 8.5%

4.13 The following sections explain how we have arrived at our price paths, including:

4.13.1 the main drivers of starting price changes; and

4.13.2 why we are applying alternative rates of change for the GPBs.

The main drivers of starting price changes

4.14 Figure 4.1 illustrates the factors influencing DPP3 starting prices. As Figure 4.1 shows, the main drivers of the change in maximum allowed revenue between rolling over real prices and our decision are:

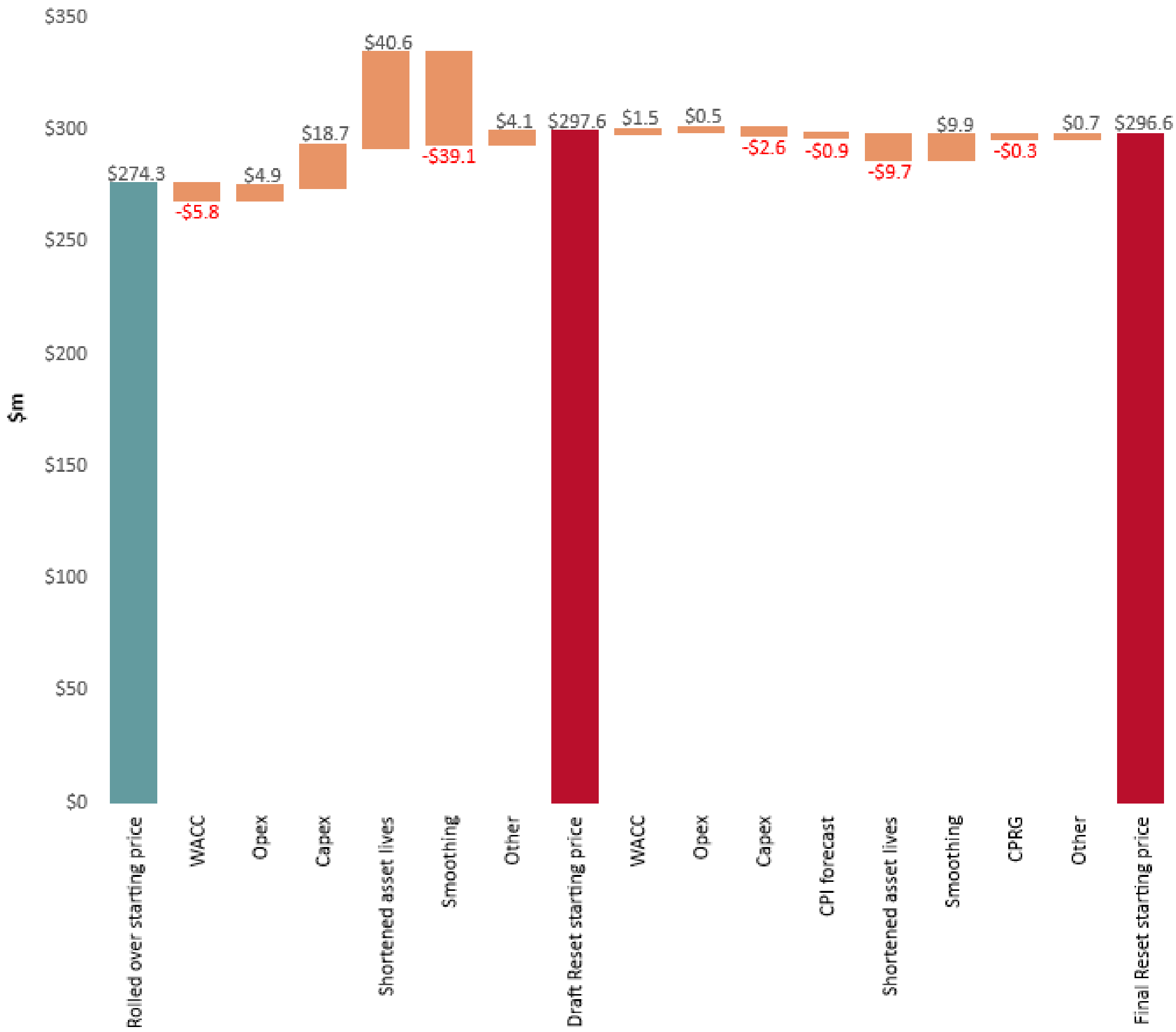
4.14.1 a reduction in the WACC estimate;

4.14.2 the opex and capex forecasts;

4.14.3 an increase in depreciation as a result of our decision to set shorter asset lives which better reflects the expected remaining economic lives of the gas pipeline networks; and

4.14.4 our decision to smooth price increases over time

Figure 4.1 : Drivers of change in allowable revenues ($m, nominal)



Changes since the draft decision

4.15 We have made the following changes since our draft decision that have influenced the starting prices we have set. We have updated:

4.15.1 our WACC estimate;

4.15.2 our expenditure modelling;

4.15.3 the adjustment factors to reflect shorter asset lives; and

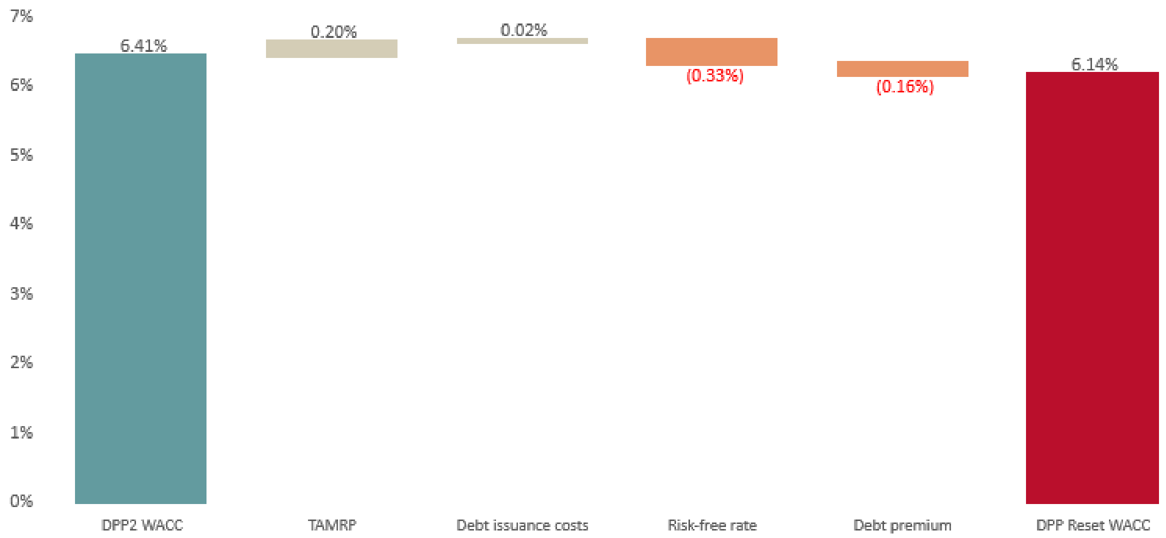
4.15.4 our modelling to include more up-to-date data such as CPI and DY21 information disclosures.

4.16 Further summary information on these changes is set out in the rest of this chapter.

The WACC estimate has decreased to 6.14%

4.17 We have used a vanilla WACC estimate (67th percentile) of 6.14%, compared to the WACC estimate used in DPP2 of 6.41%.

Figure 4.2: Weighted Average Cost of Capital Waterfall Chart



4.18 We made changes to our methodology to estimating the WACC to reflect:

4.18.1 changing the tax adjusted market risk premium from 7.0% to 7.5%, to reflect the estimate of the value of this market-wide parameter which we determined in the Fibre IMs after analysis and consultation; and

4.18.2 changes to the risk-free rate and debt issuance costs to match a four-year regulatory period.

4.19 These changes required IM amendments, which we consulted on in forming our draft DPP3 decision. We have also updated WACC input parameters since the draft decision, in particular for recent changes in interest rates and premiums on corporate debt.[115]

[115] The reasons for the IM amendments for TAMRP and the debt issuance cost are set out in our paper. Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths – weighted average cost of capital"(25 March 2022) Chapter 3.

Operating expenditure and capital expenditure forecasts

4.20 Our final decision adopts GPBs' forecasts of operating and capital expenditure from the GPB 2021 AMPs except to the extent to which:

4.20.1 forecast opex in any year exceeds our modelling of opex using a base, step, and trend approach;

4.20.2 forecast capex (for all categories other than non-network and consumer capex) in any year exceeds the historic level of capex the GPB has spent in recent years.

4.21 This is the same approach we took in our draft decision in setting capex and opex allowances. However, as we indicated in draft decision, we have incorporated the latest GPB opex and capex data (DY21 expenditure actuals) in our final decision analysis.

4.22 In response to submissions, we have made some minor expenditure allowance adjustments due to accounting reporting changes, the DY23 opex step change for GasNet, and corrected a modelling error in First Gas Transmission's network capex.

4.23 We have provided an allowance for GPBs to investigate blending of small quantities of alternative gas to natural gas. We encourage industry to work together and share knowledge in this area.

4.24 Based on our analysis and following draft decision submissions, our expenditure allowances represent 86% of total GPB 2021 AMP forecast capex and 100% of total GPB 2021 AMP forecast opex.

4.25 Figure 4.3 and Figure 4.4 respectively, illustrate, at an industry level, historical expenditure, forecast expenditure from the GPB's Information Disclosure, the DPP2 allowance settings, and the four-year DPP3 allowance settings.

Figure 4.3: Operating Expenditure Allowances (real $000s, 2021 ID year-end)

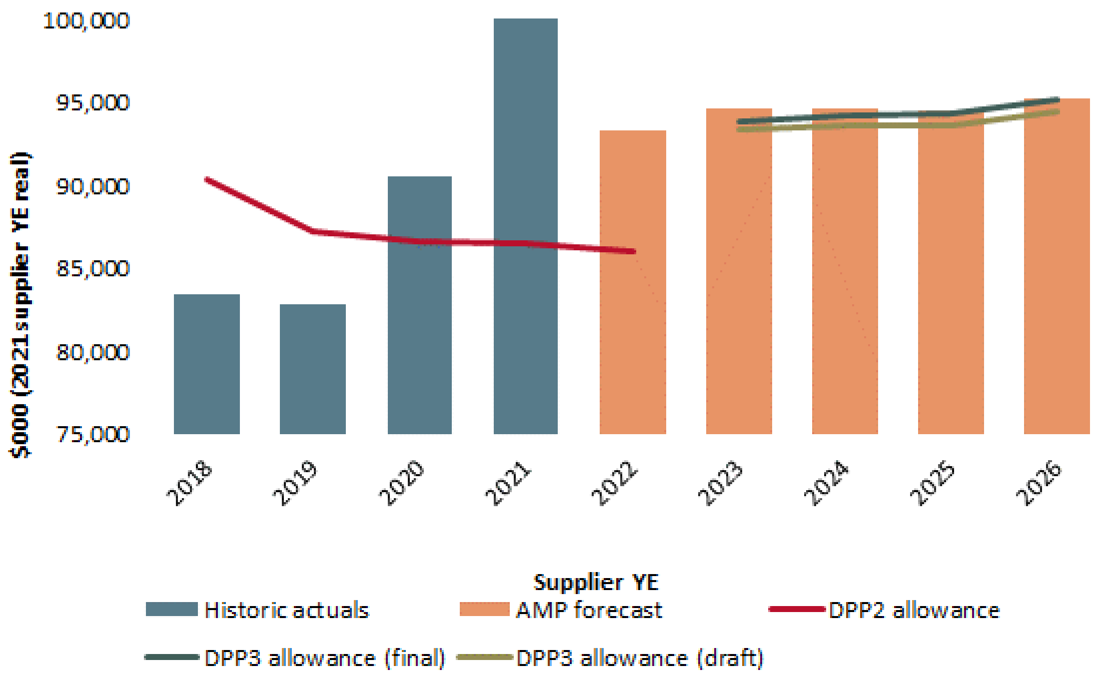
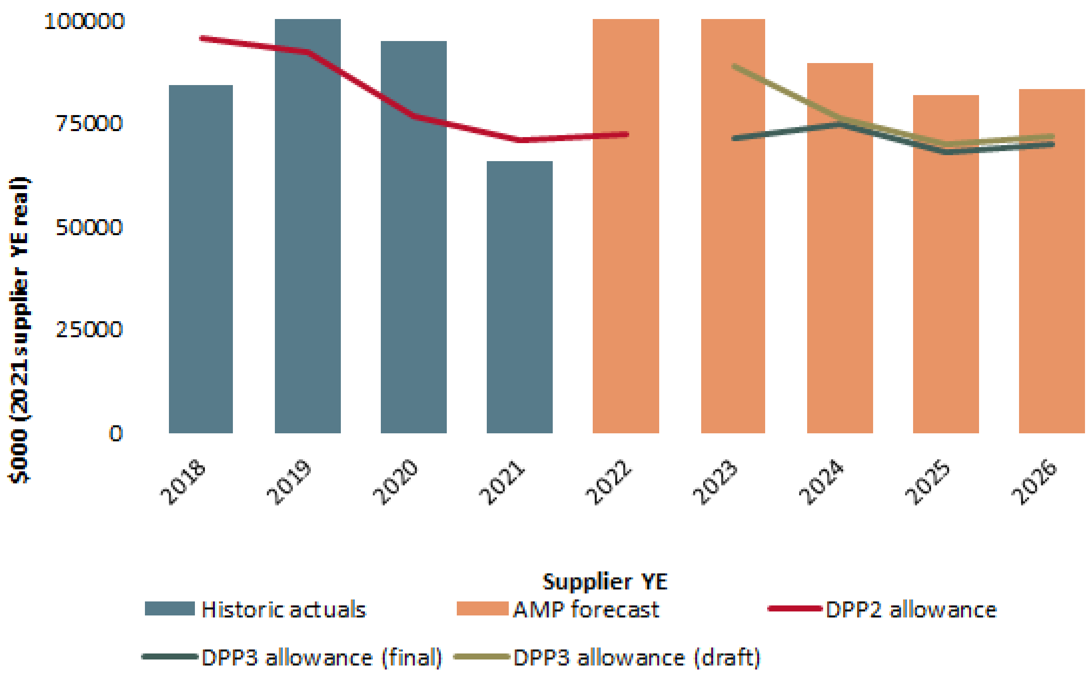


Figure 4.4: Capital Expenditure Allowances (real $000s, 2021 ID year-end)



We have shortened asset lives for regulatory purposes

4.26 To continue to apply our Building Blocks Model framework and set prices in DPP3 that better promote the Part 4 purpose, we have shortened the regulatory asset lives of GPB network assets to better match expectations of the period over which the networks are expected to convey natural gas.

4.27 We explain in Chapter 6 why we have decided to shorten asset lives (by applying a recent amendment to the Gas IMs) for both DPP and ID purposes, and the information we have used to set an asset adjustment factor, which is the mechanism we have used to shorten lives. In determining the value of the asset adjustment factor we have had regard to a range of scenarios for how long it may take to phase out the use of natural gas as well as the potential for the pipelines to have a residual value if they can be used to convey other gases (eg, hydrogen).

4.28 We have set and applied the asset adjustment factors shown in Table 4.4 for this DPP. An adjustment factor of less than 1 results in a reduction in assumed asset lives.

Table 4.4: Adjustment factors to be applied to asset lives for DPP3

Gas Pipeline Business	Adjustment Factor
GasNet	0.81
Powerco	0.84
Vector	0.66
First Gas Distribution	0.69
First Gas Transmission	0.75

4.29 Shortening the asset life over which the cost of the asset is recovered, leads to higher depreciation in each year of the remaining life. Shorter asset lives therefore increase the value of depreciation allowed in DPP3.

4.30 Our decision to give weight to a wider range of factors when determining the asset lives has led to a lower increase in depreciation, and thus prices, for DPP3 than proposed in the draft decision.

4.31 The asset adjustment factor also affects the disclosure of financial information under ID regulation as the asset lives used to calculate depreciation under ID are also shortened by the operation of the asset adjustment factor. This increases the amount of depreciation reported under ID in each year of the DPP period. This is important, as this increased depreciation reduces the RAB that will be reported each year under ID and the lower RAB reported under ID in DY25 will then be used as the base year RAB to set prices in DPP4 (if we again set prices using an assessment of current and future profitability).

We have set alternative rates of change to minimise price shocks to consumers of gas pipeline services in DPP3

4.32 Under the Act, we must set a rate of change for the GPBs. This rate of change must be based on the long-run rate of productivity improvement achieved by suppliers of the relevant goods or services in New Zealand or other comparable countries. We refer to this rate of change in productivity as the 'X-factor'. We have decided not to apply a productivity adjustment.

4.33 However, we may set an alternative rate of change for a particular GPB, as an alternative in whole or in part, to the starting prices (under s 53P(3)(b) of the Act), if this is necessary or desirable to:

4.33.1 minimise any undue financial hardship to the supplier;

4.33.2 minimise price shocks to consumers; or

4.33.3 create an incentive (under s 53M(2)) for the supplier to improve its quality of supply.

4.34 Having completed our assessment of the GPBs' current and projected profitability, we have considered whether an alternative rate of change for each GPB is necessary. To do so we have assessed whether the starting price adjustment implied by our assessment of the GPBs' current and preojected profitability might result in a price shock for consumers.

4.35 Table 4.5 shows the implied starting prices for each GPB if we were to apply a one-off starting price adjustment (and no annual real price increase).

Table 4.5: Implied real price increases due to one-off starting price adjustment ($ nominal)

Gas Pipeline Business	Implied starting price ($ m)	Implied real price increase for year 1 of DPP3
GasNet	5,256	14.3%
Powerco	62,036	13.0%
Vector	58,317	7.7%
First Gas Distribution	33,030	27.2%
First Gas Transmission	166,427	22.6%

4.36 Table 4.5 shows that the starting price increase for all GPBs except Vector would exceed 10% in real terms if we made a one-off starting price adjustment. Consistent with our draft decision, we have set an alternative rate of change where a GDB’s starting price adjustment would otherwise exceed 10% in real terms. As a result, we have reduced the size of the price increase to consumers in any given year, which should minimise price shocks to consumers of gas pipeline services.

4.36.1 For GasNet, Powerco, First Gas Distribution and First Gas Transmission we have applied an alternative rate of change.

4.36.2 For Vector we have applied a one-off starting price adjustment.

4.37 For the GPBs that we have applied alternative rates of change to, we have decided to allow constant real increases over the four years of DPP3, including the initial starting price adjustment. This provides some price predictability over DPP3.

4.38 We have also capped annual real MAR increases to 10% per annum in real terms for all four years of DPP3 (including the starting price adjustment), to minimise price shocks in subsequent years of DPP3. The 10% cap binds for First Gas Distribution.

4.39 Our rates of change for this decision are set out in Table 4.6, along with the rates we had used in our draft decision.

Table 4.6: Alternative rate of change for each GPB

Gas Pipeline Business	Rate of change in our draft decision	Rate of change
GasNet	CPI + 5.1%	CPI + 5.5%
Powerco	CPI + 7.5%	CPI + 5.0%
Vector	CPI + 5.2%	CPI + 0%
First Gas Distribution	CPI + 10.0%	CPI + 10.0%
First Gas Transmission	CPI + 10.0%	CPI + 8.5%

Submissions on our approach

4.40 In its submission on our draft decision, Vector submitted that the 10% real cap on price increases appeared arbitrary and that we had not presented an analysis of how we arrived at this value.[116]

[116] Vector "DPP3 Draft Decision submission" Public Version (16 March 2022), para 105.

4.41 The 10% cap was a judgement call and reflected a balance between ensuring prices reflect the costs of providing the service, including the impact of shorter economic lives of assets, and minimising price shocks to consumers. The value of 10% has been used in a number of previous resets, for example in the 2010 to 2015 reset for Alpine Energy Limited, Centralines, The Lines Company, and Top Energy Limited where a 10% cap on price increases was applied.

5. Our decisions on expenditure allowances

Purpose of this chapter

5.1 This chapter summarises the approach we have taken and decisions we have made in setting expenditure allowances for Gas DPP3.

5.2 Detailed analysis and explanation of how we have set the opex and capex allowances is provided in Attachments A and B respectively.

Summary of our expenditure decisions

5.3 Our GPB expenditure allowances for the four-year DPP regulatory period are provided in Table 5.1. We show the expenditure allowances as a proportion of GPB expenditure forecasts in Table 5.2.[117]

Table 5.1: Expenditure allowances for the four-year default price-quality path (real $000, 2021 ID year-end)

Gas Pipeline Business	Opex	Capex	Total
GasNet	9,454	3,309	12,763
Powerco	73,585	67,271	140,856
Vector	56,271	23,064	79,336
First Gas Distribution	39,970	47,170	87,140
First Gas Transmission	198,196	142,898	341,094
Industry Total	**377,477**	**283,712**	**661,188**

Table 5.2: Expenditure allowances as a proportion of Gas Pipeline Business 2021 Asset Management Plan forecasts

Gas Pipeline Business	Opex	Capex
GasNet	102%	78%
Powerco	100%	92%
Vector	100%	61%
First Gas Distribution	95%	82%
First Gas Transmission	100%	91%
Industry Total	**100%**	**86%**

[117] Note that this figure is greater than 100% for GasNet as we made an additional allowance for alternative gas investigation costs which was not reflected in their AMP forecasts.

5.4 The key points to note about the expenditure allowances we have included in DPP3:

5.4.1 we have allowed for the connection capex forecasts for First Gas Distribution, GasNet and Powerco;

5.4.2 we have not included Vector's forecast in the allowance as it has adopted a 100% capital contribution policy for new connections and as such these will be paid for by each consumer who obtains a new connection rather than recovered through regular pipeline charges;

5.4.3 the GDBs' system growth and non-growth related network capex has been capped by the historical average capex projections we have used to limit capex allowances;

5.4.4 First Gas Transmission's network capex has been capped by the historical average capex projections we have used to limit capex allowances in two years of the regulatory period;

5.4.5 we have allowed for the non-network capex forecast for all GPBs; and

5.4.6 following our base, step, and trend opex modelling we have capped First Gas Distribution's opex at 95% of its forecast and allowed for the opex forecasts for First Gas Transmission, Powerco, Vector and GasNet.

5.5 We have made a number of changes to our draft decision, namely that:

5.5.1 we have incorporated GPB DY21 actual expenditure data in both the capex and opex analyses;

5.5.2 we have used DY21 actual expenditure data to assist us in creating a base opex value for base, step, and trend modelling;

5.5.3 we have allowed and modelled revised GPB non-network capex forecasts following accounting reporting changes and businesses re-categorising previously disclosed non-network capex Software-as-a-Service (**SaaS**) costs as opex;

5.5.4 we have fixed modelling errors in the expenditure model; for GasNet's non-network capex, which has reduced its capex allowance by $145,000 over DPP3, and for First Gas Transmission's network capex, which has reduced the proportion of capex forecast which we allowed from 100% to 90.7%;

5.5.5 we modelled a revised GasNet's DY21 base opex and non-network opex step change occurring in Disclosure Year 2023 (**DY23**), following consideration of further information from GasNet; and

5.5.6 we have modelled a modest allowances to investigate natural gas blends.

5.6 The remainder of this chapter summarises the modelling approach we have taken and describes the assumptions we made in reaching our decisions. Attachments A and B provide additional detail of the opex and capex modelling we have carried out and the decisions we have made.

5.7 Finally, we have performed all expenditure modelling and analysis using historical and forecast expenditure expressed in real 2021 prices (**$ 2021**). We then convert the opex and capex forecasts into nominal values, where this is required, using The New Zealand Institute of Economic Research's (**NZIER's**) most recent:

5.7.1 all industries Producer Price Index (**PPI**) inflator series for capex; and

5.7.2 a 60%/40% weighted all industries Labour Cost Index (**LCI**)/all-industries PPI inflator series for opex.

5.8 All expenditure in this chapter is expressed in real $ 2021 prices unless stated otherwise.

Continued investment is necessary and promotes the Part 4 purpose

5.9 When setting maximum allowable revenues for DPP3, we were informed by capex requirements outlined in GPB 2021 AMPs. DPPs are intended to be a relatively low cost means to setting allowances that GPBs need to run their businesses, and we rely on the AMPs to inform us of these needs.

5.10 Our DPP3 allowances include capex for asset replacement and renewal as well as capex for growth and new consumer connections, because we consider that:

5.10.1 current and future gas consumers are likely to benefit from maintaining safe and reliable GPB services to the extent that they demand these services now and in the future; and

5.10.2 continuing to allow capex for growth and new consumer connections promotes the part 4 purpose as long as consumers are willing to pay for services at cost reflective prices.

5.11 GPB 2021 AMPs have signalled that there will be a need for further capex investment after DPP3. We consider that GPBs need appropriate incentives to make these investments and to ensure that consumers benefit from them by continuing to receive a safe and reliable service.

5.12 Finally, we note that, while we have applied a top-down analysis approach to limit DPP3 capex allowances. For future DPP resets we may need to consider whether this approach remains appropriate, given expected reductions in gas usage and the proposed phase-out of natural gas. In other words, as demand falls and we get closer to the point where natural gas is phased out, historical expenditure levels may be an increasingly poor guide to inform the level of expenditure required to maintain services to the remaining consumers.

Our approach to setting capex allowances

Draft decision submissions

5.13 The draft decision capex approach has generally been accepted by GPBs and other submitters with some suggested improvements. First Gas noted that the top-down capex approach was “consistent with the intent of a low-cost DPP model”,[118] and Powerco viewed the approach as pragmatic.[119] However, both First Gas Distribution and Powerco noted an asset type issue that our proposed reopeners would not accommodate.

5.14 Vector highlighted that our capex allowance represented a low proportion of its capex forecast, while GasNet stated that its capex was insufficient. Both Vector and GasNet suggested that we reintroduce capex margins to the historical average capex projections.[120,121]

5.15 Fonterra supported the top-down capex approach but qualified its support, stating that future “capital expenditure needs to be at or below historic average levels going forward due to declining growth”.[122]

5.16 The Major Gas Users’ Group (**MGUG**) stated that it had no strong view about the top-down capex approach and that it agreed that not adding capex margins was consistent with an approach to “capital under uncertainty”.[123]

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118 First Gas "DPP3 Draft Decision submission" (16 March 2022), p.19.

119 Powerco "DPP3 Draft Decision submission" (16 March 2022), p.1.

120 Vector "DPP3 Draft Decision submission" Public Version (16 March 2022), p.28 para 110.

121 GasNet "DPP3 Draft Decision submission" (16 March 2022), p.1.

122 Fonterra "DPP3 Draft Decision submission on GBP IM Amendments" (16 March 2022), p.3 para 13-14.

123 Major Gas Users Group "DPP3 Draft Decision submission” (16 March 2022), p.34.

We have retained our top-down approach

5.17 For our final decision we have retained our top-down historical average real capex projection modelling approach to modelling real network capex allowances with targeted scrutiny of AMPs for real non-network capex. We have also incorporated DY21 ID data when calculating the historical average capex projections for the GDBs and the GTB.

5.18 We have allowed each GPB's forecast real network capex unless it exceeds a projection of historical average real capex. In effect, the historical average real capex acts as a cap when we set the capex allowances for DPP3.

5.19 For GDBs we have applied the historical average capex projection approach to system growth and other non-growth network capex; and for the GTB we applied this to total network capex. We have corrected a modelling error in the expenditure model, identified by First Gas, which has reduced First Gas Transmission's capex allowance from 100% of its forecast to 90.7%.

5.20 We have calculated the historical average capex projections using GPB information disclosure data using five years of ID data for each GPB, apart from First Gas Transmission, where we used four years of ID data.

5.21 Consistent with our draft decision, we have used four years of ID data for First Gas Transmission because we consider that capex incurred prior to First Gas taking over the two transmission pipelines may not have reflected the future needs of the business. Therefore, using expenditure data prior to 2018, when calculating the historical average capex projections, may introduce error.

5.22 We have allowed the GDBs' forecasts of new connection growth and consumer connection capex. We concluded that GDB capital contributions policies' new connection payback periods were consistent with long-term demand expectations for GPBs. Our investigations revealed that these policies appeared to be subsidy free and met the requirements of the Gas IMs pricing principles.

5.23 We have used GDB forecasts of ICP growth and short term natural gas demand to form the basis of our GDB CPRG demand forecasts. Under the WAPC, CPRG forecasts predict the rate at which revenues will change due to changes in quantities delivered and the number of connected consumers, with prices remaining constant over the regulatory period.

5.24 By aligning the forecasts of near-term growth and consumer connection capex, we will maintain consistency between capex allowances and WAPC settings and offset the impact of potential upward bias in GDB demand forecasting.

5.25 Following our review of GPBs' most recent asset management plans and following responses to Requests for Information (**RFIs**), we allowed GDB and GTB non-network capex forecasts in our draft decision. Due to SaaS accounting reporting changes we have removed these costs from non-network capex forecasts so that these are not double counted in the expenditure modelling.

5.26 We have also corrected an expenditure modelling error in GasNet's non-network capex forecast, which has reduced its capex allowance by $145,000 over DPP3.

We have not added margins to historical average capital expenditure projections

5.27 In our capex modelling we have not added a margin to the historical average capex projections we have used to cap capex allowances; and have not allowed any expenditure above the level of the historical average capex projections.

5.28 The approach we have taken to set capex allowances is a variation of the approach we took in Gas DPP2. In Gas DPP2 we added a 10% margin to the historical average capex projections we used to cap allowances. We allowed expenditure that was under the 10% margin, and scrutinised expenditure above the margin.

5.29 During the DPP2 analysis process we considered that adding a 10% margin struck a balance between identifying expenditure that required further evidence and an approach that was consistent with the low-cost approach of setting DPPs.

5.30 We did not consider introducing capex re-openers in Gas DPP2 and recognised that there may be capex forecast error due to growth or risk events that were unforeseen at the time allowances were set. At the time we considered that the 10% margins minimised the impact of that potential forecast error.

5.31 For DPP3, we do not consider it appropriate to allow more capex than the historical average. This reflects expectations of a future decline in the use of natural gas.

5.32 Our decision in this DPP does not guarantee GPBs will recover their investment, only that they will have a reasonable opportunity to do so. GPBs should therefore continue to act and invest prudently, noting the expected move away from the use of natural gas, and use risk-based assessments to prioritise capex to maintain safe and reliable networks. We also expect that GPBs will assess new capex investments against decisions to maintain assets for longer in order to minimise the potential risk and quantum of stranding.

5.33 We consider that setting capex levels for DPP3 at historical average levels, combined with GPBs ability to manage their capex by adjusting expenditure and/or increasing capital contributions requirements, should enable GPBs to invest sufficiently to meet the demands of consumers of gas pipeline services and maintain safe and reliable networks.

5.34 There is uncertainty over the profile of future demand for gas given the Government's plan to phase out the use of natural gas is being developed (including the gas transition plan and the national energy strategy), and the extent to which natural gas may be used as a transitional energy source and/or as a potential supplement to renewable energy sources is unclear.

5.35 To mitigate the risk that the allowances are insufficient to meet consumers' demands to maintain safe and reliable networks, we have introduced capex reopener provisions for expenditure associated with demand growth or risk events. We explain these reopeners fully in our IM Amendments reasons paper.[124]

5.36 Finally, if GPBs consider the reopener provisions are not suitable, GPBs can apply for an alternative PQ path using a CPP to better meet their circumstances. A CPP can be tailored to meet the specific needs of the GPB and its consumers and provides the flexibility to deal with the particular challenges and opportunities that a GPB may encounter.

We have not provided a capex uplift to manage renewals risks identified by GPBs

5.37 While GDBs' AMPs may discuss projects and programmes that explain forecast expenditure uplifts above historical levels of capex, we have not scrutinised in detail the prudency and efficiency of these uplifts apart from our consideration of the asset renewals risk, highlighted by GDBs in draft decision submissions.

5.38 We have considered polyethylene (**PE**) pipe and metallic pipe asset type issues separately following draft decision submissions. We tested GDB asset management plan material to understand the issues and whether expenditure increases above historical levels were supported for the PE and metallic pipe replacement programmes.

5.39 We concluded that, while GDBs have been discussing these risks in their AMPs since at least 2018, and some GDBs appear to be applying risk-based strategies to prioritise replacements, we did not find information that supported expenditure uplifts above historical levels.

5.40 We also tested GDB gas leakage statistics and could find no clear evidence that gas leakage events were increasing, or find discussions in asset management plans that increasing gas leakage events, related to asset-type issues, were driving expenditure uplifts to address these.

[124] Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths -reasons paper" (30 May 2022).

5.41 On this basis our final decision is to retain our draft decision approach for the non-growth network capex category of expenditure. We have not made any additional adjustments.

Our approach to setting opex allowances

5.42 We have used base, step, and trend opex modelling to independently test that GPB opex forecasts are sensible and reasonable. This modelling approach reflects the fact that opex is generally more predictable than capex as it contains expenditure related to recurring activities, and it allows us to model specific adjustments that affect each GPB. While opex is generally more predictable than capex, it is challenging to determine an appropriate base opex value that reflects efficient costs.

5.43 Following our base, step, and trend modelling, we set allowances as the lesser of the base, step, and trend model output and the supplier forecast opex in each year of Gas DPP3 (see Table 5.3).

5.44 This is to ensure that the allowances we set are not higher than what each supplier has forecast it needs (noting that we have added a separate blended gas investigation allowance for Powerco and GasNet in addition to the opex modelling outputs).

Table 5.3: Base, step, and trend model output vs Gas Pipeline Business forecasts and final decision opex allowances
(real $000, 2021 Information Disclosure year-end)

Gas Pipeline Business	Base, step, and trend model output	GPB forecast opex	Final decision opex
First Gas Distribution	39,970	41,972	39,970
First Gas Transmission	201,200	198,196	198,196
GasNet Distribution	9,608	9,274	9,454
Powerco Distribution	75,562	73,405	73,585
Vector Distribution	57,923	56,337	56,271

5.45 The base, step, and trend modelling approach we have used to test supplier opex forecasts allows us an opportunity to more explicitly model:

5.45.1 the most up to date information about what a GPB may need to operate its business;

5.45.2 discrete cost step changes that are justified by each GPB; and

5.45.3 known cost drivers that affect opex trends such as network size (for GDBs), and cost inflation (all GPBs).

5.46 In our final decision analysis we relied on GPB's historical and forecast expenditure data from their most recent 2021 AMPs and DY21 information disclosures.

5.47 In our base, step and trend modelling, we have accounted for recurring and non-recurring expenditure items when calculating the base opex value, such as blended gas investigation costs, and SaaS costs and First Gas Transmission's Gas Transmission Access Code (**GTAC**) investigation costs.

5.48 We have modelled step changes in opex for First Gas Transmission and GasNet following our consideration of further information. For First Gas Transmission this step change was due to compressor fuel costs increasing and for GasNet, this step change was due to a revision of its business support opex forecast from DY23.

5.49 We considered several variables when modelling opex trends. We have scaled the base opex across the DPP3 period in real terms for estimates of network length and ICP annual growth on a real $2021 basis in each year of DPP3. The real $2021 base opex and scaled opex trend is inflated to nominal using a 60%/40% weighted all industries LCI/all-industries PPI inflator series.

5.50 MGUG disagreed with the base, step, and trend modelling approach and base year selection. It suggested that we should repeat the DPP2 approach.[125]

5.51 We have not replicated the DPP2 modelling approach in this DPP for opex. Our view is that the cost of doing so is high for a DPP and it is unlikely to provide sufficient benefit to make it worthwhile, noting that the DPP2 approach resulted in 99% of forecast industry opex being allowed.[126]

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[125] MGUG "Submission on Gas DPP3 draft decision" (14 March 2022) p. 33.

[126] Commerce Commission "Gas DPP2 Final Reasons Paper" (May 2017), p.13.

5.52 The DPP2 opex approach calculated an average historical opex projection with a 5% margin added, and GPB expenditure scrutiny only occurred if GPB forecast opex was higher than the projection. In the opex modelling approach we have taken in this DPP we have investigated and removed non-recurring opex from base opex and explicitly modelled necessary opex step changes for GPBs where this has been supported by evidence.

We have used operating expenditure data from disclosure year 2021 to set an operating expenditure base value

5.53 For our final decision opex modelling we have used GPB DY21 actual opex, with non-recurring opex removed and new recurring opex added, to set revised DY21 opex base values for each GPB. We have modelled the GasNet DY21 opex uplift based on its most recent disclosed opex.

5.54 The choice of an opex base value is important because it sets the starting point for the base, step, and trend modelling we use to estimate opex allowances over the DPP period. Ideally we want to set a base opex value that represents an efficient level of opex for each GPB and not include any costs that will be non-recurring.

5.55 During the Gas DPP3 process we considered several approaches to modelling an opex base value in the base, step, and trend modelling.[127] These options included using a multi-year average or single year of actual opex to set the base opex value. Some submitters agreed with the proposed approach using DY20 opex as base opex, while First Gas suggested that the most recent actual opex was more appropriate as a base value of opex.[128]

5.56 In the Electricity Distribution Businesses (**EDBs**) DPP3 we used actual opex from year 4 (2019) of EDB DPP2 (the most recently disclosed audited opex at the time) to set an opex base value. We reasoned that “we consider it appropriate to use 2019 actual data, as it is the most up-to-date reflection of distributors level of opex expenditure and efficiency”.[129]

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[127] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p.67 Attachment B para B34-B35.

[128] Powerco "Submission on Gas DPP3 draft decision" (14 March 2022) p.7, First Gas "DPP3 Draft Decision submission" (14 March 2022) p.1.

[129] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), p. 103.

5.57 It is less likely that opex inefficiencies exist in the opex base year for EDBs than for GPBs because of the Incremental Rolling Incentive Scheme (**IRIS**) in the EDB IMs. If EDBs were to inflate costs in the base year, they would be penalised through negative IRIS carry-forward incentive amounts and so there would be less benefit in doing so.

5.58 However, there is no IRIS mechanism in the Gas DPP IMs.[130] This means that, while we must make an assumption about what an efficient base level of opex may be, we are less confident that the last year's actual opex is efficient for GPBs than we are for EDBs. We investigated a number of approaches in setting a base opex value for this DPP.

5.59 In our draft decision we considered taking a multi-year average of actual opex to estimate base opex to smooth out over and under-forecast error. However, our analysis of GPB year-ahead opex forecasts versus opex actuals highlighted some significant differences in 2018 and 2019. It was not clear that a multi-year average would be suitable to model an efficient base opex value reflective of GPB needs, as it could lock in over or under forecast errors for GPBs over the DPP4 period.

5.60 In analysis that supported our draft decision, we noted that Disclosure Year 2020 (**DY20**) actual opex for GPBs (apart from GasNet) was very close to the DPP2 opex allowance settings, so we considered DY20 opex, inflated to real $2021, would be a reasonable base opex value to model.

5.61 Since the draft decision we analysed the effect of the most recent DY21 opex actuals. For most GPBs we found that, when non-recurrent opex costs were removed, and recurrent opex costs added, these were very close to the DY20 opex inflated to $ 2021 we used as draft decision modelled base opex.

5.62 In our draft decision we did not use DY20 data to set GasNet's base opex value because GasNet's network had a major outage in DY20. In responding to this major outage, GasNet incurred 34% higher opex than its DPP2 opex allowance. To remove the effects of this outage we used GasNet's DPP2 DY20 opex allowance to model the base value of opex.

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130 The Incremental Rolling Incentive Scheme (IRIS) mechanism provides an incentive to achieve operating cost efficiencies over a regulatory period. The scheme operates to share supplier efficiency savings with consumers.

5.63 For our final decision we have allowed GasNet's DY21 opex as modelled base opex and accept that it is higher than its DPP2 allowance setting (based on analysis carried out in 2016). We have accepted GasNet's submission that the additional costs, that have been incurred since 2016, are evidenced and likely to be efficient. These include staff costs and costs associated with its Asset Information System and a Fire Service Levy.[131]

5.64 A summary of our DY21 base opex modelling is shown in Table 5.4. This table compares the modelled base opex values from the draft decision and final decision and the percentage change between them.

Table 5.4: Draft to final modelled base operating expenditure analysis (real $000, 2021 ID year-end)

Gas Pipeline Business	Draft decision base opex	DY21 opex from GPB ID	Final decision base opex	Draft vs final % change
First Gas Distribution	8,816	9,988	9,152	3.8%
First Gas Transmission	48,386	62,112	47,233	-2.4%
GasNet Distribution	1,783	2,009	2,009	12.7%
Powerco Distribution	18,846	18,073	18,073	-4.1%
Vector Distribution	13,550	13,323	13,664	0.8%

Our approach to modelling opex step changes

5.65 We modelled the following step changes in opex:

5.65.1 First Gas Transmission compressor fuel costs;

5.65.2 GasNet non-network opex costs in DY23; and

5.65.3 an alternative gas investigation allowance for all GPBs.

First Gas and GasNet opex step changes

5.66 We sought additional information from First Gas Transmission which supported the additional compressor fuel opex and accepted that the cost increases are likely to be reasonable based on a forecast of future natural gas prices.

[131] Note that in EDB DPP3 fire service levy costs were introduced as a new recoverable cost in the EDB IMs. We have not made a Gas IM change for this but may consider this change in Gas DPP4.

5.67 In its draft decision submission GasNet sought a step change in its opex allowance to develop its internal resources. We sought additional information from GasNet and are satisfied that it has a case to increase the DY23 opex step change we had modelled to:

5.67.1 recruit additional staff;

5.67.2 pay the Fire Service Levy; and

5.67.3 improve its developing Asset Information Services.

5.68 Following our consideration of GasNet's additional information we have amended the modelled DY23 opex step change.

Blended gas investigation allowance

5.69 We have considered opex step changes related to blended gas investigation costs. In our draft decision we stated that we could not rule out 'clean' gas being a technically and economically viable alternative to natural gas.[132] However, our view was that, while natural gas that includes small quantities of biogas or hydrogen could still be considered 'natural gas', biogas or hydrogen cannot be considered 'natural gas' under the Act.

5.70 We concluded that the threshold at which a blend of hydrogen or biogas ceased to be considered natural gas could be when the gas blend required pipeline or consumer appliance conversion.

5.71 While a specific innovation allowance for conveying gases other than natural gas will not promote the Part 4 purpose, we allowed expenditure for some costs to investigate blending small proportions of other gases with natural gas and how this blending may affect GPB pipelines and consumer appliances.

5.72 In our draft decision we did not include any allowance for investigating blending although we noted some GPBs had included costs associated with the investgation of alternative gases in their AMPs. We did not have evidence from GPBs that the expenditure for such investigation could reasonably be allowed although we did not scrutinise this in depth.

[132] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 Process and Issues paper (4 August 2021), p.32, para 3.42-3.44

5.73 We considered submitter views about blended gas investigation costs. First Gas provided additional cost information about its hydrogen trial and forecast opex costs split between its transmission and distribution businesses, noting its forecast opex met our definition of the regulated service. GasNet submitted that it supported a research and development allowance but did not quantify what this should be.[133]

5.74 We reviewed the cost information provided by First Gas. We consider that the capex costs for the hydrogen trial programme cannot be approved in this DPP, as these appear to be largely for assets that are outside the scope of the regulated service.

5.75 However, we believe that some opex for the investigation of blending small proportions of other gases with natural gas meets our definition of a regulated service, and is appropriate because:

5.75.1 it provides incentives to GPBs to innovate and potentially extend the economic lives of networks, which would be a benefit to consumers of gas pipeline services; and

5.75.2 it may reduce carbon emissions whilst using natural gas and still promote the outcomes of s 52A.

5.76 In EDB DPP3, we introduced an innovation allowance for EDBs.[134] We believe that the factors we considered for this innovation allowance are similarly applicable to our consideration of a blended gas allowance in this DPP.

5.77 We consider that consumers should pay for some part of small trials of gas blends, as they would benefit if this can be done commercially - but that a modest allowance is appropriate because:

5.77.1 it will incentivise GPBs to minimise costs to ensure that customers are not exposed to the excessive financial risks associated with such investigations;

5.77.2 it will incentivise GPBs to select projects that are more likely to be successful and to benefit them financially;

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[133] First Gas “Submission on Gas DPP3 draft decision" (14 March 2022) p. 26-28, 31 GasNet "Submission on Gas DPP3 draft decision" (14 March 2022) p. 1

[134] Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision. Reasons Paper (27 November 2019), p.290 Attachment F.

5.77.3 GPBs are also able to seek contributions from other sources such as innovation and science funds in addition to their contribution;

5.77.4 GPBs may also use the funds for joint projects with other businesses or organisations, which may result in greater innovation benefits for the sector;[135] and

5.77.5 the shareholder might see the trials as a step towards a hydrogen capable network and fund this from its own capital.

5.78 Rather than model allowances for GPB investigations in isolation, we consider that the knowledge from investigations should be shared between GPBs. We considered what an appropriate industry allowance might be and decided that the First Gas Transmission and First Gas Distribution opex cost estimates for this purpose were a reasonable starting point because:

5.78.1 First Gas is the most pro-active in its blended gas investigations;

5.78.2 its hydrogen blend trial programme opex intends to include other industry participants; and

5.78.3 its ongoing opex costs includes the costs associated with the hydrogen trial blending.

5.79 We decided that appropriate gas blending allowance settings for our opex modelling were:

5.79.1 for First Gas Transmission - use 50% of its proposed opex of $400,000 per annum, reflecting the reasons set out in paragraph 5.77 and model a GTB sector annual blended gas investigation allowance of $200,000 per annum;

5.79.2 we use 50% of the First Gas Distribution proposed opex of $540,000 per annum as an annual GDB sector modelled blended gas investigation allowance envelope, reflecting the reasons set out in paragraph 5.77, and that the investigations should be shared by GDBs;

5.79.3 we model an allowance for First Gas Distribution of 50% of this GDB sector modelled allowance envelope of $270,000 p.a., given it has the most concrete investigation plans and intends to include others to participate in and contribute to the trials; and

[135] We note that industry is presently collaborating on hydrogen blending - https://www.energynews.co.nz/news/green-hydrogen/120291/firstgas-shortlists-hydrogen-pipeline-trial-sites?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

5.79.4 split the remaining modelled allowance of $135,000 p.a. equally among the three remaining GDBs.

5.80 Our final decision is that we include the following blended gas investigation opex allowances per annum in the base, step, and trend modelling - First Gas Transmission ($200,000), First Gas Distribution ($135,000), Powerco ($45,000), Vector ($45,000) and GasNet ($45,000).

5.81 The opex allowances we have set have incorporated a blended gas investigation allowance for First Gas Transmission, First Gas Distribution and Vector:

5.81.1 for First Gas Transmission and Vector, we have set opex allowances based on their AMP opex forecasts, which included costs associated with blended gas investigations; and

5.81.2 For First Gas Distribution, we have set opex allowances based on the output of our base, step and trend model, where the allowance is explicitly modelled as an opex step change.

5.82 However, for both GasNet and Powerco, the opex modelling output has set opex allowances based on GPBs opex forecasts, which do not include any blended gas investigation allowance. On this basis, we have decided to add a modelled blended gas investigation allowance of $45,000 for both GasNet and Powerco to the opex modelling output allowances.

The blended gas investigation allowance and our decision to shorten asset lives

5.83 Current evidence is that the GPB networks' physical lives exceed their useful lives and we discuss our treatment of this in Chapter 6. Although GPBs are investigating blending gas there is no certainty that this will lengthen the life of assets for supply of natural gas.

5.84 If innovation does successfully extend asset lives then it may not extend the lives of all assets to their existing physical lives, eg, it may be for a shorter period or it may relate only to some assets.

5.85 We have made an adjustment to shorten the lives of GPBs' average assets, which recognises current expectations for economic asset lives. However, it is also in consumers' interests for the assets to remain in service for as long as possible, so we are allowing a small amount of funding to provide an incentive to innovate.

5.86 This reflects the incentives we would expect in a competitive market where we would expect a firm to adjust asset lives to reflect current expectations and invest in research and development to try to extend their life. The extent to which firms in competitive markets adjust their asset lives is likely to depend in part on their expectations of successful innovation. We can mimic this outcome in DPP3 and future price paths by adjusting asset lives at each reset to reflect current expectations.

Our approach to modelling operating expenditure trends

5.87 We have used the following variables to model opex trends:

5.87.1 network scale – network length and ICP growth trends (GDBs);

5.87.2 partial productivity (GPBs); and

5.87.3 input prices – PPI and LCI costs (GPBs).

Network scale and elasticity

5.88 We have modelled the need for increased opex that reflects changes in network scale. This is modelled by scaling base opex in real terms for estimates of network length and ICP annual growth on a real $ 2021 basis in each year of DPP3.

5.89 We have allowed the GDB ICP growth and natural gas demand forecasts as the basis for our CPRG forecasts and this is reflected in our modelled opex allowances.

5.90 To forecast how increases in network length affect opex need, we have used historical trends of network length and ICP growth and the relationship between the two to predict network length increases over DPP3. We have done this because GDBs do not forecast network length increases.

5.91 The ICP growth and network length estimates are also modified by an elasticity factor that models their non-linear relationship with opex.

5.92 In the 2013 Gas DPP draft decision modelling we used overseas data from The Office of Gas and Electricity Markets (**OFGEM**) that resulted in ICP growth and network length elasticity assumption of 0.35. This was later updated to 0.4879 based on the Vector submission and Castalia analysis that supported the Vector 2013 Gas DPP draft decision submission.[136]

[136] Vector "Submission on Revised Draft Decision on Gas Initial DPP" Appendix-2 Castalia Report (7 December 2021).

5.93 In our draft decision we updated the elasticity assumption based on the OFGEM natural gas sector elasticity modelling methodology used in the 2013 Castalia report. Our update has incorporated recent Australian natural gas company opex data and the most up to date opex, consumption, ICP and network length data from the four New Zealand GDBs.

5.94 For our final decision we updated the elasticity model using the most recent DY21 disclosure data from the four New Zealand GDBs.

5.95 Our updated analysis has resulted in an elasticity factor of 0.481.

Partial productivity

5.96 In the 2013 Gas DPP decision we discussed the possible rate of change in price or revenue based on productivity improvements in the natural gas sector. This is the productivity improvement rate in the natural gas sector when compared to the economy as a whole.[137]

5.97 At the time we found no evidence to indicate that the productivity of GPBs of natural gas pipeline services improved by more or less than the rest of the economy and set a partial productivity factor of 0% in our draft decision.

5.98 In the absence of any new or updated information, our final decision is to retain a partial productivity factor of 0% for the Gas DPP3 period.

Input prices

5.99 The real $ 2021 base opex and scaled opex trend, over DPP3, is inflated to nominal opex using forecast changes in input prices over the DPP3 period. Changes in input prices affect the annual cost of providing a given level of service and are largely beyond the GPBs' control.

5.100 In our draft decision we adjusted GPB opex allowances for forecast input price changes (or inflation) using the:

5.100.1 weighted average forecast change in the 'all industries' LCI; and

5.100.2 the 'all industries' PPI.

[137] Commerce Commission "Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services" (Gas DPP1 Final Reasons paper) (28 February 2013), p. 28-29.

5.101 The NZIER provides forecasts of these indices. In our draft decision we used the same LCI/PPI weighting of 60%/40% used in Gas DPP1 and EDB DPP3 opex modelling, to calculate a single price index to inflate each GPB $ 2021 base opex, and to scale the real opex trends to nominal opex. Note that in Gas DPP2 we did not use base, step, and trend modelling.

5.102 In the absence of any new or updated information, our final decision is to retain the draft decision input price settings for the Gas DPP3 period.

6. Recognising shorter asset lives to address stranding risk

Purpose of this chapter

6.1 This chapter discusses our decision to recognise shorter asset lives for GPBs given the expected decline in demand for, and phase out of the use of, natural gas.

6.2 The chapter describes:

6.2.1 how we are addressing the changing circumstances of the natural gas sector under our DPP framework;

6.2.2 how the transition to a low-carbon economy has changed expectations of economic asset lives;

6.2.3 how our assessment of economic asset lives has been revised since our draft decision in response to submissions;

6.2.4 our final decision on asset adjustment factors to apply in DPP3 to shorten asset lives so they better reflect their remaining economic lives;

6.2.5 how these adjusted asset lives affect both DPP resets and GPB reporting under ID;

6.2.6 how the adjusted asset lives impacts prices in DPP3;

6.2.7 the residual risk that GPBs still need to manage; and

6.2.8 how further refinements may be made, including in the IM Review which has just commenced.

6.3 Additional information relevant to our final decision is provided in:

6.3.1 Attachment C: Analytical supplement – Recognising shorter asset lives to address stranding risk; and

6.3.2 Attachment D: Modelling supplement – Recognising shorter asset lives to address stranding risk.

Addressing changing circumstances under our DPP framework

Input methodologies are applied at each DPP reset to promote the long-term benefit of consumers of natural gas pipeline services

6.4 The task for us at each DPP reset is to make decisions that promote the long-term benefit of consumers of natural gas pipeline services by promoting outcomes consistent with those in workably competitive markets (s 52A of the Act).

6.5 The actions we take at DPP3 will influence economic and financial outcomes for GPBs and consumers of their services, including through:

6.5.1 incentives to promote continuing investment and operation of a reliable and safe supply of pipeline services to consumers willing to pay for natural gas;

6.5.2 limiting GPBs' ability to extract excessive profits; and

6.5.3 providing better pricing signals for consumers when using natural gas and investing in new gas-dependent appliances and infrastructure, through having allowed revenues reflect the costs of providing the regulated services.

6.6 Actions of GPBs themselves to mitigate or manage risks during DPP3 and beyond are also important and will affect outcomes.

6.7 Under our framework for DPP regulation we apply a BBM to assess current and future profitability of suppliers. The BBM is a tool for determining how the efficient costs of owning and operating long-lived assets like gas pipelines should be recovered from consumers through allowable revenues over time. Allowable revenues set for gas pipeline services will have an effect on the prices ultimately faced by consumers for delivered natural gas (see Chapter 4).

6.8 When implemented, the BBM applies the Gas IMs which specifies how relevant building blocks should be calculated. The Gas IMs have been informed, among other things, by assumptions about the long-term demand for GPB services and the economic life of pipeline assets.

6.9 The alternate approach to applying the BBM is to roll over prices for the DPP reset.[138] But our decision, and the preference of submitters, was to set starting prices based on the current and projected profitability of each GPB using the BBM and by applying the Gas IMs (see Attachment E).[139]

[138] Commerce Act, s 53P(3)(a).

[139] Commerce Act, s 53P(3)(b).

Transition to low-carbon economy has changed expectations of economic asset lives

6.10 As outlined in Chapter 3, demand for natural gas is expected to decline and the Government proposes to phase out the use of natural gas. As a result, there is a risk of whole or partial wind-down or early closure of the networks which convey natural gas.

6.11 Our current assessment is that the past assumptions about the relatively stable long-term demand for GPB services, and that physical asset lives of network assets are an acceptable proxy for economic lives, is no longer appropriate for many pipeline assets.

6.11.1 The remaining useful life of GPB assets conveying natural gas, which is the service regulated under Part 4, is likely to be shorter than the remaining physical lives of the assets due to the decline in demand and expected phase out of natural gas.

6.11.2 As gas networks wind-down, GPBs are unlikely to expect to recover all of their new or existing asset-related costs in respect of the provision of gas pipeline services under the BBM through applying the physical asset life assumptions specified under the Gas IMs. An increased risk of economic network asset stranding therefore exists for GPBs.

6.11.3 The risk of a signficant decline in demand and government phase out of natural gas was not anticipated when the Gas IMs were established or last reviewed. It is also not currently compensated for in the inputs to the BBM such as in the parameters that inform the cost of capital or through an ex ante stranding allowance.

6.11.4 If not addressed, the risk could lead to underinvestment by GPBs, and the provision of GPB services which do not satisfy consumers' demand. To the extent that the DPP3 reset provides insufficient incentives to innovate and invest, and this leads to GPB services which do not meet consumers' demands, the purpose of Part 4 will not be promoted.

6.12 While the prospect of asset-related costs not being recovered may not be imminent (ie, under-recoveries are unlikely to occur in DPP3 or DPP4), it is the *expectation* that under-recoveries may eventuate in the future (together with the challenges posed by the expectation of declining gas volumes and uncertainty over willingness or ability of consumers to pay in the interim) that signals an economic stranding event and threatens current investment incentives.

6.13 The use of long standard asset lives based on physical characteristics – which for many assets extend well beyond the time when use of the networks to convey natural gas would likely be wound-down – to set depreciation allowances for the BBM (and therefore the recovery of capital invested) acts as a disincentive to further invest. This is because some of that investment will likely remain unrecovered if the network were to wind-down sufficiently or willingness or ability of consumers to pay limits revenue recoveries.

6.14 To continue to apply our existing BBM framework and set allowable revenues in DPP3 consistent with the Part 4 purpose, we need to consider shortening the regulatory asset lives of the network to better match the period during which the network is still expected to convey natural gas.

6.14.1 The amendment we have recently made to the asset valuation Gas IM allows us to shorten average asset lives for each GPB for DPP3 by applying asset adjustment factors.

6.14.2 Going forward, through information disclosure, applying asset adjustment factors in DPP3 will allow GPBs to adjust asset lives for new and existing assets to better reflect their expected economic lives. This flows through to future DPP resets and allows recovery of asset-related costs under the BBM over a shorter, and more realistic, timeframe.[140] This mitigates economic stranding risk for GPBs.

6.15 While demand is expected to decline and the Government has signalled a phase-out of natural gas, the lack of specific information about the speed and extent of the decline in expected pipeline usage means we need to apply judgement in assessing the economic lifetimes of assets for the purposes of setting DPP3.

6.15.1 As noted below, the prospect of repurposing pipeline assets to carry zero carbon or carbon-neutral gases, or the potential for some pipeline assets to have some residual network value even if the conveyance of natural gas winds down, can affect the amount of capital (and depreciation) that is recovered through the prices for conveying natural gas.

6.15.2 We have made this decision based on the information available to us, but we may in future need to refine our assessment of economic asset lives in subsequent resets if new and materially changed information becomes available.

[140] For a description of the mechanism see Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths Reasons paper" (30 May 2022).

Submitters' views have informed our judgement for the DPP3 final decision

6.16 Our final decision follows a public consultation process in which interested persons have had the opportunity to provide feedback on our draft decision to shorten average asset lives for DPP3, increasing depreciation under the BBM and consequently raising allowable revenues for GPBs in DPP3.

6.17 As described below, our assessment of the shortening of average asset lives required for our final decision for DPP3 is less than in our draft decision as we have changed our decision in light of various factors and information put forward by submitters.[141]

6.18 We are grateful for submitters' views which canvassed many issues and offered a range of perspectives. The views provided have led to a number of changes in the assumptions underpinning our long-term modelling. In particular, submissions:

6.18.1 contended we had focused too heavily on the results from a single future scenario to inform our judgement about asset lives in the draft decision;

6.18.2 highlighted that some continuing use of pipeline networks to convey natural gas beyond the legislative net zero carbon target of 2050 is plausible and may be likely;[142]

6.18.3 suggested that there could be some residual value in the gas pipeline networks from potential repurposing to convey cleaner gases. Any such residual value should reduce the amount of capital (and depreciation) required to be recovered from consumers of natural gas; and

6.18.4 argued there could be greater capacity for future consumers to absorb depreciation recoveries in the longer-term than we had modelled for the draft decision because aggregate consumer willingness or ability to pay may not abate as quickly as we had assumed in our draft decision (and may not be approximated by a straight-line assumption).

6.19 In addition, we note that the Government's first ERP has now been published, and although a transition plan to manage the phasing out of fossil gas will be developed by the end of 2023, no target date for phase-out has yet been set.[143]

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[141] Further information relating to the points raised by submitters in the following discussion is contained in Attachment D.

[142] See, for example, New Zealand Infrastructure Commission, "Rautaki Hanganga o Aotearoa: New Zealand Infrastructure Strategy 2022 – 2052" (2022), p.56, section 6.1.1.

[143] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), p.215.

6.20 Having considered the perspectives raised by submitters, our final decision incorporates these factors into our assessment and reduces the extent to which the average regulatory asset lives for DPP3 are adjusted to reflect shorter expected economic lives, as:

6.20.1 they imply there is a longer potential period available to GPBs over which to viably recover asset-related costs than assumed in our draft decision; and/or

6.20.2 the quantum of costs to recover from consumers of regulated gas pipeline services may be less than we had assumed.

We have updated our long-term financial modelling

6.21 We updated our long-term modelling that informs our judgement for our final decision by giving weight to a wider range of assumptions and an additional future scenario. Our modelling now has regard to two primary scenarios:

6.21.1 The 2050 reference scenario used for our draft decision, with updated bulding block inputs reflecting most recent data and decisions in this paper. This scenario maintains the assumption of a straight-line declining MAR envelope to 2050 adopted in our draft decision; and

6.21.2 A 2060 wind-down scenario with a concave MAR envelope. This assumes continued use of some or all of the pipelines to supply natural gas for a decade after the 2050 net carbon zero legislative target. A moderately concave MAR is applied to reflect a greater assumption around the ability of some future consumers to absorb price increases than assumed under our straight-line profile of our 2050 reference scenario.

6.22 We consider that most weight should be accorded to the 2060 scenario, not only to acknowledge the possibility of gas use continuing past the 2050 legislative target for net carbon zero, but also to acknowledge that it could additionally be seen as a possible proxy for a wind-down scenario with residual value remaining at 2050.

6.22.1 We have accorded a one-third weighting to the 2050 wind-down scenario, and a two-thirds weighting to the 2060 wind-down scenario.

6.23 We have retained our original 2050 scenario as we still consider it plausible, but it is now not the sole modelled scenario to inform our judgement.

Our final decision is to recognise shorter average asset lives for GPBs

6.24 As discussed above, our final decision uses the IM amendment we have recently made which allows us to shorten average asset lives for DPP3 for each GPB by applying an asset adjustment factor. Applying this factor will bring regulatory asset lives for each GPB more into line with the expected economic life of the assets, rather than continue to rely on standard physical asset lives as a proxy.[144]

6.25 In this way, shortening asset lives mitigates the risk of economic network stranding because the recovery of asset-related costs by GPBs is likely to occur over a shorter timeframe which more closely aligns with how long GPB assets, on average, are expected to be used to convey natural gas to consumers willing to pay.

6.26 The mechanics of applying asset adjustment factors for DPP purposes, including the effects on ID and future DPPs, is described further in sections below.

6.27 Taking this action in DPP3:

6.27.1 Enables depreciation to be recovered over a period aligned with the length of time network assets are expected, on average, to be economically viable for conveying natural gas, and not the longer period implied by the assets' physical lives. Continuing to apply existing standard physical asset lives would be to ignore that GPBs face a declining ability to recover asset-related costs over time and that GPBs' economic circumstances differ from one another.

6.27.2 Maintains expectations of capital recovery, providing incentives for GPBs to invest to serve current and future demand.

6.27.2.1 Significant opex and capex is still required to be incurred to operate and maintain the safe and reliable supply of gas to those consumers who are still expected to demand natural gas over coming regulatory periods.

6.27.2.2 Expenditure allowances set for the four-year DPP3 include $284m of capex and $377m of opex (see Table 5.1).

6.27.2.3 GPBs estimate expenditure, in their AMPs, is required of approximately $2 billion over the coming 10 years – including capex of nearly $900m (see Table C.1).

[144] Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths Reasons paper" (30 May 2022).

6.27.3 Allows revenues to more accurately reflect all of the costs of providing the regulated services, which should flow through to more efficient consumer price signals. This should promote more efficient consumer choices including discouraging inefficient new connections.

Asset adjustment factors have been estimated for DPP3 for each Gas Pipeline Business

6.28 The final asset adjustment factors applied to average asset lifetimes of GPBs under the BBM affects the amount of depreciation, and therefore recoverable revenues, calculated for DPP3. As for our draft decision, the asset adjustment factors for each GPB have been estimated under our simplified modelling to reflect:

6.28.1 the assessment of shorter economic lives of pipeline assets than implied by the standard physical asset lives applied in the past;

6.28.2 assumptions in our long-term modelling around current and future BBM costs, including the recovery of future opex and capex, and the capacity of consumers to bear these costs over time as customer numbers and volumes of gas decline;[145] and

6.28.3 our decisions to use modelling that assumes a transitional 6-year ramp-up period (where four of the six years of increases in revenue, and approximately 50% of total additional revenues over a six year period, occur in DPP3), apply a 10% real cap per annum on price rises in aggregate in real terms in DPP3, and round annual increases in maximum allowed revenues to the nearest 0.5% per annum in real terms.

6.29 The asset adjustment factors for DPP3 implied by our two primary long-term modelling scenarios, and the blending of these to constitute the DPP3 asset adjustment factors applied by us for the purposes of clause 4.2.2(4) of the relevant amended Gas IMs for each GPB is shown in Table 6.1 (see Adjustment Factor Final).

[145] The BBM approach under the Gas IMs still requires the use of straight-line depreciation and RAB indexation.

Table 6.1: Blending of adjustment factors

Gas Pipeline Business	Revised 2050 wind-down scenario	2060 wind-down scenario	Blended result (33/67)	Adjustment Factor Final
GasNet	0.73	0.86	0.82	0.81
Powerco	0.76	0.86	0.83	0.84
Vector	0.60	0.70	0.66	0.66
First Gas Distribution	0.62	0.71	0.68	0.69
First Gas Transmission	0.68	0.78	0.75	0.75

6.30 As noted above, our final decision has also involved a judgement about how increases in DPP3 revenues under the BBM for GPBs should be smoothed to allow consumers time to adjust to higher network charges.

6.30.1 We have used modelling that assumes a transition to shorter asset lives that reflect expected economic lives over a 6-year period, and decided that a cap of 10% per annum on price rises in aggregate in real terms should apply. This is the same as our draft decision.

6.30.2 Based on current expectations, this implies further increases in allowed revenues are likely to be required in DPP4 (although we will need to make a fresh assessment for DPP4). Note that as we have shortened the regulatory period to four years so we can respond to different expectations more quickly.

6.31 The final DPP3 asset adjustment factors in Table 6.1 (see Adjustment Factor Final) applied for our final decision have been calculated to implement the above decisions on smoothing, capping and rounding.

Asset adjustment factors affect both DPP resets and Information Disclosure reporting

6.32 In this section, we explain the interrelationships between the Gas IMs, depreciation calculated under the BBM, asset lives, DPP price-setting, ID reporting and the asset adjustment factors. We explain how applying adjustment factors shorten regulatory asset lives, and the consequences for ID and future DPP resets.

6.33 The Gas IMs require that the straight-line method for calculating total regulatory depreciation allowances must be applied for both DPPs and ID. Under the straight-line method of depreciation, the amount of depreciation calculated for each year is effectively determined by remaining asset lives. For example, under ID, depreciation for each asset for a year is the result of dividing the asset's value by the remaining asset life (in years). The relevant asset lives are generally defined by reference to Schedule A of the IMs for network assets,[146] and to Generally Accepted Accounting Practice (**GAAP**) for non-network assets. The lives specified in Schedule A are standard physical asset lives. Summing the depreciation for all of the assets for a year gives the total depreciation for that GPB for that year.

6.34 We use information from ID (specifically, the total RAB and total depreciation in the base year) to determine the depreciation allowance for existing assets in the DPP for each GPB. Existing assets are those assets which are forecast to exist at the start of the DPP period. The base year determines which year's ID we use to set the DPP (DY21 in the case of DPP3).

6.35 Using this ID information, we calculate the implied remaining asset live for the existing assets. The average remaining asset life for each GPB's assets is derived from dividing its total RAB by its total amount of depreciation disclosed in the base year.

6.36 A different approach is taken in the DPP for new assets. New assets are those assets which are forecast to be commissioned during the DPP period. For new assets, the IMs prior to our recent amendment specified that they have a 45-year remaining life in their year of commissioning for DPP purposes. Taking the total cost of a new asset, and dividing it by the 45-year assumed asset life, produces the annual forecast depreciation allowance for that new asset across the DPP period (before considering the impact of revaluations).

[146] For the GTB, Gas Transmission Services Input Methodologies Determination 2021 (consolidated April 2018), p.132 Schedule A. For the GDB, Gas Distribution Service Input Methodologies 2012 (consolidated April 2018), p.138.

6.37 The sum of the forecast depreciation amounts calculated for new and existing assets for each year of the DPP period become the value of the depreciation components of the building block model for setting prices under the DPP.

6.38 Our recent amendment to the Gas IMs has introduced the ability for us to apply an asset life adjustment factor for each GPB, and we have set the asset adjustment factors shown in Table 4.4 for DPP3. An adjustment factor of less than 1 results in a reduction in average asset lives.

6.39 The asset adjustment factor alters the applicable asset lives we use to calculate forecast depreciation, and thus changes the depreciation allowance in DPP3. More specifically, we multiply the adjustment factor by:

6.39.1 the implied average useful life remaining for each GPBs assets in the base year, in respect of existing assets; and

6.39.2 the 45-year assumed life, in respect of new assets.

6.40 The following example illustrates this. Assume we have applied an adjustment factor of 0.8 to asset lives for GPB A.

6.40.1 Assume that before applying the proposed adjustment factor GPB A has a weighted average remaining asset life of 27 years for its existing assets in the base year and 25 years (27 years - 2 years) in Year 1 of DPP3.

6.40.2 After adjustment the remaining asset life is 19.6 years (27 x 0.8 - 2 years) in Year 1 of DPP3.[147]

6.40.3 To determine the depreciation allowance for new assets, the Gas IMs assume a 45-year remaining life at the time of asset commissioning for all GPBs.

6.40.4 Our proposed adjustment factor for GPB A reduces the assumed life for new assets for GPB A to 36 years (0.8 × 45 years).

6.41 Since the adjustment factors for each GPB is less than unity, the effect of multiplying the useful lives by the adjustment factor is to reduce the assumed asset lives used in the DPP. Shorter asset lives, in conjunction with straight line depreciation, increases depreciation for the new and existing assets in each year of the DPP.

[147] The asset adjustment factor applies to the base year (2021), not the first year of DPP (2023). The effect of subtracting 2 years calculates what the asset life would be in the first year of the DPP and after the asset adjustment factor has been applied.

6.42 As well as changes to the asset adjustment factors, there are other significant changes in this decision from our draft decision which affect asset lives and depreciation. In particular, we now use DY21 as our base year for the DPP3 whereas the draft decision used DY20 as the base year.

6.43 Table 6.2 shows the asset life adjustments used in this final decision compared to those in our draft decision. However, we do not think it is meaningful to directly compare these factors by themselves, as:

6.43.1 the draft decision and this decision use information from different disclosure years as the base year to calculate the remaining asset life for each GPB; and

6.43.2 there are significant changes in RAB, and total depreciation, disclosed by a number of the GPBs in DY21 compared to that reported in DY20.

Table 6.2: Adjustment factor for shortening asset lives

Gas Pipeline Business	Adjustment Factor Draft	Adjustment Factor Final
GasNet	0.64	0.81
Powerco	0.87	0.84
Vector	0.60	0.66
First Gas Distribution	0.85	0.69
First Gas Transmission	0.75	0.75

6.44 Since, as noted above, the Gas IMs require us to use the RAB and total depreciation reported in ID for the base year to estimate an implied remaining life for existing assets, changing the base year has resulted in significant changes in the implied remaining asset life (due to the different RABs and total depreciation disclosed in DY21 versus DY20). This is summarised in Table 6.3 which compares implied useful asset lives in this decision versus the draft decision before adjusting for the asset life adjustment factor.

Table 6.3: Unadjusted remaining lives in the first year of DPP3, Disclosure Year 2020 versus Disclosure Year 2021 (existing assets)

Gas Pipeline Business	DY20 data	DY21 data
GasNet	26 years	25 years
Powerco	17 years	22 years
Vector	32 years	32 years
First Gas Distribution	22 years	26 years
First Gas Transmission	21 years	23 years

6.45 It is the combination of the value of the asset life adjustment factor, the implied remaining asset life, and the RAB value disclosed by each GPB in the DY21 year which determines the depreciation allowance in the DPP. As a result, directly comparing the asset life adjustment factors used in this decision with those in the draft decision without also considering the accompanying implied remaining asset life and the value of RAB, is not meaningful. As illustrated in Tables 6.2 and Table 6.3 above, the value of the asset life adjustment factor and the implied remaining useful live have changed materially since the draft, albeit they tend to move in offsetting directions.

6.46 Table 6.4 below shows the remaining average asset lives for this decision and the draft decision. Most companies show a longer adjusted remaining life now. This is consistent with this decision taking more moderate assumptions about the extent of the shortening of the asset lives than the draft decision. Note that other variables, eg, capex, and the effect of the 10% cap discussed below, also affect the analysis of adjusted remaining lives and this is why First Gas Distribution shows a reduction in adjusted asset life from the draft decision.

Table 6.4: Adjusted remaining lives in the first year of DPP3, Disclosure Year 2020 versus Disclosure Year 2021 (existing assets)

Gas Pipeline Business	DY20 data	DY21 data
GasNet	16 years	20 years
Powerco	15 years	18 years
Vector	18 years	21 years
First Gas Distribution	18 years	17 years
First Gas Transmission	15 years	17 years

6.47 Table 6.4 shows that the adjusted remaining lives differ between GPBs. This reflects differences between the GPBs including differences in RAB values, asset ages and mixes, and the level of DY21 depreciation charges, which affect both the adjustment factor and the adjusted life. The adjusted remaining lives are shorter than the presumed remaining life of the network as they reflect averages for existing assets, when the individual assets have a wide range of remaining lives, and it does not include new assets.

6.48 The net effect of combining the asset life adjustment factor, the implied remaining asset life, and the RAB disclosed in the DY21 base year, has reduced the 2022/23 MAR by $9.7m relative to the draft decision. That is, in short, our decision to give weight to a wider range of factors when determining the asset lives has led to a lower increase in depreciation, and thus prices, than proposed in the draft decision.

Calculation of depreciation under ID

6.49 Changes have also been made to the IMs which specify the asset lives used to calculate depreciation under ID regulation. In particular, these asset lives are also shortened to match the effect of the asset adjustment factor on the forecast depreciation in DPP3.[148]

6.50 For existing assets, GPBs should reduce or extend (as the case may be) the asset lives, such that:

6.50.1 forecast depreciation in aggregate across all the disclosure years in the DPP regulatory period is equivalent to the value of forecast depreciation for existing assets across all the years as specified in the applicable DPP determination for that GPB (this latter value is from the DPP financial model); and

6.50.2 subject to equivalence of depreciation described above, the remaining average asset life for existing assets at the start of the first ID year in the regulatory period approximates the adjusted asset life for existing assets as stated in the applicable DPP determination for that GDPB (again this latter value is from the DPP financial model).

6.51 New assets enter the registry with asset lives shortened or lengthened (as the case may be) commensurately with the percentage change applied to existing assets of that class. This avoids specifying new physical assets lives, while ensuring the extent of adjustment for new assets is consistent across asset types. This is more flexible as uncertainty over the specific timing and scale of the decline in demand resolves.

[148] Commerce Commission, "Gas Distribution Services Input Methodologies Amendment Determination (No.2) 2022" (30 May 2022) subclause 2.2.8(5) and (6).

6.52 As with the DPP, this shorter assumed asset life increases the amount of depreciation reported under ID in each year of the DPP period. This is important, as this increased depreciation reduces the RAB that will be reported each year under ID and the lower RAB reported under ID in DY25 will then be used as the base year RAB to set prices in DPP4 (if we again set prices using an assessment of current and future profitability). That is, the effect of the asset adjustment factor to shorten asset lives leads to a lower starting RAB for DPP4.

Prices for gas pipeline services are expected to rise in DPP3 as a result

Shortening average asset lives to mitigate stranding risk contributes to revenue increases

6.53 Our final decision implies per annum increases in GPBs' allowable revenues, and therefore prices in aggregate, for gas pipeline services, in real terms across DPP3 (Table 6.5). The executive summary outlines the expected impact of real increases in revenues for DPP3 on consumer gas bills.

Table 6.5: Annual real revenue rises from final decision to shorten asset lives

Gas Pipeline Business	Revenue increase from shortening asset lives	Revenue increase due to other factors	Total revenue increase (Capped at 10% real and rounded to nearest 0.5%)
GasNet	2.19%	3.31%	5.50%
Powerco	2.84%	2.16%	5.00%
Vector[149]	6.18%	-3.18%	3.00%
First Gas Distribution	5.26%	4.74%	10.00%
First Gas Transmission	5.25%	3.25%	8.50%

6.54 Shortening asset lives is not the only driver of increases in allowed revenue in DPP3 for most GPBs; as outlined in Chapter 4, there are other significant contributing factors. Shortening assets lives adds approximately 2.2% - 6.2% per annum in real terms after accounting for other factors.

Acting now promotes more efficient use of gas network assets over the long-term

6.55 Acting to recognise shorter average economic lives in DPP3 promotes more efficient use of pipeline assets over time because the resulting prices are more cost-reflective for both current and future consumers.

[149] Results for Vector have been presented as equivalent annual revenue increases (rather than a one-off starting price adjustment) for ease of comparison.

6.55.1 If consumers (and potential consumers) face more cost-reflective prices, they are more likely to make more efficient decisions on how they use gas and invest in gas-dependent infrastructure over time.

6.55.2 If today's consumers of gas pipeline services pay less than cost-reflective prices that they would be willing to pay for, the likelihood that future consumers will not be supplied with services they are willing to pay for increases.

6.56 Accordingly, allowing prices to increase now likely results in greater long-term benefit of consumers overall, and over time, by ensuring that consumers are provided services that reflect their demands (s 52A(1)(b)).

There is still residual risk left for Gas Pipeline Businesses to manage

6.57 Shortening asset lives supports a reasonable expectation of recovering the cost of past and future network investments, but it does not guarantee full capital recovery for GPBs over the economic lifetime of pipeline assets.

6.57.1 DPP regulation provides for an *ex ante* expectation of recovery over the upcoming regulatory period and GPBs are exposed to forecasting risks *ex post*.

6.57.2 Rather than immediately reflecting the shorter expected asset lives in the BBM, we have used modelling that assumes a transition to expected economic lives over a 6-year period. This transition is intended to smooth revenues increases. GPBs bear the risk associated with this transition.

6.57.3 If demand drops quickly, or the Government enforces restrictions or an early phase-out of natural gas use, GPBs may be exposed to unmitigated stranding risk to the extent that the price increases required to recover their costs exceed consumers' willingness or ability to pay.

6.57.4 GPBs ultimately bear risk over time as our decision-making framework seeks to preserve an ex ante expectation of FCM only to the extent it promotes the Part 4 purpose.

6.58 While we note that all actual investment enters the ID RAB which informs future DPP resets, and is not subject to an ex post efficiency test, we consider that exposure to some residual stranding risk should encourage GPBs to make prudent investments – particularly in growth and new connections. There are also actions that GPBs can take themselves to mitigate their residual risk such as increasing capital contributions. To the extent that potential augmentation of some or all parts of the networks to carry cleaner gases (eg, facilitating blending) could extend economic asset lives then incentives for that also exist. We will continue to scrutinise GPBs' investment plans and actions.

We can further refine our approach for future regulatory periods through the IM Review

6.59 We will have the opportunity to further review the issue of economic asset lives and network stranding, and appropriate regulatory responses, in the upcoming IM Review.[150]

6.59.1 The IM Review will be able to consider any new information available, including any specific government policies or proposals developed after the Government's first ERP.

6.59.2 The IM Review can look at the more complex issues surrounding the existing treatment of RAB indexation and the use of straight-line depreciation in the gas asset valuation IM, the option of providing GPBs with additional ex ante compensation for sector specific stranding risk in the BBM, and for other solutions in the Gas IMs which we have not considered in detail as part of setting DPP3.

6.59.3 We may also have the opportunity to consider how GPBs have, or intend to, translate the shortening of *average* asset lives for DPP purposes into the shortening of lifetimes for *particular* assets in their ID RABs, as well as GPBs' own actions taken to mitigate their residual risk.

6.60 Any changes made to gas regulatory settings in the IM Review will apply to DPP resets from DPP4 onwards.

[150] Commerce Commission webpage : 2023 Input Methodologies Review

7. Our decisions on quality standards

Purpose

7.1 This chapter sets out our decisions on quality standards and outlines what we have considered in coming to these decisions for GDBs and the GTB.

Our decision

We have retained the current quality standards

7.2 Our decision is to retain the current quality standards that apply to the GPBs. These quality standards are:

7.2.1 the GTB and GDBs must respond to any emergency within 180 minutes;

7.2.2 GDBs must respond to 80% of emergencies within 60 minutes; and

7.2.3 no major interruptions for the GTB and if there was a major interruption, that the GTB must provide a detailed publicly available report.

7.3 We have not introduced new quality standards for the GTB and GDBs.

Reasons for our decision

Reliability is stable for the Gas Transmission Business and improving for Gas Distribution Businesses

Outage performance for Gas Distribution Businesses is improving

7.4 In reaching our decisions we have assessed a number of GDB reliability measures, including:

7.4.1 the total number of planned and unplanned outages that occurred, as shown in Figure 7.1;

7.4.2 the average number of planned and unplanned outages experienced across all customers, as shown in Figure 7.2; and

7.4.3 the average length of planned and unplanned outage time across all customers, as shown in Figure 7.3.

Figure 7.1: Number of planned and unplanned outages for Gas Distribution Businesses, 2014-2020 [151]

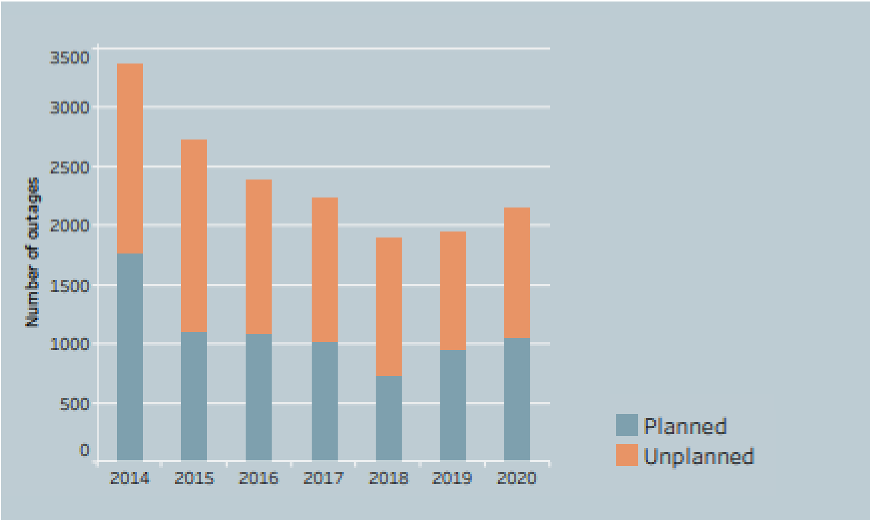
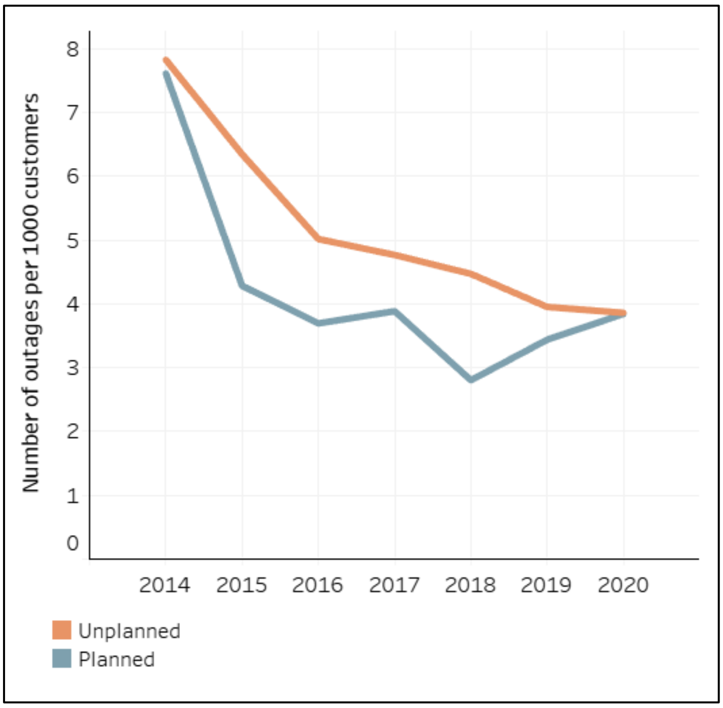


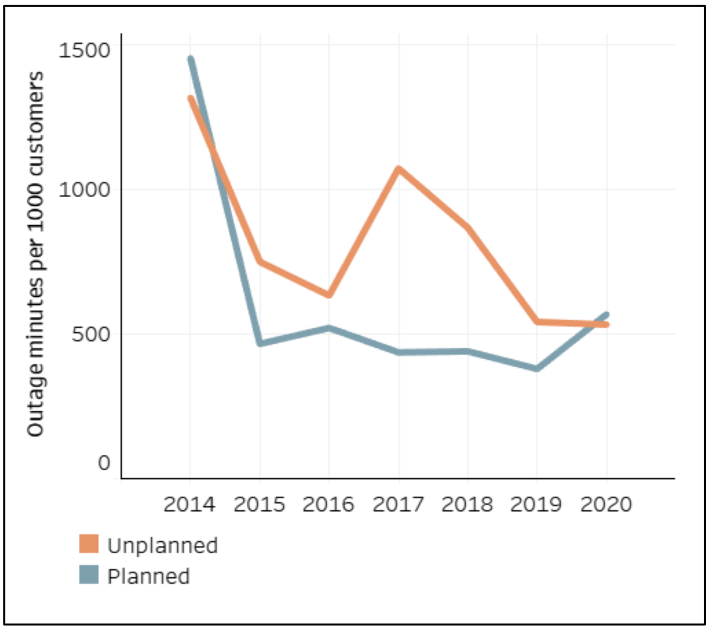
Figure 7.2: Average number of planned and unplanned outages per 1000 customers for Gas Distribution Businesses, 2014-2020[152]



151 Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021), p.49, figure 59.

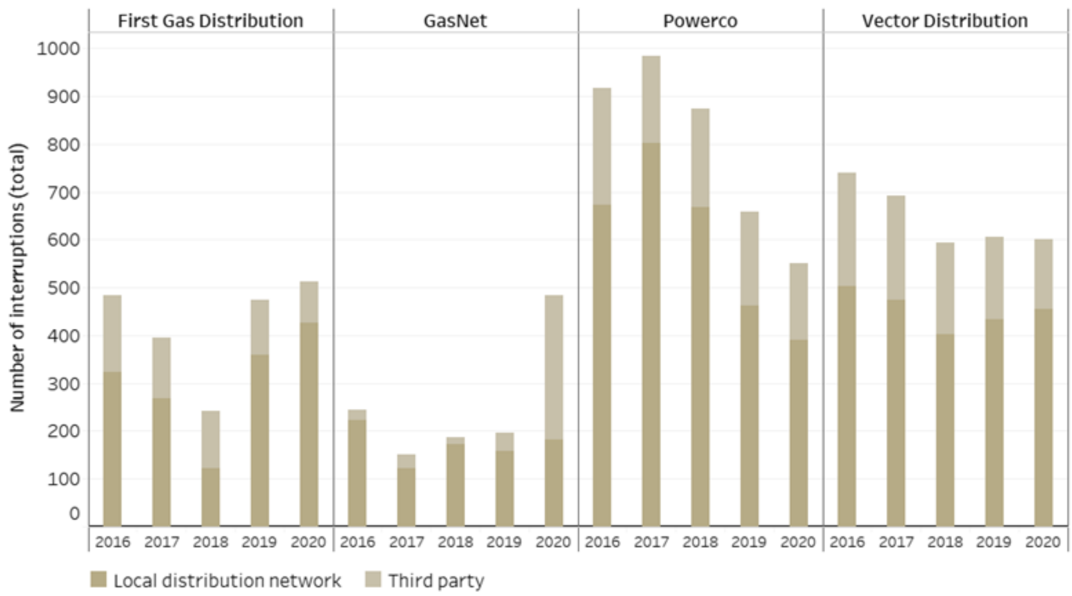
152 Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021), p.52 figure 63.

Figure 7.3: Average length of planned and unplanned outage time per 1000 customers for Gas Distribution Businesses, 2014-2020[153]



7.5 Since 2016, the total number of planned and unplanned outages as shown in Figure 7.4 and the duration of outages experienced by customers as shown in Figure 7.5 has been flat or decreasing with GasNet as an exception.

Figure 7.4: Breakdown of outages by origin for each Gas Distribution Business, 2016-2020[154]

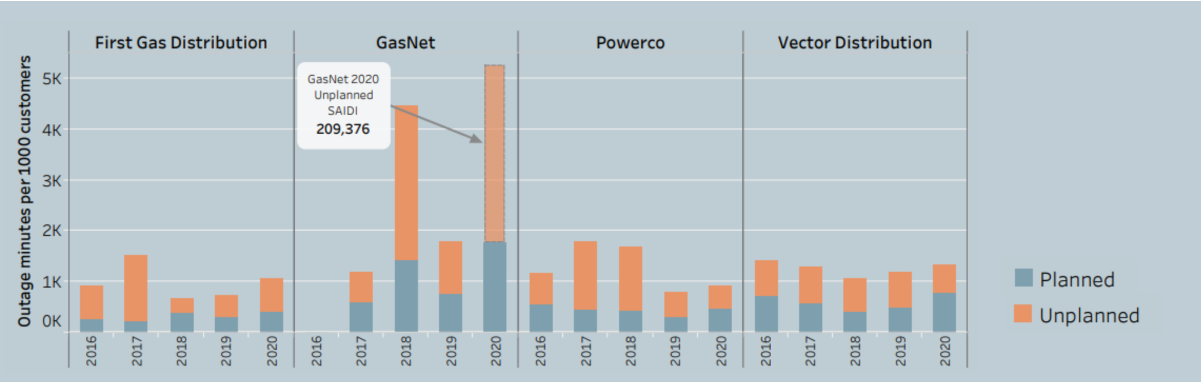


[153] Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021), p.50. figure 61

[154] Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021), p.46, figure 54

7.6 Our analysis identified that interruption results for GasNet worsened in 2018 and 2020 as shown in Figure 7.5. The higher duration of unplanned interruptions per 1000 customers on GasNet's network in 2018 and 2020 were associated with water leaks. An event in April 2018 involved water infiltration into the natural gas mains. In February 2020 approximately nine kilometres of natural gas mains and 283 gas services pipes were flooded with water.[155]

Figure 7.5: Duration of planned and unplanned outages per 1000 customers for each Gas Distribution Business, 2016-2020[156]



7.7 We do not consider that the water leak events warrant changing the quality standards for GasNet or the other GDBs at this stage.

7.8 The following metrics have also been trending downward and/or stable since 2014:[157]

7.8.1 the number of emergencies experienced on gas pipeline distribution networks;

7.8.2 the number of customer complaints associated with emergencies; and

7.8.3 network condition and integrity measures such as the number of reported natural gas escapes, self-reported leaks and third-party damage events.

155 GasNet Limited "Asset Management Plan 2021-2031 (1 July 2021)" , p. 47, Section 6.1.

156 Commerce Commission "Trends in gas pipeline business performance" (15 December 2021).

157 Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021).

Reliability performance for the GTB is stable

7.9 Interruptions to gas transmission services has been infrequent and brief between 2016 and 2020. Since the beginning of DPP2, there have been no emergencies that exceeded 180 minutes and no major interruptions on the gas transmission network. GDB outages caused by the transmission network have not occurred at all since 2014.[158]

7.10 Compressor availability and reliability to maintain transmission pipeline pressure have remained high.

There are other regulatory measures and commercial incentives for quality standards

7.11 Gas pipelines are subject to a wide range of regulations, in addition to Part 4 of the Commerce Act 1986 that we administer.

7.12 Other regulatory agencies also have responsibilities for the natural gas industry. The GIC is the natural gas industry's co-regulator, established under the Gas Act 1992.[159] It is responsible for administering governance arrangements for the downstream natural gas industry from processing through to retail.

7.13 The MBIE has a central role in governing, monitoring, and advising on the wider natural gas market, and assessing recommendations made by the GIC.

7.14 WorkSafe New Zealand is responsible for the Health and Safety in Employment (Pipelines) Regulations 1999.[160] It is also responsible for monitoring and enforcement of safety standards set out in the Gas Act (or within regulations made under the Gas Act).

7.15 GPBs are also incentivised to avoid problems related to their quality of performance because of commercial incentives like:

7.15.1 the reputational impact of quality problems;

7.15.2 the costs involved in responding to and repairing any damage; and

7.15.3 the revenue lost from undelivered services during an interruption.

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[158] Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021), p 46. Para 143.

[159] Gas Act 1992.

[160] Health and Safety in Employment (Pipelines) Regulations 1999.

Stakeholders agreed we should keep the existing quality standards

7.16 We sought views from interested parties on whether there was merit to any additional quality standards. The feedback from submitters was that no additional quality standards are necessary and they did not raise any concerns over current quality standards settings.

7.17 We did not receive any feedback from residential or commercial consumers of gas pipeline services and we do not have any direct information on whether they consider the current quality standards to be appropriate.

7.18 Submitters on our draft decision supported keeping the existing quality standards. No new evidence was raised for us to consider changing the quality standards or the creation of new quality standards.[161,162,163,164]

7.19 First Gas submitted:[165]

> We endorse the Commission's draft decision to continue with the existing quality standards for DPP3. There is no evidence to suggest a change is required here, now were changes to the quality standards raised as an issue by stakeholders submitting on the Commission's process and issues paper.

7.20 Vector submitted:[166]

> We support the Commission's decision to retain current quality standards and not to introduce any new quality standards for this DPP. We agree with the Commission current quality standards are fit for purpose.

Our analysis shows that the current quality standards are fit for purpose

7.21 The reliability measures for GPBs have not worsened over time. The total number of outages, emergencies experienced by customers, and the resulting number of complaints have decreased.

7.22 There are other regulations and incentives that ensure that GPBs maintain quality of service. GPBs have commercial incentives to maintain their quality of service.

7.23 Based on our analysis, we consider that the current quality standards are meeting regulatory requirements and do not need changes.

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[161] First Gas "DPP3 Draft Decision submission" (16 March 2022), p.3.

[162] Major Gas Users Group "DPP3 Draft Decision submission" (16 March 2022), p.5.

[163] Powerco "DPP3 Draft Decision submission" (16 March 2022), p.7.

[164] Vector "DPP3 Draft Decision submission" (16 March 2022), p.9.

[165] First Gas "DPP3 Draft Decision submission" (16 March 2022), p.3.

[166] Vector "DPP3 Draft Decision submission" (16 March 2022), p.9.

7.24 We acknowledge that there is some uncertainty on the future of natural gas in New Zealand. Despite not proposing new quality standards at this time, we recognise that in future as networks are phased out or potentially repurposed for alternative gases:

7.24.1 natural gas consumers’ preferences regarding quality may change. For example, the need for consumer engagement and consultation may be increased to understand if, when and how consumers can transition away from using natural gas;

7.24.2 GPB spending on asset replacement and maintenance may decline and this may impact on proposed and actual reliability; and

7.24.3 GPBs may need to have robust processes in place for phasing out natural gas service and/or transitioning consumers to alternative gases.

7.25 We may consider new quality standards in future DPP resets to reflect these changes.

Attachment A Forecasting operating expenditure

Purpose of this attachment

A1 The purpose of this attachment is to explain how we have set opex allowances for Gas DPP3.

A2 This attachment sets out:

A2.1 a description of our approach to setting opex allowances including our considerations of draft decision submissions;

A2.2 our analysis and conclusions from RFI responses we used to inform our opex modelling;

A2.3 a summary of the opex modelling assumptions - selection of the opex base value; step changes; and trend factors to account for changes in scale, input prices and partial productivity; and

A2.4 opex allowance settings for each GPB for each year of DPP3 (see Table A1 and Figure A1).

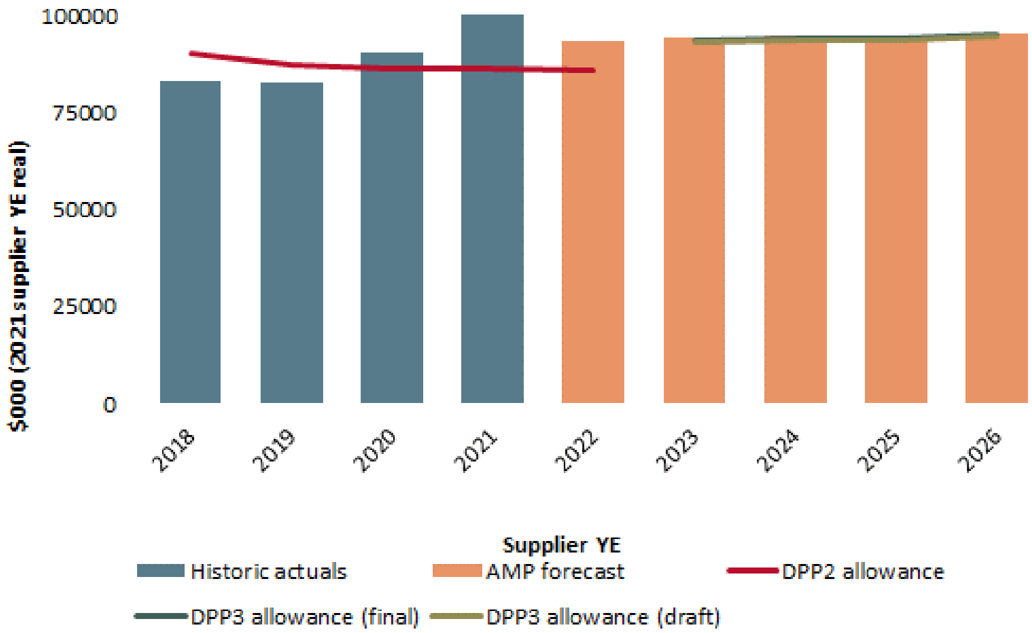
A3 We have performed all opex analysis using historical and forecast expenditure in real $ 2021 prices ($ 2021). All expenditure in this attachment is expressed in real $ 2021 prices unless stated otherwise.

Summary of operating expenditure allowances

Table A1: Gas Pipeline Business DPP3 final decision allowances for four-year DPP period (real $'000s, 2021 Information Disclosure year-end)

Gas Pipeline Business	Opex forecast	Opex allowance
GasNet	9,274	9,454
Powerco	73,405	73,585
Vector	56,337	56,271
First Gas Distribution	41,972	39,970
First Gas Transmission	198,196	198,196
Industry total	**379,184**	**377,477**

Figure A1: Industry total historical operating expenditure, GPB 2021 AMP operating expenditure forecasts and DPP final decision allowances (real $'000s, 2021 ID year-end)



Changes to our draft decision

A4 We have made the following changes to our draft decision:

A4.1 DY21 actual expenditure data is now available and included to assist us in determining the base opex value for base, step, and trend modelling;

A4.2 we have included the Software-as-a-Service (**SaaS**) costs as opex (included with capex in the draft decision) due to accounting reporting changes, and modelled ongoing SaaS costs in opex allowances;

A4.3 we have revised GasNet's non-network opex step change occurring in DY23; and

A4.4 we have allowed some blended gas investigation costs for GPBs.

Our approach to setting operating expenditure allowances

A5 A DPP is intended to be a low-cost means to set price-quality paths and we rely mostly on previously published information to set opex allowances. Our approach to setting opex allowances for DPP3 uses both the forecasts of opex included in GPBs' AMPs and historical financial performance information disclosed by the GPB under ID.

A6 Our opex allowance adopts each GPB's AMP forecasts of opex except to the extent it exceeds our forward projection of historical spending using a base, step, and approach. In short, our projection serves as a cap on the level of the GPB's opex forecasts.

The base, step, and trend modelling approach

A7 We have retained the base, step, and trend modelling approach we used in the draft decision to independently test and cap each GPB's opex forecasts.

A8 Our base, step, and trend forecast of opex modelling starts from a base value of opex which is then projected forward for known step changes in cost, with trends based on known cost drivers and input price inflators.

A9 We have used GPBs' DY21 actual opex to assist us in setting a base opex value, and following investigations, we removed non-recurring expenditures and added recurring expenditures where this was supported.

A10 The base, step, and trend model also factors step change cost adjustments to reflect additional expenditure for First Gas Transmission and GasNet, that has been sufficiently supported by evidence and that would not otherwise be captured by trend modelling.

A11 We have modelled opex trends using the following three main cost drivers of:

A11.1 network scale – the size of the network will affect operating expenditure because the volume of service provided will change;

A11.2 partial productivity – changes in operating efficiency will affect the amount of operating expenditure needed to provide a given level of service; and

A11.3 input prices – changes in input prices will affect the cost of providing a given level of service over time.

A12 This approach is consistent with our draft decision. We have retained this approach for our final decision because opex in the natural gas pipeline industry is typically recurring, ie, likely to be repeated regularly, and influenced by predictable factors.

A13 Following our base, step, and trend modelling, we have set allowances as the lesser of the model output or GPB opex forecast in each year of Gas DPP3. This ensures that the allowances we set are not higher than each GPB has forecast it needs.

A14 We performed all opex analysis using historical and forecast expenditure expressed in real $ 2021. In setting opex allowances we inflated the opex real $ 2021 forecast estimates to nominal using the most recent NZIER's all industries LCI/all-industries PPI inflator series, published on 1 March 2022, for opex with a 60%/40% weighting.

Draft Decision submissions on our base, step, and trend modelling approach

A15 We received several draft decision submissions about how we set the draft decision opex allowances, with most submitters generally supportive of the base, step and trend modelling approach.

A16 First Gas supported the overall approach to setting DPP allowances and noted that it was consistent with a 'low-cost DPP model'. First Gas also encouraged us to "consider that using the most recent data set for our GTB and GDB is sensible as it provides the best reflection of our business as usual (**BAU**) costs".[167]

A17 First Gas elaborated on the DY21 opex costs stating that: [168]

> Over DPP2, we have seen several changes to our cost base, driven by factors such as accounting rule changes (e.g., treatment of leases and software as a service costs) and our maturing approach to risk management (e.g., a new corrective maintenance process for distribution, increased monitoring of the distribution network, and leak surveys as part of our risk management of pre-1985 polyethene pipe). These changes may be muted or excluded if FY21 is not used as the base year.

A18 Powerco noted support for the base, step, and trend modelling approach and believed that its opex forecasts were 'robust'. However, Powerco made no comment about how base opex should be set.[169]

A19 Vector did not comment specifically on our application of base, step, and trend modelling, although it supported the approach in its Process and Issues paper submission. With reference to using the most recent DY21 opex as base opex, Vector noted that:[170]

> While the use of the DY21 figures will partly alleviate Vector's overall low capex acceptance rate in the draft decision, it could also result in less opex allowance due to Vector's lower opex spend in RY21.

A20 MGUG disagreed with our use of the base, step, and trend modelling approach, stating that:[171]

> Scrutinising opex forecasts disclosed from latest AMPs available as was adopted in DPP2 captures the suppliers' knowledge and understanding of risk moving forward. We consider this a more reliable starting point for the Commission even though it may be more resource intensive for the Commission.

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[167] First Gas "Submission on Gas DPP3 draft decision" (14 March 2022)" p.3, p.17.

[168] First Gas "Submission on Gas DPP3 draft decision" (14 March 2022)" p.17.

[169] Powerco "Submission on Gas DPP3 draft decision" (14 March 2022)" p.7.

[170] Vector "Submission on Gas DPP3 draft decision" (14 March 2022)" p.29 para 113.

[171] MGUG "Submission on Gas DPP3 draft decision (14 March 2022)" p.33.

A21 MGUG suggest that the base, step, and trend approach is 'being used here purely as a matter of convenience for the Commission' and that we 'should keep with the approach adopted in DPP2' concluding that it is 'difficult to understand why an approach that was accepted as better in DPP2, and could be reapplied in future DPP setting, is not fit for purpose in DPP3'.[172]

A22 Additionally, submitters made several points about aspects of opex modelling that we address below. These include:

A22.1 whether alternative fuel investigation costs should be included in expenditure allowances based on our definition of natural gas;

A22.2 how SaaS costs are now treated as opex for all GPBs;

A22.3 compressor fuel costs for First Gas Transmission; and

A22.4 a proposed opex step change for Vector.

We have retained the base, step, and trend modelling approach in our final decision

A23 In our draft decision we explained that we considered using and scrutinising GPB AMP opex forecasts to assist us to set DPP opex allowances, like the approach we took in Gas DPP2 in 2017. [173]

A24 The DPP2 opex allowance approach was based on calculating an average historical opex value (called the BAU opex) and using this to project across the GPB opex forecasts from their most recent asset management plans. A 5% margin was added to the BAU opex projections. Any forecast expenditure that was under the BAU plus 5% projection was accepted and any forecast expenditure that was over the BAU plus 5% projection was investigated further for justification.

A25 We have not replicated the DPP2 modelling approach in this DPP for opex. We consider it is unlikely to provide any more benefit than base, step, and trend modelling. Our view is that the cost of doing so is high for a DPP and is unlikely to provide sufficient benefit to make it worthwhile, noting that the DPP2 approach resulted in a 99% acceptance rate of forecast industry opex.

A26 Base, step, and trend modelling is a widely accepted opex modelling approach, is consistent with our most recent EDB DPP3 reset, and previous resets where we applied the same or similar treatment to all suppliers on a DPP with reference to historical levels of expenditure.

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[172] MGUG "DPP3 Draft Decision submission" p.36 para 121.

[173] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2017. Final Reasons Paper" (31 May 2017), p. 63-64.

A27 The base, step, and trend modelling approach also provides a tailored estimate to compare against each GPB's forecast opex by allowing us to more explicitly model:

A27.1 the most up to date information about what a GPB may need to operate its business;

A27.2 discrete cost step changes that are justified by each GPB; and

A27.3 known cost drivers that affect opex trends such as network size (for GDBs), and cost inflation (all GPBs).

Our Request for Information process

A28 In support of our draft decision we sought additional information from GPBs regarding operating expenditure items that need to be explained, accounted for in base opex calculations or modelled as opex step changes using RFIs. The information requested was in the following areas:

A28.1 Gas Transmission Access Code (**GTAC**) project opex costs - First Gas Transmission;

A28.2 Operating lease costs - all natural gas pipeline businesses;

A28.3 GPB historical and forecast expenditure for the investigation of alternative gases such as biogas, hydrogen and blends with natural gas - all natural gas pipeline businesses;

A28.4 First Gas Transmission - forecast step change in compressor fuel costs from Disclosure Year 2022 (**DY22**); and

A28.5 GasNet - forecast uplift in non-network opex between DY22 and DY23.

A29 Following draft decision submissions, we also sought further information about DY21 and ongoing SaaS costs to ensure we were correctly capturing recurring SaaS expenditure over the DPP3 period, and analysed Vector's proposal for additional leakage survey costs.

Adjustments to base opex

First Gas Transmission Gas Transmission Access Code costs

A30 In our draft decision analysis, we sought information about the GTAC project, as we were aware that the project had been discontinued. The GTAC project began in 2016 and was planned as a single access code for the transmission system intended to replace the existing Maui Pipeline Operating Code and Vector Transmission Code.

A31 First Gas Transmission has been managing and implementing the GTAC project and stated in its 2020 AMP that the project would "provide a more effective way of making pipeline capacity available, thereby reducing barriers to market entry and improving the efficiency of the gas market".[174]

A32 First Gas Transmission notified us on 19 March 2021 that it had "permanently discontinued the project".[175] First Gas further state that:

> The GTAC was conceived as a single set of transmission arrangements to replace the two existing transmission operating codes. Work on its development began in 2016, during a period of relatively plentiful gas supply and high gas demand for electricity generation. Accordingly, the design of the GTAC was heavily influenced by the perceived need to anticipate and manage capacity constraints.
>
> Since that time, both the operating and policy environments have changed. The industry has moved to a more constrained gas supply position, and there appears to be little prospect of capacity constraints eventuating. Further, it seems clear that the industry will need to keep evolving in response to policy imperatives. These factors suggest that transmission arrangements will similarly need to evolve to support the use of zero carbon fuels, for instance, or to cater for peak generation loads.
>
> In addition, the recent review of GTAC and our software vendors has uncovered a number of technical and design challenges that would add significant cost, complexity, and risk to address.

A33 First Gas Transmission has been incurring costs in its development of GTAC since 2016 and given we are using historical capex and opex data to set expenditure allowances, we asked it to provide us with those costs on a financial year basis so they could be removed from the historical dataset.

A34 In its 2021 AMP Update, First Gas Transmission confirmed that no opex costs related to GTAC had been incurred to date and that all project costs have been written off.[176]

A35 However, in its Schedule 14 Information Disclosure for the year ending 30 September 2021, First Gas Transmission confirmed that:

> Firstgas has incurred material atypical expenditure in FY2021. As outlined above, Firstgas decided not to proceed with the Gas Transmission Access Code (GTAC) implementation project due to challenges experienced with the project and changes in the external environment facing the gas sector. This decision is reflected in our financial and regulatory accounts for FY2021 through the inclusion of $12.8 million in business support OPEX

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174 First Gas Transmission 2020 Asset Management Plan Final , p. 30.

175 First Gas Limited letter to Commerce Commission, MBIE and Energy Minister - Discontinuation of GTAC (for MBIE, Energy Minister and ComCom) 19 March 2021.

176 First Gas Transmission 2021 Asset Management Plan Update , p. 34.

A36 We have removed the one-off GTAC cost of $12.8 million from the First Gas Transmission DY21 opex as it is atypical and non-recurring over the DPP3 period.

A37 We received no submissions on First Gas' treatment of GTAC project costs.

Operating lease costs

A38 In 2016, the New Zealand Accounting Standards Board adopted a new financial reporting standard – the New Zealand Equivalent to International Financial Reporting Standard 16 Leases (**NZ IFRS 16**). NZ IFRS 16 sets out the accounting principles for operating leases and requires that all operating lease costs are capitalised instead of being classed as opex. [177]

A39 Operating lease costs were classed as opex prior to 1 January 2019. If we take a multi-year average approach to calculate a base opex value in the base, step, and trend opex model, operating lease expenditure would need to be removed as this is no longer an operating cost.

A40 We sought expenditure information from all GPBs about operating lease expenditure incurred in the 2018-2020 disclosure years.

A41 GPBs responded with the following information:

A41.1 GasNet had no material operating leases under NZ IFRS 16;

A41.2 First Gas provided information on operating lease costs incurred in its transmission and distribution business in 2018 and 2019 prior to NZ IFRS 16 taking effect;

A41.3 Vector provided information on operating leases incurred in 2018 stating that "Operating lease expenses in regulatory year ended 30 June 2018 remained as opex and were not capitalised" and did not incur operating lease costs subsequent to this; and

A41.4 Powerco stated that it had adopted NZ IFRS 16 from 1 April 2017 and had not incurred any operating lease costs since then.

[177] https://www.xrb.govt.nz/accounting-standards/for-profit-entities/nz-ifrs-16/

A42 The GPB operating lease costs are summarised in Table A2.

Table A2: GPB operating lease costs
($ expressed on DY18, DY19 and DY20 year-end)

Gas Pipeline Business	DY18	DY19	DY20
First Gas Distribution	34,036	63,587	0
First Gas Transmission	184,060	313,336	0
Vector	388,703	0	0

A43 In our draft decision we decided to use a single year of opex: DY20, to set the base value of opex. No GPB has incurred opex in relation to operating lease costs since DY19, and therefore no adjustment was required.

A44 First Gas, in its draft decision submission, supported our draft decision modelling treatment of operating leases stating that it:[178]

> Endorse[s] the Commission incorporating base Opex associated with operating leases into our DPP3 allowances to ensure we are compensated for this change.

A45 We received no other submissions regarding our treatment of historical operating lease costs.

Operating expenditure step change – blended gas investigation costs

Alternative gas investigation costs – draft decision

A46 In our process and issues paper we noted that new low carbon emission ‘clean’ gas solutions (biogas and hydrogen) may replace natural gas and that there was a considerable amount of research being undertaken internationally on the potential use of hydrogen.[179]

A47 We understood that First Gas Transmission had been studying the possibility that its natural gas pipelines may be re-purposed for ‘clean’ gas use and recently published a report on the feasibility of hydrogen as a future conveyance gas.

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[178] First Gas “Submission on Gas DPP3 draft decision”, p.24.

[179] Commerce Commission “Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p.30 Chapter 3.

A48 Additionally, the Gas Infrastructure Future Working Group has been considering the future of natural gas. The Gas Infrastructure Future Working Group concluded that, while there were technical and economic issues to resolve, re-purposing natural gas pipeline infrastructure for hydrogen or biogas use was feasible.[180]

A49 We stated in our process and issues paper that we could not rule out 'clean' gas being a technically and economically viable alternative to natural gas. Our view was that, while biogas or hydrogen cannot be considered 'natural gas' under the Act, natural gas that includes small quantities of biogas or hydrogen could still be considered 'natural gas'.[181]

A50 We concluded that the threshold at which a blend of hydrogen or biogas ceased to be considered natural gas could be when the alternative gas blend required pipeline or appliance conversion.

A51 While a specific innovation allowance for conveying gases other than natural gas appears to be beyond the scope of Part 4, we could potentially allow expenditure for investigating gas blending and how this may affect GPBs' pipelines and consumers' appliances.

A52 During the analysis phase of our draft decision we sought additional information from GPBs on alternative gas costs incurred to date and forecast to be incurred.

A53 First Gas confirmed it had incurred approximately $0.5 million of opex in its net zero-carbon trial programme in DY20 and $0.2 million in DY21. First Gas also confirmed that it intended to incur capex of approximately $3 million in DY22 to carry out a Net-Zero Carbon trial. First Gas stated that it would "expect to share these costs with partners who partake in the trial".

A54 In response to our questions, First Gas noted that it planned for ongoing alternative gas investigation opex in both its transmission and distribution businesses from DY23 stating:

> We have allocated $400,000 per annum for our gas transmission business and $540,000 per annum for our gas distribution business. Our 2021 AMP Updates also outlines the introduction of a General Manager Future Fuels to our Executive team, to drive this work.

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180 The Gas Infrastructure Working Group report – NZ Gas Infrastructure Future Findings Report (13 August 2021).

181 Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p. 32 Chapter 3.

A55 The First Gas Transmission 2021 AMP Update, describes the Future Fuels trials expenditure as:

> In order to take the first steps towards replacing natural gas with hydrogen by utilising the existing gas transmission and distribution assets. It must be demonstrated that there are no adverse effects to gas consumers or gas transportation assets. This allocation is included in the forecast to support these trials[182].

A56 Powerco confirmed that it had incurred approximately $0.2 million opex to date to developing consumer information and scenario modelling to inform the economic and regulatory implications of a transition. This amount had been incurred since 2018. It did not forecast any opex for the future investigation of alternative gases.

A57 Vector stated that, to date, it had not incurred any capex or opex for the investigation of alternative gases, but that it had forecast to spend opex of about $0.6 million per annum from DY23 for this purpose. Vector referred to its 2021 AMP Update where it stated it was "participating in an industry-wide group that is evaluating the feasibility of undertaking a hydrogen trial programme" and that:[183]

> The initial stages of the programme are scheduled to be completed in RY22 and will focus on undertaking consumer equipment assessments and network material assessments to develop a comprehensive understanding of how network materials and equipment connected to the network will be impacted by the introduction of hydrogen/hydrogen blends.

A58 In our draft decision, we did not specifically include an opex allowance for the investigation of alternative gases because we considered there was insufficient evidence provided by GPBs that all, or part of, the proposed expenditure met the Part 4 purpose.

A59 While First Gas and Vector suggested that the expenditure was necessary to investigate natural gas blending, we considered they provided insufficient detail about the expenditure programmes and how the amounts were arrived at.

A60 Consequently, our draft decision was to not model a specific opex step change allowance for alternative gas investigation costs and to remove historical expenditure from the analysis for the purpose of estimating our base opex calculations. We noted in our draft decision that GPBs could still carry out alternative gas investigations, but that costs associated with these investigations would need to be funded by shareholders.

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[182] First Gas "Gas Transmission Business Asset Management Plan Update" (September 2021), p.50.

[183] Vector "Gas Distribution Asset Management Plan Update – 2021-2031" (2021), p. 26 section 6.10.6.

A61 Our draft decision concluded we were open to including additional expenditure for the investigation of the conveyance of blends that would qualify as natural gas, if GPBs provide sufficient evidence of the amount of expenditure that was reasonably required for this purpose.

Alternative gas investigation costs – draft decision submissions

A62 We received several submissions on alternative gas costs and who should meet those costs. Fonterra's view was that "GPB's shareholders should cover the cost for projects to investigate ways to repurpose and decarbonise the existing gas pipelines."[184]

A63 MGUG linked the question of funding for alternative gas investigations to gas pipeline repurposing noting that "pipeline repurposing options are under active consideration by GPBs (including First Gas receiving funding from the government for funding hydrogen trials)".[185]

A64 In its draft decision submission First Gas provided additional reasoning for the inclusion of expenditure for the investigation of alternative gases, stating that it is seeking to ensure that it has "appropriate incentives to explore future fuels and preserve the option of using existing gas infrastructure in a net-zero economy".[186]

A65 While First Gas agreed that the "regulated service should include blends of alternative gases that do not materially change user requirements" it stated that its Future Fuels work programme meets this definition.

A66 First Gas also provided additional cost information about its hydrogen trial and proposed ongoing opex costs split between its transmission and distribution businesses.[187]

A67 GasNet stated it supported a research and development allowance but did not qualify the amount.[188]

Alternative gas investigation costs – analysis and final decision

A68 We reviewed the cost information provided by First Gas. We consider that the capex costs for the hydrogen trial programme cannot be approved in this DPP, as these appear to be largely for assets that are outside the scope of the regulated service.

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[184] Fonterra "Submission on Gas DPP3 draft decision - IM Amendments" (24 February 2022), p.3 para 16.

[185] MGUG "Submission on Gas DPP3 draft decision" (14 March) , p.4 para X12.

[186] First "Submission on Gas DPP3 draft decision" (14 March) , p. 26.

[187] First Gas "Submission on Gas DPP3 draft decision" (16 March 2022), p. 26-28, 31

[188] GasNet "Submission on Gas DPP3 draft decision" (16 March 2022), p. 1.

A69 However, we believe that we should approve some opex for the investigation of gas blends in gas networks, that meets our definition of a regulated service, and that this is appropriate because:

A69.1 it provides incentives to GPBs to innovate to extend the economic lives of networks, which would be a benefit to consumers of natural gas; and

A69.2 it may reduce carbon emissions whilst using natural gas and still promote the outcomes of s 52A.

A70 In EDB DPP3, we introduced an innovation allowance for EDBs.[189] We believe that the factors we considered for this innovation allowance are similarly applicable to our consideration of a blended gas allowance in this DPP.

A71 We consider that consumers should pay for some part of small trials of gas blends, as they would benefit if this can be done commercially - but that a modest allowance is appropriate because:

A71.1 it will incentivise GPBs to minimise costs to ensure that customers are not exposed to the full financial risks associated with such investigations;

A71.2 it will incentivise GPBs to select projects that are more likely to be successful and benefit them financially;

A71.3 GPBs are also able to seek contributions from other sources such as innovation and science funds in addition to their contribution;

A71.4 GPBs may also use the funds for joint projects with other businesses or organisations, which may result in greater innovation benefits for the sector; and

A71.5 the shareholder might see the trials as a step towards a hydrogen capable network and fund this from its own capital.

A72 Rather than model allowances for GPB investigations in isolation, we consider that the knowledge from investigations should be shared between GPBs. We considered what an appropriate industry allowance might be and decided that the First Gas Transmission and First Gas Distribution opex cost estimates for this purpose were a reasonable starting point because:

A72.1 First Gas is the most pro-active in its alternative gas investigations;

[189] Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2020. Final decision. Reasons paper (27 November 2019)., p.290, Attachment F.

A72.2 its hydrogen blend trial programme opex intends to include other industry participants; and

A72.3 its ongoing opex costs includes the costs associated with the hydrogen trial blending.

A73 We decided that that appropriate gas blending allowance settings for our opex modelling were:

A73.1 for First Gas Transmission - use 50% of the proposed opex of $400,000 per annum, reflecting the reasons set out in paragraph A72, and model a GTB sector annual blended gas investigation allowance of $200,000 per annum;

A73.2 we include 50% of the First Gas Distribution proposed opex of $540,000 per annum as an annual GDB sector modelled blended gas investigation allowance envelope, reflecting the reasons set out in paragraph A70, and that the investigations should be shared by GDBs;

A73.3 we model an allowance for First Gas Distribution of 50% of this GDB sector modelled allowance envelope of $270,000 p.a., given it has the most concrete investigation plans and intends to include others to participate in and contribute to the trials; and split the remaining modelled allowance of $135,000 p.a. equally among the three remaining GDBs.

A74 Our final decision is that we set the following blended gas investigation opex allowances per annum in the base, step, and trend modelling: First Gas Transmission ($200,000), First Gas Distribution ($135,000), Powerco ($45,000), Vector ($45,000) and GasNet ($45,000).

A75 The opex allowances we have set following base, step, and trend modelling have incorporated a blended gas investigation allowance for First Gas Transmission, First Gas Distribution and Vector:

A75.1 for First Gas Transmission and Vector, we have set opex allowances based on their AMP opex forecasts, which have costs associated with blended gas investigations embedded; and

A75.2 for First Gas Distribution, we have set opex allowances based on the output of our base, step and trend model, where the allowance is explicitly modelled as an opex step change.

A76 However, for both GasNet and Powerco, the base, step, and trend opex modelling output has set opex allowances based on supplier opex forecasts, which do not include any blended gas investigation allowance. On this basis, we have decided to add a modelled blended gas investigation allowance of $45,000 for both GasNet and Powerco to the opex modelling output allowances.

Opex step change - First Gas Transmission compressor fuel costs

A77 In its 2021 AMP, First Gas Transmission forecast an increase in opex of approximately 10% between DY21 and DY22 which is sustained across the DPP3 period and beyond.[190]

A78 First Gas Transmission states that this is due to an increase in compressor fuel costs which "represents a 11.7% increase in costs over the planning period and is due to tightening market conditions for gas and growing the use of renewable gas (biomethane and hydrogen) over time".[191]

A79 To support our draft decision analysis, we asked First Gas Transmission to provide us with more detailed compressor fuel cost increase information so that we could test whether the increase in costs was appropriate.

A80 First Gas Transmission responded with an explanation for the compressor fuel cost increases stating that "our 2021 AMP forecast assumes a gas price of $19 / GJ in 2022 (carbon inclusive) and further escalation of 11.5% by 2028" and that "prices on the gas market were relatively steady from 2015 through 2017 but have tripled from 2017 to 2021".[192]

A81 The forecast compressor annual costs are summarised in Table A3**.**

Table A3: First Gas Transmission compressor fuel annual cost (real $000s, 2021 ID year-end)

	DY22	DY23	DY24	DY25	DY26	DY27
Compressor fuel cost increase	2,592	2,592	2,792	2,792	3,292	3,292

A82 In our draft decision we considered that the First Gas Transmission information aligned with the gas market prices increases discussed in the latest gas industry supply/demand report produced by Concept for the GIC.[193]

[190] First Gas Transmission 2021 Asset Management Plan Update, p. 46.

[191] First Gas Transmission 2021 Asset Management Plan Update, p. 46.

[192] RFI response to FG-05 First Gas RFI 6 Oct 2021 provided to Commerce Commission on 12 Oct 2021.

[193] Concept Consulting Ltd. "Gas demand and supply projections – 2021 to 2035" (May 2021).

A83 However, while we modelled these compressor fuel step changes in our draft decision, we were not convinced about First Gas Transmission's prediction that these gas prices would be sustained over the DPP3 period. Concept had predicted supply restrictions might continue into 2022 but that:[194]

A83.1 these restrictions may ease in 2023-2024; and

A83.2 there is likely to be around 35-40 PJ per year additional gas availability from 2024 due to renewable power projects coming online and planned work at existing gas fields to increase productivity.

A84 In our draft decision we sought industry views on whether the increases would be sustained beyond Disclosure Year 2024 (**DY24**), and that the additional step change in price from Disclosure Year 2026 (**DY26**), were reasonable assumptions.

A85 In draft decision submissions First Gas reiterated its forecast compressor fuel cost increases and stated that these "forecasts for compressor fuel have been informed by gas market trades" and that "our forecast compressor fuel costs remain valid".[195]

A86 MGUG supported the proposed opex step change for First Gas Transmission's compressor fuel costs because this was based on AMP scrutiny.[196]

A87 After considering submissions, our final decision is to accept and model the First Gas Transmission forecast step change in opex due to compressor fuel cost increases.

Operating expenditure step change – GasNet non-network operating expenditure

A88 In its 2021 AMP, GasNet forecast a step change in non-network opex of $0.8 million between DY22 and DY23. This step change was sustained across the DPP3 regulatory period and beyond.[197]

[194] Concept Consulting Ltd. "Gas demand and supply projections – 2021 to 2035" (May 2021).

[195] First "Submission on Gas DPP3 draft decision", p. 20-21.

[196] Major Gas Users Group (MGUG) "Submission on Gas DPP3 draft decision" (16 March 2022), p.34.

[197] GasNet 2021 Asset Management Plan, p.59.

A89 After we sought further information about this step change, GasNet informed us that:

A89.1 its 2021 AMP Update material was incorrect;

A89.2 that the required non-network opex uplift was $0.3 million, not $0.8 million; and

A89.3 that the $0.3 million was needed to recruit two additional engineering staff and improve its Asset Information Services.[198]

A90 We reviewed the additional material provided by GasNet and considered that the need for additional resource had been reasonably explained. In our draft decision we modelled an opex step change of $0.3 million from DY23.

A91 MGUG supported the modelling of this step change because it was based on AMP information which had been subject to scrutiny.[199]

A92 GasNet stated that we should "consider an opex margin adjustment (or perhaps a specific opex reopener) to mitigate risk associated with the opex allowance limited to historical cost." Additionally, GasNet noted that it was "working to develop its internal resources to best enable it to operate with added operational costs only coming through in ID 2021 and forecast ID 2022".[200]

A93 We sought further information from GasNet about its submission, and to test whether any of the DY23 step change allowance for additional staff had been brought forward in DY21.[201]

A94 GasNet confirmed that its disclosed DY21 opex did not contain expenditure that we had modelled for additional staff, as a step change in DY23.

A95 However, GasNet indicated that the quantum of the modelled step change was now insufficient. GasNet stated that the original step change amount of $0.3 million ($ 2021) was now out of date because it was based on information from the 2021-2031 AMP that was finalised prior to 30 June 2021, and that it was a forecast based on known facts at that time.

198 GasNet email to Commerce Commission 11 November 2021.

199 Major Gas Users Group (MGUG) "DPP3 Draft Decision submission" (16 March 2022),p.34.

200 GasNet "DPP3 Draft Decision submission (16 March 2022), p.20-21.

201 Email from GasNet to Commerce Commission 20 April 2022.

A96 GasNet proposed a revised DY23 step change assumption:

A96.1 there is an annual Fire Service Levy of $31,000, $24,000 of which was incurred in DY21 – which requires a step change of $7,000 to be modelled from DY23 (all amounts real $ 2021);

A96.2 Asset Information System (**AIS**) and communications expenditure to assist with scheduled maintenance and ensure GasNet has stand-alone call management system – which requires a step change of $38,000.

A96.3 Recruitment budget increases for engineer and technician roles, AIS support and financial administration – which requires a step change of $328,000.

A97 In total GasNet suggests that that the DY23 opex step change should be amended to $373,000 in the final decision. Following our investigation of GasNet's DY21 opex disclosure data, and the additional information it provided we have agreed to include the DY23 opex step change of $373,000 for the final decision opex modelling.

Operating expenditure step change – Vector leakage survey costs

A98 In its draft decision submission Vector stated it is seeking additional expenditure to address gas leaks and save on carbon emissions. Vector proposes to "update its approach to surveying the network for gas leaks by moving from two yearly surveys to quarterly surveys", seeking additional opex of $320,000 per annum and a one-off capex investment of $600,000, in order to save it an estimated 1380 tonnes of CO_2 equivalent.[202]

A99 GPBs are required by the Gas Act to maintain and operate networks in accordance with the Gas (Safety and Measurement) Regulations 2010 which includes requirements for safety inspections.[203]

A100 Our view is it is appropriate for consumers to bear the costs of reasonable steps to prevent gas escaping from the pipelines given they are the final consumers of the service and will pay for unaccounted for gas.

A101 GPBs operate in a particular context and environment, and it is reasonable for them to have regard to that evolving context when running their businesses. Part of this context could be taking additional steps to reduce carbon emissions in light of climate change and the Government's target of net-zero carbon emissions by 2050.

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[202] Vector DPP3 Draft Decision public submission p.30, para 125-127.

[203] Gas (Safety and Measurement) Regulations 2010.

A102 Vector's proposed change to its gas leakage surveying practices is significant and involves significant additional expenditure. Our view is that:

A102.1 Vector has not properly justified the additional expenditure by explaining either the need for quarterly surveys or the benefits (cost, efficiency, reduction in CO_2 emissions costs) in preventing the gas escaping; and

A102.2 has not explained how this would be efficient and cost effective - there is no explanation why quarterly surveys are required, for example would annual surveys achieve most of the benefits (cost, efficiency, reduction in carbon dioxide - CO_2).

A103 Vector also did not provide information about how opex and capex costs were arrived at.

A104 We have decided not to approve this additional capex and opex in the final decision Vector provided insufficient evidence as to how costs were arrived at and what additional benefits accrued to consumers above present leakage survey practices.

The components of our base, step, and trend modelling approach

A105 The remainder of this attachment discusses individual components of the base, step, and trend model, specifically:

A105.1 base level of opex;

A105.2 opex trend factors due to network scale and partial productivity; and

A105.3 input price effects.

Modelling base operating expenditure

Base operating expenditure – our draft decision

A106 The choice of a base level of opex is important because it sets the starting point for our calculation of allowances over the DPP period. Ideally, we need to set a base level of opex that represents an efficient level of opex for each GPB.

A107 We considered a range of options to model the base level of opex, namely:

A107.1 the most recent opex expenditure incurred by each GPB. For the draft decision this was DY20 opex actuals for all GPBs and for the final decision this would be DY21 opex;

A107.2 a multi-year opex average which would smooth historical over and under-spend effects (eg, DY19 to DY21);

A107.3 use the lowest level of historical opex between DY19 and DY21; or

A107.4 use the opex allowance from the final year of DPP2 inflated to the first year of DPP3.

A108 In the 2013 Gas DPP1 reset we used the most recent historical opex for each GPB as the base opex. At the time we considered that using the most up to date opex was appropriate and we had limited reliable historical ID data to calculate a historical average value.

A109 In Gas DPP2 in 2017 we took a different approach to modelling opex, developing metrics to test forecast expenditure, and scrutinising AMP explanatory material or GPB responses to our questions.[204]

A110 In the EDB DPP3 reset we implemented a base, step, and trend opex modelling approach, using actual opex from year four (2019) of EDB DPP2 (the most recently disclosed audited opex at the time) to set an opex base value. We reasoned that "we consider it appropriate to use 2019 actual data, as it is the most up-to-date reflection of distributors level of opex expenditure and efficiency".[205]

A111 Opex inefficiencies are less likely to exist in the opex base year for EDBs because of the IRIS in the EDB IMs. The IRIS mechanism disincentivises EDBs from inflating opex costs and means that, in EDB DPP3, using the 2019 opex actual costs in the base, step, and trend modelling likely reflected an efficient base year for EDBs.

A112 If EDBs were to inflate costs in the base year, they would be penalised through negative IRIS carry-forward incentive amounts and so there would be less benefit in doing so.

A113 There is no IRIS mechanism in the Gas DPP IMs.[206] This means that we must make an assumption about what an efficient base level of opex may be for GPBs.

A114 In our draft decision we considered taking a multi-year average of actual opex to model base opex. However, our analysis of GPB year-ahead opex forecasts versus opex actuals highlighted some significant differences in 2018 and 2019 that may have locked in over or under-forecast error.

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[204] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2017 – Final reasons paper" (31 May 2017) , p. 28-33.

[205] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), p. 103.

[206] The Incremental Rolling Incentive Scheme (IRIS) mechanism provides an incentive to achieve operating cost efficiencies over a regulatory period. The scheme operates to share supplier efficiency savings with consumers.

A115 In analysis that supported our draft decision we noted that DY20 actual opex for GPBs (apart from GasNet) was very close to the DPP2 opex allowance settings. We considered that DY20 actual opex would be a reasonable starting point to setting a base opex to use in the draft decision opex modelling.

A116 We also stated that we would have GPB DY21 opex actuals available for the final decision and would use this to inform what base opex value we use in final decision opex modelling.

Base operating expenditure – draft decision submissions

A117 We received several draft decision submissions about the base opex value we should use in our final decision analysis.

A118 In its submission First Gas supported using DY21 opex as base opex, noting that recent cost changes in its business had impacted opex need in the future, and that its actual DY21 opex had captured those changes:[207]

> Over DPP2, we have seen several changes to our cost base, driven by factors such as accounting rule changes (e.g., treatment of leases and software as a service costs) and our maturing approach to risk management (e.g., a new corrective maintenance process for distribution, increased monitoring of the distribution network, and leak surveys as part of our risk management of pre-1985 polyethene pipe). These changes may be muted or excluded if FY21 is not used as the base year.
>
> FY2021 is also the first year that Firstgas has included the Term Credit Spread Differential (TCSD) allowance for both our transmission and distribution businesses in our IDs. Firstgas issued long-term debt during the last regulatory period, and regulatory allowances for DPP3 should provide for these additional efficient debt costs.

A119 Neither GasNet or Powerco submitted on what base opex we should use although Powerco supported the base, step, and trend method.

A120 Vector did not disagree with the use of DY21 actual opex as base opex but noted that "the use of the DY21 figures will partly alleviate Vector's overall low capex acceptance rate in the draft decision, it could also result in less opex allowance due to Vector's lower opex spend in RY21".[208]

A121 We tested Vector's DY21 actual opex, and whether it may prove to be disadvantageous as base opex in the base, step and trend modelling. In our draft decision we used Vector's DY20 actual opex inflated to $2021, of $13,550,000 as base opex.[209]

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[207] First Gas "DPP3 Draft Decision submission" (16 March 2022), p.17.

[208] Vector "DPP3 Draft Decision submission" (16 March 2022), p.29, para 113.

[209] Vector "Gas Distribution Asset Management Plan Update 2021-2031", Schedule 11b.

A122 While Vector's DY21 opex actual opex amount of $13,323,000 is lower than the draft decision base opex, the final opex modelling has resulted in Vector opex allowances being set at forecast levels.

Base opex – Software as a Service costs

A123 During FY21, accounting reporting changes mean that SaaS costs must now be treated and reported as opex. These SaaS costs were formerly treated as non-network capex.

A124 The SaaS accounting reporting change is driven by IFRS. In New Zealand we adopt the equivalents to IFRS, in this case NZ IFRS. The NZ IFRS frameworks are adopted by all domestic public companies. The standards constitute generally accepted accounting practice (**GAAP**) in New Zealand and is recognised as such by the current Gas IMs.

A125 In draft decision submissions both Vector and First Gas stated that the accounting changes would impact its opex need over the DPP3 period.

A126 Vector noted this change but did not quantify the impact stating:[210]

> Recently the IFRS Interpretations Committee (IFRIC) published two agenda decisions clarifying how arrangements in respect of a specific part of cloud technology, Software-as-a-Service (SaaS), should be accounted for. IFRIC's decisions could result in expenditure previously treated as capital expenditure being treated as operating expenditure in the future. We recommend the Commission takes these recent IFRIC decisions into account when setting future expenditure allowances.

A127 First Gas quantified the DY21 opex impact stating that "our opex has increased by $3.5 million for our GTB and $0.7 million for our GDB in FY2021. While these costs may fluctuate, we expect SaaS costs to be no less than those incurred in FY2021 for the DPP3 period".[211]

A128 We sought additional information from GPBs about SaaS costs they had incurred in DY21 and what those costs were likely to be ongoing across DPP3. We also requested that they supply us with revised non-network capex forecasts given SaaS costs were formerly accounted for as non-network capex.

A129 Powerco informed us that it was going to make a SaaS cost capex to opex adjustment in DY22, and that this adjustment was not ongoing. As DY22 for Powerco (1 October 2021 to 30 September 2022) is outside of the DPP3 period (1 October 2022 to 30 September 2026), this adjustment does not affect how we set Powerco's DPP3 allowances.

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[210] Vector "Submission on Gas DPP3 draft decision" (16 March 2022) p.30, para 124.

[211] First Gas "Submission on Gas DPP3 draft decision" (16 March 2022), p. 19.

A130 Vector informed us that:

A130.1 SaaS opex costs of $68,584 were incurred in DY21 and this is included in Vector's DY21 disclosed opex total of $13,323,000;

A130.2 SaaS non-network capex of $47,000 should be removed from the non-network capex forecast in DY21; and

A130.3 ongoing SaaS costs of $410,000 should be considered ongoing annual opex costs from DY22, fully offset by a reduction of non-network capex by the same amount in each year.

A131 In our final decision opex modelling we revised Vector's DY21 actual opex to reflect these SaaS opex changes and revised Vector's non-network capex forecast downwards from its 2021 AMP, by $410,000 from DY22.

A132 First Gas provided us with a revised non-network capex forecast which appeared to be inconsistent with its draft decision statements that DY21 disclosed SaaS opex costs of $3.5 million for its transmission business, and $0.7 million for its distribution business were ongoing across the DPP3 period.

A133 Following investigation of this difference, First Gas revised its view of ongoing DPP3 SaaS opex costs to $1.88 million per annum for its transmission business, and $164,000 per annum for its distribution business.

A134 For our final decision opex modelling we revised First Gas Transmission and First Gas Distribution DY21 base opex to reflect these SaaS opex changes. We also accepted the revised non-network capex forecasts for both businesses.

Base operating expenditure – First Gas Distribution operating expenditure increase

A135 For our final decision, we have retained our decision to not explicitly model First Gas Distribution's opex step changes noted in its 2020 AMP. However, we do note that First Gas Distribution has been incurring, on average, approximately 15% more opex per annum than its DPP2 opex allowance settings.

A136 We tested First Gas Distribution DY21 opex actuals against our draft decision base opex setting of $8,816,000 and note that, once recurring and non-recurring costs (such as SaaS costs) are accounted for the DY21 opex of $9,988,000 is consistent with our draft decision base opex setting.

A137 In our draft decision analysis, we observed an expenditure step change in First Gas Distribution's forecast opex between DY20 and DY21. We asked First Gas Distribution to explain this expenditure increase and whether the increase was expected to be sustained beyond DY21.[212]

A138 First Gas explained that most of the expenditure uplift was for non-network opex giving a variety of reasons such as communications and insurance costs, and for new connections marketing and research and development. First Gas also stated that some of these costs were not ongoing.

A139 We did not investigate this issue further and concluded that the opex uplift had only been described at a very high level, with little supporting explanatory material to justify the projects or programmes, nor a reasonable description of the need.

A140 In our draft decision, we did not model this proposed opex step change in our base, step, and trend modelling and instead used DY20 actual opex to set the base opex in the base, step, and trend modelling. We received no submissions on this decision.

Base operating expenditure – our final decision

A141 We analysed the effect of the most recent DY21 opex actuals. For most GPBs we found that, when non-recurrent opex costs were removed, and recurrent opex costs added, these were very closely aligned to the DY20 opex we used in the draft decision opex modelling.

A142 For our final decision opex modelling we have used GPB DY21 actual opex, with the recurring and non-recurring opex issues addressed, to set revised DY21 opex base values for each GPB. We modelled the GasNet opex uplift based on its most recent disclosed opex and following our analysis of its revised DY23 opex step change information.

A143 In our draft decision we did not use DY20 data to set GasNet's base opex value because GasNet's network had a major outage in DY20. In responding to this major outage, GasNet incurred 34% higher opex than its DPP2 opex allowance. To remove the effects of this outage we used GasNet's DPP2 DY20 opex allowance to set the base value of opex in our draft decision.

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[212] First Gas "Gas Distribution Asset Management Plan 2020", p 42.

A144 For our final decision modelling, we have accepted GasNet's DY21 opex as base opex. This is higher than its DPP2 allowance setting (as discussed above), which was based on analysis carried out in 2016. We have accepted GasNet's view that additional costs have been incurred such as staffing needs and retention costs, insurance costs, investing in an Asset Information System and Fire Service Levy costs.

A145 For our final decision base, step, and trend modelling we have used revised DY21 opex values as base opex for all GPBs, because:

A145.1 this is consistent with our draft decision modelling approach (albeit we now use data from a later year as our base) and we did not receive strong submissions that this was inappropriate;

A145.2 DY21 opex contains all accounting change effects that have occurred in the last three years such as SaaS opex changes and operating lease costs; and

A145.3 DY21 opex is the most recent opex that GPBs need to run and operate their businesses.

A146 A summary of our DY21 base opex analysis is shown in Table A4. This table compares the base opex values from the draft decision and final decision and the percentage change between them.

Table A4: Final decision base operating expenditure comparisons (real $000s, 2021 Information Disclosure year-end)

Gas Pipeline Business	Draft decision base opex	DY21 opex from GPB ID	Final decision base opex	Draft to final % change
First Gas Distribution	8,816	9,988	9,152	3.8%
First Gas Transmission	48,386	62,112	47,233	-2.4%
GasNet Distribution	1,783	2,009	2,009	12.7%
Powerco Distribution	18,846	18,073	18,073	-4.1%
Vector Distribution	13,550	13,323	13,664	0.8%

Modelled operating expenditure trend factors and input price effects

A147 In our base, step, and trend opex model we incorporate several factors that affect opex trends namely:

A147.1 network scale and elasticity effects;

A147.2 opex partial productivity; and

A147.3 input prices that inflate base opex trends calculated in real $2021 terms to nominal.

Gas Distribution Business network scale

A148 In our draft decision we modelled the need for increased opex based on changes in network scale. This was modelled by scaling base opex in real terms for estimates of network length and ICP annual growth in each year of DPP3.

A149 We accepted GDB ICP growth and natural gas demand forecasts as the basis for our CPRG forecasts and this was consistent with how we modelled opex trends related to growth.

A150 To forecast how increases in network length affect opex need, we used historical trends of network length and ICP growth and the relationship between the two. GDBs do not forecast network length increases in their AMPs so we estimated this relationship based on historical data.

A151 The ICP growth and network length estimates were also modified by an elasticity factor that models their non-linear relationship with opex.

A152 In the draft decision submissions, none of the GDBs provided an opinion on our approach to network scale, while MGUG stated it agreed with our modelling.[213]

A153 In summary, and for our final decision, we have decided to:

A153.1 retain the modelled trend of opex based on network scale changes;

A153.2 retain the modelled linkage between GDB ICP growth and natural gas demand forecasts; and

A153.3 use historical trends of network length and ICP growth and the relationship between the two to estimate opex need.

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[213] MGUG Submission on Gas DPP3 draft decision p.34.

Elasticity

A154 Elasticity models the relationship between network scale and opex. For example, if we calculate an elasticity of 0.9, then a 10% increase in network scale is associated with a 9% increase opex need.

A155 In our draft decision we split network scale elasticity effects equally between estimates of ICP growth and network length increases. This approach is consistent with our modelling of elasticity opex trend effects in previous DPPs.

A156 In the 2013 Gas DPP1 decision modelling we used international data from OFGEM that resulted in ICP growth and network length elasticity assumption of 0.35. This was later updated to 0.4879 based on the Vector submission and Castalia analysis that supported the Vector 2013 Gas DPP draft decision submission.[214]

A157 In our draft decision analysis, we updated the elasticity assumption based on the OFGEM gas sector elasticity modelling methodology used in the 2013 Castalia report. This update incorporated recent Australian gas company opex data and the most up to date opex, consumption, ICP and network length data from the four New Zealand GDBs.[215]

A158 In the draft decision submissions, none of the GDBs provided an opinion on our approach to elasticity, while MGUG stated it agreed with our modelling.[216]

A159 For our final decision modelling we further updated the elasticity model and incorporated the latest opex, gas consumption, ICP and network length data from the four New Zealand GDBs for DY21, resulting in an opex elasticity factor of 0.481.

Operating expenditure partial productivity

A160 In the 2013 Gas DPP decision we discussed the possible rate of change in price or revenue based on productivity improvements in the gas sector. This is the productivity improvement rate in the gas sector when compared to the economy as a whole.[217]

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[214] Vector "Submission on Revised Draft Decision on Gas Initial DPP Appendix 2 Castalia Report" (7 December 2012".

[215] Australian Gas Networks (SA) - Access arrangement 2021-26 proposal (July 2020), Attachment 7.5 – Benchmarking operating and capital costs.

[216] MGUG "Submission on Gas DPP3 draft decision" (14 March 2022), p.34.

[217] Commerce Commission "Gas DPP1 Final Reasons Paper - Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services" (28 February 2013), p.28-29.

A161 At the time we found no evidence to indicate that the productivity of GPBs, providing gas pipeline services, improved by more or less than the rest of the economy. Our draft decision was to retain a partial productivity factor of 0% for this DPP3 period.

A162 In the draft decision submissions, none of the GDBs provided an opinion on our approach to opex partial productivity, while MGUG stated it agreed with our decision.[218]

A163 Our final decision is to retain a modelled partial productivity factor of 0% for this DPP3 period.

Input prices

A164 Changes in input prices affect the annual cost of providing a given level of service and are largely beyond the GPBs' control. In all opex analysis in our draft decision we assumed that the real $2021 base opex and scaled opex trend, over DPP3, was inflated to nominal opex using forecast changes in input prices over the DPP3 period.

A165 We inflated the GPB opex allowances for forecast input price changes (or inflation) using the:

A165.1 weighted average forecast change in the 'all industries' LCI; and

A165.2 'all industries' PPI, or the non-labour cost index.

A166 In our draft decision, we used forecasts of these indices provided by the NZIER. We assumed the same LCI/PPI weighting of 60%/40%, used in Gas DPP1 and EDB DPP3, to calculate a single price index in our opex trend modelling.[219]

A167 In its draft decision submission, Vector noted that "New Zealand is currently facing rising inflation and cost pressures" and that this makes inflation assumptions even more critical. Vector concluded that "An incorrect assumption around inflation could have a material impact on expenditure allowances and the ability of a business to invest".[220]

A168 None of the other GDBs provided an opinion on our modelling of inflation, while MGUG stated it agreed with our approach.[221]

[218] MGUG "Submission on Gas DPP3 draft decision" (14 March 2022), p.34.

[219] Note that we did not carry out base, step, and trend modelling in Gas DPP2.

[220] Vector "Public Submission on Gas DPP3 draft decision" (14 March 2022), p.30.

[221] MGUG "Submission on Gas DPP3 draft decision" (14 March 2022), p.34.

A169 For our final decision we have retained our draft decision approach to inflation and used the most recent NZIER quarterly inflation forecast that was made available to us on 1 March 2022.

A170 Finally, we note that, while differences between forecast and actual inflation will affect GPB cashflows they are actually sheltered from inflation risk by RAB indexation.

Summary of operating expenditure allowances by GPB

Figure A2: Comparison of First Gas Transmission historical operating expenditure, 2021 AMP operating expenditure forecasts and DPP operating expenditure allowances (real $000s, 2021 ID year-end)

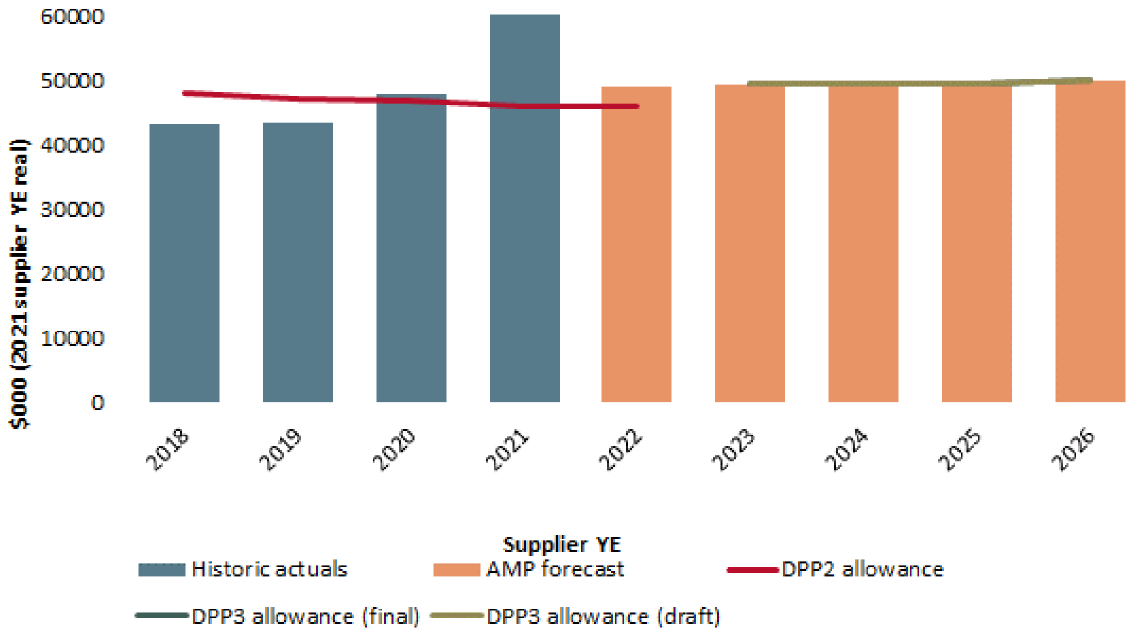


Figure A3: Comparison of First Gas Distribution historical operating expenditure, 2021 AMP operating expenditure forecasts and DPP operating expenditure allowances (real $000s, 2021 ID year-end)

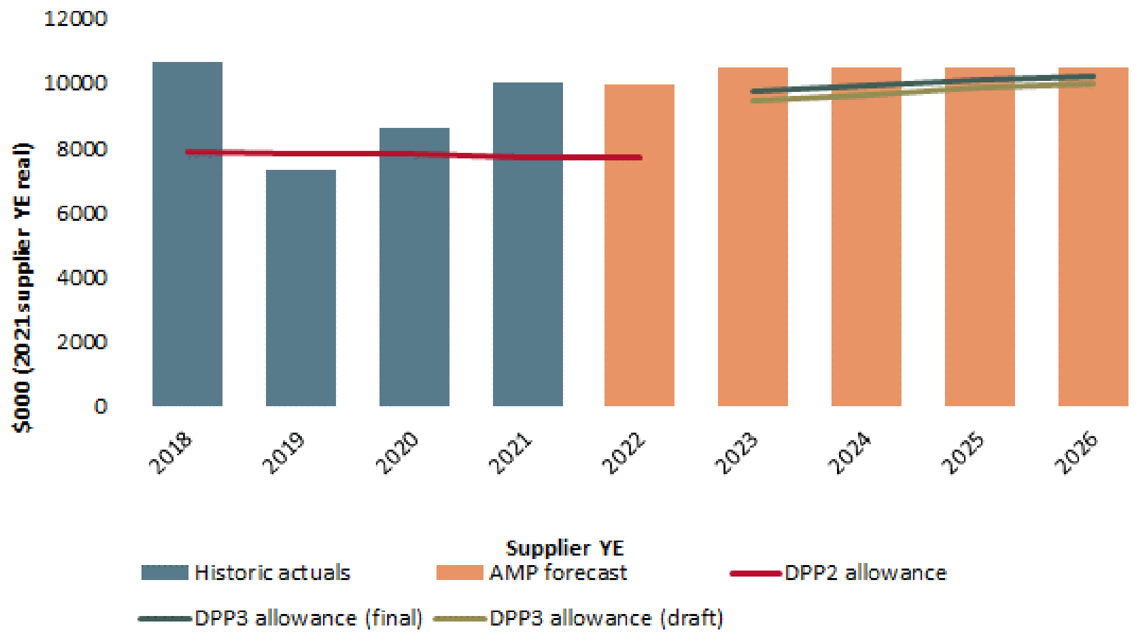


Figure A4: Comparison of Vector historical operating expenditure, 2021 AMP operating expenditure forecasts and DPP operating expenditure allowances (real $000s, 2021 ID year-end)

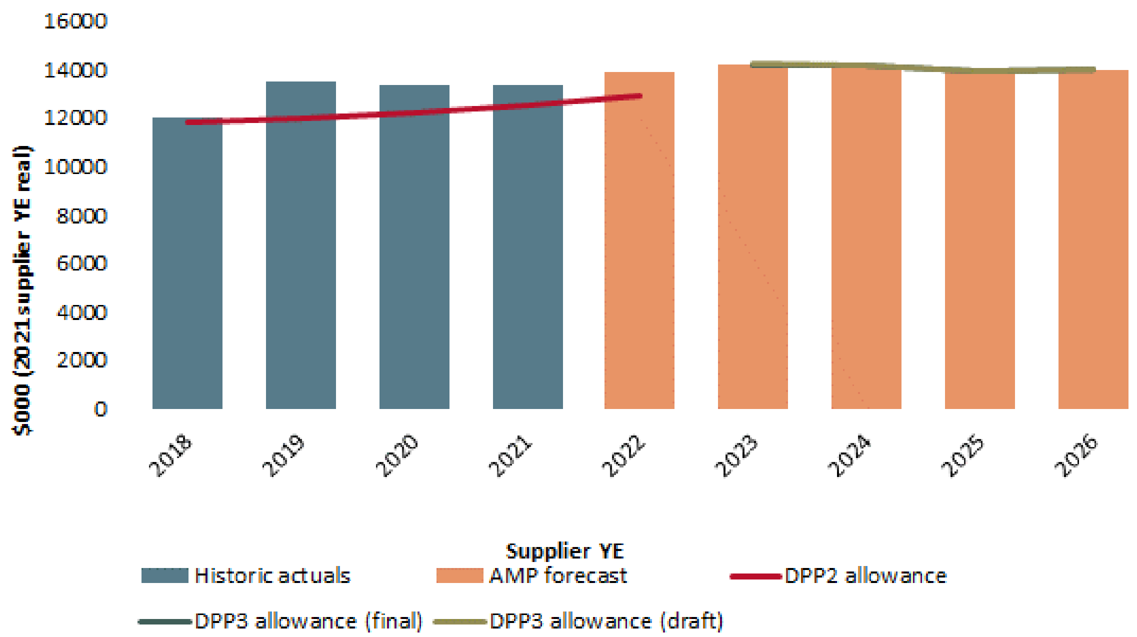


Figure A5: Comparison of Powerco historical operating expenditure, 2021 AMP operating expenditure forecasts and DPP operating expenditure allowances (real $'000s, 2021 ID year-end)

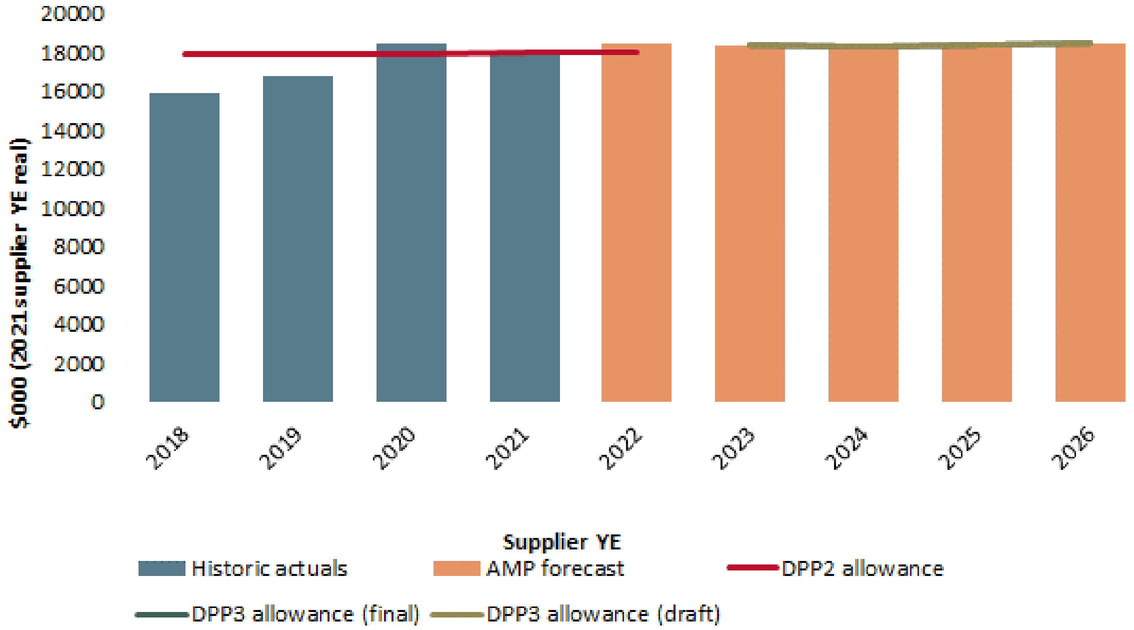
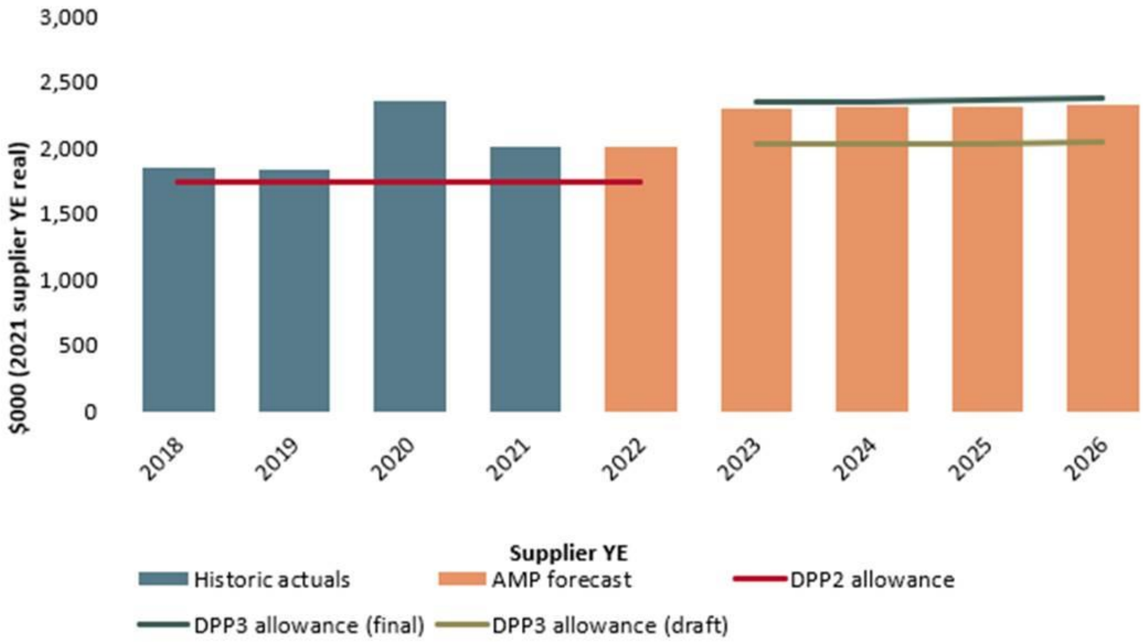


Figure A6: Comparison of GasNet historical operating expenditure, 2021 AMP operating expenditure forecasts and DPP operating expenditure allowances (real $000s, 2021 ID year-end)



Attachment B Forecasting capital expenditure

Purpose of this attachment

B1 The purpose of this attachment is to explain how we set the capex allowances for Gas DPP3.

B2 This attachment sets out:

B2.1 a description of our approach to setting capex allowances including submissions on our draft decision;

B2.2 our analysis and conclusions from RFI responses we used to inform our capex modelling;

B2.3 a summary of our capex modelling assumptions; and

B2.4 final capex allowance settings for each GPB for each year of DPP3 (see Table B1 and Figures B1 and B2).

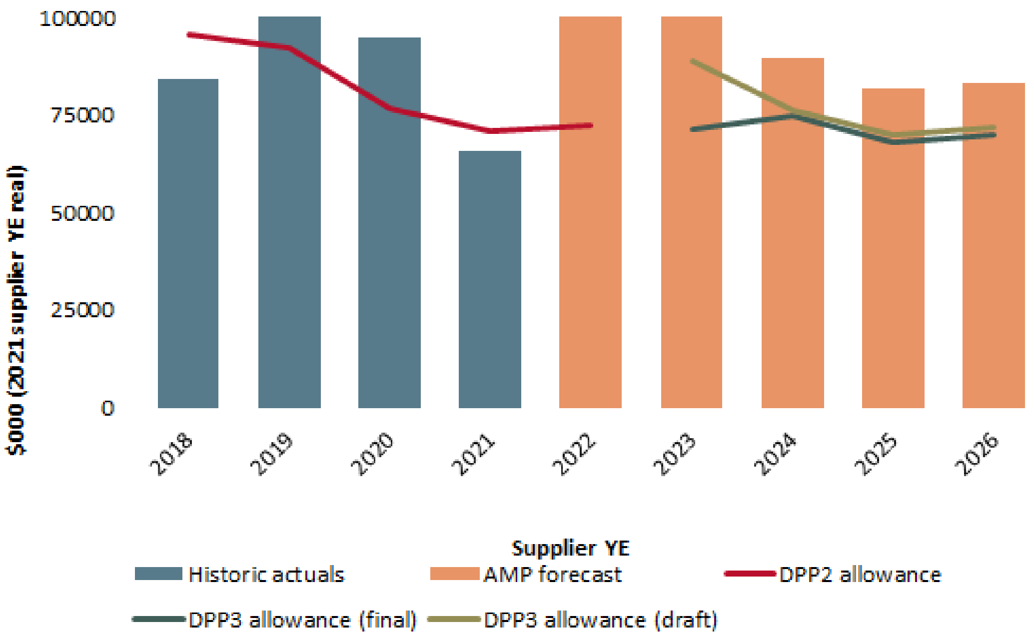
B3 We have performed all capex analysis using historical and forecast expenditure in real $ 2021 prices ($ 2021). All expenditure in this attachment is expressed in real $ 2021 prices unless stated otherwise.

Summary of allowances

Table B1: Gas Pipeline Business 2021 AMP capital expenditure forecasts and DPP3 draft decision allowances for four-year DPP period (real $000s, 2021 Information Disclosure year-end)

Gas Pipeline Business	Capex forecast	Capex allowance
GasNet	4,215	3,309
Powerco	72,694	67,271
Vector	36,673	23,064
First Gas Distribution	57,601	47,170
First Gas Transmission	156,101	142,898
Industry total	**327,284**	**283,712**

Figure B1: Gas Distribution Business total historical capital expenditure, Gas Distribution Business 2021 AMP capital expenditure forecasts, DPP2 allowances and four-year DPP3 allowances (real $000s, 2021 ID year-end)



Summary

Changes to our draft decision

B4 We have made the following changes to our draft decision capex modelling:

B4.1 we have used DY21 actual expenditure data to add an additional year to the calculation of historical average capex projections;

B4.2 we have fixed modelling errors in the expenditure model; for GasNet's non-network capex, which has reduced its capex allowance by $145,000 over DPP3, and for First Gas Transmission's network capex, which has reduced the proportion of capex forecast which we have allowed from 100% to 90.7%; and

B4.3 we have accepted revised GPB non-network capex forecasts following accounting reporting changes and businesses re-categorising previously disclosed non-network capex SaaS costs as opex.

Our approach to setting capex allowances

B5 Our approach to setting capex allowances, like for opex, is intended to be a low-cost approach which relies mostly on previously published information. We use both the forecasts of capex included in GPBs' AMPs and historical financial performance information disclosed by the GPBs under ID.

B6 We have accepted each GPB's forecast real network capex by category unless it exceeds a projection of historical average real capex. In effect, the historical average real capex acts as a cap when we model the capex allowances for DPP3.

B7 We have performed all capex modelling using historical and forecast expenditure expressed in real $ 2021. In modelling capex allowances, we inflated the capex real $ 2021 forecast estimates to nominal using NZIER's all industries PPI inflator series.

B8 Following draft decision submissions, we have retained our top-down historical average real capex projection modelling approach to model real network capex allowances with targeted scrutiny of AMPs for real non-network capex. We have also incorporated DY21 ID data when calculating the historical average capex projections for GDBs and the GTB.

B9 Table B2 summarises our approach to modelling capex allowances, as well as forecast capex and capex allowances by category.

Table B2: Approach to setting capital expenditure allowances by category of capital expenditure, total forecast amounts, total allowance amounts (real $000, 2021 Information Disclosure year-end)

Sector	Capex category	Historical average cap or accept forecast	Total forecast amount ($000)	Total allowance amount ($000)
GTB	Network capex	Historical average cap	134,185	119,597
GTB & GDBs	Non-network capex	Accept forecast	42,791	42,611
GDBs	System growth capex	Historical average cap	34,600	22,689
GDBs	Non-growth network capex	Historical average cap	73,913	53,588
GDBs	Consumer connection capex	Accept forecast	44,843	45,226

B10 For GDBs we applied the historical average capex projection approach to system growth and other non-growth network capex; and for the GTB we applied this to total network capex.

B11 We have calculated the historical average real capex using GPB information disclosure data and based the average calculation on what we considered reflected the most recent need of the business. We calculated historical average real capex using five years of ID data for each GPB (DY17 - DY21), apart from First Gas Transmission, where we used four years of ID data (DY18 - DY21).

B12 Consistent with our draft decision, we have used four years of ID data for First Gas Transmission because we consider that capex incurred prior to its establishment may not have reflected the future needs of the business. Therefore, using expenditure data prior to 2018, when calculating the historical average capex projections, may introduce forecast error.

B13 We have accepted the GDBs' forecasts of new connection growth and consumer connection capex. We concluded that GDB capital contributions policies' new connection payback periods were consistent with long-term demand expectations for GPBs. Our investigations revealed that these policies appeared to be subsidy free and met the requirements of the Gas IMs pricing principles.

B14 We have used GDB forecasts of ICP growth and short-term natural gas demand to form the basis of our GDB CPRG demand forecasts. Under the WAPC, CPRG forecasts predict the rate at which revenues will change due to changes in quantities delivered and number of connected consumers, with prices remaining constant over the regulatory period.

B15 By aligning the forecasts of near-term growth and consumer connection capex, we will maintain consistency between capex allowances and WAPC settings and offset the impact of potential upward bias in GDB demand forecasting.

B16 Following our review of GPBs' most recent asset management plans and following responses to RFIs, we accepted GDB and GTB non-network capex forecasts in our draft decision. Due to SaaS accounting reporting changes we have removed these costs from non-network capex forecast so that these are not double counted in the expenditure modelling.

We have not added margins to historical average capital expenditure projections

B17 In our capex modelling we have not added a margin to the historical average capex projections we have used to cap capex allowances, and have not allowed any expenditure above the level of the historical average capex projections.

B18 In Gas DPP2 we added a 10% margin to the historical average capex projections we used to cap allowances. We accepted forecast expenditure that was under the cap and scrutinised expenditure above the cap.

B19 During the DPP2 analysis process we considered that adding a 10% margin struck a balance between identifying expenditure that required further evidence and an approach that was consistent with the low-cost approach of setting DPPs.

B20 We did not consider introducing capex reopeners in Gas DPP2 and recognised that there may be capex forecast error due to growth or risk events that were unforeseen at the time allowances were set. At the time we considered that the 10% margins minimised the impact of that potential forecast error.

B21 For DPP3, we do not consider it appropriate to allow more capex than the historical average. This reflects expectations of a future decline in the use of natural gas.

B22 We expect GPBs will continue to act and invest prudently, noting the expected move away from the use of natural gas, and that GPBs will use risk-based assessments to prioritise capex to maintain safe and reliable networks. We also expect that GPBs will assess new capex investments against decisions to maintain assets for longer in order to minimise the potential risk and quantum of stranding.

B23 We consider that setting capex levels for DPP3 at historical average levels, combined with GPB's ability to manage their capex by adjusting expenditure and/or increasing capital contributions requirements, should enable GPBs to invest sufficiently to meet the demands of consumers of gas pipeline services and maintain safe and reliable networks.

B24 There is still uncertainty over the profile of future demand for gas, given the Government's plan to phase out the use of natural gas is still being developed (including the gas transition plan and the national energy strategy). The extent to which natural gas may be used as a transitional energy source and/or as a potential supplement to renewable energy sources is still unclear.

B25 To mitigate the risk that the allowances are insufficient to meet consumers' demands to maintain safe and reliable networks, we have introduced capex reopener provisions for expenditure associated for demand growth or risk events. We explain these reopeners fully in our IM Amendments reasons paper.

B26 Finally, if GPBs consider the reopener provisions are not suitable, GPBs can apply for an alternative PQ path using a CPP to better meet their circumstances. A CPP can be tailored to meet the specific needs of the GPB and its consumers, and provides the flexibility to deal with the particular challenges and opportunities that GPBs may encounter.

Submissions on our approach to setting capital expenditure allowances

The top-down capital expenditure approach

B27 Submitters were generally supportive of the top-down capex modelling approach we took in the draft decision although there were several suggested improvements and issues highlighted for us to consider.

B28 In its draft decision submission First Gas discussed the needs of its transmission business. It noted the “lumpy” nature of transmission business expenditure stating that the commission should “scrutinise our total GTB capex across the regulatory period against the historic average (ie, historic average x 4 years for DPP3). This approach retains the historic average approach with no margin, while recognising the lumpy nature of transmission Capex profiles”.[222]

B29 First Gas also stated that, while the top-down capex modelling approach was “consistent with the intent of a low-cost DPP model”, it had a distribution network asset-type issue in its fleet that required a greater level of asset replacement and renewals expenditure than historical levels, which our proposed reopeners would not be able to accommodate.[223]

B30 Powerco:

B30.1 viewed our expenditure modelling as pragmatic and supported the top-down capex approach but requested that non-growth network capex be reconsidered to “support prudent and efficient investment where it exceeds historical levels”; [224]

B30.2 highlighted the asset-type issue raised by First Gas and noted that our proposed reopeners would not address this risk; [225]

B30.3 stated that an improved approach to setting capex allowances could include “a change to the margin applied to historical averages, targeted scrutiny, or a bespoke approach eg opex/capex payback period lengths aligned to the pay-back assessment applied to the scrutiny of non-network capex”;[226] and

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[222] First Gas "Submission on Gas DPP3 draft decision" (14 March 2022), p.19.

[223] First Gas "Submission on Gas DPP3 draft decision" (14 March 2022), p.3, 17.

[224] Powerco "Submission on Gas DPP3 draft decision" (14 March 2022), p.1.

[225] Powerco "Submission on Gas DPP3 draft decision" (14 March 2022), p.4.

[226] Powerco "Submission on Gas DPP3 draft decision" (14 March 2022), p.4.

B30.4 suggested that we apply a similar cost driver test that was applied in EDB DPP3, a test based on the assumption that over the long-term, renewals expenditure should be proportional to renewals depreciation.

B31 Vector noted the low capex acceptance rate in our draft decision when compared to forecast capex, stating that it was “concerned that Vector’s capex allowance for asset replacement and renewal, and for reliability, safety and environment has been significantly reduced from forecast”.[227]

B32 Further, Vector recommended that we “maintain the 10% margin to the historical average capex projections we used to cap allowances. This would mitigate the reduction in Vector’s allowance for asset replacement and renewal, and for reliability, safety and environment”.[228]

B33 Entrust, a majority shareholder of Vector, stated that it was “important to recognise GPBs need to be able to invest to protect the integrity of their networks and maintain the quality of services they provide to consumers”. Entrust supported the Vector submission stating that “the Commission maintain a 10% margin to the historical average capex projections, as this would mitigate the reduction in Vector’s allowance for asset replacement and renewal, and for reliability, safety and environment”.[229]

B34 GasNet submitted that the capex allowances we set in our draft decision were insufficient and suggested increasing our proposed expenditure levels or that we reintroduce capex margins to “to mitigate risk associated with limiting the capital allowance to historical average capex”.[230]

B35 Fonterra supported the top-down capex approach but qualified its support, stating that future “capital expenditure needs to be at or below historic average levels going forward due to declining growth”.[231]

B36 MGUG stated that it had no strong view about the top-down capex approach and that it agreed not adding capex margins was “consistent with [our] approach to capital under uncertainty”.[232]

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227 Vector "Submission on Gas DPP3 draft decision" Public Version (14 March 2022), p.28 para 110.

228 Vector "Submission on Gas DPP3 draft decision" Public Version (14 March 2022), p.28 para 111.

229 Entrust "Submission on Gas DPP3 draft decision" (14 March 2022), p.5.

230 GasNet "Submission on Gas DPP3 draft decision" (14 March 2022), p.1.

231 Fonterra "Submission on Gas DPP3 draft decision on GBP IM Amendments" (14 March 2022), p.3 para 13-14.

232 Major Gas Users Group "Submission on Gas DPP3 draft decision” (14 March 2022), p.34.

B37 Following consideration of submissions, analysis of further information and asset management plans, and suggestions of alternative approaches to setting capex allowances, we have decided to retain our top-down capex modelling approach and have not added margins to the historical average capex projections used to limit capex allowances.

B38 DPPs are intended to be set in a relatively low-cost way and are not intended to meet all the circumstances that a GPB may face. This imposes some limits on the type and amount of scrutiny we can undertake.

B39 In Gas DPP2 we tested GPB Asset Management Plans and scrutinised capex forecasts that exceeded historical averages with 10% margins added. This served the dual purpose of setting DPP capex allowances and testing gas GPB asset management practices. This provided a degree of confidence in the process that we did not consider worthwhile repeating in DPP3.

B40 We have attempted to tailor some aspects of GPB forecasts in this DPP, outside of the top-down allowance setting approach, by considering GDB capital contributions policies and new connection growth separately (see para B72). We have also scrutinised and addressed GPB non-network capex separately due to the fluctuating nature of this category of expenditure (see para B95).

B41 We have retained our draft decision not to add capex margins to the historical capex projections used to limit allowances for GDB system growth and non-growth network capex, and GTB network capex. We do not consider it is appropriate to allow more capex than the historical average. This reflects the expectations of a future decline in the use of natural gas.

B42 However, we have introduced reopener provisions to mitigate the risk that the allowances are insufficient and GPBs are also able to apply for a CPP to better meet their circumstances.

B43 In response to GDB submissions that the non-growth network capex draft decision allowances were insufficient, we carried out further investigations of asset-type issues noted by GDBs.

B44 We reviewed additional expenditure information provided by GDBs as well as their AMPs back to 2018. While GDBs had been discussing these asset-type issues and had largely taken a risk-based approach to investment prioritisation, we could find no justification why non-growth network capex needed to increase over DPP3. Consequently, in our final decision, we retained our draft decision approach for non-growth network capex.

B45 We have described this issue more fully when we discuss GDB non-growth network capex later in this attachment.

How we addressed Gas Distribution Business growth capital expenditure

B46 We received some feedback on our decision to accept GDB consumer connection capex forecasts from the 2021 AMPs.

B47 Powerco supported the approach "in principle given that forecasts and expenditure allowances will be linked", while MGUG agreed with the approach to consumer connection capex.[233,234]

B48 Fonterra, while accepting GDB forecasts of new connections, suggested that the Commission should "at minimum ensure that the DPP3 mandates that all new connections must cover the full cost of the connection (similar to Transpower or EDB causer pays position) and the capital payback must occur prior to 2050, and not be cross subsidised by other end-users".[235]

B49 Further Fonterra stated that: [236]

> The DPP3 does not mandate the elimination of new connection expenditure or alternatively full contribution for connection costs. We do not agree with providing compensation for new connections as that stranding risk should be carried by the new end user.
>
> This is also outlined in the discussion in section B63 and B84 with respect to payback periods. This shows that some GPB's recover costs at an appropriate rate matching the design life and charge new connections for full capital recovery, whereas other GPB's do not. The DPP3 should seek to standardise that cost allocation to ensure that new connections do not generate stranded assets and other end users having to pay accelerated depreciation.

B50 In our analysis that supported these decisions we investigated how GDBs were approaching forecasting growth, and how they were factoring in gas sector uncertainty. We concluded that GDB capital contributions policies' new connection payback periods were consistent with long-term demand expectations for GPBs.

B51 We accepted GDB consumer connection capex forecasts. These forecasts are consistent with our acceptance of GDB near term ICP and gas demand growth estimates, which we used in our CPRG forecast modelling.

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233 Powerco "Submission on Gas DPP3 draft decision" (14 March 2022), p.8.

234 Major Gas Users Group "Submission on Gas DPP3 draft decision" (14 March 2022), p.34.

235 Fonterra "Submission on Gas DPP3 draft decision on GBP IM Amendments" (14 March 2022), p.3 para 13-14.

236 Fonterra "Submission on Gas DPP3 draft decision on GBP IM Amendments" (14 March 2022), p.3-4 paras 20-21.

B52 Following our analysis we concluded that, while it appears GDBs are seeking capital contributions from new connections to ensure the connections are not subsidised by existing consumers of gas pipeline services, and that the new connection payback periods appear to be consistent with a possible gas network closures by 2050, GDBs had significant discretion about how they applied capital contributions policies.

Our Request for Information process and key material we have relied on

B53 To support our decisions, we sought additional information from GPBs regarding capital expenditure items that needed to be explained, accounted for in top-down analysis using historical capex projection, or modelled as capex step changes, namely:

B53.1 Whanganui sales gate capex assigned as non-network capex in DY22 - GasNet;

B53.2 GTAC project capex costs - First Gas Transmission;

B53.3 revised non-network capex forecasts due to SaaS costs;

B53.4 historical and forecast asset-type expenditure information; and

B53.5 capital contribution policies – GasNet, Powerco and First Gas Distribution.

Whanganui sales gate capital expenditure – GasNet

B54 We enquired about the Whanganui sales gate project cost; why it was classed as non-network capex and why there were ongoing costs associated with it.

B55 GasNet responded that an error had been made in describing the project as the Whanganui Sales Gate project; that it only cost $10,000 and that it will be incurred in DY22 only.

B56 GasNet stated that the non-network capex item should have been assigned to “van replacements”. Subsequently, GasNet has disclosed it had purchased one van in 2021 at $72,500 and will purchase another in 2022 for the same price, with ongoing costs of $35,000 from 2023 to 2025.

B57 In our draft decision modelling we accepted GasNet’s explanation as reasonable and amended its non-network forecast capex to $72,500 in DY21 and DY22, with ongoing costs of $35,000 from DY23 to DY25.

B58 We have retained this change for our final decision but note that the change was incorrectly modelled in the draft decision expenditure modelling. We have corrected GasNet’s amended non-network capex forecast in the expenditure model and this has reduced its capex allowance by $145,000 over DPP3.

Gas Transmission Access Code project capex costs

B59 We sought the capex and opex costs associated with the now halted GTAC project so these costs could be removed from historical expenditure. First Gas Transmission confirmed that all the GTAC project costs incurred prior to March 2021 had been classed as capex and that no incremental opex had been incurred. Since GTAC has been abandoned and not commissioned, those capex amounts are not part of the RAB.

B60 Given we are treating non-network capex separately and accepting GPB non-network capex as forecast, unless there were expenditure uplifts that are unexplained in AMP material, we did not have to remove GTAC costs incurred to date in First Gas Transmission's historical capex. We understand there are no GTAC costs included in the First Gas Transmission capex forecast over DPP3.

Revised non-network capex forecasts due to Software-as-a-Service costs

B61 During FY21, accounting reporting changes meant that SaaS costs must be treated and reported as opex. These SaaS costs were formerly treated as non-network capex. This required us to seek revised non-network capex forecasts (discussed in Attachment A) as the accounting change requirement occurred after 2021 Asset Management Plan forecasts were completed.[237]

B62 Following our investigations of SaaS costs (see para A123), GPBs affected by the accounting change informed us of the effect on their 2021 AMP non-network capex forecasts. We have revised these accordingly in our final decision capex modelling.

Asset-type issue expenditure

B63 Following draft decision submissions, we sought additional expenditure information from GDBs, specifically historical and forecast PE pipe replacement costs for First Gas Distribution, Powerco and Vector, and cast-iron metallic pipe replacement costs for GasNet.

B64 In conjunction with our review of asset management plan information, we used this expenditure information to set GDB non-growth network capex allowances in the final decision. How we have addressed this issue is discussed in the non-growth network capex analysis section.

[237] We explain the SaaS accounting change more fully in Attachment A.

Gas distribution business capital contributions policies and consumer connection capex

B65 Capital contributions are contributions from new connecting or relocating parties that gas distribution businesses require as an upfront contribution towards the cost of a new connection or asset relocation. GDBs recover the remainder of the new connection or relocation cost over the lifetime of the assets through pipeline charges.

B66 In line with the pricing principles set out in the Gas Distribution Services IMs, prices GDBs charge new consumers will reflect the economic costs of service where they are subsidy free; that is “equal to or greater than incremental costs and less than or equal to standalone costs”.[238]

B67 In an environment where the future of gas is uncertain, GDBs’ approaches to capital contributions may need to be revised to reflect shorter payback periods for new connections.[239]

B68 Vector, in its 2021 Asset Management Plan, has discussed a change in its capital contributions policy, stating that:[240]

> We have recently changed our capital contributions policy for new customer connections to a full-recovery contribution. This, together with an anticipated softening in future residential growth (we have already begun to experience a change to our annual net residential connections with Housing New Zealand’s policy of not installing reticulated natural gas and removing natural gas from its Auckland housing stock), has led to a situation where we are forecasting a decline in the growth rate for gas connections. Notably, this forecast does not take into account effects from any potential policy changes such as those recommended in the CCC’s draft advice.

B69 First Gas Distribution, in its 2021 Asset Management Plan, published 30 September 2021, has stated it has modified its capital contributions policy stating that:[241]

> To mitigate the network economic stranding risk, we have significantly increased the proportion of Capex that must be met by capital contributions. This proportion has moved from 7% to 20% in FY2023, growing up to 30% in FY2031. Work is also underway to review and update the Capital Contributions Policy and the accompanying commercial models.

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[238] Gas Distribution Services Input Methodologies Determination 2012 (Consolidated April 2018)Part 2 Subpart 5 clause 2.5.2 (1)(a).

[239] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p. 51 Chapter 6.

[240] Vector Gas “2021 Gas Asset Management Plan June 30 2021 Update”, p.5.

[241] First Gas Distribution “2021 Asset Management Plan Update September 30 2021”, p.37.

B70 Powerco and GasNet have not made any changes to their capital contributions policies. Powerco stated in its submission to the process and issues paper that:[242]

> We can assess and adjust our contributions policy at any time and will do so as/when it's prudent to do so.
>
> We can't forecast how our approach to new connections will evolve to reflect policy that hasn't been finalised yet. We can, however, update our policy to reflect customer expectations and policy settings as they evolve.

B71 Powerco's 2021 Asset Management Plan Update, published 30 September 2021, did not discuss this issue.

Gas distribution business capital contribution policies and our pricing principles

B72 Using RFIs we sought additional information about how GDBs had decided on their capital contributions policies and how these policies met the requirements of clause 2.5.2 (1)(a) of the GDB IMs, in being subsidy free.

B73 We were particularly interested in how the GDBs had calculated the capital contribution and the assumptions made about the new connection incremental costs and revenues, particularly the timeframes for new connection cost recovery that each business had made to ensure at least Net Present Value = 0 (**NPV**) for the new connection.

B74 We asked GasNet, Powerco and First Gas Distribution to:

B74.1 supply us with the high-level policy calculations that demonstrated how they had decided on the capital contribution settings for some typical connection types eg, residential and commercial; and

B74.2 explain how these remained consistent with the pricing principles set out in clause 2.5.2 of the Gas Distribution Services Input Methodologies Determination part 1 sub part 5.

B75 GasNet presently reviews new connections on a case-by-case basis and assesses the contribution required only if the connection is not NPV neutral over a maximum 40-year payback period for residential consumers. This includes a risk assessment of the consumers remaining connected, and a 20-year payback period for commercial and industrial consumers of gas pipeline services.

B76 GasNet sets different contribution rates for different customer types and its contribution analysis is guided by the NPV neutral principle.

[242] Powerco "submission on Gas DPP 2022 process and issues paper (30 August 2021), p.7-8.

B77 Our view is that, while GasNet's risk-based approach to assessing contributions from new connections is a reasonable one, a 40-year payback period for residential consumers may be too long given the current climate. The payback period in GasNet's capital contributions policy may need to be revised.

B78 Powerco's policy is that payback periods are generally based on a risk assessment of the connecting party remaining a customer following connection. Payback periods range from 3 years for new commercial connections, to 19 years for new residential connections.

B79 During our investigations, First Gas Distribution noted that it may revise its view of the payback period for NPV>0 for new connections to reflect a greater risk of network stranding. It is considering reducing the revenue timeframes in its models from 40 years to 30 years and to introduce customer contributions for all residential connections.

B80 First Gas consider that 30 years is approximately two "appliance lifecycles", given that an instantaneous hot water unit is expected to last around 15 years. The 30-year payback period starting from 2022 also aligns with the 2050 net zero emissions target date in legislation.

B81 First Gas Distribution consider that, as capital contributions rise consumer connection capex will decline across DPP3. It is predicting new connections will peak in DY22 and then trend downwards from DY23 as the capital contributions policy starts to change new connection decisions.

B82 Of the GDBs, Vector has made the most significant change to its capital contributions policy, now requiring a 100% contribution from all new connecting parties. Vector is still predicting significant growth in new connections as evidenced by its forecast of consumer connection capex.

B83 Vector predicted in its 2021 AMP that while there will be ICP growth, it will decline over the DPP3 period, with 3,515 new connections predicted in DY23, falling to 3,061 new connections by DY26.[243]

B84 We have summarised the GDB capital contribution payback periods by sector in Table B3.

[243] Vector Gas "2021 Gas Asset Management Plan June 30 2021 Update", p.43.

Table B3: Gas distribution business capital contribution policy 'payback' periods

Gas Distribution Business	Sector	Payback period (years)
GasNet	Residential	40
	Commercial	20
	Industrial	20
First Gas Distribution	all sectors	30
Vector	N/A	N/A
Powerco	Residential	19
	Commercial	3
	Industrial	5-7

B85 Both Powerco and GasNet appear to consider the risk of the new connecting party disconnecting when calculating the capital contribution. Powerco clarified that its payback periods for each sector are typical or averaged and not a definitive range. It is likely that applying a risk analysis may result in longer or shorter payback periods and capital contributions, depending on the outcome of that risk analysis.

B86 We concluded that Powerco and First Gas Distribution have capital contributions policies with payback periods that are consistent with possible network closure by 2050 (the year in which New Zealand is currently required to reach net zero emissions).

B87 The payback periods indicate that GPBs will generally get revenues sufficient to cover the new connection costs before 2050.

B88 GPBs need to consider the risk that capex related to network growth may be stranded in the future. This may create an incentive for GPBs to manage future asset stranding risk for growth-related assets by seeking greater levels of contribution from new connecting parties.

B89 All GPBs are forecasting new connection growth albeit at differing rates across the DPP3 period. The forecast ICP growth, and consumer connection capex it relates to, is tied to the customer willingness to pay to connect to the gas network. This will be a customer value judgement balanced by the upfront payment required by the GDB, the ongoing cost of the connection and the reasons for connecting to gas.

B90 We currently do not have information regarding new customers, and their willingness to pay an upfront contribution to connect to the gas network. In the current environment it could be argued GDBs are best placed to make judgements on customers' willingness to pay to connect as they are engaging with existing and new customers on a day-to-day basis.

B91 On balance, for our final decision, we have accepted that the GDBs hold the best information about consumer enquiries, new consumer behaviour, and their willingness to pay to connect.

B92 For these reasons, for our final decision, we have accepted the following forecasts and have used them to set consumer connection capex allowances in this DPP:

B92.1 ICP growth forecasts from GasNet, Vector, Powerco and First Gas Distribution; and

B92.2 consumer connection capex forecasts from GasNet, Powerco and First Gas Distribution.

B93 We also note that:

B93.1 Vector and First Gas Distribution have amended their capital contributions policies and growth forecasts to reflect their understanding of the gas industry's long-term future;

B93.2 Powerco's policy has payback periods that are consistent with net zero carbon emissions by 2050; and

B93.3 Powerco and GasNet appear to explicitly apply risk analysis of new consumers remaining connected in setting capital contribution rates, although GasNet's residential connection policy may need to be revised.

B94 The GDB ICP and gas demand forecasts have formed the basis of our CPRG demand forecasts for each GDB. This ensures that there is consistency between our capex allowances and the WAPC settings, and offsets the impact of upward bias in GDB growth forecasting.

Our approach to setting capital expenditure allowances

Non-network capital expenditure

B95 We considered GTB and GDB non-network capex separately; accepting forecasts and seeking explanations in AMPs only for unexplained significant forecast uplifts.

B96 We took this approach because we have observed that non-network capex tends to contain one-off expenditure uplifts and trends that can distort historical expenditure projections. Non-network capex contains atypical non-annually recurring expenditure items such as ICT investments and building upgrades.

B97 We did not identify any uplift or expenditure exception issues with First Gas Transmission, First Gas Distribution or Powerco forecasts of non-network capex and accepted these.

B98 We investigated the significant expenditure uplift in DY23 forecast by GasNet, and Vector's forecast sustained expenditure uplift from DY22.

B99 In reviewing GasNet's 2021 Asset Management Plan the DY23 expenditure uplift was coded as non-network capex for the Whanganui Sales Gate project. GasNet disclosed that this project would cost $135,000 ($ 2021) in FY23 and incur ongoing costs of $35,000 ($ 2021) per annum thereafter. We could find no explanation for this expenditure in the AMP material so sought additional information using an RFI.

B100 We tested GasNet about the uplift and were provided with an explanation in its RFI response to our Whanganui sales gate question that non-network capex had been incorrectly coded in ID. We accepted GasNet's explanation and revised its non-network capex forecast accordingly.

B101 In 2020, Vector forecast that it would be spending approximately $20 million ($ 2020) over the DY21 and DY31 periods to upgrade business areas with upgraded and linked supporting technology.

B102 In its 2021 AMP Update, Vector states that it has forecast a non-network capex cost increase of $5 million ($ 2021) over the DY22 to DY30 period due to:[244]

B102.1 increased investment in cyber security and IT network infrastructure and key system software; and

B102.2 increase in property and lease costs, from changes in office lease timing and deferral of office refurbishment.

B103 Vector described the basis of its non-network costs and the reasoning provided for the 2020 AMP vs 2021 AMP cost increase appeared to be reasonably described and were therefore accepted.

B104 Following the SaaS accounting reporting changes, we sought clarifying information from GPBs about how this had impacted their 2021 Asset Management Plan non-network capex forecasts which we used in our draft decision.

B105 First Gas noted the largest movement of non-network capex to opex, mainly in its transmission business, and re-supplied us with amended non-network capex forecasts.

[244] Vector "2021 Asset Management Plan update", p. 29.

B106 First Gas stated that non-network capex would reduce by $6 million for its transmission business and $0.5 million for its distribution business over the DPP3 period, with commensurate increases in opex. We reviewed this forecast information to ensure that the capex reductions and opex increases were consistent and accepted these.

B107 Powerco notified us that the accounting change only affected a small part of DY22 expenditure, which is not covered by the DPP3, which starts in DY23 for all GPBs.

B108 Vector informed us of a minor SaaS cost change in DY21 opex and non-network capex, but that from DY23, $0.41 million per annum would shift from non-network capex to opex each year of DPP3.

B109 In summary, following our investigations, we have retained our draft decision approach to non-network capex and have accepted all revised GPB non-network capex forecasts in our final decision.

Gas Transmission Business network capital expenditure

B110 We took a different approach when we set GTB network capex allowances compared with our GDB approach. Analysis of historical and planned expenditure reveals that gas transmission network capex is dominated by expenditure for renewals which is more consistent over time, while about 60% of gas distribution network capex is to accommodate growth.

B111 In our draft decision we applied a top-down historical average network capex projection to limit network capex allowances. Most submitters considered that this approach seemed reasonable and appropriate for a DPP, although First Gas questioned whether that was the case for its business.

B112 In its draft decision submission First Gas noted the “lumpy” nature of transmission business expenditure stating that the Commission should “scrutinise our total GTB Capex across the regulatory period against the historic average (ie, historic average x 4 years for DPP3). This approach retains the historic average approach with no margin, while recognising the lumpy nature of transmission Capex profiles".

B113 First Gas also noted it is “forecasting increased expenditure due to our programme of work to replace two of our compressor units. The programme of work began in FY2020 and is scheduled to continue through DPP3, with much of the expenditure incurred in FY2023 (and FY2022). This results in variation in annual capex over the regulatory period of around $20 million per year”.

B114 In our draft decision we explicitly considered and approved non-network capex separately for all GPBs, as this expenditure had historically been lumpy in nature. This separate consideration of non-network capex mitigates some of First Gas’ concerns.

B115 We also tested whether First Gas' proposed compressor replacements were in response to an identified and known risk that the DPP settings and reopeners may not capture.

B116 In its 2021 Asset Management Plan Update, First Gas Transmission states that the proposed compressor replacements are due to poorly performing gas compressor units, that are now becoming obsolete and are no longer "fit for purpose". The programme is part of a wider replacement strategy to replace gas units with electric units that will "allow improved capacity ramp up and down as well as significant CO2 emissions savings."

B117 In reviewing First Gas Transmission disclosure information that supported our decisions on quality, we did not observe a concerning or significant reduction in compressor availability, nor did any submitters state that this was causing gas user issues.

B118 It appears that the compressor replacement programme, while providing operational and economic benefits may be discretionary, and not a fully risk-based decision. We consider that approving expenditure of this nature, which is based on a change in asset strategy and results in an expenditure uplift, should be considered as part of a CPP application. This would allow the expenditure to be scrutinised in greater detail and give interested parties an opportunity to engage with the proposed expenditure.

B119 We have retained the top-down modelling approach for transmission network capex for our final decision. We consider that it is appropriate for a DPP and that the reopeners provide an opportunity to seek additional funding to address capacity events and risk events. Additionally, First Gas Transmission can also apply for a CPP should its circumstances change and if DPP allowances are insufficient.

B120 Finally, in its draft decision submission, First Gas notified us that there was an error in its capex allowance calculation in the expenditure model.[245] The draft decision capex allowance for First Gas Transmission was reported as $162 million and should have been set at $150.3 million.

B121 This error wrongly accepted the First Gas Transmission forecast expenditure in DY23 when it should have been capped at the historical capex average. We have corrected this error in the final decision expenditure modelling.

[245] First Gas "Submission on Gas DPP3 draft decision" (14 March 2022), p.22.

B122 In updating the expenditure model with DY21 actual data and using historical average capex projections based on four years of expenditure data (DY18-DY21), the network capex allowance for First Gas Transmission has been set at $118.5 million for the final decision.

Gas Distribution Business consumer connection and system growth capital expenditure

B123 Following our analysis of the GDB capital contributions policies, and given we accept GDB forecasts of ICP growth and gas demand, we have accepted GDB's forecasts of consumer connection capex in our final decision.

B124 System growth capex is necessary for wider network upgrades driven by new connection growth. If we accept that GDBs have forecast near term ICP growth reasonably and agree that their capital contributions policies also reflect gas sector uncertainty and reduced payback periods for new connection assets, then we should also accept that near term system growth capex may also be likely.

B125 To set system growth capex allowances we performed top-down historical average capex projection analysis and added no capex margin. The First Gas Distribution, GasNet and Powerco analysis resulted in allowance settings that are generally consistent with their most recent forecasts in this expenditure category.

B126 However, the Vector allowances are significantly less than it has forecast. In our draft decision we discussed this issue specifically noting that Vector had predicted a large uplift in system growth capex from DY22 when compared to the historical average capex projections.

B127 On average, between Disclosure Year 2017 (**DY17**) and DY21 Vector has spent approximately $1.2 million per annum on system growth capex and forecasts it will spend $2.8 million per annum across the DPP3 period. Our top-down capex allowance setting approach has not allowed for this significant uplift.

B128 In our draft decision we noted that incorporating Vector's DY21 data may raise the top-down system growth capex limit. The addition of the DY21 actual system growth capex has raised Vector's system growth capex allowance from $3.3 million to $4.8 million.

B129 We have not scrutinised the prudency and efficiency of expenditure uplifts above the historical average capex projections in the GDB AMPs. Given the expected decline in gas use, it is our expectation that capex should not exceed historical average levels.

B130 Finally, GPBs can apply for a CPP to better meet their circumstances. A CPP can be tailored to meet the specific needs of the GPB and its consumers and provides the flexibility to deal with uncertainties that GPBs may encounter.

B131 Following our capex modelling, the draft to final system growth capex allowances, and the effect of adding an additional year of expenditure data to the historical average capex projections, are summarised in Table B.4.

Table B4: Gas Distribution Business system growth capital expenditure allowances ($000s 2021 ID year-end)

Gas Distribution Business	DY23-DY26 Forecast	Draft decision allowance	Final decision allowance
First Gas Distribution	17,382	12,852	12,193
GasNet Distribution	600	528	528
Powerco Distribution	5,443	5,347	5,131
Vector Distribution	11,113	3,289	4,840

Gas Distribution Business non-growth related network capital expenditure

B132 In our draft decision we applied the top-down historical average capex approach when setting non-growth network capex allowances.

B133 This category of non-growth network capex contains expenditure related to asset relocations capex not funded by capital contributions, reliability, safety and environment capex, and asset replacement and renewals capex.

B134 In draft decision submissions, both First Gas and Powerco suggested that asset replacement and renewals capex allowances needed to be increased to deal with an asset-type issue (a known pre-1985 PE pipe issue).

B135 Powerco stated that its AMP update forecasts included $6.5m for pre-1985 PE pipe replacement over the DPP3 period but that our DPP3 settings did not allow for this by "being $5.8m lower than the forecasts over the period".[246]

B136 Powerco also correctly noted that our proposed reopeners would not address this risk, as the risk was known at the time the DPP was set.

[246] Powerco "Submission on Gas DPP3 draft decision" (14 March 2022), p.6.

B137 In its cross-submission, Powerco stated that "the Commission should review its approach to forecasting non-growth capex. Like Powerco, First Gas' forecast uplift in expenditure is centred around replacing pre-1985 PE pipes. Further, Powerco noted:[247]

> We think the Commission should reconsider its non-growth forecasting approach because prudent and efficient investment can justifiably exceed historical levels. The Commission has acknowledged that some situations justify forecast expenditure being uncoupled from historical levels. We believe that GDB expenditure on pre-1985 pipe replacement is one of these.

B138 First Gas stated that its asset replacement and renewals capex programme is "centred around the replacement of the pre-1985 PE pipes on our network" and that it had "undertaken further investigations and developed a risk-based strategy for replacing these pre-1985 PE pipes".[248]

B139 While Vector did not specifically discuss an asset-type issue on its network, it stated that it was concerned "that Vector's capex allowance for asset replacement and renewal, and for reliability, safety and environment has been significantly reduced from forecast".[249]

B140 GasNet suggested that an uplift in draft decision capex allowances was necessary to "account for typical year-on-year functions that tend to occur in capex" and that "the risk that the capex allowances we set in this DPP are insufficient to deal with network asset risk".[250]

B141 We carried out further investigations of the PE pipe issue identified by First Gas and Powerco, and the network risk GasNet referred to. We tested GDB asset management plans from 2018 and sought additional expenditure information of PE pipe replacement expenditure for First Gas, Powerco and Vector, and expenditure related to GasNet's cast-iron metallic pipe replacement programme, which it had signalled in its asset management planning, was its key network risk.

B142 We tested GDB asset management plan material to understand the issues and whether expenditure increases above historical levels were supported for the PE and metallic pipe replacement programmes.

B143 While businesses have been discussing these risks in their AMPs since at least 2018, and appear to be applying risk-based strategies to prioritise replacements, we did not find information that supported an uplift in expenditure above historical levels.

[247] Powerco " Gas DPP3 Draft Decision cross-submission" (4 April 2022), p.4.

[248] First Gas "Submission on Gas DPP3 draft decision" (14 March 2022), p. 17-18.

[249] Vector " Submission on Gas DPP3 draft decision" (14 March 2022), p.28 para 110.

[250] GasNet "IM Amendments Draft Decision submission" (10 March 2022) p.2-3.

B144 We also tested GDB gas leakage statistics and did not find clear evidence that gas leakage events were increasing, or discussions in asset management plans that increased gas leakage events, related to asset-type issues, were driving expenditure uplifts to address these.

B145 On this basis we have retained our draft decision approach for the non-growth network capex category of expenditure as our final decision.

B146 The addition of DY21 expenditure data has modified the historical average capex projections for all the GDBs we have used to set DPP3 allowance limits, and this has modified the final decision allowance settings (see Table B5).

Table B5: GDB non-growth network capital expenditure allowances ($000s, 2021 Information Disclosure year-end)

Gas Distribution Business	DY23-DY26 Forecast	Draft decision allowance	Final decision allowance
First Gas Distribution	$20,636	$16,277	$15,196
GasNet Distribution	$2,500	$1,666	$1,741
Powerco Distribution	$31,832	$26,586	$26,520
Vector Distribution	$19,046	$9,149	$9,661

Cost of finance adjustment

B147 The Gas IMs specify that the capital expenditure allowances we set must reflect the cost of financing capital works under construction.[251]

B148 GPBs have forecast the cost of financing on a nominal basis throughout the length of the regulatory period. These forecast costs are set out in their asset management plans in Schedule 11a(i). We have reviewed these costs for each GDB and GTB and accepted these as reasonable.

B149 The cost of financing forecasts in Schedule 11a(i) are expressed in nominal terms and the allowances we set are expressed in real terms in our modelling.

B150 In our final decision we have taken the following approach to express the cost of finance adjustments in real terms in our modelling. We:

B150.1 calculate the total forecast nominal cost of finance adjustments throughout the regulatory period from each GPB's AMP (cost of finance);

[251] Gas Distribution Services Input Methodologies Determination 2012 (Consolidated April 2018), Clause 2.2.11(3)(b), Gas Transmission Services Input Methodologies Determination 2012 (Consolidated April 2018) , Clause 2.2.11(3)(b).

B150.2 calculate the total forecast nominal capital expenditure throughout the regulatory period from each GPB's AMP (total capex);

B150.3 calculate the cost of finance as a percentage of total capex; and

B150.4 for each year in the regulatory period, multiply this percentage by our capex allowances in real terms, to determine the cost of finance adjustment in the relevant year of DPP3.

Summary of capital expenditure allowances by Gas Pipeline Business

Figure B3: Comparison of First Gas Transmission historical capital expenditure, AMP capital expenditure forecasts and DPP capital expenditure allowances (real $'000s, 2021 Information Disclosure year-end)

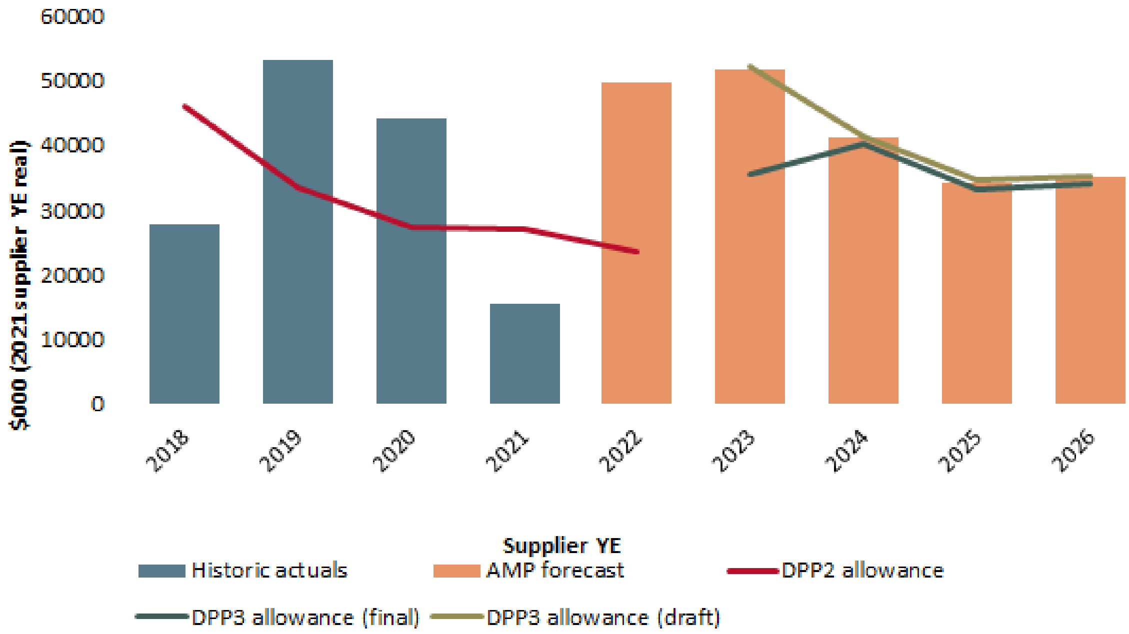


Figure B4: Comparison of First Gas Distribution historical capital expenditure, AMP capital expenditure forecasts and DPP capital expenditure allowances (real $'000s, 2021 Information Disclosure year-end)

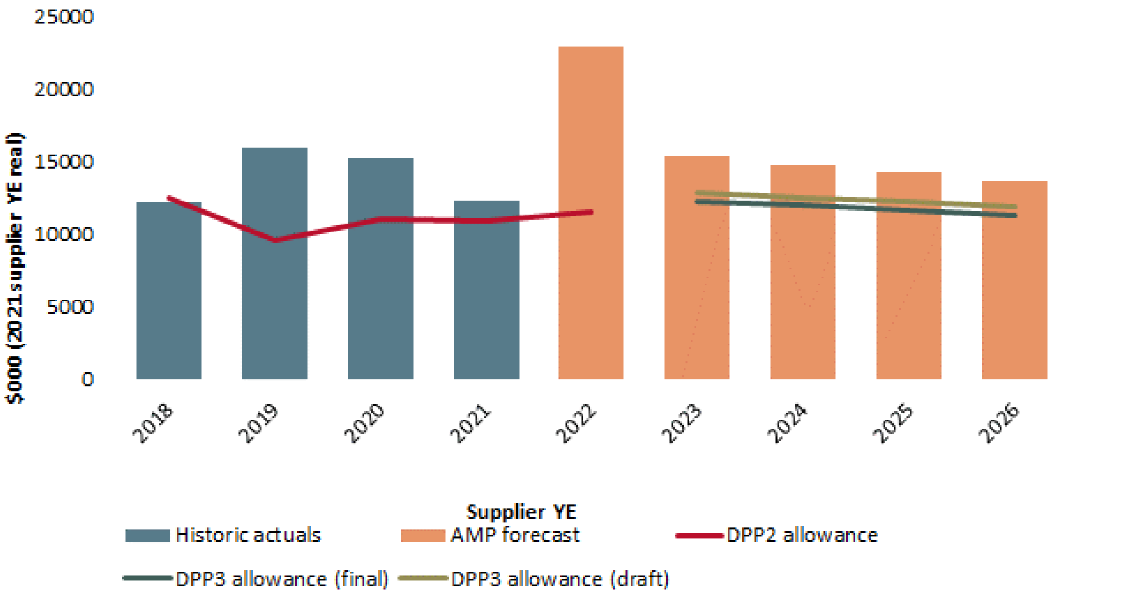


Figure B5: Comparison of Powerco historical capital expenditure, AMP capital expenditure forecasts and DPP capital expenditure allowances (real $'000s, 2021 Information Disclosure year-end)

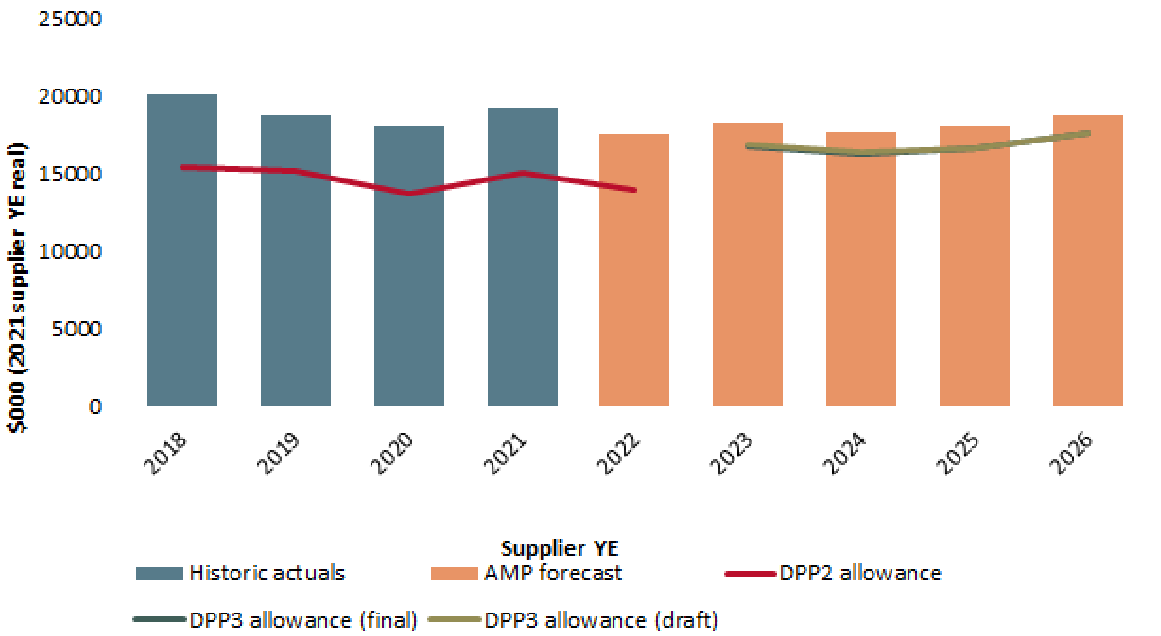


Figure B6: Comparison of GasNet historical capital expenditure, AMP capital expenditure forecasts and DPP capital expenditure allowances (real $'000s, 2021 Information Disclosure year-end)

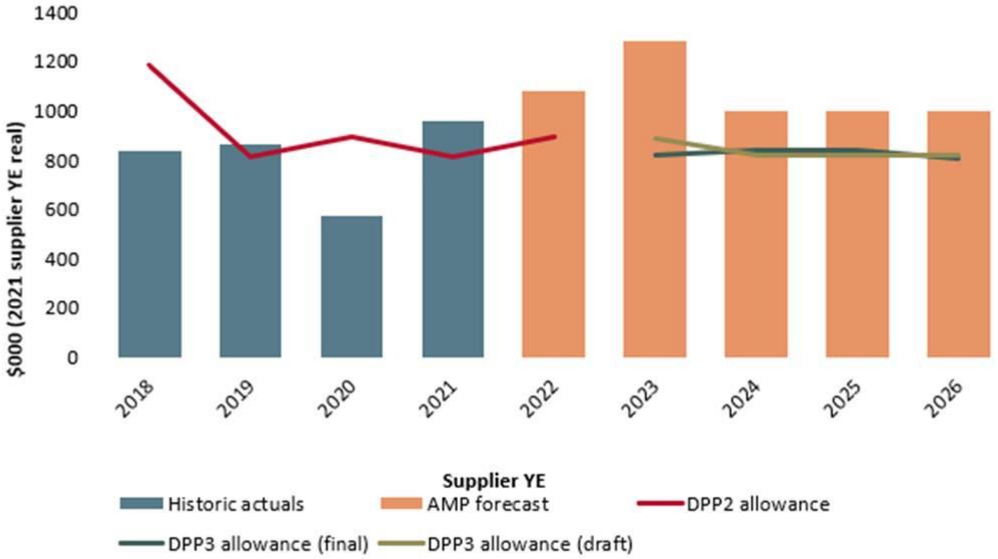
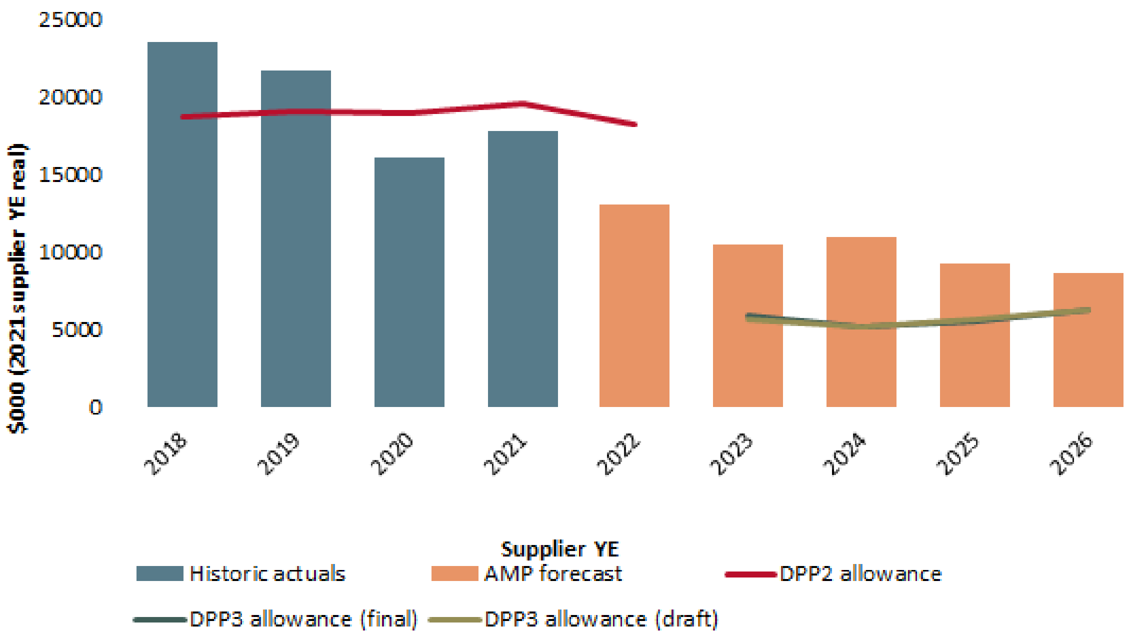


Figure B7: Comparison of Vector historical capital expenditure, AMP capital expenditure forecasts and DPP capital expenditure allowances (real $'000s, 2021 Information Disclosure year-end)



Attachment C Analytical supplement - recognising shorter asset lives to address economic network stranding risk in DPP3

Purpose of this attachment

C1 This attachment provides additional information on:

C1.1 the economic problem posed by altered expectations of gas asset lifetimes and the risk of network stranding faced by GPBs;

C1.2 our assessment of the implications of the problem for the DPP3 reset and beyond for GPBs and consumers of gas pipeline services; and

C1.3 our conclusion that acting to shorten regulatory asset lives in DPP3 promotes the long-term benefit of consumers.

Problem of economic stranding: incentivising investment for the long-term benefit of consumers

Regulated services and the building block model.

C2 Like a range of other infrastructure providers, GPBs have made large upfront investments in long-lived assets and need to continue to invest to maintain the assets in order to provide safe and reliable natural gas pipeline services to consumers. The long physical asset lives of the assets means they are exposed to risk of under-recovery as the expected useful lives of those investments are now shorter.

C3 The DPP regime operates under a BBM which applies the Gas IMs, under which allowable revenues are set for each regulated period to allow GPBs the expectation of recovering the prudent and efficient costs incurred in operating gas networks, together with a normal return.

C4 Costs include a return of capital invested in assets, depreciation, calculated under a straight-line depreciation method where the amount of depreciation for that period (and thus how quickly investment costs are returned) is determined by remaining asset lives at each price reset.

C5 Regulatory asset lives are determined by the Gas IMs, which up until now have been set largely by reference to expectations of physical asset lives, rather than the timeframe over which the assets are economically viable.[252]

[252] There are limited exceptions available in the Gas IMs to shorten lives due to use or physical characteristics, but there is no ability to shorten based on expected economic lifetimes.

C6 Schedule A of the Gas IMs prescribes a range of "Standard Physical Asset Lives" for GPBs, in which:

C6.1 high pressure pipelines, valves and spares have a lifetime of 80 years;

C6.2 intermediate pressure pipelines, services, valves and spares have a lifetime of 70 years;

C6.3 medium pressure pipelines, services, valves and spares have a lifetime of 60 years;

C6.4 station site development costs and buildings have a lifetime of 50 years; and

C6.5 other assets listed in Schedule A have lifetimes of between 10 and 35 years.

C7 The BBM costs do not include an allowance for the new risk that the network may cease being used to convey natural gas before all of the investment can be recovered through prices due to sector-specific risks. Examples of these sector specific risks include a permanent fall in demand for the services, or a government mandate to restrict new connections or phase out natural gas.

Role of ex ante Financial Capital Maintenance in incentivising investment under our Building Block Method framework.

We apply our ex ante Financial Capital Maintenance principle to support incentives for suppliers to invest where doing so promotes the Part 4 purpose

C8 Under Part 4 regulatory settings GPBs have been provided with an (ex ante) expectation of normal profits, this concept is encapsulated in our ex ante real financial capital maintenance (ex ante FCM) principle. Ex ante FCM provides suppliers with incentives to invest while protecting consumers against the ability of suppliers to extract excessive profits.

C9 Ex ante FCM requires suppliers to have:

C9.1 a reasonable expectation that the RAB can be recovered through return of capital (depreciation) in the long run; and

C9.2 an expectation of making a normal return on capital invested.

C10 The BBM operationalises these expectations, alongside the expectation of recovering efficient operating costs and other building blocks. In the DPP, forward-looking forecasts of building block costs are determined in accordance with the Gas IMs, including for asset-related costs like depreciation.

C11 While there is no guarantee under Part 4 DPP regulation of making normal profits ex post, it is the ex ante expectation of normal profits over time that supports continued investment incentives, including incentives to innovate.

C12 GPBs ultimately bear some risk as our decision-making framework seeks to preserve an ex ante expectation of FCM only to the extent it promotes the Part 4 purpose. For example, ex ante FCM may not promote the Part 4 purpose if such large numbers of customer disconnections means that remaining consumers will not be willing or able to pay the prices that would be required for suppliers to achieve FCM.

C13 At some point we may need to rethink how and/or if we apply the ex ante FCM principle and the BBM if, for example, early industry wind-down was to become certain. But given the central importance of FCM and the BBM to promoting incentives for efficient investment, we would not depart lightly from them, and we would need clear evidence that departing from these would better promote the Part 4 purpose than maintaining them.

Our past treatment of assets maintains ex ante Financial Capital Maintenance where relatively stable demand growth is expected

C14 For DPP resets in the past, the Gas IMs required that the value of the RAB be recovered by GPBs through prices charged to consumers over assumed physical asset lives by straight-line depreciation.

C14.1 When establishing the IMs in 2010, we noted that physical asset lives reflected the likely economic lifetime of assets given long-term expectations of relatively stable demand growth and so physical asset lives and straight-line depreciation was a proxy for economic depreciation.[253]

C14.2 Under the BBM for the DPPs, the Gas IMs also index the RAB annually by inflation to manage inflation risk. While this preserves the real value of the RAB over time, it effectively defers recovery of asset-related costs to the future, relative to not indexing the RAB.

C15 With long-term expectations of relatively stable demand, the combined impact of adopting physical asset lives, straight-line depreciation and RAB indexation is a relatively flat aggregate pricing profile in real terms over time.

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[253] Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons paper (December 2010), p.351 para E10.21.

Expected economic asset lifetimes are now shorter than previously assumed

C16 As discussed in Chapter 3, there is broad acknowledgement of the risk of long-term declining usage of natural gas pipeline services and/or eventual cessation of gas pipeline services as New Zealand transitions to a low-carbon economy.

C17 The Government's ERP states that fossil fuels will need to be replaced with low-emissions fuels such as biofuels and hydrogen. Specific actions highlighted in the ERP include managing the phase-out of fossil fuels, including fossil gas, and developing low-emissions fuels.[254]

C18 This is a material change in expectations from when we last undertook a review of the Gas IMs in 2016. It constitutes a move away from the presumption of steady or growing long-term demand that has previously applied for energy utilities in New Zealand and was implicitly adopted in regulatory settings for GPBs up until now.

C19 The primary concern from the perspective of promoting the s 52A purpose is that an expected decline in future pipeline usage and/or the prospect of full or partial network closures means that past assumptions of asset lives are unlikely to allow recovery of asset-related costs (depreciation) over the expected economic lifetime of network assets.

C20 The potential for unrecovered investment costs by applying the Schedule A standard physical asset lives for calculating depreciation under the BBM indicates that there is stranding risk, and since there has been no compensation for sector-specific stranding risk this is likely to compromise incentives for efficient continuing investment by suppliers. If the continuing investment required for DPP3 and beyond is not made, it could result in:

C20.1 early closure of the GPBs networks (or parts of the networks) in the future, and unmet demand despite consumers otherwise being willing to pay for continued investment; and

C20.2 the services no longer being provided at a quality that reflects consumer demands.

C21 Further, if action to allow recovery of asset-related costs in an appropriate timeframe is not taken now, the burden of trying to recover remaining asset-related costs will fall on a smaller group of consumers than today and have to be recovered over a shorter period of time than previously assumed. This may increase prices to unaffordable levels in the future for those consumers who continue to demand piped natural gas and are unable to easily switch.

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[254] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), p.215.

C22 While declining pipeline usage over time is likely, there is significant uncertainty about the speed and extent of the decline. There is no definitive data available on likely future demand, and a range of competing views exist over which industry scenarios might be most likely.

C22.1 Much of the uncertainty is due to the fact that pipeline usage will be affected by policy intervention by current and future governments in response to climate change, which will develop over time. The Climate Change Commission noted there were economic issues involved in transitioning away from fossil fuel use, and the Government's first ERP states that:[255]

> Phasing out fossil gas presents short-term and long-term challenges, including balancing capital investment with declining fossil gas use, fossil gas affordability and the risk of stranded network assets. The Government is working to address these challenges and set out a pathway for the fossil gas sector.

C22.2 Industry prospects will also be governed by factors such as the viability (or otherwise) of alternative energy sources for consumers, whether pipelines can be repurposed to carry alternative gases, economic interdependencies with services in sectors such as electricity, and consumer preferences.

C22.3 MBIE has issued a terms of reference for developing the Gas Transition Plan. This set out the short to medium term outcomes the Government seeks to achieve (to 2035) and its aims for the transition plan. It also sets out two pillars for the plan, namely the transition pathways for the fossil gas sector (including the implications for legacy gas pipeline infrastructure); and the role of renewable gases.[256]

C23 Given these factors, and that Government is still to develop its plan, there is uncertainty over future levels of demand for, and use of, natural gas and we have had to reach a judgement based on the evidence before us.

C24 New Zealand businesses are not unique in facing uncertainty caused by moves to decarbonise the economy, and overseas regulators are increasingly being called on to consider what actions to take now to best ensure consumer welfare is maximised over the longer-term.

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[255] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), p.216.

[256] MBIE "Terms of Reference – Gas Transition Plan" (May 2022).

C25 Drawing on foundational economic literature concerning approaches to depreciation in the face of economic stranding, the Australian Energy Regulator noted, for the regulated gas sector in Australia, that:

> Our ability to adjust prices as a means to reduce price uncertainty and stranded asset risk will diminish over time and there is a window of opportunity, ie, a period of time, within which we can make decisions that will produce a desired outcome.[257]

We have reviewed gas asset life assumptions in light of expectations of declining usage

C26 A range of factors suggests expected economic lives of GPB assets have reduced significantly relative to past assumptions, and that action to address the risk under our BBM framework should be considered.

C26.1 Chapter 3 sets out why we expect demand for natural gas to decline and the Government's proposals to reduce emissions from the use of natural gas.

C26.2 If the past regulatory assumption about asset lives were to be continued, a potential network stranding problem arises that has material adverse consequences for consumers as explained below.

C26.3 Regulators internationally have addressed the increasing risk of asset stranding of gas pipeline assets, including by shortening asset lives.

C27 Given the expected decline in pipeline usage, which implies shorter economic asset lives, and a consequent increase in stranding risk, we consider it is appropriate to review if regulatory assumptions under the BBM contained in our IMs remain fit for purpose.

Current and future consumers require continuing investments to be made

C28 A key conclusion to be drawn from the transition to declining pipeline usage is that continuing with our past approach to asset lives for DPP3 produces a disincentive for GPBs to continue investing in replacement, upgraded or new long-life assets.

C28.1 This is because there is not a reasonable prospect of GPBs recovering their investment costs over the economic lifetimes of the assets. Expectations of not recouping the costs of existing investments over their economic lifetimes affects businesses' willingness to continue to make investments.

C28.2 This may undermine the continuity of safe and reliable natural gas supply to consumers who continue to demand, and are willing to pay for, gas in their businesses and homes in the coming decades.

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[257] Australian Energy Regulator "Regulating gas pipelines under uncertainty" (November 2011), p.40.

C29 Gas is currently used by approximately 300,000 consumers to run businesses, heat water and homes, and to cook. Consumers value its reliability, price, and for some users there are few economic alternatives. Industrial gas users requiring high temperature process heat, for example, may have limited alternatives – particularly in the short term.

C30 Consumers too have made investments, such as in boilers and appliances, which they may wish to continue to use before they require replacement. Changing energy sources to low-carbon alternatives will be progressed over many years and may require significant long-term planning.[258] Also, new gas consumers are expected between now and 2050, it is not about an industry serving current consumers alone.

C31 As discussed in Chapter 2, the task for us under the Act is to make decisions at each price reset that promote the long-term benefit of consumers of natural gas pipeline services. The actions we take now will influence economic and financial outcomes for GPBs and consumers, including by ensuring incentives to promote continuing reliable and safe supply to those consumers who are willing to pay for piped natural gas and through pricing signals for consumer investments. Actions of GPBs themselves during the reset period and beyond are also important and will affect outcomes.

C32 When setting allowed revenues for DPP3, our allowances include capex requirements outlined in each GPB's 2021 asset management plan, provided it is less than that GPB's historical average real capex (see Chapter 5). The resulting expenditure allowances for the four-year DPP include $284m of capex and a further $377m of opex (see Table 5.1) for all GPBs.

C33 GPBs' 2021 AMPs signal there is expected to be a need for significant further investment after DPP3. Table C1 shows that GPBs plan expenditure over the next 10 years of nearly $2b, including capex of nearly $900m.

[258] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), p.201-203.

Table C1: AMP forecast capital expenditure and operating expenditure 2022-2031 ($m nominal; capex is net of capital contributions)

Gas Pipeline Business	Opex	Capex
GasNet	23,082	10,370
Powerco	205,088	202,028
Vector	156,135	75,618
First Gas Distribution	116,631	159,741
First Gas Transmission	557,594	416,587
Total	**1,058,530**	**864,344**

C34 Our DPP3 allowances included capex for asset renewal as well as capex for growth and new consumer connections (see Chapter 5).

Increased risk of economic network stranding threatens Financial Capital Maintenance and incentives to invest

C35 Networks can become fully or partially economically stranded if at any point in time a network owner can no longer expect to recoup their investment, including through depreciation.

C35.1 This can occur if all or a significant part of the consumer base disconnects or reduces consumption such that the revenue GPBs are able to recover from the remaining customer base is insufficient to recover the costs of the network over time. Consumers would disconnect or reduce consumption if prices required to recoup investment rise beyond consumers' willingness to pay given their economic alternatives.

C35.2 We note that individual network assets can also be stranded. However, the IMs allow for assets to stay in the RAB even though they have ceased to be used (ie, become stranded) which mitigates this risk. It is the economic stranding risk of the network, not of individual assets, which we are focused on in this decision.

C36 Economic network stranding risk is an 'asymmetric' or one-sided, downside risk for regulated suppliers under current DPP settings for GPBs.

C36.1 If GPBs continue to operate as regulated providers, then the commitment to keep assets in the RAB should be sufficient to provide them with an opportunity to recover the cost of their investment and to make a normal return.

C36.2 But if operations cease prior to full recovery of the RAB, or consumers are not willing to pay the required charges, then GPBs may be unable to recover the cost of their investment and may make less than normal profits.

C37 With expectations of declining demand in the long-term, current DPP settings imply increasing prices in real terms over time. This implies an increased risk that consumers may at some point in the future not be willing to pay the required charges. Furthermore, operations may cease prior to full recovery of the RAB, irrespective of consumer willingness or ability to pay.

C38 GPBs are not compensated for the likely extent of the current risk under existing DPP settings. Risks relating to climate change policies which affect the natural gas industry are likely to be non-systematic risk and so are not compensated through the parameters that determine the WACC in the Gas IMs.[259] Regardless of wider economic conditions, the impact of decarbonisation efforts on GPBs is likely to be negative and material.

C39 The regulation of maximum prices under a DPP limits the profits a GPB can earn, but the risk to the downside is not limited. When the downside risks include a real possibility of material stranding risk, ex ante FCM might not be maintained.

C40 Reflecting the (shorter) expected economic lives of assets in the BBM can allow recovery of capital costs, achieving ex ante FCM and maintaining investment incentives, whilst still limiting GPBs' ability to earn excessive profits.

Submitters expressed strong views about stranding risk and the role of Financial Capital Maintenance

C41 We received a wide range of views on the extent of network stranding risk in DPP3, including whether continued application of our ex ante FCM principle under the BBM approach would promote the Part 4 purpose.

C41.1 GPBs were strongly of the view that economic network stranding risk was material, and that action should be taken now to address the risk to continue to incentivise investment.

[259] See Commerce Commission "Input methodologies review decisions – Topic paper 4 – Cost of capital issues" (20 December 2016) , paras 423-433.

C41.2 Most non-supplier participants were less convinced of a material risk of economic network stranding. Some submitters argued that it was not necessary to act in DPP3, or pointed to possibilities indicating the risk was less than we had assessed in our draft decision.

C41.3 We received one submission arguing that the expected decline in long-term demand (and implied stranding risk) was so significant that we should abandon our commitment to ex ante FCM at this time.

C42 We expand on the views expressed by submitters in more detail below.

We have concluded that stranding risk has increased materially for Gas Pipeline Businesses

Extent of stranding risk depends on the range of credible future outcomes for GPBs

C43 The extent of stranding risk under current settings depends on the wide range of credible future outcomes for GPBs. It is credible that networks may have some residual economic value of (as yet) unknown quantum in conveying alternative gases. However, it is also credible that networks or parts of networks are decommissioned with limited or no residual economic value.

C44 We acknowledge that network wind-down is not likely to be imminent, that is, not occurring within DPP3 or DPP4. We agree with submitters that there is currently no legislative or policy requirement for gas pipelines to cease at any particular date in the future. Nor is there any firm view on the viability of using existing or future networks to convey (currently) unregulated clean gases, despite many of the GPBs having investigation programmes underway. Furthermore, there may be short-term increases in demand for GPB services.

C45 However, in terms of preserving incentives to invest and an ex ante expectation of FCM, it is the material risk of economic network stranding that matters, not that the event has occurred or its occurrence is knowable. There is a material risk that in the long run GPBs will not be able to recover the RAB under a wind-down scenario if we continue to use physical asset lives to set the allowed recovery for depreciation. As noted above (para C36), this is an asymmetric risk that is not compensated for by current IMs.

Existing asset life assumptions appear inconsistent with ex ante Financial Capital Maintenance

C46 Prima facie, given the risk of a network wind-down, using the standard physical asset lives provided in the IMs to depreciate existing and incremental investments, will not allow recovery of capital and therefore no longer supports ex ante FCM.

C46.1 The asset lives in the Gas IMs applied in the past imply recovery of the cost of some assets under the BBM will continue for several more decades, when demand will likely diminish materially before that.

C46.2 As incremental assets eventually become sunk assets (ie, at the beginning of the subsequent regulatory period), and GPBs anticipate this, then continuing to apply standard physical assets lives in calculating depreciation for existing assets also fails to signal or support ex ante FCM.

C47 To quantify the potential extent of unrecovered RAB for existing assets, and thus estimate reasonable economic lives, we took current DPP settings and rolled forward the value of the RAB out to 2070. We sourced the actual distribution of remaining regulatory asset lives for existing assets from GPBs.

C48 Table C2 shows that, based on our assumptions, and even with no new investment that there will be significant unrecovered RAB across existing depreciable assets for all GPBs in 2040, 2050, 2060 and 2070 under current DPP settings.

Table C2: Regulated Asset Base adopting current DPP settings ($million) – 2020 existing assets only

Gas Pipeline Business	2020 Existing	2040	2050	2060	2070
GasNet	24	16	10	6	2
Powerco	389	180	88	28	6
Vector	434	352	252	141	51
First Gas Distribution	174	115	83	59	30
First Gas Transmission	850	404	140	36	21
Total	**1,871**	**1,067**	**573**	**270**	**110**

Expectations of declining consumer willingness or ability to pay lead to increased stranding risk

C49 A long-term decline in delivered natural gas volumes is expected as New Zealand transitions to a low-carbon economy.

C50 However, as raised by submitters it is important not to equate declining gas pipeline volumes with declining willingness to pay on the part of consumers and so the potential for revenue recovery in the future.

C50.1 For example, as noted by some submitters, small consumers, like residential and small business consumers, contribute much more revenue per unit of gas transported than larger users, and are seen as less price sensitive. It may be possible to increase prices for these consumer groups to offset reductions in revenue from consumers that have reduced demand or exited the network.

C51 We agree that it is expectations of aggregate willingness or ability to pay over the future given expectations relating to the future of gas supply that matters for ex ante FCM, not delivered volumes. More precisely it is the risk that the total remaining RAB cannot be recovered within expectations of achievable potential revenue over the remaining lifetime of the assets.

C52 Achievable potential revenue over the remaining lifetime of the assets depends on a range of unknown factors. It may be possible for repurposing (or other opportunities) to limit any reduction in achievable potential revenue, in which case regulated networks would retain an expectation of making normal profits. However, there are clear and material downside risks to achievable potential revenue, which may result in an expectation of achieving less than normal profits over time if these risks remain material and uncompensated for. There is a risk:

C52.1 of network closure, which would essentially truncate consumers' ability to pay for gas pipelines, regardless of whether they still demand the service;

C52.2 that future governments place restrictions on gas pipeline usage which would limit which consumers have access to gas pipelines;

C52.3 that in the future the cost of alternative fuels declines relative to delivered natural gas, which essentially caps individual consumers' willingness to pay for natural gas;

C52.4 that consumers place less value on delivered gas because of environmental or other concerns relating to climate change; and

C52.5 that consumers anticipate potential network wind-down and when needing to replace assets with new assets, choose energy alternatives that do not use natural gas and/or are not dependent on gas pipelines to avoid the risk that their own investments may become stranded.

C53 Each individual consumer's demand responsiveness to changes in price (price elasticity of demand) is a key uncertainty, that may counter some of these concerns in the short run. In the short run, we agree with submissions that tariff restructuring such as increased fixed charges, can offset lower delivered volumes and limit the impacts on achievable potential revenue. Any short-term increase in gas volumes further increases headroom. But tariff restructuring is unlikely to offset revenue from lower gas volumes in the long run as it increases the risk of disconnections.

C53.1 Increasing fixed charges imply increased average charges, which means consumers end up paying more for less useful energy.

C53.2 The sensitivity of demand to price rises will differ between different consumer types, but for some consumers, gas is discretionary so consumers can disconnect in the long run to avoid fixed charges where there are more cost effective alternatives (e.g. electric space heating)

C53.3 We also note gas usage projections by Concept (see Chapter 3) show declines in gas usage for most consumer segments by 2035. Tariff restructuring, without increasing disconnections, is more difficult when usage by all or most groups is expected to decline.

C54 Our conclusion is that despite the ability to restructure tariffs, consumer disconnections would eventually occur if volumes declined with significant impacts on aggregate willingness and/or ability to pay and the potential for revenue recovery. The expectation of declining volumes therefore leads to increased stranding risk at this time.

Continuing support for ex ante Financial Capital Maintenance would best promote the Part 4 purpose at present

C55 As noted above, neither network closure nor economic network stranding appear imminent at this time. However there is clear evidence that economic asset lives are now shorter than physical asset lives. Continuing to use physical asset lives will increase the risk of asset stranding in the future. Shortening asset lives to better reflect economic lives addresses this risk through DPP3 to support (ex ante) expectations of FCM.

C56 Some submitters argued however, that we should abandon the ex ante FCM principle that underpins the building block method applied to calculate depreciation and set prices under DPP regulation.

C56.1 Fonterra and MGUG submitted that existing quality and safety regulations require necessary investments to be made and ex ante FCM is not needed for incentives;[260,261]

C56.2 Methanex and Nova submitted that GPBs have sufficient interests in maintaining revenues from existing sunk assets to incentivise prudent behaviour. [262,263]

C57 We do not agree. As discussed in Chapter 5, we consider that continued investment in maintaining and renewing the network is needed to maintain safe and reliable gas pipeline services. Safety legislation and existing financial interests are not sufficient to incentivise all types of investment needed to meet consumer demand where consumers are willing to pay for the service (including system growth and new connections).

C58 Some submitters argued that we should only provide an expectation of FCM for incremental investments and suggested we should revise asset lives for new investments only.[264,265]

C59 Again, we do not agree. Maintaining ex ante FCM on sunk assets is important to incentivise new investment. This is because at the next regulatory period, the current period's incremental investments become sunk. For businesses to have incentives to invest now, they need to have an expectation on average of at least recovering the full cost of their investments. Adjusting asset lives for existing assets to better reflect their economic lives provides the expectation that once assets become sunk, they will still be provided an expectation of FCM.

There are strong reasons to act in DPP3

There were a range of views on the urgency of action

C60 As mentioned above, several pipeline users and gas retailers argued that we should defer action for DPP3 and wait for more certainty before addressing the changes in long-term demand expectations for GPB services.

C60.1 Submitters including MGUG and Fonterra argued that other existing or proposed mechanisms are adequate to address the risk for DPP3, given the uncertainty. This included GPBs adjusting capital contribution policies, our

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260 Fonterra "Submission on Gas DPP3 draft decision (10 March 2022), para 10.

261 MGUG "Submission on Gas DPP3 draft decision", para 13.

262 Methanex "Submission on Gas DPP3 Draft Decision (15 March 2022), para 34.

263 Nova Energy "Submission on Gas DPP3 draft decision" (14 March 2022), p.1 para 2.

264 Munro Duignan Submission on Gas DPP3 draft decision (14 March 2022) , p.1 para 3.

265 Nova Energy "Submission on Gas DPP3 draft decision" (14 March 2022), p.1 para 2.

proposed capex reopener, the four-year regulatory period and the availability of a CPP during DPP3 if necessary. These submitters also suggested that issues surrounding stranding risk would be better considered in the upcoming IM Review and not in DPP3.[266] [267]

C60.2 MGUG, Methanex, Fonterra, NZ Steel, Greymouth Gas and Nova expressed concern that our draft decision to shorten asset lives for DPP3 risks accelerating decline in demand for GPBs. For example, Methanex noted that signals from rising prices could result in irreversible outcomes from consumer behaviour which "contribute to the wind-down in pipeline revenues, perhaps inducing it, and increasing risk of real-world stranding event". MGUG likewise argued that acting now risks premature disconnection on the part of some consumers.[268,269,270,271,272,273]

C60.3 Methanex and Munro Duignan also submitted that the proposed DPP3 approach to the risk of asset stranding is not consistent with what would occur in a workably competitive market.[274]

C61 On the other hand, GPB submitters such as Vector considered that we should act now. Vector stressed that not providing an expectation of ex ante FCM would disincentivise efficient investment to the detriment of consumers:[275]

> it would become economically unfeasible for a business to consider investing in long lived assets without an expectation of recovering this investment. Indeed, a director may be unable to discharge their fiduciary duty to act in their company's best interests if they considered approving new expenditure.

C62 Vector also noted that shortening asset lives in DPP3:

C62.1 supports the welfare of future consumers by ensuring future prices are lower than they would otherwise have been and ensuring the cost burden of asset stranding does not fall on future consumers that were unable to disconnect from the network;

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266 MGUG "Submission on Gas DPP3 draft decision" (14 March 2022), para 5 and p.33.

267 Fonterra "Submission on Gas DPP3 draft decision" (10 March 2022), p.1 and p.3.

268 MGUG "Submission on Gas DPP3 draft decision" (14 March 2022), para X14.

269 Methanex "Submission on Gas DPP3 draft decision" (16 March 2022), para 29.

270 Fonterra "Submission on Gas DPP3 draft decision" (10 March 2022), para 23.

271 New Zealand Steel "Submission on Gas DPP3 draft decision" (14 March 2022), p.1.

272 Greymouth Gas "Submission on Gas DPP3 Draft Decision" (15 March 2022), para 12.

273 Nova Energy "Submission on Gas DPP3 draft decision" (14 March 2022), p.1.

274 Methanex "Submission on Gas DPP3 draft decision" (14 March 2022), para 12 and Munro Duignan "Submission on Gas DPP3 draft decision" (14 March 2022), p.5.

275 Vector "DPP3 Draft Decision submission" Public Version (16 March 2022), para74.

C62.2 supports the future optionality of GPB assets to provide a smoother transition to clean gases if this becomes technically feasible; and

C62.3 is NPV-neutral (with respect to the WACC) so cannot raise any concerns around the ability of GPBs to extract excessive profits (s52A(1)(d)).

We conclude that acting in DPP3 promotes the long-term benefit of consumers

C63 A range of considerations support the case for acting now to address the risks from declining long-term gas pipeline usage, rather than waiting for more certainty or giving assurances that we will act in the future.

C63.1 Acting now enables us to give better effect to the Part 4 purpose. There is a material likelihood that many existing and most incremental investments will have much shorter economic lives if networks winddown as a result of government policies to phase out fossil fuels. It would appear inconsistent with the Part 4 purpose to set allowable revenues for DPP3 over the next 4 years on the basis of a depreciation building block reflecting standard physical asset lives which make no accommodation for the risk of asset redundancy or network closure.

C63.2 Acting now supports an expectation of FCM in response to a material and present risk under current DPP settings. As discussed above, almost $300m of capex alone has been approved for DPP3. It would not be credible to set a DPP using regulatory asset lives that equate to physical lives of the assets, when there are strong grounds to believe that the economic lives of those assets are shorter. Doing so would disincentivise continuing efficient investment and undermine the ex ante FCM principle.

C63.3 Acting now to setting maximum allowed revenues that better reflect long-term expectations of demand for GPBs promotes more efficient use of pipeline assets over time. We expect it should result in more cost-reflective consumer prices, on average, for both current and future consumers. If consumers (and potential consumers) face more cost-reflective prices, they are more likely to make more efficient decisions on how they use gas and invest in gas-dependent infrastructure over time. If today's consumers of gas pipeline services pay less than cost-reflective prices that they would be willing to pay for, it increases the likelihood that future consumers will not be supplied with services they are willing to pay for. So allowing prices to increase now likely results in greater long-term benefit of consumers overall and over time by ensuring that consumers are provided services that reflect their demands (s52A(1)(b)).

C63.4 Acting now is supported by our efforts to assess the financial implications of deferring action. Shortening average asset lives in DPP3 reduces the revenue that needs to be recovered from consumers in future regulatory periods. Modelling deferring action compared to acting now shows that, for the identified risk, we expect the need for permanently higher allowed revenues after a transition to expected economic lives than if we act in DPP3 (Attachment D). This is a conclusion that was supported by analysis presented on behalf of Powerco, Vector and First Gas in response to our process and issues paper. The report by Houston Kemp showed a predicted price path from 2027 would be 8.8 percent higher if no change was made during 2022-27.[276]

C63.5 Acting now preserves options which may be valuable to consumers of natural gas. There is considerable uncertainty over possible future scenarios and shortening asset lives to more effectively maintain the incentive to invest provides a valuable option to prolong the use of the network (or parts of it) than alternatives (like assuming early closure, or only providing expectations of FCM for incremental investment).

C64 We also disagree that shortening asset lives in DPP3 will lead to significant premature consumer disconnections during DPP3 or beyond.

C64.1 There is no persuasive evidence before us that consumers' willingness to pay will be exhausted by an increase in prices.

C64.1.1 Our final decision to accelerate depreciation leads to real price increases for consumers (in aggregate) of approximately 3.0% - 10% per annum in real terms, and we have capped total real price increases at 10% per annum across all GPBs (see chapter 4).

C64.1.2 Vector's submission reported significant falls in pipeline charges over the past decade on its network, implying a large cumulative decline. It states that its gas prices have reduced by about one-third in real terms since DPP1. Vector submitted that "even with a more aggressive tilting of depreciation (including removing the deferred recovery of inflation) Auckland charges could increase by less than what customers historically paid for their distribution network".[277]

C64.1.3 First Gas, using MBIE data on delivered energy prices over the last 20 years, submitted analysis that gas prices have decreased in real terms, while electricity prices have increased.[278]

C64.2 Arguments from submitters that we may prematurely trigger a decline in demand are somewhat contrary to submitters' own points made elsewhere that increased willingness to pay on part of some consumers in the future means we should defer action until after DPP3.

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[276] Houston Kemp (on behalf of Powerco, Vector and First Gas) Declining gas utilisation report "submission on Gas DPP 2022 process and issues paper" (1 September 2021), p.15.

[277] Vector "DPP3 Draft Decision submission" Public Version (16 March 2022).para 106, 108.

[278] First Gas "DPP3 Draft Decision submission" (16 March 2022), p.13-14.

C64.3 GPBs retain choices about how to price across consumer classes, and incentives to do this in a way that minimises medium to long-term revenue loss. In addition, the allowable revenues set under DPP3 imply the *maximum* amounts to be recovered through prices and GPBs do not have to price to the maximum (foregoing short-term revenue).

C65 We acknowledge that the changes to asset lives that affect BBM depreciation are NPV-neutral with respect to GPBs' WACC (and GPBs therefore remain limited in their ability to extract excess profits), but that the impacts on individual consumers are more varied.

C65.1 Consumers expected to remain on the network longer are better off, while consumers who are expected to cease using gas pipeline services in the nearer term are worse off as a result of shortening asset lives in DPP3.

C65.2 All consumers of gas pipeline services, however, benefit from having the service, and should contribute to the cost of providing it. Future customers pay disproportionately more if asset life shortening is delayed.

C66 In conclusion, we consider that acting now to address the risks from declining long-term pipeline usage will better promote the Part 4 purpose than deferring action.

Attachment D Modelling supplement – recognising shorter asset lives to address economic network stranding risk in DPP3

Purpose of this attachment

D1 This attachment provides additional information on:

D1.1 long-term modelling that has informed our judgement on the action required in DPP3 to better reflect economic asset lives of GPB assets;

D1.2 submitter views received on our draft decision that informed our analysis and revisions to our long-term modelling;

D1.3 the estimation of the asset adjustment factors to apply as part of our DPP3 final decision to shorten GPB asset lives for regulatory purposes; and

D1.4 the results of modelling a deferral of action until DPP4.

Our decision to shorten assets lives to more realistically reflect expected economic lives is a judgement supported by long-term financial modelling

Estimating the extent of asset life reductions involves long-term modelling

D2 As discussed in chapter 6, and in Attachment C, we consider that shortening asset lives at the DPP3 reset enables us to set a DPP which better promotes the Part 4 purpose notwithstanding the significant changes and uncertainty now facing the regulated gas sector. This is because it:

D2.1 aligns asset lives with a shorter timeframe more consistent with how long pipeline assets are expected to convey natural gas to consumers willing to pay; and

D2.2 credibly supports an expectation of FCM under our BBM framework which promotes incentives to invest.

D3 Under the straight-line depreciation method required by the Gas IMs, shortening asset lives will result in a better expected long-term profile of RAB recovery through depreciation for DPP3 under the BBM framework.

D3.1 Through GPBs translating the shortening of *average* asset lives for DPP purposes into the shortening of *particular* asset lifetimes for ID, more appropriate values of the unrecovered RAB will be rolled forward to future periods. That is, an increased allowance for depreciation in DPP3 will reduce the RAB which is used to inform future resets in DPP4.

D4 Our approach to estimating the extent of asset life reductions for GPB assets to more realistically reflect economic lives has been to undertake analysis and exercise judgement by:

D4.1 examining a range of credible long-term scenarios where changes to the long-term profile of RAB recovery through depreciation mitigate economic network stranding risk over network lifetimes; and

D4.2 considering impacts on consumers of short-term price increases.

We have developed a long-term model addressing stranding risk to inform our decision

D5 Assessing the magnitude of the stranding risk and the extent of asset life reductions to more realistically reflect economic lives requires projections of long-term revenues of GPBs under the BBM.[279] This assessment extends beyond the scope of existing DPP financial models, so we developed an additional financial model to explore a number of long-term scenarios for each GPB with full recovery of the RAB for depreciable assets by an assumed network shut down year.

D6 The long-term model draws on available GPB-specific data combined with some basic assumptions and projections (eg, future opex and capex profile) to understand the effect on short-term and long-term BBM revenues.

D6.1 The model demonstrates full RAB recovery by shaping the aggregate BBM depreciation profile to recover the RAB by an assumed shut down year. This addresses the risk of a network wind-down prior to full recovery of the RAB under existing physical asset life assumptions. However, it does not address the risk that consumers' aggregate willingness and/or ability to pay declines, impacting on achievable potential revenue prior to the assumed shut down year.

D6.2 We shape the long-term MAR profile to address expectations of declining potential revenue prior to the assumed shutdown year. Gas volumes are expected to decline, but there is significant uncertainty about the relationship now and in the future between gas volumes and aggregate willingness to pay (see paras C49 to C54). Given this uncertainty, the model assumes a simple downward linear or concave trend, before reaching a fixed proportion of the 2023 MAR in the assumed shut down year.

[279] In the absence of an application and approval process like for EDBs, we have undertaken simplified modelling of the stranding risk ourselves, sought views from interested persons on our draft decision, and used our judgement as outlined in this paper to determine the appropriate degree of risk mitigation for DPP3.

D7 The model only implies that economic network stranding is avoided to the extent that the shaped MAR profile is less than expected aggregate willingness and/or ability to pay for all building block components over the lifetime of the assets. Shaping the MAR does not ensure that maximum allowed revenues are always less than maximum potential revenue given consumers' willingness and/or ability to pay for a given scenario, as it is practically very difficult to quantify the latter.

D8 However, given expectations of declining gas volumes in the long-term, shaping the long-term MAR profile has the effect of limiting expected price increases per unit of volume delivered (eg, $/GJ). This helps to address the risk of economic network stranding that results from the potential for declining aggregate willingness to pay as the number of customers decline.

D9 The results from this long-term financial model then inform our decision on the likely economic lives of GPB assets and the extent of asset life reduction to apply in the DPP3 financial model. It is the DPP3 financial model that determines the actual profile of the MAR set under the DPP, which is based on BBM for DDP3 and applies the Gas IMs, and in-period smoothing using an alternative X factor to mitigate DPP3 starting price shocks, where applicable.

D10 Note that to deliver the allowed revenues implied by the long-term financial model beyond DPP3 we would need to make further adjustments to BBM settings in those future periods. This could either be by making further average asset life adjustments consistent with the updated IMs, or changing IMs, for example to use an alternative depreciation profile or to not index the RAB for inflation.

Our analysis for our draft decision was anchored in a 2050 reference scenario

D11 For our draft decision we modelled (using the long-term financial model) a reference scenario consisting of a network closure at 2050, with a MAR profile that allowed constant real increases in revenue for an initial six-year period, but was shaped to ramp down (linearly to 20% of the of the 2023 nominal MAR) in the long-term out to 2050. It also assumed capex on depreciable assets after DPP3 that ramped down in the long-term, with no net costs incurred for relocations, consumer connections and system growth. The scenario did not assume any residual value of depreciable pipeline assets arising during this timeframe.

D12 Comparison of the reference scenario with 2040 and 2060 wind-down year sensitivities produced by the model indicated that there was significant uncertainty about the extent of adjustment that should be made to asset lives to reflect expected economic asset lives. Modelling results were particularly sensitive to the year in which full RAB recovery of depreciable assets was required.

D13 While stressing that no one scenario or sensitivity could be described as most likely, our draft decision adopted the 2050 reference scenario as a starting point. Specifically, we considered the probability of a 2050 wind-down scenario with no residual value was a non-negligible risk. We aimed to demonstrate how applying asset adjustment factors to shorten average asset lives could provide a credible expectation of capital recovery under that scenario.

Submitters commented on the robustness of our long-term modelling approach

D14 We received feedback from submitters on the modelling approach that informed the judgment for our draft decision.[280] We acknowledge that the long-term financial model simplifies many aspects of the problem of the financial future of the gas networks and that some submitters wanted additional rigour and flexibility added to the modelling approach. However, all models, including the DPP3 financial model must make simplifications and assumptions about the future, and we consider that the long-term financial model is of sufficient rigour for setting a fit-for-purpose DPP3.

D15 We note also that Frontier Economics on behalf of Vector, First Gas and Powerco reviewed the long-term financial model used in the draft decision. Frontier expressed two main concerns: [281]

D15.1 the divergence between maximum allowable revenues between the long-term financial model and the DPP3 financial model; and

D15.2 the depreciation allowance produced by the Asset Stranding Model may result in the RAB being depreciated more/less quickly in the Financial Model than is implied by the adjustment factor.

D16 With respect to the divergence between the MAR in both models, we were aware of this issue when developing the model, and it arises because of simplifications between the building blocks model used in the long-term financial model and the DPP3 financial model. Because of these simplifications we were unable to have consistency between the models for both depreciation and the MAR for DPP3. We considered that it was more important for our purposes, calculating an asset life adjustment factor to mitigate economic network stranding risk, that we align depreciation between the two models rather than the MAR.

[280] See for example, Methanex "Submission on Gas DPP3 Draft Decision (15 March 2022), para 22, MGUG "Submission on Gas DPP3 draft decision" para 21.

[281] "Vector, First Gas and Powerco joint letter accompanying frontier economics report (14 March 2022)" and "Frontier Economics (submitted by Vector, First Gas and Powerco on Gas DPP3 draft decision) – Review of Asset Stranding Model" (13 March 2022)

D17 For the final decision we have retained our approach from the draft, aligning depreciation rather than MAR. With respect to the concern that the RAB is being depreciated more/less quickly in the Financial Model than is implied by the adjustment factor, we consider that the RAB is being depreciated in the Financial Model at precisely the rate required by the adjustment factor. The adjustment factor in the financial model determines the remaining asset lives which in turn determine the depreciation.

D18 This is because the fundamental purpose of the long-term financial model is to determine the extent of asset life reduction to apply in DPP3, which specifically impacts on the amount of depreciation allowed in DPP3.

We have had regard to submitter views regarding other plausible scenarios

D19 Submitters raised a number of points about the assumptions underpinning our long-term modelling and the suitability of the 2050 reference scenario for informing our judgement on asset life shortening. We are grateful to submitters for engaging with the logic and reasons behind our draft decision, and for providing further information and views which we summarise below.

2050 wind-down assumption and net carbon zero legislative target

D20 MGUG noted that New Zealand's current legislative climate policy objective is for "net accounting carbon zero by 2050", and that conveyance of natural gas by pipeline is not legislatively constrained beyond 2050:

> "It remains entirely plausible and consistent with a net zero accounting carbon target that natural gas can continue to be part of New Zealand's energy system by 2050 and beyond".[282,283]

D21 Greymouth Gas, The Major Electricity Users' Group (**MEUG**) and Methanex raised similar points, and Fonterra noted that both the Climate Change Commission and Concept Consulting had assumed that fossil gas is likely still to be in use post-2050.[284,285,286,287]

282 MGUG "Submission on Gas DPP3 draft decision" (14 March 2022), p.7.

283 MGUG "Cross submission on Gas DPP3 Draft Decision" (28 March 2022), para 13b.

284 Greymouth Gas "Submission on Gas DPP3 Draft Decision" (15 March 2022), para 4a.

285 MEUG "Submission on Gas DPP3 draft decision" (14 March 2022), para 6.

286 Methanex "Submission on Gas DPP3 Draft Decision (15 March 2022), para 5.

287 Fonterra "Submission on Gas DPP3 draft decision (10 March 2022), para 3.

D22 Munro Duignan, on the other hand, referred to the Climate Change Commission's advice that gas usage should be eliminated for residential, commercial and public buildings by 2050, and was of the view that we should assume that gas pipeline services "will terminate by 2050 at the latest". [288]

D23 The Gas Infrastructure Future Working Group, explored a number of possible scenarios in its Initial Analysis Paper, including a wind-down by 2040 (labelled a 'fast wind-down') and by 2050 (labelled a 'slow wind-down'). [289]

D24 We acknowledge the point raised by MGUG, and other submitters, that natural gas use might not have fully wound-down by 2050, which in light of the Climate Change Commission's advice that some fossil gas use could continue past 2050, we consider credible. We acknowledge there is currently no definite date that can be pointed to for the phasing-out of gas delivery, including as part of the Government's first ERP, although there is a high degree of uncertainty over how, and which parts of, the GPBs' pipeline networks may be used over the coming decades.

D25 While we still consider it plausible that pipeline usage may in fact have fully wound down *prior* to 2050, we agree that it is credible to put weight on a scenario that has piped natural gas use continuing for some users post-2050, and a phase-out of regulated gas services might thus be assumed to occur at some later date.

Greater ability to recover revenues as a wind-down date is approached than assumed under our straight-line MAR envelope assumption

D26 A likely long-term decline in natural gas usage was generally accepted by submitters. MGUG and Methanex submitted, however, that price elasticity of demand effects might allow GPBs to continue to recover significant revenues from consumers in the future such that a straight-line reduction in the available MAR envelope is an over-simplification.

D27 MGUG noted:[290]

> By differentiating consumer classes and mapping these to GPB revenues it is possible to have both a significant reduction in gas demand, and still retain the majority of the revenue to maintain a viable pipeline business.

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[288] Munro Duignan "Submission on Gas DPP3 draft decision" (14 March 2022), p.1-2.

[289] Gas Infrastructure Future Working Group "Submission on Gas DPP3 draft decision" (14 March 2022), table 3.1.

[290] MGUG "Submission on Gas DPP3 draft decision" (14 March 2022), para X8.

D28 Methanex noted:[291]

> We would expect that under a business-as-usual scenario the decline in gas demand would lead to a distinctly concave shape to the actual feasible revenue profile, as large volume gas users who pay a proportionately smaller share of pipeline revenues and have a lower willingness to pay at higher gas prices exit the market first …
>
> But conversely, it might be the case that the impact of higher pipeline tariffs arising from accelerated capital recovery when combined with other gas pricing factors first affects the demand of a different class of consumers with a higher proportionate share of pipeline revenue to their gas demand.

D29 Methanex suggested:[292]

> A comprehensive assessment of 'willingness to pay' should be a fundamental input into establishing the degree of risk faced by pipeline owners into the future, but this appears to be insufficiently addressed in the Commission's analysis.

D30 For our draft decision modelling we assumed a simple linear downward trend for the MAR profile leading up to the assumed shutdown year. We expected gas volumes to decline but given the significant uncertainty about both the shape of the decline, and the relationship between gas volumes and aggregate willingness to pay, we chose the simplest possible option to shape the MAR profile and used a linear downward trend.

D31 We acknowledge there is significant uncertainty about aggregate willingness or ability to pay in the future. The difficulty Methanex alludes to, is that the issue involves assumptions around fact-specific aspects of future consumers' characteristics, and which extend over many years into the future, and we have not identified any recent studies or other objective evidence that points one way or the other. Moreover, willingness to pay will be influenced by a number of other hard-to-forecast variables including the availability of low-carbon alternatives, cost curves for developing alternate sources of energy, and the future wholesale price of gas and electricity (both of which has been volatile in recent years).

D32 Noting the issues raised by submitters, we think the prospect that consumers may be able to absorb price increases in the future more readily than a straight-line modelling assumption would imply is also credible. As discussed above, to some extent, and for a limited number of years, GPBs may be able restructure tariffs to avoid revenue losses. As a result, aggregate willingness and/or ability to pay may decline in a concave manner (lesser decreases at first, offset by greater decreases closer to any shut down year), if actual volumes were to decline linearly.

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[291] Methanex "Submission on Gas DPP3 Draft Decision (15 March 2022), para 25.

[292] Methanex "Submission on Gas DPP3 Draft Decision (15 March 2022), para 29.

D33 However, it is also credible that actual volumes could decline in a convex manner (faster at first and slowing closer to a shutdown year). In this case, even with tariff restructuring a straight-line modelling assumption could in fact over-estimate the ability of consumers to absorb future price increases.

D34 Acknowledging that there is significant uncertainty about the expected shape of decline in aggregate willingness of ability to pay, we considered that for our final decision it is reasonable to use either a linear or concave trend in the long-term financial model. Neither option is better than the other, but it is appropriate to consider multiple credible outcomes when shaping the long-term MAR profile.

Possibility of a residual network value that gas consumers should not be paying for

D35 Our draft decision noted there is considerable uncertainty over whether repurposing the pipelines to alternate gas is a credible scenario. The technical and economic feasibility of repurposing GPB pipelines to low or no carbon gases is not yet confirmed. We did not explicitly model a repurposing scenario or a scenario with explicit residual value for depreciable assets, but doing so was not necessary in order to give these factors some weight in our overall judgement.

D36 Our view remains that it is unclear whether any positive residual value could arise from network repurposing, and if there is value, how much is that value.

D36.1 Powerco submitted that excluding a residual value assumption from modelling was reasonable because the technology was not proven, low emissions gas may not be able to compete on price with other low emission sources like electricity, and converting the existing pipeline networks may strand some pipeline assets in the process.[293]

D36.2 Vector noted the existence of other potential unavoidable and unaccounted for costs which could reduce or offset any net residual value from networks, such as decommissioning and relocation costs.[294]

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[293] Powerco “Gas DPP3 Draft Decision cross submission” (29 March 2022), p.2.

[294] Vector "Submission on Gas DPP3 draft decision" Public Version (14 March 2022) paras 117 to 120.

D37 Other submitters pointed out, however, that there are concerted efforts being made internationally to investigate ways to deliver low emission gases through existing pipeline infrastructure, and Nova submitted that "pipeline companies have been actively promoting and pursuing investigation of such alternative future uses for their pipelines".[295] Methanex submitted that it could be "reasonably anticipated that emerging energy policy will address the promotion of alternative gases (green hydrogen and biogas) and that will serve to reduce network stranding risk and the need to accelerate capital recovery."[296]

D38 We note that the Government's first ERP included, as a forthcoming focus area for it, actions to develop low-emissions fuels such as bioenergy. It noted that "Green hydrogen will also be significant for reducing emissions in areas of the economy that are hard to electrify, such as high temperature industrial processes …".[297] Key initiatives include investigating low-emissions energy supply options for renewable gas and bioenergy, developing a roadmap for hydrogen in Aotearoa New Zealand by 2023, and ensuring hydrogen regulatory settings are fit for purpose. In our view these statements do not materially change the uncertainty over whether repurposing might eventually be viable.

D39 Nevertheless, and despite the current uncertainty, we believe on balance that we should attach weight to a possible future outcome which involves positive residual value of pipeline networks. Factoring in such an amount would mean that the full asset-related costs of the pipeline networks should not be recovered through revenues from consumers of natural gas services alone. Alternatively, introducing blends of hydrogen or biogas to existing natural gas supply may serve to slow the decline in overall natural gas usage and allow GPBs more time to recover their capital costs from natural gas users.

D40 The financial effects of repurposing over the long-term, including what plausible range of residual values could be anticipated, are difficult to know. It is also unclear how a residual value should best be reflected in the modelling informing our current assessment. As mentioned above, modelling undertaken for our draft decision did not explicitly address a repurposing scenario or take into account residual value.

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[295] Nova Energy "Cross submission on Gas DPP3 draft decision " (4 April 2022)., p12.

[296] Methanex "Submission on Gas DPP3 Draft Decision (15 March 2022), para 5.

[297] Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan (16 May 2022), p.216.

D40.1 One potentially relevant insight is that if a network closure were to occur at a date earlier than a scenario assumed under our modelling, then the value of the unrecovered RAB at the point of closure could effectively be seen as a residual value. In this way, modelling a 2060 wind-down scenario, could provide a proxy for modelling a 2050 wind-down scenario with a residual value equal to the amount unrecovered at 2050 under that 2060 wind-down scenario.

Extent of shortening to better reflect economic assets lives in DPP3 should be less

D41 Taking the matters raised by submitters described above, regarding other plausible scenarios into account, we consider that the shortening of current asset lives should be less than that suggested by our draft decision.

D42 We consider three factors should be given weight:

D42.1 a post-2050 wind-down. A later assumed wind-down date extends the MAR recovery envelope, implying that less of the RAB-related costs need to be recovered in DPP3 thereby decreasing the need for higher depreciation in DPP3 and reducing asset life shortening in DPP3;

D42.2 concave MAR-envelope, reflecting a potentially greater future willingness or ability to pay on the part of consumers than assumed in our draft decision. This results in relatively more MAR being recovered under the modelling in future periods thereby decreasing the need for higher depreciation in DPP3 and reducing asset life shortening in DPP3; and

D42.3 possibility of some residual value becoming evident at or before 2050. This would effectively remove the requirement to recoup the full costs of sunk pipeline investments from natural gas consumers, lessening the quantum of risk to be mitigated in DPP3 and decreasing the need for higher depreciation in the near term and reducing asset life shortening in DPP3.

D43 The long-term financial model has been further developed to enable these factors to be considered. We have also developed the model to quantify the option of deferring action until DPP4 (see below).

We derived relevant asset adjustment factors from two primary scenarios

D44 In updating the long-term modelling that informed our judgement for our final decision and the calculation of an appropriate adjustment to asset lives, we have had regard to two primary scenarios:

D44.1 our 2050 reference scenario, with updated building block inputs reflecting most recent data and decisions in this paper. This scenario maintains the assumption of a straight-line declining MAR envelope to 2050 adopted in our draft decision; and

D44.2 a 2060 wind-down scenario with a concave MAR envelope. This assumes continued use of some or all of the pipelines to supply natural gas for a decade after the 2050 net carbon zero legislative target. A moderately concave MAR is applied to reflect an assumption of a greater ability of some future consumers to absorb price increases than assumed under our straight-line profile of our 2050 reference scenario.

D45 In the current circumstances, these appear to us to be the central scenarios in terms of the distribution of risks. That is, we consider both a 2040 wind-down and a 2070 wind-down remain plausible scenarios, but that these fall on either end of a spectrum of possibilities. A 2060 wind-down with a higher residual value is also credible – equivalent to, say, a 2070 wind-down with no residual value.

D46 In addition, we think that most weight should be accorded to the 2060 scenario above, not only to acknowledge the possibility of gas use continuing past the 2050 legislative target for net carbon zero, but also to acknowledge that it can be seen as a possible proxy for a wind-down scenario with residual value. We have not explicitly modelled a repurposing scenario or a residual value, but a longer wind-down scenario can be seen as approximating a shorter wind-down scenario with residual value.

D47 We have retained our original 2050 scenario as we still consider it plausible, but it is now not the sole modelled scenario to inform our judgement.

D48 Being guided by two primary scenarios that reflect a wider range of assumptions in this way reflects the current uncertainty, consistent with making an overall judgement and with the lack of specific evidence that submitters could point to, either in support or otherwise of action being taken now. In this way we consider it better informs our judgement on the extent to which current asset lives should be shortened to better reflect their economic lives.

Table D1: Summary of key assumptions used in both scenarios

Network closure year	MAR ramp-up years	MAR ramp-down start	MAR in last year ÷ 2023 MAR	MAR ramp-down shape	Weight allocated
2050	6	2029	20%	Linear	33%
2060	6	2029	20%	Concave	67%

We have also considered further the impacts on consumers from price increases

D49 For our final decision we remain of the view that the short-term revenue ramp-up assumption adopted in the modelling for our draft decision remains appropriate and should be applied to each of the two primary scenarios above. The six-year ramp-up assumption results in four of the six years increases in revenue for the six year ramp-up period occurring in DPP3. As the increases are cumulative, approximately 50% of the total additional revenues occur in DPP3, and implies the remaining 50% occurs in the two years following (ie, in the next DPP period).

D50 We consider that addressing most, but not all, of the transition to new revenue and pricing levels required to better align asset lives in the BBM with economic lives in DPP3 strikes an appropriate balance between the benefits of moving relatively quickly in the long-term interests of consumers, against the impact of short-term price increases. Specifically:

D50.1 assuming that four years of increases (out of a total of six years) will occur in DPP3 provides a credible practical commitment to addressing the economic problem while minimising the risk that worse than expected outcomes will make it difficult, if not impossible, to preserve options for appropriate investment incentives in future regulatory periods;[298]

D50.2 increasing prices earlier has a significant impact on the overall extent to which prices will have to increase at all, and mitigates the risk of unmanageable consumer price shocks in future regulatory periods. It also seems appropriate that the split of revenue over the two periods not be less than 50:50, which is what a six-year ramp achieves approximately; and

D50.3 other aspects of our DPP3 decision allow GPBs to manage risks over the ramp-up period, including:

D50.3.1 a four-year regulatory period which enables DPP settings to be updated sooner, including if the outlook for the industry is worse than expected at present;

D50.3.2 The ability for GPBs to address some stranding risk themselves. For example, GPBs can mitigate increased stranding risk by lowering expenditure on new connection and system growth, and requiring larger contributions from new connections; and

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[298] As discussed below, our actions are not intended to address the more extreme possible scenarios within DPP3 (eg, network shut down by 2040). We will be able to consider whether further actions to address stranding risk in DPP4 and future regulatory periods are in the long-term benefit of consumers at the time of those resets, and will consider any new information that is relevant to our decisions.

D50.3.3 CPPs remain an option if over the course of DPP3, the risk for individual GPBs increases markedly. A CPP allows further flexibility in how assets are depreciated, and for Gas IMs to be varied by agreement – although we expect that our decision to use a four-year regulatory period for DPP3 should reduce the need for a CPP.[299]

D51 Lastly, as discussed in Chapter 4, rather than exposing consumers to large one-off starting price adjustments, we have used smoothing mechanisms for the majority of GPBs to ensure that real average annual price increases are constant over DPP3. We have also applied a 10% real cap to overall price increases, for consumers in aggregate. This 10% cap binds for First Gas Distribution.

Asset adjustment factors are derived from a weighting of scenarios

D52 Table D2 presents the asset adjustment factors implied for DPP3 by each of the two scenarios referred to in paragraph D2 above, and the results of incorporating these as a blended result for our DPP3 final decision.

Table D2: Blending of adjustment factors[300]

Gas Pipeline Business	Revised 2050 wind-down scenario	2060 wind-down scenario	Blended result (33/67)
GasNet	0.73	0.86	0.82
Powerco	0.76	0.86	0.83
Vector	0.60	0.70	0.66
First Gas Distribution	0.62	0.71	0.68
First Gas Transmission	0.68	0.78	0.75

D53 For the reasons given above, we have accorded most weight to a 2060 wind-down scenario that incorporates an assumption of a later network wind-down than our reference scenario and a concave MAR envelope out to that point. The blended result reflects one-third weighting of our 2050 wind-down scenario, and a two-thirds weighting for the 2060 wind-down scenario.

D54 As discussed above, we calculated the blended asset adjustment factor for each GPB necessary to allow four years of revenue increases (out of a total of six years) to occur in DPP3 (see Table D2).

[299] For DPP3 GPBs may submit a CPP proposal any time before 23 October 2024.

[300] Figures are rounded to two decimal places for presentational purposes.

D55 As a final step we calculate asset adjustment factors consistent with applying a 10% real cap per annum in DPP3, and rounding annual revenue increases to the nearest 0.5% per annum in real terms. These final asset adjustment factors are set out in Table 4.4 and are applied for the DPP3 reset.

Shorter asset lives will flow into future DPP resets via Information Disclosure

D56 As mentioned above, the recent IM amendments require GPBs to translate the shortening of *average* asset lives for DPP purposes into the shortening of *particular* asset lifetimes for ID. This results in higher depreciation amounts calculated for particular assets in ID, reducing the RAB values for these assets as they are rolled forward to future periods.

D57 The shortened asset lives under ID persist for the next DPP period so applying adjustment factors to asset lives for DPP3 implies that asset lives will remain shorter if no further adjustments are made at the next DPP reset. In this way, it implies a quicker recovery of depreciation amounts in future DPP periods.

D58 This means that economic lives are better reflected across all future regulatory periods. However, as discussed above (para D2) our decision is informed by modelling that assumes that only four years of annual increases, out of a total of six years, should occur in the DPP3 period, and we have decided that a cap of 10% per annum on price rises in aggregate in real terms should apply.

D59 The adjustment factors we have applied for DPP3 therefore deliver only the first four years of real annual increases. By implication, further adjustment factors would need to be applied in DPP4 in respect of all GPBs to achieve revenue increases for a total of at least six years. As previously discussed we will assess the situation facing GPBs at the time of the future resets taking account of any new information, sector developments, and the IMs applicable at that time.

D60 Lastly, we received feedback from several submitters that we should explicitly consider the option of deferring action in our modelling to inform our judgement on whether it is appropriate to act now (including amending IMs) or defer any action until DPP4.[301]

D61 MGUG stated that the “counterfactual is waiting until DPP4 to implement possible measures for preserving FCM (should these be needed)” and that the counterfactual argument “is not demonstrated by the model”.[302]

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301 MGUG "Submission on Gas DPP3 draft decision” (14 March 2022), table on p.8 and para 15.

302 MGUG "Submission on Gas DPP3 draft decision” (14 March 2022), table on p.8 and para 15.

D62 Methanex stated that:

> one of the fundamental sensitivities that appears to be missing is measuring the impact of modelling a counter-factual to the draft decision. That is, of exploring the impacts of deferring some or all of the acceleration proposed to be covered in DPP3 into the next regulatory period. It does not appear the Asset Stranding Model is configured to run this particular sensitivity. In any event, this work should have been undertaken by the Commission before it arrived at its conclusion of needing to take immediate action in DPP3, particularly given the concerns that Methanex and other submitters had raised in regard to scale and urgency of response in their submissions on the Issues Paper. [303]

D63 As noted in Chapter 6, we consider there are strong conceptual and economic arguments for why acting now based on current expectations is consistent with our usual BBM approach and supports the long-term benefit of consumers.

D64 However, we agree with submitters that it is useful to also consider modelling for the counterfactual scenario of deferring action until DPP4. Such modelling can illustrate the potential consequences of acting now versus deferring action until DPP4, given our expectations of declining gas pipeline usage in the long-term.

D65 Our analysis shows that deferring action results in permanently higher allowed annual revenues after the transition period than if we act in DPP3. This occurs regardless of the MAR transition time frame for the deferred action. The analysis does not show the price outcomes directly, specifically the effect of falling gas usage on average prices per unit of delivered gas. However, we note that falling gas usage will compound the effect of higher allowed revenue on unit price increases, annual price shocks are also expected to be larger the shorter any transition period.

D66 Figures D1 and D2 illustrate potential revenue profiles after DPP3 that could achieve full capital recovery by an assumed shut down. These figures are for the sum of all GPBs; however, the results are very similar for individual GPBs. Full RAB recovery under these scenarios also requires sufficient aggregate willingness to pay from consumers.

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303 Methanex "Submission on Gas DPP3 Draft Decision (15 March 2022), para 24.

Figure D1: Maximum Allowable Revenue profile all GPBs – shut down year 2050 (nominal $000s)

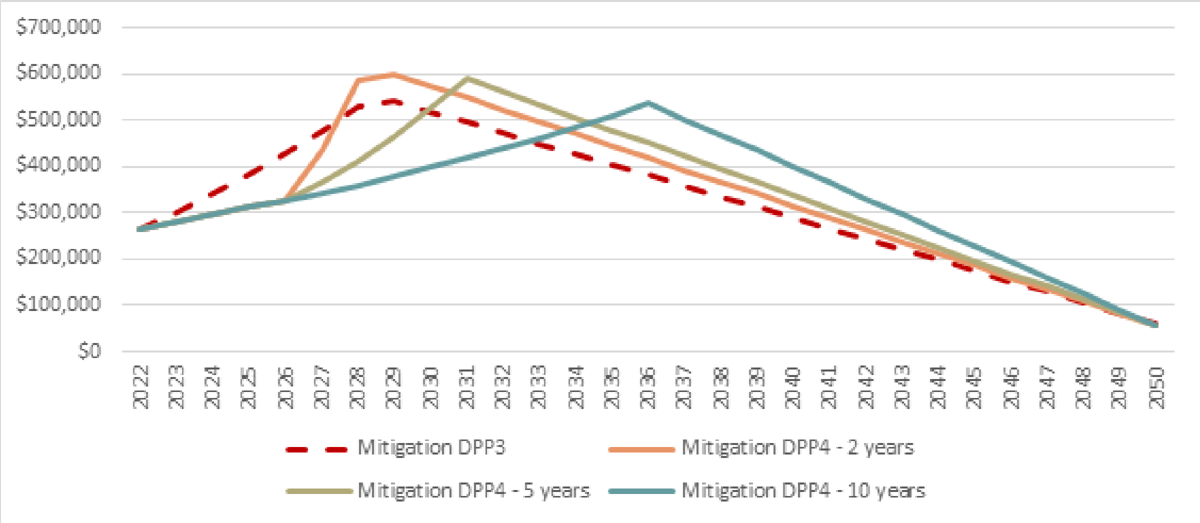
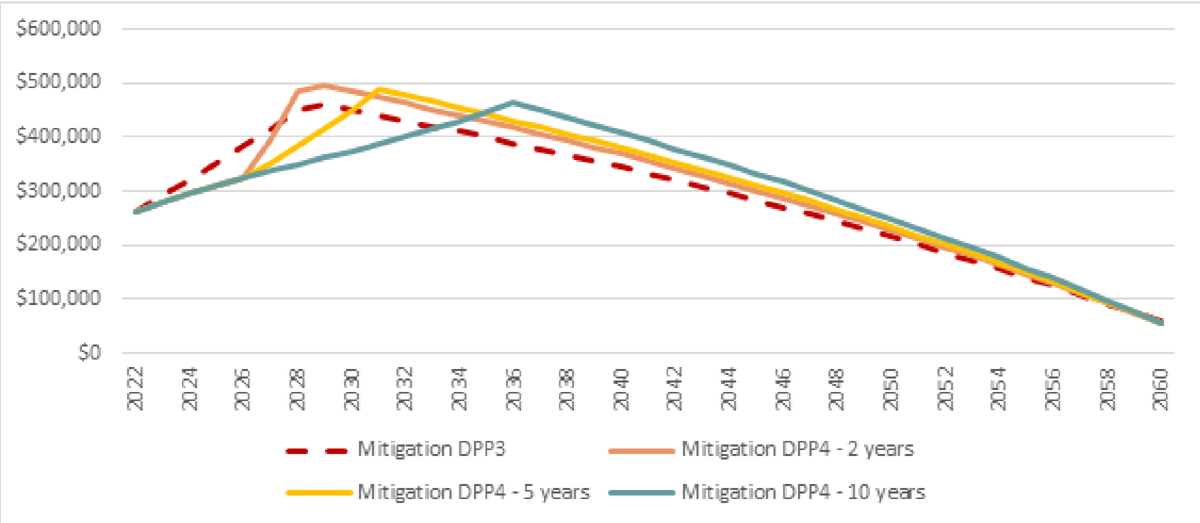


Figure D2: Maximum Allowable Revenue profile all GPBs - shut down year 2060 (nominal $000s)



D67 Three sensitivities to the MAR ramp up period are presented – all which assume no action from 2023-2026:

D67.1 two years of real MAR increases from 2027 to 2028;

D67.2 five years of real MAR increases from 2027 to 2031; and

D67.3 ten years of real MAR increases from 2027 to 2036.

D68 While the model cannot be definitive with respect to ex ante FCM, it is important to note that:

D68.1 spreading the increase over more years, increases the risk that allowed revenues may exceed aggregate willingness to pay, all else equal;

D68.2 this implies a lesser extent of risk mitigation and a higher risk of economic network stranding; and

D68.3 if risk mitigation is not spread over multiple years, then consumers may face detrimental price shocks.

Attachment E Price setting features

Purpose of this attachment

E1 This attachment sets out additional details on the core components for how we have set price-paths for DPP3. It covers:

E1.1 our approach to setting starting prices at the start of DPP3 and the rate of change in prices in subsequent years of the price path;

E1.2 the length of the regulatory period; and

E1.3 our reasons why we believe these settings best promote the long-term benefit of consumers.

E2 Asset stranding risk mitigation is covered in Chapter 6, Attachment C and Attachment D, and is not further discussed in this attachment.

How we set starting prices

E3 In accordance with s 53M of the Act and for each GPB, the DPP must specify:

E3.1 maximum price(s) or revenue for each GPB and quality standards throughout the regulatory period. The two main components of these price or revenue limits which are specified in s 53O are:

E3.1.1 the 'starting price' allowed in the first year of the regulatory period; and

E3.1.2 the 'rate of change in price', or X-factor, relative to the CPI, that is allowed in later parts of the regulatory period.

We have set starting prices based on our assessment of current and projected profitability

E4 We have set starting prices based on our assessment of current and projected profitability, which is consistent with the approach we proposed in our draft decision.

E5 The Act specifies that we may set starting prices based on an assessment of current and projected profitability or roll over the prices from the final year of the previous DPP reset.[304]

E6 We have set starting prices based on an assessment of current and projected profitability. Our view is that this is appropriate for DPP3. We do this using a building blocks approach, which is set out in the following section.

[304] Commerce Act 1986, s. 53(P).

E7 In our process and issues paper we set out our reasons for considering a rollover:

E7.1 a rollover appeared to be a means of mitigating the risk of economic network stranding (see chapter 6). Our assumption was that starting prices were likely to fall under a projected profitability approach and rolling over starting prices would advance cash flows to GPBs. This would mitigate the risk of economic network stranding by bringing forward capital recovery;

E7.2 an assessment of current and projected profitability requires projections of operating expenditure, capital expenditure, capital contributions, and growth (or reduction) in demand, as well as other inputs. Due to the current uncertainty around the future of the industry, any assessment of projected profitability would be subject to a higher degree of uncertainty and potential error.

E8 We requested views on whether rolling over the starting prices from the previous reset would best serve the long-term benefit of consumers.

E9 Submissions on our process and issues paper supported an approach based on current and projected profitability:

E9.1 Vector believed a roll over would be a non-decision about the new efficient level of prices or revenues for GPBs, and would not serve the long-term benefit of consumers;[305]

E9.2 Greymouth Gas stated it is clear that the sector is on a downward trajectory, it is just a question of how fast, and this should be reflected in the upcoming reset;[306]

E9.3 First Gas supported an assessment of current and projected profitability, with suitable adjustments to accelerate capital recovery;[307] and

E9.4 MGUG believed the prevailing uncertainty is not materially different from previous DPP resets, and advocated for an assessment of current and projected profitability.[308]

E10 In our draft decision, we proposed setting prices based on an assessment of current and projected profitability.

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305 Vector "submission on Gas DPP process and issues paper" (1 September 2021).

306 Greymouth Gas “Submission on Gas DPP 2022 process and issues paper (30 August 2021).

307 First Gas – submission on Gas DPP 2022 process and issues paper (1 September 2021).

308 Major Gas Users Group (MGUG) "submission on Gas DPP process and issues paper" (1 September 2021).

E11 Our reasoning was that while a rollover may have been a viable alternative for mitigating some of the risks facing the sector, the circumstances the sector were facing had changed considerably from the prior reset, in terms of both GPBs' efficient costs, and the outlook for the sector.

E12 Our view was that resetting starting prices based on a projected profitability approach better promoted the long-term benefit of consumers, providing GPBs with incentives to invest in maintaining a safe and reliable network, while limiting their ability to extract excessive profits.

E13 In a submission on our draft decision, MGUG supported our decision to set starting prices based on an assessment of current and projected profitability.[309]

E14 Our view is that the reasoning used at the draft decision stage remains sound. Therefore, we have maintained the draft decision and set starting prices based on an assessment of current and projected profitability.

The building blocks allowable revenue approach

E15 We use a building blocks approach to determine the projected profitability. The starting prices we have set for both gas distribution and transmission businesses are specified in terms of MAR which is an amount that does not include pass-through costs and recoverable costs. We have calculated the MAR amount through two key processes.

E15.1 Process 1: Determining a building blocks allowable revenue (**BBAR**) for each year of the regulatory period. At the simplest level the BBAR is calculated using separate cost building blocks as follows:

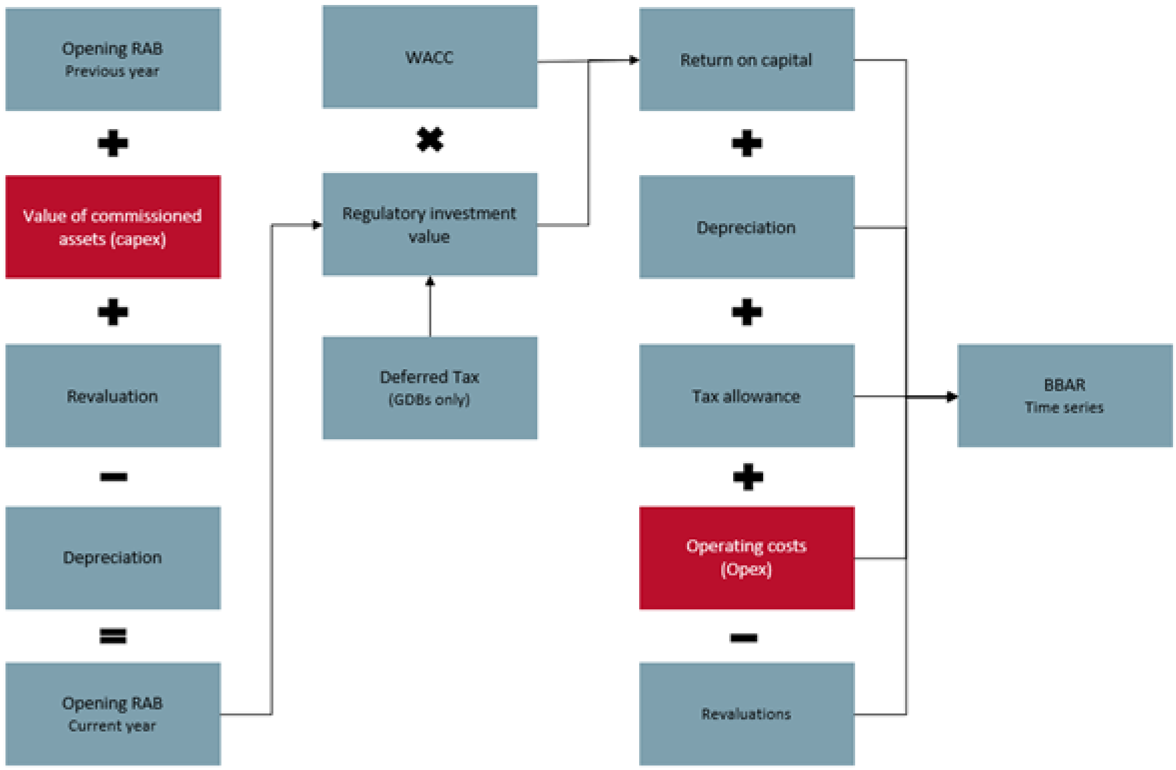
E15.1.1 Return on capital - Revaluations + Depreciation + Operating costs (opex) + Tax allowance.

E15.1.2 A high-level schematic is provided below in Figure E1.

E15.2 Process 2: Smoothing each of the separate BBAR amounts over the regulatory period by CPI and the X-factor in present value terms, and for distribution businesses, also by the CPRG forecast. This represents the yearly changes to the price or revenue limits that are allowed over the regulatory period. A diagram of this step is provided below in Figure E2.

[309] Major Gas Users Group "Submission on Gas DPP3 draft decision" (14 March 2022).

Figure E1: From the regulatory asset base to building blocks allowable revenue



E16 The elements of the BBAR highlighted in red are not determined by the IMs and must be forecast by us throughout the price-setting process. For further discussion on how we have treated these issues, refer to Chapter 5 and Attachment B.

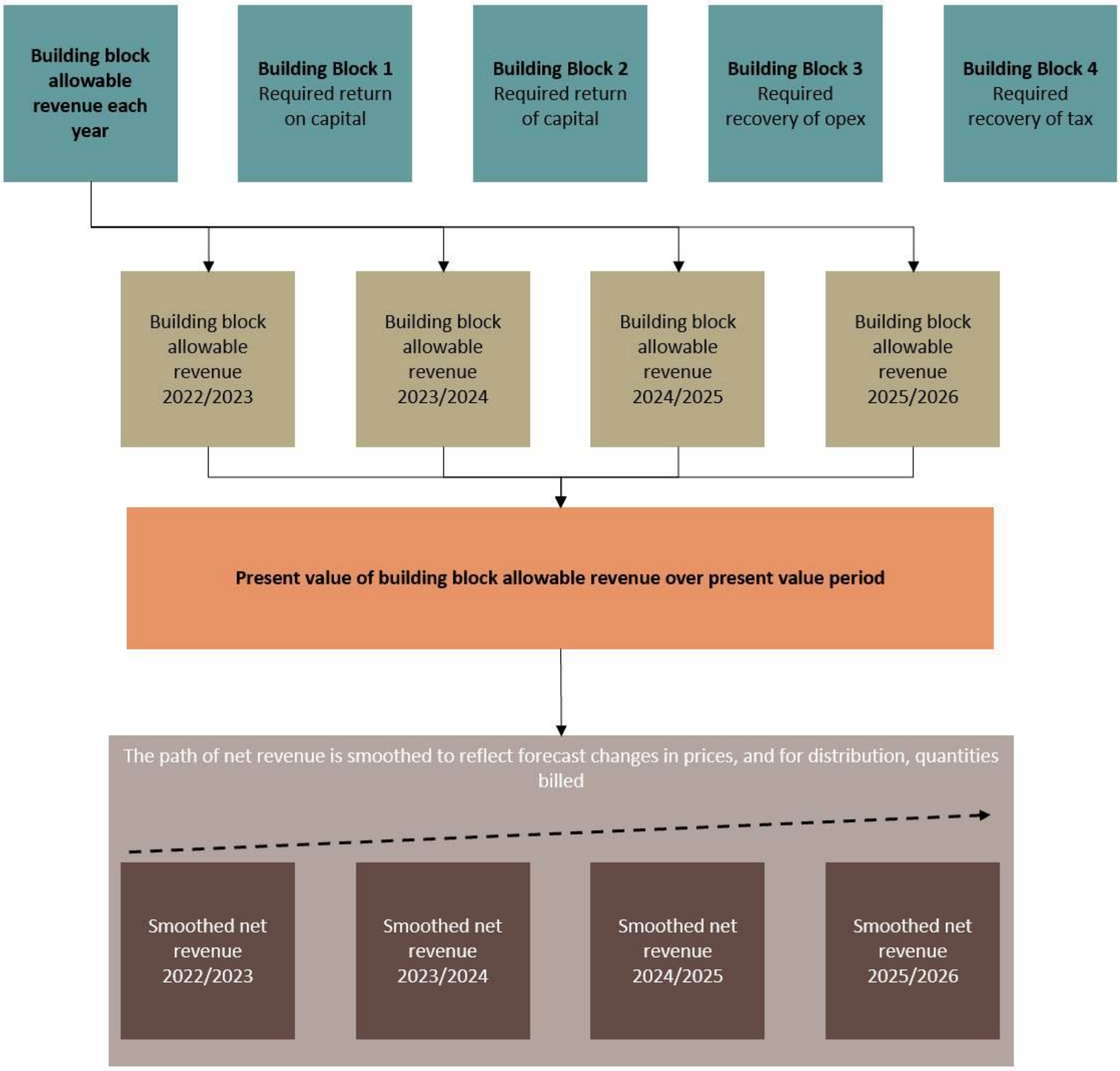
E17 Some inputs into the elements of the BBAR come from information disclosures. For example, forecasts of opex and capex are disclosed in AMPs and we use these as inputs into our decisions on opex and capex allowances.

E18 Other inputs into the elements of the BBAR are wholly or largely set in the IMs. For example, the Cost of Capital IM sets out:

E18.1 how we must estimate WACC including specifying values for most of the parameters eg; beta, leverage, TAMRP; and

E18.2 a methodology for estimating the risk-free rate and the debt premium.

Figure E2: Setting forecast revenues equal to forecast costs



E19 Certain costs that are considered outside of the GPBs' control are recovered through separate allowances for 'pass-through costs'. Certain other costs that GPBs have little control over are recovered through allowances for 'recoverable costs'. The items that qualify under these categories, and the criteria for inclusion that must be satisfied, are set out in the IMs.[310]

[310] Gas Transmission Services Input Methodologies Determination 2012 (Consolidated April 2018). , clause 3.1.2 and 3.1.3. and Commerce Commission "Gas Distribution Services Input Methodologies Determination 2012 (consolidated 3 April 2018)", clauses 3.1.2 and 3.1.3.

E20 Pass-through costs include things such as rates payable by a GPB to a local authority, levies payable under various regulations such as the Act or the Gas Act 1992, or levies payable to Utilities Disputes (formerly the Electricity and Gas Complaints Commissioner) by virtue of their membership. They must be associated with the supply of gas pipeline services.

E21 Recoverable costs include:

E21.1 application fees for a customised price-quality path;

E21.2 wash-up amounts for the GTB**;** and

E21.3 fees for audits that are necessary to meet statutory obligations, such as fees related to ID disclosures and compliance reporting under Part 4 regulation.

E22 The expenditure allowances we set through the building blocks approach described above do not include pass-through and recoverable costs. These pass-through and recoverable costs may be recovered by GPBs in addition to the MAR.

Incentives to focus on controllable costs and outperform the demand forecast

E23 The default price-paths that we have set must specify maximum prices or revenues.

E24 Setting ex ante price and revenue limits means that ex post profitability depends on the extent to which costs are controlled. Actual costs may differ from forecasts for a variety of reasons but the incentive to increase profits helps to incentivise GPBs to minimise costs while still meeting their quality standards.

E25 The way in which we have specified price limits for GDBs also means that profitability depends on the assumptions we make about quantity growth, such as growth in connections and throughput over the regulatory period.

E26 GDBs have an incentive to outperform their given demand forecast in the DPP. Under a WAPC, GDBs bear the within-period demand risk and therefore if they are able to grow demand at a rate higher than their CPRG forecast, they will earn additional revenue, which they are able to retain.

How we specify prices – form of control

E27 The decision on whether the DPP limits maximum prices or revenues, known as the form of control, is determined by the IMs and currently depends on the type of service provided.

E28 For the upcoming DPP reset, we have maintained a WAPC for GDBs, and a revenue cap with a wash-up mechanism for the GTB.

E28.1 GDBs are subject to a WAPC, which places a limit on their maximum average prices during each year of the regulatory period.

E28.2 The GTB is subject to an annual revenue cap with an annual wash-up mechanism, which places a limit on its maximum revenue during each year throughout the length of the regulatory period.

E29 Ultimately, the form of control determines who bears the within-(regulatory) period demand risk. Under a WAPC, the GDBs bear the within-period demand risk and are incentivised to grow demand while maintaining incentives for cost efficiency. Under a revenue cap, consumers bear the within-period demand risk. However, over the life of the assets the long-term demand risk mostly remains with consumers under current settings as assets remain in the RAB when capacity exceeds demand.[311]

E30 Within-period demand risk falls on GDBs under a WAPC as when volumes vary, the weighted average prices GDBs can charge remain the same. Therefore, if quantities delivered fall below the forecast quantities, GDBs earn less revenue (until prices are reset in DPP4). They also bear the upside of this risk. If they outperform the forecast of quantities delivered, they retain the additional revenue during DPP3.

E31 Under a revenue cap, the GTB is subject to a limit on its maximum revenues. The purpose of the annual wash-up mechanism is to ensure that revenue is not over or under-recovered during the regulatory period given the forecast revenue for each year is based on prices multiplied by forecast quantities. The GTB is allowed to set prices in a manner consistent with the relevant transmission and operating codes, but cannot exceed the revenue cap on a forecast basis.[312,313]

E32 For the GTB, under-recovered revenue can be carried forward to the next regulatory period but no more than a 20% reduction in revenue compared to the forecast amount may be recovered through the wash-up mechanism. This is to ensure that the GTB is exposed to some within-period demand risk and has an incentive to manage this risk, and to address concerns about large positive price shocks for consumers when demand significantly changes.

[311] For further discussion on the allocation of risk (including demand risk) in the context of a reduction in the asset lives, refer to Chapter 6.

[312] First Gas “Vector Transmission Code” (1 October 2015).

[313] First Gas "Maui Pipeline Operating Code" (14 May 2016).

E33 Consumers bear the within-period demand risk under a revenue cap. If quantities delivered are lower than forecast when we set the revenue cap, the GTB can raise prices in subsequent years to ensure revenue is not permanently under-recovered.

E34 In our draft decision, we proposed to retain the current form of control to promote the long-term benefit of consumers.[314]

E35 While some submitters favoured a change to the form of control, most submissions on our process and issues paper supported maintaining a WAPC for GDBs, and a revenue cap for the GTB for DPP3.

E35.1 MGUG believed the current forms of control for GDBs and GTBs are fit for purpose. As GDBs are still forecasting connection growth, a WAPC provides them with the appropriate incentives to invest while limiting excess profitability. MGUG was ambivalent as to whether the GTB should remain on a revenue cap, stating that the wash-up mechanism has not resulted in material price shocks to consumers.[315]

E35.2 Powerco believed there was merit in maintaining a WAPC, with the introduction of demand reopeners, that would reopen the price path if there was a significant shock to demand.[316]

E36 Among submitters who preferred a change to the form of control, many acknowledged that further analysis on this issue would be a time-consuming process, and preferred that we prioritised the issue of asset stranding:

E36.1 First Gas stated that given the materiality and impact of other issues, it did not consider that changes to the form of control should be advanced at the DPP reset;[317]

E36.2 Vector believed a revenue cap would be more suited to current circumstances, however recommended we prioritise the topic of asset stranding as the primary focus for the DPP reset;[318] and

[314] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), para A1.

[315] Major Gas Users Group (MGUG) "submission on Gas DPP process and issues paper" (1 September 2021).

[316] Powerco "submission on Gas DPP 2022 process and issues paper" (1 September 2021).

[317] First Gas “submission on Gas DPP 2022 process and issues paper” (1 September 2021).

[318] Vector "submission on Gas DPP process and issues paper" (1 September 2021) .

E36.3 Vector submitted the form of control should be changed for GDBs to a revenue cap due to falling gas demand and inability to forecast gas volumes in a dynamic environment. Vector also argued that if we were to retain a WAPC significant further action will be needed to mitigate disincentives to efficient investment caused by forecast risk:

> "We consider the following actions would be necessary:
>
> - The introduction of a CPRG re-opener; and
>
> - The Commission should update Vector's CPRG forecast as the current forecast is not fit for purpose. We are happy to make our modelling experts available to work through forecasting issues."[319]

E37 We considered Vector's points from the submission but did not find any new evidence that a change in the form of control would better promote the long-term benefit of consumers. We consider that Vector has other options to mitigate this risk including by adjusting pricing policy settings, by adjusting the ratio of its line and volume charges, by reducing (or increasing) expenditure as demand (and thus revenue) decreases (or increases) or through a CPP.

E38 We continue to consider that, even in the current environment where there is potentially more uncertainty, that GDBs are best placed to manage the within period demand risk and still have incentives to maintain their customer base.

E39 Furthermore, as Vector has stated in a recent Operational Performance report, the recent decline in volumes delivered can be partially attributed to the impact of Covid-19.[320] As restrictions, such as lockdowns and border closure, are eased, the volumes delivered will likely recover.

E40 We considered short term demand volatility in the draft decision and found insufficient evidence to change the form of control now.

E41 Powerco argued there would be a merit to change the form of control but suggested deferring consideration of changes to the form of control to the IM Review and agrees with continuing with the WAPC for DPP3.

E42 First Gas and MGUG supported our draft decision to retain the current form of control.[321]

319 Vector "Gas DPP3 Draft decision submission" (14 March 2022).

320 Vector "Operational Performance for the 6 Months Ended 31 December" 25 January 2022.

321 First Gas "Gas DPP3 Draft decision cross submission" (4 April 2022).

E43 Nova in its cross-submission stated that the merits of price versus revenue caps should be reserved for the next IM review and agrees that it is reasonable to continue with price control for GDBs rather than changing to revenue control.[322]

E44 Given the evidence before us and considering the submissions, we consider that GDBs are best placed to manage short term demand risk and still have incentives to maintain their customer base. We have therefore maintained the current form of control, being a WAPC for GDBs, and a revenue cap for the GTB. We can consider issues relating to the form of control in the IM review process currently under way.

We are not introducing demand reopeners.

E45 As noted above, Vector recommended a reopener to address the risk that volumes differed from the demand forecast used in the CPRG model.

E46 Under a WAPC GDBs bear the upside, and the downside, of the within-period demand risk. It is our view that GDBs are best placed to manage this within-period demand risk, and therefore should bear this risk. Maintaining a WAPC while introducing demand reopeners would shift some downside risk to consumers, while GDBs would still benefit if they were to outperform the CPRG forecast. In our view this would not be to the long-term benefit of consumers.

Why we consider the current settings are still appropriate

E47 Allocating risk to the party that is best placed to manage it promotes the Part 4 purpose. This is reflected in our economic principles.

E48 We consider the current settings to be appropriate, as they are likely to place the within-period demand risk on the party who is best able to manage this risk.

E49 Under a WAPC, the allowable revenue can change depending on the actual demand of customers, compared to the GDB demand that is forecast when the DPP is set. A WAPC will incentivise GPBs to maintain their existing customer base and manage their costs.

E50 A WAPC provides GDBs with the appropriate incentives to invest while limiting excess profitability. Meeting demands by consumers willing to pay for the service is in the long-term benefit of consumers.

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[322] Nova Energy "Cross submission on Gas DPP3 draft decision " (4 April 2022).

E51 The GTB differs from GDBs in that they are highly exposed to volatility in demand throughout the regulatory period from factors outside of their control, such as changes in global prices for certain commodities. We have therefore maintained a revenue cap for the GTB.

E52 Furthermore, as the IMs try to promote certainty, maintaining the status quo is preferable when we do not believe there is a sufficiently strong argument in favour of changing the form of control.

E53 Lastly, while demand for gas pipeline services is likely to decline in the long-term, businesses are forecasting the demand is likely to remain relatively stable in the short-term, throughout the length of this regulatory period. This means that a change to the form of control is an issue that would be better addressed in the statutory IM reviews.

We have amended the GTB DPP3 determination to enable revenue wash-ups from DPP2 to be carried over to DPP3

E54 We changed the form of control that the GTB is subject to in the 2016 IM Review. The outcomes of statutory IM reviews apply to future DPP resets. Hence, the change in the form of control for the GTB from a WAPC to a revenue cap was implemented for the first time in DPP2.

E55 While the form of control for the GTB has not changed for DPP3, the context for its application has. For DPP2 there were no wash-ups generated in the previous regulatory period DPP1 that needed to be accounted for. For DPP3 there will be wash-up amounts incurred from the fourth and fifth assessment periods of DPP2 that will have pricing impacts during the first two assessment periods of DPP3.

E56 We have therefore amended Schedules 6, 7 and 8 of the GTB DPP3 determination.

How we specify prices – constant price revenue growth

E57 CPRG forecasts predict the rate at which GDBs' revenues will change due to changes in quantities delivered and number of connected consumers, with prices remaining constant. The forecast is used to set starting prices as well as revenue growth. The CPRG forecasts for the first year of the regulatory period are displayed below in Table E1.

Table E1: Forecast Constant Price Revenue Growth for the year ending 2023

Gas Distribution Business	CPRG forecast
GasNet	-0.29%
Powerco	1.42%
Vector	1.55%
First Gas Distribution	0.14%

E58 As the GTB is subject to a revenue cap, which does not use a CPRG forecast in the revenue-setting methodology, the following does not apply to the GTB.

Forecasting approach

E59 The CPRG model requires a forecast of the quantity of gas demanded throughout the regulatory period.

E60 We have agreed with GDBs' forecasts of gas demand and ICP numbers and have directed Concept to produce forecasts of gas demand by consumer group that align with GDBs' forecasts of gas demand and ICP numbers.[323]

E61 For the period of 2021 to 2026, Concept has taken GDB's aggregate demand and ICP projections in their AMPs, and estimated the split between residential, commercial, and industrial consumer groups using the following methodology:

E61.1 data from information disclosures was used to derive historical proportions between three consumer classes: residential, commercial, and industrial;

E61.2 the most recent year's disclosed values were used as a base value, then observed recent growth rates (from the last three years) were projected forward;

E61.3 factors were then applied to these continuation-of-trend projections for each GDB so that aggregate demand and ICP numbers across all consumer classes match the aggregate GDB AMP projections; and

[323] Concept Consulting Report "Basis and methodology for producing gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses" (27 April 2022). Available from 31 May on Commerce Commission website.

E61.4 values for the year 2027 were then projected on a continuation-of-trend basis from 2025 to 2026. The forecast for this additional year is necessary due to the fact that Vector and GasNet report on a June year-end basis, and the forecast for the year 2026 will not cover the entire regulatory period.

E62 The consumer allocations between 'residential', 'commercial', and 'industrial' consumer segments are slightly different when compared to the allocations from the 2017 Gas DPP reset. This is due to slight changes in categorisation of consumer tariff groups between these segments to better align with MBIE's reporting of segmental demand.

Incorporating gas distribution businesses' 2021 Asset Management Plan forecasts in the forecast of gas demand

E63 There are several reasons why we believe using GDBs' AMPs as a basis for the forecasts of gas demand is appropriate:

E63.1 we do not consider there to be a clear alternative that is superior in the short term;

E63.2 AMPs should reflect GPBs' outlook of their business, how they will be managing their assets, and their expectations of changes in demand. As GPBs' have better information on their own businesses than we do, AMPs form the basis for some aspects of our price path, such as expenditure allowances;

E63.3 the expenditure allowances are, to some degree, related to forecasts of demand and ICP numbers. For the sake of being internally consistent with our decisions, the CPRG forecasts were aligned with the forecasts of gas demand and ICP numbers which the GDBs used to forecast growth capex; and

E63.4 the forecast growth rates in number of ICPs and gas demand for the DPP3 regulatory period are not materially different than historic trends. We therefore believed that these forecasts are credible and the best option available given the current uncertainty.

E64 Submissions on our draft decision raised the following issues. First Gas noted a concern with the inputs to the CPRG model. First Gas' reporting date changed from a June year-end to a September year-end in 2017, so the ID data reflects 15 months-worth of volumes delivered.[324] This was dealt with by pro-rating the quantities by a factor of 12/15. As this 15-month period reflects two winters, the resulting amount overstates the quantities delivered for the year ended 30 September 2017.

E65 Powerco noted that it supported our approach, given the demand forecasts and expenditure allowances will be linked.[325]

E66 In our Gas DPP3 Process and Issues paper we discussed the GDB form of control and that our initial view was that we were likely to retain a WAPC for GDBs and that in doing so we would rely on the most up-to-date information to forecast gas demand trends in the CPRG modelling.[326]

E67 In its Process and Issues paper submission, Vector noted that while there is risk associated with a forecast of real revenue growth being misaligned with actual demand under a WAPC, it planned to update its 2021 AMP 10-year forecasts at the end of 2021, once it had more detail around the Government's Net Zero plan. Vector recommended that we use these updated forecasts for DPP3.[327]

E68 In our draft decision we retained the WAPC form of control and used GDB 2021 AMP gas demand and ICP growth forecasts in our CPRG modelling. We considered that the 2021 AMPs were the most up-to-date forecast information available and that GDBs held the best information about their consumers, gas demand, and ICP growth.[328]

E69 In its draft decision submission Vector questioned the demand forecast we had used in the CPRG model. It stated that its 2021 AMP was prepared on a "business-as-usual" basis, with the intention to submit a revised AMP once the Government's response to the CCC's advice became clear, and that because this has been delayed " it did not provide a revised AMP as intended".[329]

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324 First Gas "DPP3 Draft Decision submission" (14 March 2022)

325 Powerco "Submission on Gas DPP3 draft decision" 14 March 2022.

326 Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p.66 para B25.

327 Vector "submission on Gas DPP process and issues paper" (1 September 2021), p.30-31 paras 106-112.

328 Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 Draft reasons paper" (10 February 2022), p.134 Attachment B para B85.

329 Vector Draft decision submission (16 March 2022), p.11 para 20.

E70 Vector concluded that, while the CPRG forecast is consistent with its 2021 AMP, the 2021 AMP was “not intended to provide a volume forecast to be used in DPP3.[330]

E71 Vector qualified its view about its 2021 AMP forecast not being suitable, stating that:[331]

E71.1 CPRG forecasts differ significantly between GDBs and that this illustrates “the current uncertainty inherent in forecasting”;

E71.2 the draft decision CPRG forecast does not align with the volumes delivered on its network which have been “declining for the past four years”; and

E71.3 the 2021 AMP forecast does not reflect the ongoing disruption caused by the COVID pandemic, the impact on demand of Vector’s move to 100% capital contributions and ongoing high gas prices caused by the scarcity of commercial quantities of gas, nor the move by retailers to wash-up meter readings with a 12-month delay.

E72 In a cross-submission responding to Vector’s submission, MGUG noted that:[332]

E72.1 Vector’s gas volumes have declined over the last two years, which is primarily an outcome of the Covid-19 pandemic. The decline in volumes is attributable to just one of its 16 gas gates, Papakura. This gate services the central Auckland area, including the hospitality sector most impacted by a loss of international tourists and lockdowns;

E72.2 no other GPB has experienced such a decline in volumes in the last four years;

E72.3 while gas volumes are down, the number of connections has been steadily increasing;

E72.4 Vector has experienced an increase in their total number of connections since the 100% capital contributions policy has been implemented;

E72.5 time-series modelling performed by MGUG decomposed recent connections into trend, seasonal components, and remainder terms. MGUG noted there is no evidence of a structural break in the trend component around the time of events such as the CCC advice, or the introduction of the 100% capital contributions policy. Based on this modelling work, MGUG suggests ICP numbers are expected to continue to grow.

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[330] Vector Draft decision submission (16 March 2022), p.10 para 18.

[331] Vector Draft decision submission (16 March 2022), p.10-11 para 17.

[332] MGUG "Re: Cross submission GPB IM Review and DPP3 Reset." 28 March 2022.

Our response to submissions

E73 We have decided to maintain the current approach of aligning forecasts of gas demand with GDBs' most recent AMPs. While we consider there is a degree of uncertainty regarding the outlook of the sector, we do not believe there is an alternative approach that is likely to yield more accurate forecasts at this point.

E74 In response to First Gas' submission regarding the change in year-end, for the final decision, the CPRG model has been updated using the period of 2018 to 2021, rather than 2017 to 2020 for the input data. As the change in year-end only impacts data from the year ending 30 September 2017, and this data is not used as an input to the final CPRG model, the change in year-end does not impact the final CPRG model.

E75 We have considered Vector's concern about its 2021 AMP gas demand forecast being out of date and not suitable for Gas DPP3. We further discussed this issue with Vector and the possibility that we would use a revised gas demand forecast, supplied to us on a confidential basis, in our final decision CPRG modelling. However, we consider that using a confidential forecast without stakeholders and Auckland consumers being able to comment on the impact of the forecast change is not appropriate for this DPP.

E76 In our analysis of Vector's likely gas demand we have concluded that COVID effects were likely to be temporary, and we agree with MGUG on this point. Vector has also acknowledged that Covid-19 restrictions have driven a reduction in their volumes delivered in a recent operational performance announcement.[333] Accordingly, volumes will likely recover as restrictions ease and the borders re-open.

E77 We consider that Vector's comparison with other GDB forecasts is not accurate as each GDB has different growth strategies and connection policies, and gas usage patterns are likely to differ in different regions. However, we have noted a known permanent loss of commercial / industrial load, which had not been captured in Vector's 2021 AMP forecast modelling. We have modelled this step reduction in demand in Vector's CPRG model for our final decision.

E78 Finally, we note that Vector has a number of means to manage its forecast risk through altering the structure of its line and volume price components.

[333] Vector "Operational Performance for the 6 Months Ended 31 December" 25 January 2022.

Risks associated with our forecasting approach

E79 GDBs have an incentive to under-forecast the demand for gas throughout the regulatory period. This is because under a WAPC, prices are fixed, and if the quantity delivered exceeds the forecast, their revenue and profit increases. Therefore, to the extent demand has been under-forecast, GDBs have a greater chance of outperforming the forecast.

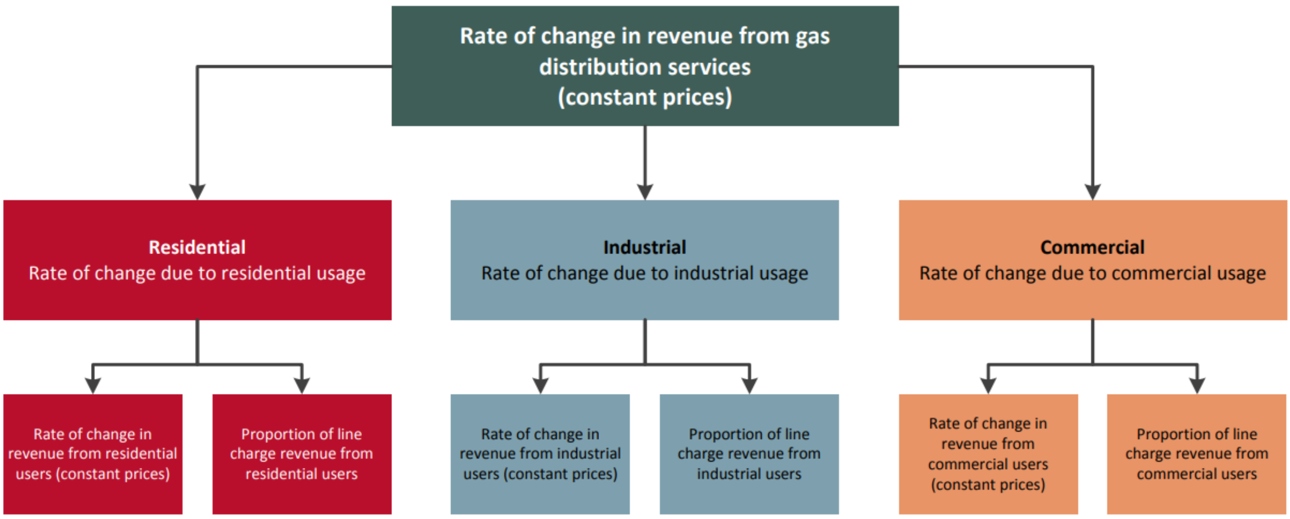
E80 We have undertaken analysis to understand the materiality of any forecast error. We examined the impact on revenue in DY20 if the rate of ICP growth was 25% greater than the historical average. Our results suggest that in this scenario, revenue for GDBs would only increase by between 0.32% and 1.22%.

E81 We believe that aligning the demand forecasts with the GDBs' projections based on their most recent AMPs is appropriate. As GDBs have greater information than we do on the future outlook of their own businesses, and have published those views through the release of their AMPs to all stakeholders following internal review and approval from their respective boards, we do not believe there is an alternative approach that is likely to yield more accurate forecasts of gas demand. We are wary, too, of relying on alternate unpublished forecasts which have had less scrutiny and review.

Structure of the CPRG model

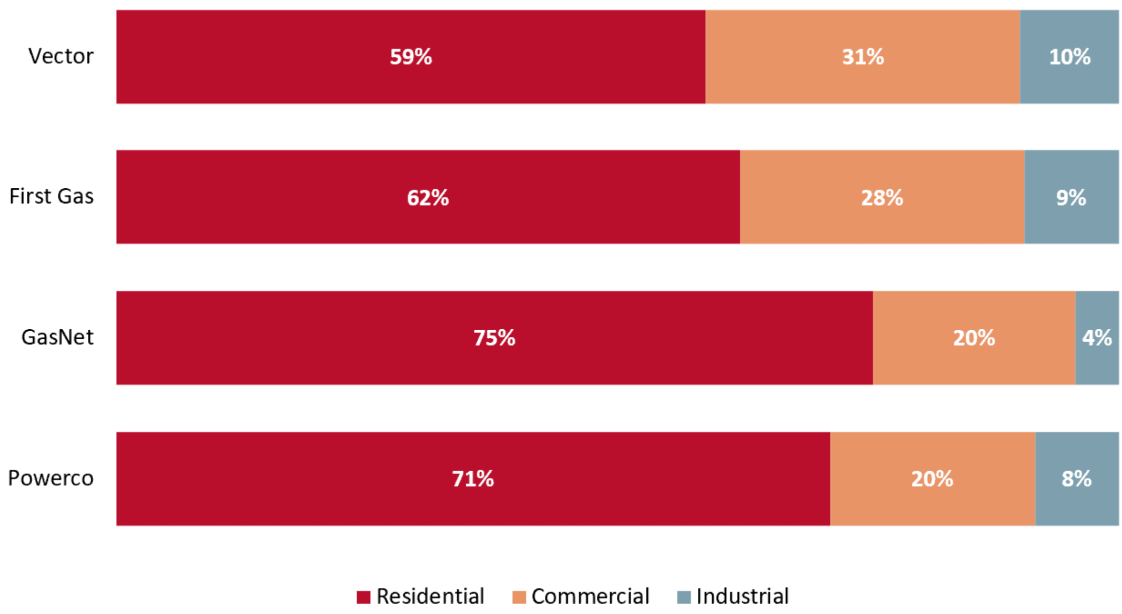
E82 In line with the previous Gas DPP, we have designated gas users into three separate classes of consumers: residential, commercial, and industrial consumers. We have modelled CPRG separately for each of the three classes of consumer. Once again, we have relied on load group information from GDBs ID data. Figure E3 highlights this approach below.

Figure E3: Modelling constant price revenue for gas distributors



E83 We modelled each consumer class separately as each user group makes up different shares of each GDB' user group, as detailed in figure E4.

Figure E4: User group revenue breakdown by distribution business (DY21)[334]



Length of the regulatory period

E84 We have adopted a regulatory period of four years for DPP3 as we consider this better promotes the Part 4 purpose at this time than a longer period.

E85 This is consistent with our draft decision.

E86 The default length of a regulatory period for a default price-quality path is five years. However, the Act states that we may shorten the regulatory period to no less than four years if we believe that doing so would better meet the Part 4 purpose.[335] Our draft decision to shorten the length of the regulatory period was a means of mitigating the impact of uncertainty.

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[334] GasNet "GDB Information Disclosure Requirements Information Templates for Schedules 1-10" (5 May 2021)
Powerco "GDB Information Disclosure Requirements Information Templates for Schedules 1-10" (31 March 2021)
Vector "GDB Information Disclosure Requirements Information Templates for Schedules 1-10" (18 December 2020)
First Gas Distribution "Information disclosure for the gas distribution business" (31 March 2021)

[335] Commerce Act 1986, Part 4.

E87 At the time of the draft decision, the CCC had published its advice to the Government on the path to net zero emissions of all greenhouse gases except biogenic methane by 2050. Among their recommendations was the suggestion that the use of natural gas must be phased out.

E88 The Government published its ERP responding to this advice in May 2022. Further announcements can also be anticipated as the Government develops more detailed policy.

E89 These matters have resulted in significant uncertainty about the future direction of climate change policy, and its impact on the sector.

E90 Shortening the length of the regulatory period to four years will allow us to reset the price path after considering further developments in the sector at the earliest point we are able to do so.

E91 Submissions on our draft decision were generally supportive of a shortened regulatory period:

E91.1 Powerco supported a shortening of the regulatory period as part of the broader package of settings to apply over a period of policy change;[336]

E91.2 Similarly, GasNet, Vector, First Gas, and MGUG supported a shortened regulatory period;[337, 338, 339, 340]

E91.3 Fonterra opposed a shorter regulatory period but did not state its reasoning;[341]

E91.4 MEUG opposed a shortened regulatory period on the following basis:[342]

E91.4.1 if accelerated depreciation is introduced as a means of managing uncertainty, the argument for a shorter regulatory period is weakened; and

E91.4.2 a longer regulatory period would minimise the price shocks to consumers, as there would be an additional year which the ramp up of accelerated depreciation could be spread over.

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336 Powerco "Submission on Gas DPP3 draft decision" 14 March 2022.

337 GasNet "Submission on Gas DPP3 draft decision" (16 March 2022).

338 Vector "Submission on Gas DPP3 draft decision" (16 March 2022).

339 First Gas "Submission on Gas DPP3 draft decision" (16 March 2022).

340 Major Gas Users Group "Submission on Gas DPP3 draft decision" (16 March 2022).

341 Fonterra "Submission on Gas DPP3 draft decision" (16 March 2022).

342 Major Electricity Users' Group "Draft Decision submission" (16 March 2022).

E92 There are two reasons why we preferred to set a shorter regulatory period as well as increasing depreciation.

E92.1 We viewed shortening the regulatory period as part of a package of overall measures to address the uncertainty that is present in this reset. Shortening asset lives reflects current expectations in DPP3. Shortening the regulatory period will allow us to consider further developments in the sector that may not be reflected in the price path earlier than if we set a five-year period.

E92.2 The mechanism that we used to estimate the increase to depreciation associated with shortened asset lives includes a transition period that extends beyond the regulatory period. This transition period mitigates price shocks and enables reconsideration of the adjustment in the next DPP. As such the length of the regulatory period and the annual increase in the level of depreciation were determined independently. Therefore, adopting a longer regulatory period will not reduce the annual allowable revenue.

E93 We have specified under s 53O(e) that any application for a customised price-quality path must be received before 23 October 2024. In setting this date, we have taken into account our timeframes for processing and deciding on such an application and for resetting a default price-quality path. A date of 23 October 2024 will allow us to finalise our decisions on any applications for a customised price-quality path before we start the process of resetting the default price-quality path for the next regulatory period.

Attachment F Forecasts of other inputs to the financial model

Purpose of this attachment

F1 This attachment explains the inputs to the financial model we must include in addition to our forecasts of opex and capex discussed in other attachments, such as WACC, CPI, and forecasts of disposals and other regulatory income.

High level approach

F2 Our approach has been to largely adopt the forecasting methods used in DPP2, while checking that this remains consistent with the current IMs.

F3 Submissions on the DPP3 process and issues paper did not include any submissions on the forecasting methods discussed in this attachment.[343]

Cost of capital estimate

F4 As explained in Chapter 4, we have updated the WACC estimate as required by the relevant IM. We estimated WACCs for both a four-year and a five-year regulatory period. Since our final decision is to set a four-year regulatory period the WACC estimate for a four-year regulatory period applies. The update has resulted in a small increase to the estimate used in the draft. The updated WACC has been estimated as at 1 March 2022.

F5 Table F1 sets out the WACC parameters used in our estimate as at 1 March 2022 and compares these to those used in DPP2. The estimate of WACC we use to set the DPP (67th percentile vanilla WACC) has fallen 52 basis points from 6.66%

[343] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021)

Table F1: Parameters used to calculate Weighted Average Cost of Capital estimates

Parameter	DPP2 estimate	Estimate as at 1 March 2022
Risk-free rate	2.75%	2.36%
Average debt premium	1.81%	1.43%
Leverage	42%	42%
Asset beta	0.40	0.40
Equity beta	0.69	0.69
Tax adjusted market risk premium	7.0%	7.5%
Average corporate tax rate	28%	28%
Average investor tax rate	28%	28%
Debt issuance costs	0.20%	0.25%
Cost of debt	4.76%	4.04%
Cost of equity	6.81%	6.87%
Standard error of midpoint WACC estimate	0.0105	0.0105
Mid-point vanilla WACC	5.95%	5.68%
Mid-point post-tax WACC	5.39%	5.21%
67th percentile vanilla WACC	6.66%	6.14%
67th percentile post-tax WACC	5.85%	5.67%

Consumer Price Index forecasts

F6 The revenue path is determined on a nominal basis (consistent with the CPI-X DPP/CPP regime outlined in Subpart 6 of the Act). When using a BBAR/MAR model to determine starting prices, we require a forecast of CPI to project annual revenues for each year of the DPP3 period. Because the asset valuation IM requires the RAB to be indexed to CPI, we also require a forecast of CPI to determine BBAR.

F7 The approach we must use is determined by the IMs. For both the rate of change of forecast CPI for RAB revaluations and the rate of change for the price path calculation, the IMs require us to base our CPI forecasts on the Reserve Bank of New Zealand (**RBNZ**) forecasts of inflation issued as part of its Monetary Policy Statement immediately prior to the determination of the WACC for the DPP.

F8 The updated CPI forecasts we have used are set out in the Table F2 below, and reflect the CPI estimates from RBNZ's Monetary Policy Statement released in February 2022.

F9 CPI forecasts for both June and September year ends are required to calculate revaluations for the disclosure years of GPBs which have both June and September year-ends. Both lagged and not lagged inflation rates are required to reflect the different requirements of the two forms of control that have been applied. These inflation rates are only required for September year ends as all GPBs' pricing years have September year ends.

Table F2: Forecasts of Consumer Price Index[344]

Pricing year ending in calendar year	2023	2024	2025	2026	2027+
Revaluation rate, June year-end	2.60%	2.30%	2.00%	2.00%	2.00%
Revaluation rate, September year-end	2.50%	2.20%	2.00%	2.00%	2.00%
Inflation rate, lagged, September year-end	5.21%	4.63%	2.47%	2.15%	2.00%
Inflation rate, not lagged, September year-end	3.09%	2.32%	2.02%	2.00%	2.00%

Forecasts of disposed assets

F10 A disposed asset is an asset that is, or is forecast to be, sold or transferred, but is not a lost asset.[345] We are required to forecast disposed assets because disposed assets are removed from the RAB when rolling forward the RAB value.

F11 We have forecast the value of disposed assets in each year of the regulatory period in real terms as equal to the historical average real value of disposals. The real forecast time series has then been converted to a nominal time series by adjusting for forecast CPI changes. These results are set out in table F3.

[344] Reserve Bank of New Zealand "Monetary Policy Statement Data Pack" (February 2022), sheet 5.1.

[345] Commerce Commission "Gas Distribution Services Input Methodologies Determination 2012 (consolidated 3 April 2018)", clause 1.1.4(2).

Table F3: Forecasts of disposed assets (nominal, $000)

Gas Pipeline Business	2023	2024	2025	2026	2027
GasNet	5.2	5.3	5.4	5.5	5.6
PowerCo	369.6	377.7	385.3	393.0	400.9
Vector	107.8	110.3	112.5	114.7	117.0
First Gas Distribution	32.5	33.2	33.8	34.5	35.2
First Gas Transmission	477.7	488.2	498.0	507.9	518.1

F12 The treatment of gains or losses on disposals as other regulated income is noted in the next section.

Forecasts of other regulated income

F13 Other regulated income is defined in the IMs, and is income associated with the supply of gas, including gains or losses on disposed assets, but excluding:

F13.1 income through prices;

F13.2 investment related income;

F13.3 capital contributions; and

F13.4 vested assets.[346]

F14 We have forecast the value of other regulated income using the same approach as described above for disposed assets, ie, the other regulated income in each year of the regulatory period has been forecast in real terms as equal to the historical average real value of other regulated income. The real forecast time series has then been converted to a nominal time series by adjusting for forecast CPI changes. These results are set out in the table F4 below.

[346] Commerce Commission "Gas Distribution Services Input Methodologies Determination 2012 (consolidated 3 April 2018)", clause 1.1.4(2).

Table F4: Forecasts of other regulated income ($000)

Gas Distribution Business	2023	2024	2025	2026	2027
GasNet	48.4	49.5	50.5	51.5	52.5
PowerCo	614.3	627.8	640.4	653.2	666.2
Vector	(106.1)	(108.5)	(110.7)	(112.9)	(115.2)
First Gas Distribution	276.6	282.7	288.4	294.1	300.0

F15 There is no forecast required for First Gas Transmission as its other regulated income is accounted for in its revenue cap wash-up process.

Attachment G Assessing compliance with the price-quality path

Purpose of this attachment

G1 This attachment sets out our decisions on assessing GPB compliance with the price-quality path.

Our decisions on assessing compliance with the price-quality path

G2 We have retained the substance and content of price path and quality standards compliance reporting requirements from DPP2.

G3 We have not introduced new requirements for price path and quality standards compliance reporting.

G4 We have changed the timing of the compliance reporting for price path and quality standards to align with ID.

G5 We have changed the manner by which we specify the compliance reporting requirements by specifying these requirements in s 53N notices rather than within the DPP determinations.

Reasons for our decisions

We have retained the content of the DPP2 compliance reporting requirements for DPP3 and not introduced new requirements

G6 We have retained the decision from DPP2 requiring GPBs to demonstrate whether they are complying with their price-quality paths by submitting annual compliance statements.

G7 GDBs must provide a single compliance statement covering both the price path and the quality standards. The GTB must provide a compliance statement covering price-setting, and a compliance statement covering the wash-up amount calculation and the quality standards.

G8 We do not consider there is a case to change the substance of the compliance reporting requirements, how GPBs demonstrate compliance and how we assess compliance with the price-quality path.

G9 Based on our current experience of receiving compliance statements from GPBs and assessing these during DPP2, we consider the current approach is still appropriate and working well.

G10 We received no submissions from stakeholders suggesting that we change the substance or content of compliance reporting nor introduce new compliance reporting requirements.

G11 The compliance statement requirements for the price-quality path are derived from the form of control and quality standard settings. We have not made any changes to the form of control and quality standard settings for GPBs in our DPP3 decisions as detailed in Chapters 4, 7 and Attachment E.

G12 We set out in Tables G1 and G2 a summary of the key requirements for annual compliance statements for the GTB and GDBs for DPP3. The compliance requirements are set out in full in the s 53N notices which were issued with the DPP3 determinations.

We have changed the timing of the compliance reporting for Gas Pipeline Business to align with Gas Pipeline Business information disclosure requirements

G13 In our DPP3 draft decision, we proposed retaining the timing of the submission of compliance statements from DPP2, ie,

G13.1 for the GTB:

G13.1.1 submit the ex ante price-setting compliance statement before 1 October, the start of each assessment period; and

G13.1.2 submit the ex post wash-up amount calculation and quality standards compliance statement within 50 working days of 30 September which is the end of each assessment period.

G13.2 for the GDBs, submit the ex post compliance statements for price-path and quality standards within 50 working days of 30 September which is the end of each assessment period.

First Gas suggested we align the timing of compliance statements with Information Disclosure

G14 First Gas suggested that we consider aligning the reporting of ex post compliance existing ex post ID schedules, ie, six months after the financial year-end of GPBs.

G15 First Gas said that:

G15.1 the alignment of disclosures would improve processes, reduce compliance costs by aligning the audit timing for both compliance statement and ID, achieve synergies and time savings for GPB staff working with auditors and their boards; and

G15.2 its proposal is in line with the approach adopted for EDB DPP3 where compliance reporting timing was changed from 50 working days post assessment period to five months post assessment period to coincide with ID timing. [347]

G16 First Gas also submitted that it had discussed this idea informally with other GPBs and that they were of the view that this amendment has merit. It encouraged us to consult with other GPBs. We did not receive any feedback on First Gas' proposal from other GPBs via cross-submissions.

G17 Implementing First Gas' proposal would mean:

G17.1 no change to the timing of the GTB's ex ante price-setting compliance statement, ie, still due before 1 October, the start of each assessment period; and

G17.2 instead of 50 working days post 30 September:

G17.2.1 Vector and GasNet submit their compliance statements by 31 December, six months after their financial year-end of 30 June; and

G17.2.2 First Gas Transmission, First Gas Distribution and Powerco submit their compliance statements by 31 March, six months after their financial year end of 30 September.

We accepted First Gas' proposal to align the timing of compliance statements with Information Disclosure

G18 We considered the following factors when evaluating First Gas' proposal:

G18.1 impact on our ability to assess compliance, investigate and conclude on potential price-quality breaches;

G18.2 impact on GPBs; and

G18.3 impact on consumers.

G19 We consider that the change in timing of the compliance reporting will have minimal impact on our ability to assess compliance statements and investigate and conclude on any potential price-quality breaches. With the change First Gas proposed, we will receive GPB compliance statements in two tranches, 31 December and 31 March instead of once around approximately mid-December.

[347] First Gas "Draft Decision submission" (16 March 2022), p.24-25.

G20 By aligning compliance statements with their Information Disclosure obligations, GPBs can:

G20.1 reduce their compliance costs by engaging auditors once instead of twice; and

G20.2 save GPB staff time and effort for the preparation and approval of the disclosed information.

G21 We are willing to accept early compliance statement reporting from GPBs wanting to retain the status quo if, for example, changing submission dates results in disruption to established processes.

G22 We consider that the change in timing of reporting will have minimal impact on consumers. The change in timing of reporting would mean that we are notified of price-quality breaches:

G22.1 for Vector and GasNet, only two weeks later than the status quo; and

G22.2 for First Gas and Powerco, three and a half months later than the status quo.

G23 From a price perspective:

G23.1 if distribution consumers are overcharged for the assessment period just ended, there will still be sufficient time for us to investigate the price path breach and take action which may include corrective actions for the GDBs to return funds to consumers by reducing prices for the upcoming assessment period; and

G23.2 if transmission consumers are overcharged, there is still sufficient time for funds to be returned to consumers via prices for the upcoming assessment period which accounts for wash-ups from over or under recovery of revenue.

G24 From a quality perspective, we consider that the later notification of possible quality breaches relating to responses to emergencies will not be to the detriment of consumers. As outlined in Chapter 7, GPBs are subject to other regulatory measures and incentives to avoid problems related to quality standards. Existing metrics on emergencies and consumer complaints associated with emergencies have been trending downward and/or have been stable since 2014.

We have specified compliance reporting requirements in section 53N notices instead of DPP determinations

G25 For DPP2, we specified compliance reporting requirements in the GTB and GDB draft determinations for DPP2.

G26 We indicated in our draft decision that we were considering specifying the compliance reporting requirements in s 53N notices accompanying the determinations rather than including the requirements in the determinations. We received no submissions on this issue.

G27 For DPP3, we have specified the compliance reporting requirements in s 53N notices accompanying the determinations.

G28 We consider this better reflects the position that the compliance reporting requirements are issued under s 53N of the Act and are not part of a GPB's price-quality path. We note that this change does not have any adverse impact on GPBs as we are not changing the content of the requirements.

Table G1: Compliance statement summary for the Gas Transmission Business

	Compliance statement for price-setting	Compliance statement for wash-up amount calculation and quality standards
Timing of submission to us	Before 1 October, ie, the start of the assessment period	Within six months of GTB financial year-end
Key content	Written statement from the GTB stating whether (or not) the GTB has complied with the price path: - forecast revenue from prices ≤ forecast allowable revenue In the case of non-compliance with the price path: - reasons for non-compliance - actions taken to mitigate non-compliance - actions to prevent similar non-compliance in future assessment periods	Written statement from the GTB stating whether (or not) the GTB has complied with the requirements to: - calculate the wash-up amount for each assessment period - comply with the quality standards, ie: - response time to emergencies (**RTE**) to any emergency does not exceed 180 minutes - No major interruption In the case of non-compliance with quality standards: - reasons for not meeting the quality standard - actions taken to mitigate non-compliance - actions to prevent similar non-compliance in future assessment periods
Requirement to provide supporting information	Yes. For all components of the calculation for forecast revenue from prices & forecast allowable revenue	Yes Details of wash-up amount calculation and supporting information for all components of the calculation Supporting data for emergencies Supporting data for major interruptions
Requirement to provide signed Directors' Certificate	Yes	Yes
Requirement for auditor's report	No	Yes

Table G2: Compliance statement summary for Gas Distribution Businesses

	Compliance statement for price-path	Compliance statement for quality standards
Timing of submission to us	Within six months of GDB financial year-end	Within six months of GDB financial year-end
Key content	Written statement from GDBs stating whether (or not) they have: - complied with the price path for the assessment period: - notional revenue ≤ allowable notional revenue - undertaken a restructure of prices during the current or preceding - assessment period, and if so, the nature and impacts of the restructure on the price path - complied with the notification requirements for any amalgamations, mergers, transfers or major transactions that have occurred In the case of non-compliance with the price path: - reasons for non-compliance - actions taken to mitigate non-compliance - actions to prevent similar non-compliance in future assessment periods	Written statement from GDBs stating whether (or not) they have complied with the requirements to: - comply with the quality standards, ie: - RTEs that are greater than 60 minutes make up less than 20% percent of the total of all RTEs - RTE to any emergency does not exceed 180 minutes In the case of non-compliance with quality standards: - reasons for not meeting the quality standard - actions taken to mitigate non-compliance - actions to prevent similar non-compliance in future - assessment periods
Requirement to provide supporting information	Yes. For all components of the calculation for notional revenue and allowable notional revenue For impacts on the price path for any restructure of prices which may have occurred	Yes Supporting data for emergencies and RTE statistics
Requirement to provide signed Directors' Certificate	Yes	Yes
Requirement for auditor's report	Yes	Yes