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

Draft 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 26 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)
31 May 2017	ISBN 978-1-869455-87-3	Default price-quality paths for gas pipeline businesses from 1 October 2017 – Final reasons paper" (31 May 2017)
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 978-1-869459-79-6	Proposed amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths - Reasons Paper
10 February 2022	ISBN 978-1-869459-74-1	[DRAFT] Gas Distribution Services Default Price-Quality Path Determination 2022 – 10 February 2022
10 February 2022	ISBN 978-1-869459-75-8	[DRAFT] Gas Transmission Services Default Price-Quality Path Determination 2022 – 10 February 2022
10 February 2022	ISBN 978-1-869459-84-0	[DRAFT] Gas Distribution Services Input Methodologies Amendment Determination 2022 – 10 February 2022
10 February 2022	ISBN 978-1-869459-85-7	[DRAFT] Gas Transmission Services Input Methodologies Amendment Determination 2022 – 10 February 2022
10 February 2022	ISBN 978-1-869459-82-6	[DRAFT] Gas Distribution Information Disclosure Amendment Determination 2022 – 10 February 2022
10 February 2022	ISBN 978-1-869459-83-3	[DRAFT] Gas Transmission Information Disclosure Amendment Determination 2022 – 10 February 2022

Commerce Commission
Wellington, New Zealand

Contents

Glossary

Acronym	
2050 target	New Zealand's target to achieve net zero emissions of greenhouse gases by 2050
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 (1 October 2026 – 30 September 2031)
the Act	Commerce Act 1986
AER	Australian Energy Regulator
AMP	Asset Management Plan
BAU	Business-as-usual
BBAR	Building Blocks Allowable Revenue
capex	Capital expenditure
CCC	Climate Change Commission
CCRA	Climate Change Response Act 2002
CPI	Consumer Price Index
CPP	Customised Price-quality Path
CPRG	Constant Price Revenue Growth
DY17	Disclosure Year 2017
DY20	Disclosure Year 2020
DY21	Disclosure Year 2021
DY22	Disclosure Year 2022
EDB	Electricity Distribution Businesses
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
FCM	Financial Capital Maintenance
FLA	Financial Loss Asset
Gas IMs	Input Methodologies for gas pipeline services
GDB	Gas Distribution Business
GIC	Gas Industry Company
GPB	Gas Pipeline Business
GTAC	Gas Transmission Access Code

GTB	Gas Transmission Business
ICP	Installation Control Point
ID	Information Disclosure
IMs	Input Methodologies
IRIS	Incremental Rolling Incentive Scheme
LCI	Labour Cost Index
MAR	Maximum Allowable Revenue
MBIE	The Ministry of Business, Innovation and Employment
NPV	Net Present Value
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
PPI	Producer Price Index
RAB	Regulated Asset Base
RBNZ	Reserve Bank of New Zealand
RFI	Request For Information
Stranding risk	risk of economic network stranding
RTE	Response Time to Emergencies
TAMRP	Tax Adjusted Market Risk Premium
WACC	Weighted Average Cost of Capital
WAPC	Weighted-Average Price Cap

DPP3 draft at a glance

Change relative to DPP2

Unchanged | Minor change | Major change

#	Change	Policy measure
Price path		
P1	Unchanged	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	Major change	Set alternative rates of change for each GPB (**X-factor**).
P3	Unchanged	Apply a revenue cap with a wash-up mechanism for the Gas Transmission Business (**GTB**) as the form of control.
P4	Unchanged	Apply a weighted average price cap for Gas Distribution Businesses (**GDBs**) as the form of control.
P6	Unchanged	Use GDBs' Installation Control Point (**ICP**) and gas demand growth forecasts to forecast Constant Price Revenue Growth (**CPRG**).
Uncertainty		
U1	Major change	Set a regulatory period of four years.
U2	Major change	Introduce a capital expenditure (**capex**) capacity reopener for projects and programmes that were unforeseen at the time of publishing supplier expenditure forecasts that we based its allowances on (via an Input Methodologies for gas pipeline services (**Gas IM**) amendment).
U3	Major change	Introduce a capex capacity reopener for projects and programmes 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 (via a Gas IM amendment).
U4	Major change	Introduce a mechanism via a Gas IM amendment to allow us to adjust asset lives when calculating depreciation for a DPP as doing so would better promote the purpose of Part 4.
U5	Major change	Shorten asset lives in DPP3 to an extent that we consider addresses most of the risk of economic network stranding, preserving investment incentives. This is the main driver of MAR increases for DPP3.
Operating expenditure		
O1	Major change	Use a base, step, and trend approach to forecast real operating expenditure (**opex**).
O2	Major change	Use actual opex from DPP2 Year 3 (**Disclosure Year 2020**) as the opex base value.
O3	Minor change	Model and provide for step changes in opex for First Gas Transmission and GasNet.
O4	Unchanged	Inflate opex using a weighted average of all-industries Labour Cost Index (**LCI**) (60%) and Producer Price Index (**PPI**) (40%).
O5	Unchanged	Apply an opex partial productivity factor of 0%.
O6	Unchanged	Use GPB projections of ICP growth.
O7	Unchanged	Scale base opex for forecast of network length and ICP growth based on historical relationship of network length to ICP growth.
O8	Minor change	Update elasticity factor based on the most recent available Australian and New Zealand gas supplier data.
Capital expenditure		
C1	Major change	Use a top-down historical network real capital expenditure (**capex**) projection approach to limit network capex forecast allowances.
C2	Major change	Accept GPB non-network capex following high level scrutiny of forecasts and Asset Management Plan (**AMP**) material.
C3	Major change	Accept GDB consumer connection capex as this aligns with our CPRG forecast.
C4	Major change	Not add margins to historical network capital expenditure projections.
C5	Unchanged	Obtain nominal capex series by inflating real $2021 capex using NZIER forecast of all-industries PPI.
Other inputs to the financial model		
M1	Major change	Weighted average cost of capital (**WACC**) of 6.07%. The WACC figure for the final decision will reflect the four-year average risk-free rate observed in December 2021- February 2022.
M2	Major change	Increase the tax-adjusted market risk premium (**TAMRP**) from 7.0 to 7.5% (via a Gas IM amendment).
M3	Unchanged	Base Consumer Price Index (**CPI**) forecasts on Reserve Bank of New Zealand's forecasts of inflation as per IMs.
M4	Unchanged	Include an allowance for disposed assets, based on historical levels.
M5	Unchanged	Include an allowance for other regulated income, based on historical levels.

#	Policy measure
Quality Standards	
QS1	Retain response time to emergencies (**RTE**) standard for GPBs.
QS2	Retain major interruptions standard for the GTB.
QS3	Do not introduce new quality standards for GPBs.
Compliance reporting	
CO1	Retain price-path and quality compliance reporting requirements for GPBs.
CO2	Do not introduce new price-path and quality compliance reporting requirements for GPBs.

Executive summary

Purpose of this paper

X1 This paper sets out our draft decisions on the default price-quality paths (**DPP**) we propose setting for gas pipeline businesses (**GPBs**) which convey natural gas, to apply from 1 October 2022. The GPBs consist of:

X1.1 the natural gas transmission business (**GTB**), First Gas Transmission; and

X1.2 four natural gas distribution businesses (**GDBs**) namely, First Gas Distribution, GasNet, Powerco and Vector.

X2 This paper sets out:

X2.1 the price-paths we propose;

X2.2 the quality standards we propose; and

X2.3 how GPBs must demonstrate compliance with the DPP.

X3 We are seeking your views on our draft decisions by 10 March 2022 (for submissions) and 25 March 2022 (for cross-submissions). Our consultation process and details on how you can provide your views are set out in Chapter 1.

X4 Alongside this paper, we have also published:

X4.1 proposed amendments to the Input Methodologies (**Gas IMs**) and information disclosure (**ID**) determinations for gas pipeline services; and

X4.2 draft Gas IM determinations for the GTB and GDBs that incorporate our draft decisions.

Context for the default price-quality path for the third regulatory period

X5 We are resetting the DPP for the third regulatory period beginning 1 October 2022 (**DPP3**) at a time when there is uncertainty about the role of gas in New Zealand's pathway towards net-zero carbon emissions.

X6 A number of climate change announcements are expected to be made by the Government in the coming years to support this transition, including an emissions reduction plan and national energy strategy to support the plan.

X7 The pathway towards net zero emissions may mean an increasingly significant role for electricity, a decline in natural gas use, and a potential future role for biogas and hydrogen. The pace of decline of natural gas use is unclear and will depend on many currently uncertain factors including natural gas availability, yet to be announced government policies, changing consumer preferences, the cost of using natural gas and alternative gases, and technology developments.

X8 In the long-term, natural gas pipelines and networks may need to wind-down or be repurposed to carry alternative low or no carbon gases. There is a risk that GPBs will be unable to, at some point in the future, fully recover their capital investment in natural gas pipelines as customers disconnect from GPB networks (the risk of economic network stranding). Most GDBs are expecting new connection growth in DPP3, but at a lower rate than for the second regulatory period 1 October 2017 – 30 September 2022 (**DPP2**).

Draft decisions on setting price-paths for the Gas Transmission Business and Gas Distribution Businesses

X9 We must reset price paths for both the GTB and GDBs. We propose resetting prices based on current and projected profitability. The proposed price settings are based on our analysis of the revenue GPBs need to earn in order to cover their forecast costs over the DPP3 regulatory period. The proposed revenue includes the accelerating of depreciation to help mitigate the risk of economic network stranding. For GDBs, we have factored in forecasts of constant price revenue growth (**CPRG**).

X10 We must also set a rate of change, relative to the consumer price index (**CPI**), by which prices increase by over the regulatory period (referred to as the 'X-factor'). We propose setting alternative rates of change for each GPB between 5-10% to minimise price shocks to consumers.

X11 Table X1 sets out the draft starting prices in the first year of the DPP3 regulatory period and the alternative rates of change we have determined for each GPB.

Table X1 : Proposed starting prices and rate of change

Supplier	Starting prices (Maximum allowable revenue in 2022/23 ($m))	Rate of change [1] (relative to CPI)
GasNet	4.839	-5%
Powerco	58.875	-7%
Vector	56.856	-5%
First Gas Distribution	28.250	-10%
First Gas Transmission	148.762	-10%
Industry total	**297.582**	

X12 We have reviewed our current form of control settings and propose that we retain a weighted-average price cap (**WAPC**) for GDBs and a revenue cap with a wash-up mechanism for the GTB.

X13 We have not identified a case to change our form of control settings as it is not clear that changing the form of control for GDBs or the GTB will better promote the purposes of the Gas IMs or Part 4 (**Part 4**) of the Commerce Act 1986 (**the Act**).

Key drivers of changes in starting prices

X14 As figure X1 shows, there are three key drivers which influence the proposed starting prices:

X14.1 the accelerated depreciation to help mitigate the risk of economic network stranding;

X14.2 changes to our estimate of the weighted-average cost of capital (**WACC**) used to determine GPBs' return on capital; and

X14.3 the levels of forecast operating expenditure (**opex**) and capital expenditure (**capex**) that we have accepted and proposed for each GPB.

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[1] This figure is negative because the rate of change is expressed in "CPI minus X" terms, so the X-factor must be negative for a distributor to be allowed to increase their annual revenue at this rate. The figures for rate of change are shown as rounded here for presentation purposes. We have used unrounded figures in our financial models.

Figure X1 : Drivers of change in proposed starting prices ($m)

X15 We discuss accelerated depreciation and WACC changes at paragraphs X16 and X20 and expenditure levels at paragraph X26.

Accelerated depreciation

X16 The risk for economic network stranding for GPBs has increased since we last reviewed the Gas IMs in 2016. We propose introducing a mechanism via a Gas IM amendment to allow us to adjust asset lives when calculating depreciation for a DPP as doing so would better promote the purpose of Part 4. For DPP3, we propose using this mechanism to reduce assets lives and accelerate depreciation for GPBs, thereby bringing forward the expected recovery of capital to mitigate GPBs' stranding risk from declining use of gas networks.

X17 We propose applying GPB specific adjustment factors of between 0.60 and 0.87 to the 45-year asset life assumption applying to new assets and to the weighted average remaining asset life calculated for existing assets in the DPP3 financial model. The adjustment factors shorten the asset lives for each GPB, increasing the straight-line depreciation during DPP3.

X18 We propose not requiring GPBs to formally apply for the adjustment to be applied to asset lives. Further adjustments may be required in future regulatory periods, depending on the situation facing GPBs at the time, including assessing any new information or sector developments.

X19 We acknowledge that accelerating depreciation, which brings forward recovery of GPBs' capital costs, implies significant price increases for consumers in DPP3. However, we believe that changes of this magnitude for DPP3 are consistent with outcomes likely to be produced in competitive markets in similar circumstances and therefore likely to be in the long-term interests of consumers. This is because these steps:

X19.1 will continue to provide a reasonable expectation of Financial Capital Maintenance (**FCM**) for the GPBs, which in turn provides incentives for investment to maintain safe and reliable networks; and

X19.2 provide some headroom if other building block model cost components increase in future regulatory periods to better manage consumer price shocks.

Changes to the Weighted Average Cost of Capital

X20 The WACC estimate we used for DPP2 was 6.41%. The draft WACC estimate we are using to set our DPP3 draft price-path, estimated as at 18 January 2022, is 6.07%. We discuss the drivers contributing to the change in WACC estimate from 6.41% to 6.07% below.

X21 Given recent changes in market conditions we propose updating the parameters used to estimate the WACC, for example, the risk-free rate. Our view is that an updated WACC estimate will provide a better indication of the WACC we will determine for the final decision.

X22 In addition to updating the parameters, we have made changes to our approach to estimating the WACC to reflect:

X22.1 changing the tax adjusted market risk premium from 7.0% to 7.5%, reflecting the most recent estimate we determined in the fibre IMs; [2] and

X22.2 changes to the risk-free rate and debt issuance costs to match a four-year regulatory period.

X23 These two proposed changes require Gas IM amendments which we are consulting on alongside our draft DPP3 decision. We require the Gas IM amendments to enable us to make the proposed adjustments to the WACC parameters ahead of the final decision.

X24 We will determine the WACC for our final DPP3 decision by 31 March 2022 and publish our decision in a WACC determination by the end of April 2022.

X25 Figure X2 shows the cumulative effect of changes in the parameters used to estimate the WACC since DPP2.

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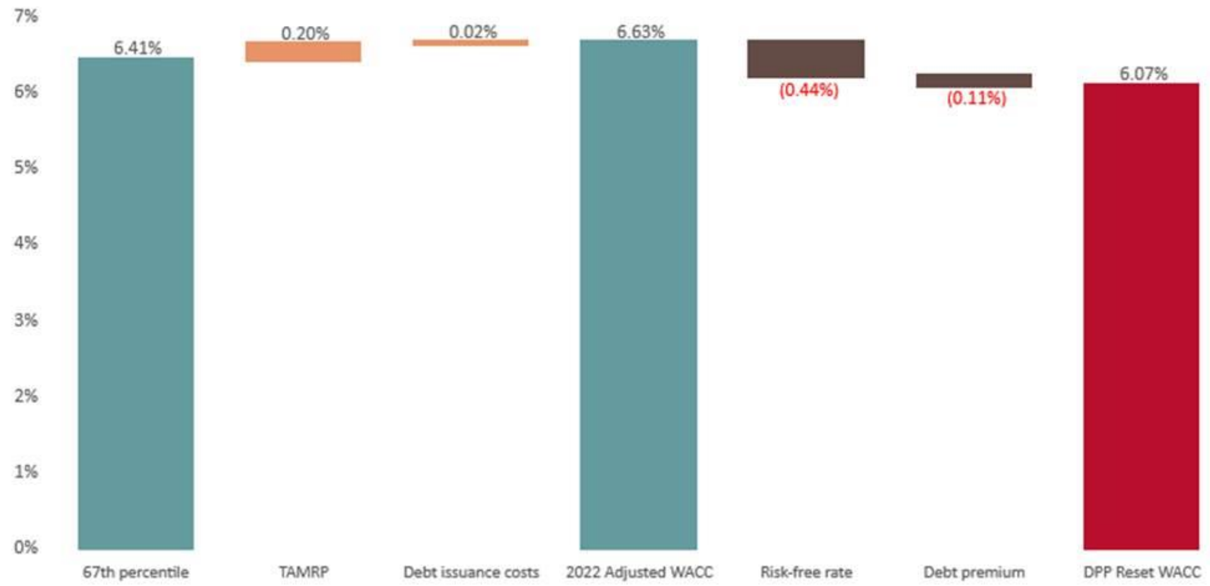
[2] Commerce Commission "Fibre input methodologies – Main final decisions – reasons paper (13 October 2020)

Figure X2 : Cumulative effect of changes to the Vanilla WACC



Draft decisions on forecasting expenditure

How we have approached forecasting expenditure

X26 We have set opex allowances using a base, step, and trend modelling approach and set capital expenditure (**capex**) allowances using a top-down approach that uses historical average capex projections to set limits on the allowances we set.

X27 We performed all opex and capex analysis using historical and forecast expenditure expressed in real $2021. In setting opex and capex allowances we inflated the capex and opex real $2021 forecast estimates to nominal using the New Zealand Institute of Economic Research's (**NZIER**):

X27.1 all industries Producer Price Index (**PPI**) inflator series for capex; and

X27.2 a 60%/40% weighted all industries Labour Cost Index (**LCI**)/all-industries PPI inflator series for opex.

Capex forecast approach

X28 We have taken a top-down historical average real capex projection approach to setting real network capex allowances with targeted scrutiny of Asset Management Plans (**AMP**s) for real non-network capex. We have accepted 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.

X29 For GDBs we applied the historical average real capex projection approach to system growth and other network capex; and for the GTB we applied this to total network capex.

X30 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 appeared to reflect the natural gas industry's long-term future. Our investigations revealed that these policies appeared to be subsidy free and met the requirements of the Gas IMs pricing principles.

X31 We have used GDB forecasts of ICP growth and natural gas demand to form the basis of our supplier Constant Price Revenue Growth (**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.

X32 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 any upward bias in GDB growth forecasting.

X33 For GDB and GTB non-network capex, we sought information to support the forecasts and have accepted these forecasts based on explanations in the most recent AMPs and following Request For Information (**RFI**) responses to questions.

X34 We have not added a margin to the historical average capex projections we have used to cap capex allowances or allowed any expenditure above the caps. To mitigate the risk that the allowances are insufficient, we have introduced capex re-opener provisions for unforeseen growth projects and for expenditure related to maintaining the network.

X35 We have converted the real capex allowances we have set to nominal using the NZIER forecast of all industries PPI inflator series.

Opex forecast approach

X36 We have set real opex allowances using a base, step, and trend approach which we have applied in previous DPPs, eg, the default price-quality path for the first regulatory period 1 October 2013 – 30 September 2017 (**DPP1**) and Electricity Distribution Businesses' (**EDB**) default price-quality path for the third regulatory period.

X37 We used DPP2 Year 3 (Disclosure Year 2020) opex which is the most recent disclosed opex for GPBs to set opex base values. We have removed alternative gas costs incurred by Powerco and First Gas Transmission from the historical opex we have used to calculate a base value of opex.

X38 We provided for step changes in opex for First Gas Transmission and GasNet. For First Gas Transmission this step change was due to compressor fuel costs increasing and for GasNet, a revision of its opex forecast following our investigations.

X39 We also consider several variables when modelling opex trends. We have scaled the base opex in real terms for estimates of network length and Installation Control Point (**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.

Draft capital expenditure and operating expenditure forecasts

X40 Figure X3 and Figure X4 below present our industry total real opex and capex forecasts for DPP3 compared with DPP2 allowance settings, GPB Asset Management Plan (**AMP**) forecasts and historical actual expenditure.

Figure X3 : Comparison of industry total historical opex, GPB opex forecasts, DPP2 opex allowances and four-year DPP3 opex allowances (real $'000s, 2021 ID year-end)

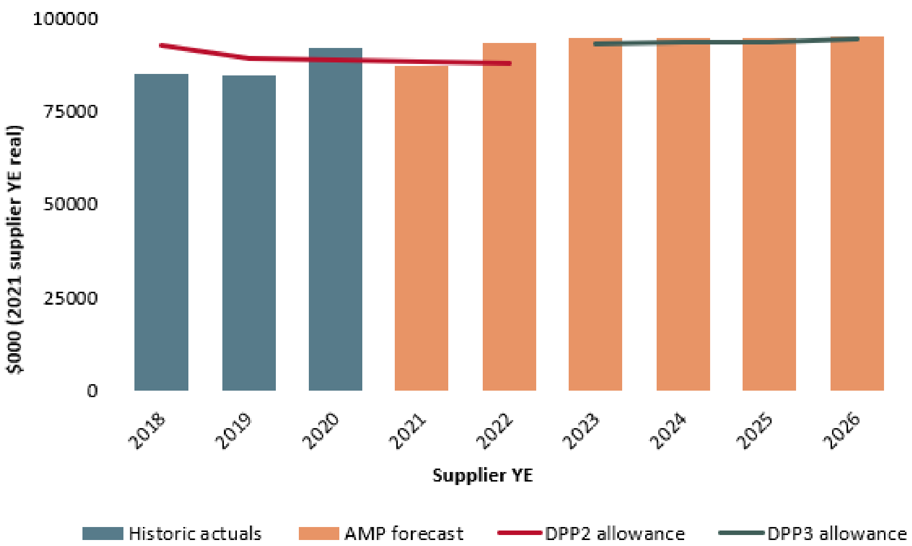
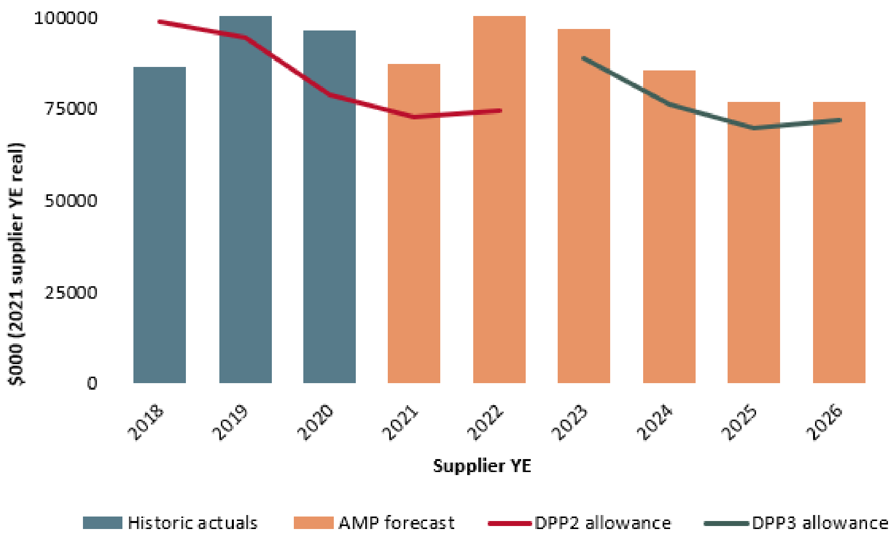


Figure X4 : Comparison of industry total historical capex, GPB capex forecasts, DPP2 capex allowances and four-year DPP3 capex allowances (real $'000s, 2021 ID year-end)



X41 Our capex and opex forecasts for each GPB are set out in Table X2 below.

Table X2 : Expenditure Forecasts for four-year DPP3 (real $’000s, 2021 ID year-end)

Supplier	Opex	Capex
Gas Net	$8,150	$3,359
Powerco	$73,405	$67,552
Vector	$56,337	$22,727
First Gas Distribution	$38,983	$49,441
First Gas Transmission	$198,196	$163,528
Industry total	$375,071	$306,608

X42 Table X3 compares our DPP3 expenditure forecasts to supplier AMP forecasts.

Table X3 : Acceptance rates of supplier forecasts for four-year DPP3 (real $’000s, 2021 ID year-end)

Supplier	Opex	Capex
Gas Net	88%	80%
Powerco	100%	93%
Vector	100%	57%
First Gas Distribution	93%	85%
First Gas Transmission	100%	100%
Industry total	99%	91%

X43 Supplier forecasts were accepted where these were below our thresholds. The key points to note about the differences between supplier forecasts and the acceptance rates are:

X43.1 a reduction of GasNet’s forecast step change in non-network opex following our RFI process;

X43.2 GasNet and Powerco non-growth related network capex has been capped by the historical average capex projections we have used to limit allowances; and

X43.3 First Gas Distribution and Vector network capex has been capped by the historical average capex projections we have used to limit allowances.

X44 We investigated the source of Vector’s low capex acceptance rate of 57%. Vector has predicted a large uplift in system growth and asset replacement and renewals capex from DY22 when compared to the historical average capex projections based on DY17-DY20 expenditure data.

X45 Our final decision analysis will incorporate Vector's DY21 actual capex in calculating the historical average capex projections, which will likely result in the capex acceptance rate increasing. Suppliers have the option to apply for a CPP if this would better meet their needs.

Impact of our proposed price-path decisions

X46 The impact on household gas bills of bringing revenues forward will be an increase of about 4.5% per annum on average for each of the four years of DPP3. For a typical annual household gas bill of about $1,275 this will be an increase of around $55 per year for each of the four years of the regulatory period. The impact on individual households, as well as commercial and major industrial users will depend on their particular circumstances and arrangement with natural gas suppliers.

Draft decisions on quality standards

X47 We must set standards for the quality of service that GPBs must meet.

X48 Our analysis suggests that there is little evidence that the existing quality standards need to be reviewed or that new quality standards need to be introduced. Our draft decision is that we retain the existing standards of quality:

X48.1 the GTB and GDBs must respond to any emergency within 180 minutes;

X48.2 the GTB and GDBs must respond to 80% of emergencies within 60 minutes; and

X48.3 no major interruptions for the GTB and if there was a major interruption, that the GTB must provide a detailed publicly available report.

X49 We are not proposing to introduce new quality standards for the GTB and GDBs.

Draft decisions on reporting compliance with the price-quality path

X50 We require GPBs to report whether or not they are complying with their price-quality paths by submitting annual compliance statements.

X51 We propose retaining our current DPP2 requirements on how GPBs report on compliance. Compliance statement requirements are derived from form of control and quality standard settings, neither of which we propose changing for DPP3.

How our draft decisions will benefit consumers

X52 Our package of draft decisions seeks to:

X52.1 promote the long-term benefit of consumers of natural gas pipelines services consistent with s 52A(1)(a) – (d) of the Act by promoting outcomes that are consistent with outcomes produced in competitive markets such that GPBs are:

X52.1.1 incentivised to innovate and invest;

X52.1.2 improve efficiency and provide services at a quality that reflects consumer demands;

X52.1.3 share with consumers the benefits of efficiency gains, including through lower prices; and

X52.1.4 are limited in their ability to extract excessive profits.

X52.2 provide an appropriate level of certainty to GPBs and consumers of natural gas, while incentivising GPBs to continue to maintain safe and reliable networks; and

X52.3 preserve options for GPBs to allow them to better respond in future when there is greater certainty and clarity for the sector.

X53 We consider that in the context of information we have available to us at this time, our package of draft decisions provides a reasonable balance between necessary short-term considerations and the long-term future of natural gas. We will reconsider this balance at the next reset and may make adjustments. We also recognise that the upcoming review of the IMs will allow for further consideration of our approach to issues for the natural gas sector over the longer-term.

X54 Table X5 summarises how our key draft decisions benefit consumers.

Table X5 : Benefit delivered by our draft decisions

Draft decision	Key features of draft decision setting out how consumers will benefit
Shortest possible length of regulatory period available to us (four years instead of the standard five years)	• Enables changes in the natural gas sector subsequent to DPP3 (new Government climate change policy initiatives and the sector's initial response to them) to be reflected in a revised price path at the earliest opportunity • The allowances for expenditure, and demand profiles, will be updated earlier to reflect changes due to new government policies and settings. Prices to consumers will more quickly and accurately reflect those revised costs and profiles • GPBs will have more up-to-date information reflected in their respective price paths earlier which will likely result in better investment decisions by them, benefitting consumers in the long-term.
Advancing revenue for capital recovery of natural gas pipeline investment to address network stranding risk	• The advancing of revenue for capital recovery through accelerating depreciation is a Net Present Value (**NPV**)-neutral measure that will enhance incentives for GPBs to continue investing in their networks so that consumers benefit from having safe and reliable supply of natural gas. • Advancing revenue will result in increased prices for consumers in DPP3. However, this will provide headroom to manage future consumer price shocks as New Zealand moves to a low carbon economy.
Limiting the capex allowance to historical average capex and introducing capex reopeners instead. Proposed opex allowances largely agree with GPB opex forecasts.	• We have recognised that capex investment requirements may need to be more restrained in the near term due to sector uncertainty and expected future transition away from natural gas. • Consequently, we have capped capex allowances to GPB historical capex levels and not included margins to historical capex projections we used to limit capex allowances. This will mitigate some risk capex allowances are set too high. • We have introduced capex reopeners to allow GPBs to seek additional funding where there is sufficient justification (for network capacity issues or to mitigate a risk that was unknown at the time the DPP was set) and where capital contributions are not appropriate. • The combination of upfront revenues and reopeners limits excessive GPB profits whilst providing a mechanism for additional investment if necessary, in line with incentives to innovate and invest. • Opex allowances we have set consistent with supplier forecasts and should ensure suppliers have sufficient funds to maintain natural gas networks so that consumers continue to receive safe and reliable supply.

Proposed Input Methodologies amendments to implement our draft decisions

X55 The purpose of Input Methodologies (**IMs**), set out in s 52R of the Act, is to promote certainty for suppliers and consumers in relation to the rules, requirements and processes applying to the regulation, or proposed regulation, of goods or services under Part 4. To that end, s 52T(2)(a) requires the IMs, as far as is reasonably practicable, to set out relevant matters in sufficient detail so that each affected supplier is reasonably able to estimate the material effects of the methodology on the supplier.

X56 However, as recognised in ss 52X and 52Y, these rules, processes and requirements may change. Leading up to a DPP reset, we may need to consider and identify potential changes to the IMs that are necessary to help ensure that the DPPs we set are workable and effective in promoting the outcomes in s 52A.

X57 As part of our DPP3 process we have proposed the following amendments to the Gas IMs:

X57.1 amending elements of the asset valuation IM to provide for accelerated depreciation by shortening assets lives for new and existing assets to allow for faster capital recovery by GPBs of their asset costs, thereby helping to mitigate the risk of economic network stranding in the future;

X57.2 two additional reopeners for capex to deal with risk or projects that are unforeseen at the time of setting DPP3;

X57.3 updating the cost of capital IMs to enable us to estimate a WACC that reflects a four-year regulatory period;

X57.4 updating the value of the TAMRP in the cost of capital IMs to reflect the most recent estimate we determined in the fibre IMs;

X57.5 amendments to better align the ID and price-quality treatment of capitalised 'right of use' assets with new accounting standard NZ IFRS16;

X57.6 amending elements of the general provisions in Part 1 of the IMs to provide greater clarity on when different parts of the IMs apply to DPPs; and

X57.7 drafting refinements and/or improvements to the IMs clauses that are related to the IM amendments under consideration in X57.3 and X57.4.

X58 If the amendments are made, we will be required to apply the amended Gas IMs to our decisions for DPP3. The proposed amendments, which have been applied in our DPP3 draft decisions, are discussed further in our Draft IM Amendments Reasons Paper.[3]

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[3] Commerce Commission "Proposed amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths - Reasons Paper" (10 February 2022)

The DPP reset and the Input Methodologies review under s 52Y

X59 We are required by s 52Y of the Act to review all IMs, including the Gas IMs, at least every seven years. The last review of the Gas IMs was completed in December 2016 except for IMs relating to CPP information requirements for GPBs which was completed in December 2017. We are therefore required to complete the next statutory IM review by December 2023. We commenced this statutory IM review in February 2022.

X60 The outcomes of the statutory IM Review will not apply to DPP3, but only to future DPP resets, ie, from the default price-quality paths for the fourth regulatory period beginning on 1 October 2026 (**DPP4**) onwards. The statutory IM review will consider all IMs, including the IM amendments made as part of the DPP3 reset.

X61 We published an open letter on 29 April 2021 to seek views on the emerging issues for electricity networks, natural gas networks and airports as they relate to our responsibilities under Part 4.[4]

X62 Specific to natural gas, we received submissions relating to New Zealand's decarbonisation pathway and the transition away from natural gas. We thank parties for their submissions. The submissions helped identify the key issues and priorities for DPP3 set out in our process and issues paper which later also informed our DPP3 draft decisions.[5] We will also take these open letter submissions into consideration as we plan for the upcoming statutory review of IMs.

X63 We do not consider the DPP3 reset is the appropriate time to comprehensively consider the Gas IMs. We consider our draft decision appropriately considers the risks raised by GPBs in the meantime, noting the statutory IM review is an opportunity for further consideration for the longer-term.

X64 We are assessing if it would be beneficial to consider additional ID requirements for GPBs that could be useful for setting future DPPs. This may form part of the scope of a future ID review.

Next steps

X65 We will consider submissions and cross-submissions in making our final decision by 31 May 2022. The new price-quality paths will take effect from 1 October 2022.

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

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

1. Introduction

Purpose of this paper

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

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

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.

1.3 Alongside this paper we have published:

1.3.1 the core models we have used and an external consulting report we have relied on to reach our draft decisions;

1.3.2 draft versions of the GDB DPP determination and GTB DPP determination that incorporate our draft decisions and that will give legal effect to our final decisions once made;

1.3.3 a draft Gas Input Methodologies amendments reasons paper outlining how we propose to amend the Input Methodologies for natural gas pipeline services (**Gas IMs**), including amendments that are necessary to implement our proposed decisions on the default price-quality path for the third regulatory period (1 October 2022 to 30 September 2026) (**DPP3**) for GDBs and the GTB, if finally made;

1.3.4 draft Gas IM amendment determinations that if finally made will give effect to the proposed Gas IM amendments referred to in paragraph 1.3.3; and

1.3.5 draft Gas ID amendment determinations that are necessary for any Gas IM amendments that are finally made to apply to the Gas ID determinations.

1.4 We seek views from interested parties on our draft decisions, draft determinations and published supporting information by 10 March 2022 for submissions and 25 March 2022 for cross-submissions ahead of us making our final decision on 31 May 2022.

1.5 We discuss the details of the submission process from paragraph 1.12 onwards.

How we have structured this paper

1.6 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 to date and next steps on how and when stakeholders should provide their views.
Chapter 2	**Framework for setting the Default Price-Quality Path**	Describes the high-level framework we propose to apply in setting DPP3, including Part 4 statutory requirements and objectives, relevant Gas IMs and our decision-making framework.
Chapter 3	**Context for our draft decisions**	Discusses context for the ongoing changes in the natural gas sector, in particular increased demand uncertainty.
Chapter 4	**Summary of our draft decisions**	Provides an overview of our draft decisions and summarises how we are managing uncertainties in the DPP.
Chapter 5	**Our draft decisions on expenditure allowances**	Summarises our draft decisions on our expenditure forecasting approach, proposed allowances for operating expenditure (**opex**) and capital expenditure (**capex**), and expenditure reopeners.
Chapter 6	**Addressing stranding risk**	Sets out the economic network stranding risk problem for DPP3 and our decision-making framework for addressing it. Summarises our draft decision to introduce an accelerated depreciation mechanism to address stranding risk and the rationale for our decision.
Chapter 7	**Our draft decisions on quality standards**	Summarises our draft decisions on quality standards and settings.
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 proposed opex allowances.
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 proposed capex allowances.

Section	Title	Description of content
Attachment C (Supporting information for Chapter 4)	**Price-setting features**	Provides further details of (and explanations for) how we set the price path for GPBs and 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 D (Supporting information for Chapter 4)	**Forecasts of other inputs to the financial model**	Provides further details of (and explanations for) the settings we have used for Weighted Average Cost of Capital (**WACC)**, Consumer Price Index (**CPI**), the approach we have taken and draft decisions we have made on asset disposals and other regulated income.
Attachment E	**Assessing compliance with the price-quality path**	Provides further details of (and explanations for) how GPBs will demonstrate compliance with the price-quality path over the regulatory period.

Process to date and next steps

How we have got to this point

1.7 We published an open letter on 20 April 2021 to seek views on the emerging issues for electricity networks, natural gas networks and airports as they relate to our responsibilities under Part 4.[6] We used submissions on the open letter to help identify the key issues we considered needed to be addressed in resetting the DPP which we set out in our process and issues paper published on 4 August 2021 [7,8] We provided options to address the issues and sought the views of interested parties. The process and issues paper also included the framework for resetting the DPP and the process we intended to follow.

1.8 On 8 December 2021, we published a notice to advise stakeholders of our draft decision to set a four-year regulatory period for DPP3. The early notice was provided to assist GPBs intending to hedge their exposure to interest rate changes.

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

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

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

1.9 On 4 February 2022, we published a notice to advise stakeholders of the scope of potential amendments to targeted aspects of the Gas IMs.[9]

1.10 We have appreciated the submissions received on our open letter and process and issues paper and cross-submissions on our process and issues paper.[10] These have been considered in our draft decision.

1.11 We will consider submissions and cross-submissions received on our DPP3 draft decision in making our final decision which will be published by 31 May 2022.

Next steps

1.12 The table below sets out our consultation process steps between now and the final decision.

Table 1.2 : Process Steps

Date	Key process or publication
10 February 2022	DPP3 Draft decision published
24 February 2022	Submissions due on draft decision on Cost of Capital IM 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 are on a faster track than the other IM amendments)
4 March 2022	Cross-submissions due on draft decision on Cost of Capital IM amendments
10 March 2022	Submissions due on: • DPP3 draft decision • Draft decision on remaining IM amendments
25 March 2022	Cross-submissions due on: • DPP3 draft decision • Draft decision on remaining IM amendments Final decision published on Cost of Capital IM amendments
12 May 2022	Final decision published on remaining IM amendments
31 May 2022	Final DPP3 decision published

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

10 Process and issues paper submissions and cross-submissions

How you can provide your view

Timeframe for submissions

1.13 We welcome your views on the matters raised in this paper, and on any other matters relevant to the Gas DPP3 reset, within the timeframes below:

1.13.1 submissions by 5pm on **Thursday 10 March 2022**; and

1.13.2 cross-submissions by 5pm on **Friday 25 March 2022**.

1.14 The scope of cross-submissions is restricted to comments on submissions only. We strongly discourage the raising of new matters via cross-submissions.

Address for submissions

1.15 Please email submissions to regulation.branch@comcom.govt.nz with “GPB DPP3 reset” in the subject line of the email.

1.16 We prefer submissions in both a format suitable for word processing (such as a Microsoft Word document) as well as a ‘locked’ format (such as a PDF) for publication on our website.

Confidential submissions

1.17 While we encourage public submissions so that all information can be tested in an open and transparent manner, we recognise that there may be cases where parties that make submissions wish to provide information in confidence. We offer the following guidance:

1.17.1 if it is necessary to include confidential material in a submission, the information should be clearly marked, with reasons why that information is confidential;

1.17.2 where commercial sensitivity is asserted, submitters must explain why publication of the information would be likely to unreasonably prejudice their commercial position or that of another person who is the subject of the information;

1.17.3 both confidential and public versions of the submission should be provided;

1.17.4 the responsibility for ensuring that confidential information is not included in a public version of a submission rests entirely with the party making the submission.

1.18 Parties can also request that we make orders under Section 100 of the Commerce Act 1986 (the **Act**) prohibiting the publication or communication of any confidential information. If we receive a request we will exercise our judgement in deciding whether or not an order is appropriate and any order we make will apply for a limited time as specified in the order. We will provide further information on these orders if requested by parties.

1.19 We request that you provide multiple versions of your submission if it contains confidential information or if you wish the published electronic copies to be 'locked'. This is because we intend to publish all submissions on our website. Where relevant, please provide both an 'unlocked' electronic copy of your submission, and a clearly labelled 'public version'.

Stakeholder workshops

1.20 At this stage, we do not propose holding workshops on any aspect of our draft decision after our draft decision has been published. If you think a workshop is necessary, please explain in your submission:

1.20.1 why a workshop should be held;

1.20.2 what the scope and purpose of the workshop should be; and

1.20.3 when you think it should be held.

2. Framework for setting the Default Price-Quality Path

Purpose of this chapter

2.1 This chapter describes the high-level framework we intend to apply 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 proposed framework for making decisions for DPP3 which includes three key economic principles.

2.2 This chapter does not discuss our proposed framework for considering changes to the Gas IMs for GPBs. This is discussed in our Draft Gas IM Amendments Reasons Paper that sets out and explains our proposed IM amendments.[11]

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 natural gas pipeline services:

2.3.1 information disclosure (**ID**) regulation, under which regulated suppliers are required to publicly disclose information relevant to their performance;[12]

2.3.2 default/customised price-quality regulation, under which price-quality paths set the maximum prices or revenues that the regulated supplier can charge. They also set standards for the quality of the services that each regulated supplier must meet.[13] This ensures that businesses do not have incentives to reduce quality to maximise profits under their price-quality path.

[11] Commerce Commission "Proposed amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths - Reasons Paper" (10 February 2022)

[12] Commerce Act, s 52B and s 55C

[13] 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 Methodlogies (**IMs**), which we are required to apply when determining the prices and quality standards applying to the supply of natural gas pipeline services;[14]

2.4.2 what the determinations used to set DPPs must specify;[15]

2.4.3 the content and timing of DPPs;[16] and

2.4.4 requirements when resetting DPPs.[17]

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 the Commerce Act 1986 used 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.[18]

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
>
> (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.

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14 Commerce Act, s 52S(b)(ii)

15 Commerce Act, s 53O

16 Commerce Act, s 53M

17 Commerce Act, s 53P

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

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".[19] This includes both the direct acquirers of the natural 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 s 52A(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;[20] and

2.10.3 when exercising our judgement, we are guided by what best promotes the long-term benefit of consumers of natural gas pipeline services.[21]

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

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.

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[19] Commerce Act, s 52C

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

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

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.[22] 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.

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

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[22] 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.

Interaction of climate change policy with the Section 52A purpose

2.17 New Zealand is targeting net zero greenhouse gases (excluding biogenic methane for which there are separate provisions) 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. [23]

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.[24] 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 legislated target of net zero emissions of greenhouse gases (excluding biogenic methane) by 2050.

2.19 The Government is due to deliver its emissions reduction plan by the end of May 2022, the same month that we are required to make our final determination of the DPP3.

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.

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.[25]

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

[24] Climate Change Commission's advice to Government on a low emissions future.

[25] 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."

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.[26]

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.

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.

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

2.32 At this time only the 2050 net zero emissions target is available and we are taking it into account for DPP3. As noted in paragraphs 2.17 and 2.19 above, we expect the Government to finalise the emissions budgets and a related emissions reduction plan that will cover the period from 2022 to 2035 by 31 May 2022. Once it does so and if we think it fit, we will take these matters into account in our future decisions. However, the statutory timing requirements for DPP3 mean that we do not expect to be able to have regard to the the emissions budgets and emissions reduction plan for purposes of our DPP3 decisions.

Input methodologies

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

2.33.1 Specification of Price;

2.33.2 Cost Allocation;

2.33.3 Asset Valuation;

2.33.4 Treatment of Taxation.[27]

2.34 We will need to apply the Cost of Capital IM when we estimate the WACC that will apply to DPP3. We are required to estimate the WACC by 31 March 2022 and do so via a separate process.

2.35 Alongside our draft DPP3 decisions, we have proposed several Gas IM amendments that:

2.35.1 enable us to implement our proposed approach to addressing economic network stranding risk and the uncertainty in how the Government's climate change mitigation plans will be implemented (discussed further in Chapter 6 and Chapter 4 respectively);

2.35.2 enable us to estimate a WACC that reflects a four-year regulatory period; and

2.35.3 update the estimate of the tax adjusted market risk premium which is used in the WACC estimation.

2.36 The draft decisions in this paper apply the Gas IMs as we propose to amend them.

2.37 As we are still consulting on the proposed Gas IM amendments these may change before we make our final DPP3 decisions.

2.38 We will apply the Gas IMs that are in place when we make our final DPP3 decisions.

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[27] 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).

Our proposed framework for making decisions on DPP3

2.39 We have developed a decision-making framework and set of economic principles over time to support our decision-making under Part 4. As discussed below, these have been consulted on and used as part of prior processes and help provide consistency and transparency in our decisions.

Decision-making framework for DPP3

2.40 Our decision-making framework for DPP3 is to apply the same approaches we used for the last DPP reset unless making changes would:

2.40.1 better promote the purpose of Part 4; [28]

2.40.2 better promote the purpose of DPP regulation; [29] or

2.40.3 reduce unnecessary complexity and compliance costs.

2.41 As we consider the Part 4 purpose to be the most important consideration for our decisions, we will not make a change on the basis of the other criteria in paragraph 2.40 where we consider that doing so would detract from that purpose.

2.42 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.[30]

2.43 In addition to the above, we have also made changes that where appropriate carry across new approaches developed for the DPP we set in 2019 for EDBs, to the extent that those elements are relevant to the GPB DPP3 and are justified against the criteria identified in paragraph 2.35.[31]

Economic principles

2.44 We have three key economic principles that we will have regard to in setting the DPP, unless doing so is inconsistent with s 52A. We consider that these are useful analytical principles when determining how we might best promote the Part 4 purpose.

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[28] Commerce Act, s 52A

[29] Commerce Act, s 53K

[30] 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

[31] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision – reasons paper" (27 November 2019)

2.45 *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 to setting this DPP within that more challenging and uncertain context is discussed in Chapter 4.

2.46 *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:

2.46.1 actions to influence the probability of occurrence where possible;

2.46.2 actions to mitigate the costs of occurrence; and

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

2.47 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.

2.48 *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.[32] 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.

2.49 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.[33]

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[32] 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

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

3. Context for our draft decisions

Purpose of this chapter

3.1 This chapter discusses the context for setting the natural gas DPP, in particular, the uncertainty that the natural gas sector is facing, including:

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

3.1.2 the use of pipelines for natural gas; and

3.1.3 the prospect of alternative gases as substitutes for natural gas.

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

3.2 The New Zealand economy is in a period of change and uncertainty. The Government has recently committed to net zero emissions by 2050. This target requires all greenhouse gases, other than biogenic methane, to reach net zero by 2050.[34]

3.3 While the Government is targeting a net zero carbon emissions economy by 2050, the path to achieving that target is uncertain. The use of natural gas will likely decline, but we do not know the rate at which it will do so. The Government is currently considering advice from the CCC on its emissions reduction plan and first three emissions budgets.

3.4 We are required to set DPP3 in May 2022, around the same time as the Government expects to respond to the CCC by publishing its first emission reduction plan and emissions budget. There will be uncertain details about government policies and initiatives, even once the Government's response is known and further details may emerge over time.

3.5 The Government is currently considering advice from the CCC on its first three emissions budgets which cover the period from 1 January 2022 to 31 December 2035 and which must be set and notified publicly by 31 May 2022.[35] When the Government sets and publishes the emissions budgets it must respond to the CCC's advice with a plan that outlines the policies and strategies New Zealand will take to meet the emissions budgets.[36]

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

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

[36] Climate Change Response Act, s 5ZB(3) and Ministry for the Environment "Emissions reduction plan discussion document" (October 2021), p. 10-12

3.6 The final advice from the CCC to the Government outlined a decarbonisation pathway that would likely mean:

3.6.1 a larger role for electricity;

3.6.2 a decline in natural gas use;

3.6.3 encouraging gross emissions reduction through the New Zealand Emissions Trading Scheme; and

3.6.4 a potential future role for biogas and hydrogen.[37]

3.7 The CCC has recommended setting a target of 50% of all energy consumed coming from renewable sources by 2035. It also recommended treating the Government's existing target of 100% renewable electricity by 2030 as aspirational.[38]

3.8 The CCC stated that the speed at which New Zealand replaces natural gas use with electricity needs to be managed to ensure electricity remains reliable and affordable. Households and businesses (eg, greenhouses, hospitals, restaurants) use natural gas primarily for cooking and water and space heating, while some larger industrial processes may use natural gas as a feedstock.[39] To manage the transition, the CCC's final advice proposes no later than 2025 or earlier if possible:

3.8.1 setting a date from when no new natural gas connections are permitted; and

3.8.2 that, where feasible, all new or replacement heating systems installed should be electric or bioenergy.

3.9 To supplement the recommended emissions budgets, the CCC recommended that the Government publish, prior to June 2024, a national energy strategy to decarbonise the energy system and ensure the electricity sector is ready to meet future needs. According to the CCC, the strategy should:

3.9.1 set targets for the energy system;

3.9.2 ensure access to affordable and secure low-emissions electricity for all consumers; and

3.9.3 manage the phase out of fossil fuels (including planning for the diminishing use of natural gas in the energy system, and phasing out coal for electricity generation).

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[37] Climate Change Commission "Ināia tonu nei: a low emissions future for Aotearoa" (2021), p. 29, 69, 111, 284-288, 292-294

[38] Ministry for the Environment "Emissions reduction plan discussion document" (October 2021), p. 84

[39] Commerce Commission "Trends in gas pipeline business performance" (15 December 2021), p.11

3.10 The CCC advised that the Government should make decisions that keep options open as far as possible as the energy system decarbonises. The CCC also advised that the scope of the national energy strategy ought to cover how to eliminate natural gas use in residential, commercial, and public buildings by 2050. They recommend:

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

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

3.10.3 determining how to transition existing natural gas users towards low-or-no-emissions alternatives like biogas or hydrogen.

Use of natural gas

3.11 There are other factors in addition to potential Government policies affecting the supply of and demand for natural gas. These factors also create longer-term uncertainty regarding the path of the natural gas sector.

3.12 The use of natural gas is expected to decline given the transition to renewable energy. However, the rate at which use decreases is uncertain. The CCC assumes that natural gas use will gradually decline over the next 15 years. The CCC suggests that natural gas use would likely decline over the next 37 years but is likely to still be in use past 2050 with the current climate policy settings. This viewpoint is supported by the Gas Industry Company's (**GIC**) position that natural gas will remain in the energy mix out to 2050.

3.13 Based on the demand projections prepared by Concept Consulting Ltd for the GIC, a decline in use of natural gas may not materialise until late in (or after) DPP3.[40] Concept Consulting Ltd also observed that:

3.13.1 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;

3.13.2 natural gas use by larger industrial users is likely to gradually decline through to 2035; and

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

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

3.14 Different parts of the natural gas network face a more uncertain future than others.[41] 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 substitute their consumption of natural gas to renewables than other users.

Demand uncertainty in the natural gas sector

3.15 There are a number of factors affecting demand for natural gas. These are described in the paragraphs below.

3.16 The New Zealand Emissions Trading Scheme is a key tool for the Government to reduce greenhouse gas emissions and meet international and domestic climate change targets. A rising carbon price discourages the use of natural gas, through energy efficiency improvements and fuel switching. The scheme has already resulted in rising carbon prices potentially impacting the demand for natural gas.

3.17 Demand for natural gas can be impacted by large customers, businesses or industries shutting down and the uncertainty about when they might exit the New Zealand economy. 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.[42] Methanex also funds a large proportion of natural gas exploration and its departure would accelerate the decline in demand due to a loss of confidence in supply. 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.[43]

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

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

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

3.18 Some consumers may consider switching away from natural gas and fossil fuels, independent of government climate change policies. This could be due to growing climate change awareness and electricity 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. 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 level of substitutability away from natural gas to other energy sources, including alternative gases.

3.19 There is growing social pressure on corporations to invest and operate in a way that is environmentally sustainable. Increased efforts to decarbonise by corporations will likely lead to a decrease in demand for natural gas.

Supply uncertainty in the natural gas sector

3.20 GIC estimates show that there is sufficient 'gas in the ground' to meet mass market, industrial and power generation demand for the next decade.[44] However, the production of natural gas, during the transition to 2030 and beyond, will require development of new resources. This is dependent on suppliers' willingness to invest more capital in supply-side assets.

3.21 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 suppliers' investment in the production of natural gas.

3.22 According to the GIC, future capital investment in existing sites is at risk and a higher risk premium is being attached to any investment to compensate. The GIC considers that insufficient investment will be committed to ensure that 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.

3.23 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 will also affect Emissions Trading Scheme prices, carbon credit policies, and energy pricing differentials that will impact the natural gas sector.

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

Alternatives to natural gas

3.24 The prospect of repurposing existing gas pipelines to carry low or no carbon gases provides a potential means for suppliers to continue operating in the long term. GPBs, the GIC and the Gas Infrastructure Future Working Group continue to explore scenarios for the long-term future of natural gas pipeline businesses.

3.25 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:[45]

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

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

3.26 The global natural 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.[46] 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.[47]

3.27 In addition, a recent joint study between Beca, First Gas, and Fonterra outlined an initial pathway for the use of biogas and biomethane, though we note that further research is needed.[48]

3.28 However, the technical and economic feasibility of transitioning to low-to-no-carbon gases and their role in New Zealand is unclear. If a transition from natural gas to low-to-no carbon gases occurs, it is unlikely to during DPP3.

3.29 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. It does not see hydrogen blending with biogas and natural gas as possible until at least 2030.

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[45] 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.

[46] David Williams "The burning questions about gas" (21 October 2021)

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

[48] Beca "Biogas and Biomethane in NZ : Unlocking New Zealand's Renewable Natural Gas Potential" (July 2021)

Our role to support a transition to alternative gases is limited

3.30 The Act's definition of natural gas limits the extent to which we can support the optionality of alternative gases. The service we regulate is the conveyance of 'natural gas' by pipeline (s 55A), but 'natural gas' is not a defined term under the Act. Our view is that neither biogas nor hydrogen can be considered 'natural gas' under the Act, while a blend of biogas or hydrogen with natural gas where natural gas is the most significant component could be considered 'natural gas'. However, we consider that if the blend requires a change in appliances that use natural gas it would not be natural gas.

3.31 There are implications of this for our consideration of alternative gases as part of DPP3. The limiting of the scope of regulated natural gas pipeline services means that research and development costs for alternative gases cannot be attributed to the regulated service. For example, we cannot facilitate the recovery of the costs of conveying any gas other than natural gas. Firms can still carry out investigations and invest in the conveyance of alternative gas, but that cost would be part of establishing a new service and cannot be recovered through lines charges from consumers of natural gas.

3.32 However, we can account for potential residual network value for GPBs under current policy settings. There is the potential for residual value from repurposing towards 'clean' gases or because existing networks conveys natural gas longer than expected. To the extent that the residual value is realised, it would reduce the risk of economic network stranding (Chapter 6) and costs to existing consumers of natural gas.

4. Summary of our draft decisions

Purpose of this chapter

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

4.1.1 an overview of our draft decisions;

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

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

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

An overview of our draft decisions

4.2 As discussed in Chapter 3, a high degree of uncertainty exists regarding the path of the natural gas sector. Given this uncertainty, we have been mindful to limit changes in our approach to DPP3.

4.3 For the most part, we consider that our existing approach to setting DPPs remains fit for purpose. The areas we have prioritised in this draft decision seek to ensure that GPBs are incentivised to continue to make efficient investments so that consumers benefit from the continued supply of natural gas, while having regard to the Government's 2050 emissions target in the CCRA and that the use of natural gas is expected to decline the decarbonisation goal.

4.4 In reaching our decisions we have been guided by the Part 4 purpose. We must promote the long-term interests of consumers of natural gas in accordance with the objectives listed in s 52(a) to (d). In making our decisions to best promote the Part 4 purpose we have considered:

4.4.1 the balance between:

4.4.1.1 incentivising GPBs to continue investing to provide safe and reliable services in the face of the potential for economic network stranding;

4.4.1.2 inefficient investment or investment that becomes stranded due to the long-term decline in demand for natural gas; and

4.4.1.3 predictable natural gas pipeline prices for consumers while limiting excess profitability.

4.5 Table 4.1 summarises the key decisions we have made to mitigate the uncertainty the GPBs face and how these decisions promote the Part 4 purpose.

Table 4.1 : Summary of key decisions

Decision	Benefit delivered
Resetting starting prices based on current and projected profitability	• We are using the building blocks approach to better reflect current and updated information including on costs, demand, the value of the Regulated Asset Base (**RAB**), and WACC, when setting the starting prices for GPBs in DPP3. This approach ensures that consumers are not paying more than necessary to maintain a safe and reliable network (Chapter 4 and Attachment C).
Operating expenditure allowances set using base, step and trend modelling approach and suppliers' actual opex in Disclosure Year 2020 (**DY20**) to set base opex.	• Base, step and trend modelling allows us to model known factors that affect opex trends such as network length, ICP growth and cost step changes that are supported by supplier information. • Using the most recent actual opex (DY20) actual opex, which, apart from GasNet, closely matches DPP2 opex allowance settings, is likely to reflect what each GPB needs to operate its business over DPP3.
Capital expenditure allowances set using a top-down approach without a margin on historical average capex (the capex allowances are capped at 100% of the historical average spend) and introducing capex allowance reopeners	• We are setting capital expenditure allowances using a top-down approach based on GPBs' own forecasts of capex. • The capex allowance will not include a margin to the historical capex which we included in Default Price-Quality path for the second regulatory period (1 October 2017 – 30 September 2022) (**DPP2**). Our objective is to incentivise GPBs to identify and prioritise prudent and efficient expenditure to maintain a safe and reliable network. • Given the sector uncertainty we have proposed growth and asset relocation capex re-openers to provide GPBs with some flexibility to seek additional expenditure in circumstances where capital contributions are not appropriate (Chapter 5 and Attachment B). • The purpose of the capex 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.
Accelerating recovery of capital costs	• To address the risk of economic network stranding, we are shortening the average lives of new and existing assets to increase the depreciation allowance for DPP3, bringing revenues forward to maintain incentives to invest and maintain optionality for GPBs (Chapter 6) • Our view is that accelerating depreciation by shortening asset lives is a low-cost, NPV-neutral and less complex approach than alternatives such as providing ex-ante compensation or removing CPI indexation of GPB RABs. • Consumers benefit from investment in the network and GPBs can recover their investment together with a risk-related rate of return.
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 C). • The GTB is under a revenue cap with a wash-up mechanism (Attachment C). • Our view is that changing the current form of control settings would not result in better outcomes for consumers or reduce compliance costs, other regulatory costs, or complexity.

Decision	Benefit delivered
Shortening the regulatory period to four years	• The shorter regulatory period will allow us to reflect any Government policy decisions and relevant market changes sooner in the next DPP.
Forecasting demand using GDB data	• Our view is that at present using GDB's Installation Control Point (**ICP**) and demand forecasts is the best option to address concerns about over/under forecasting demand, given the demand uncertainty for DPP3. Our approach 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 C).

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

4.6 The DPP must specify allowable revenues and quality standards for each distributor 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:

4.6.1 the 'starting price' – revenue allowed in the first year of the regulatory period; and

4.6.2 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.

4.7 The decision on whether the default price-path limits maximum prices or revenues is determined by the IMs and depends on the type of service provided.

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

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

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

4.9 A four-year regulatory period will allow us to set new price-quality paths for GPBs at the earliest feasible point that best promotes the Part 4 purpose in light of government climate change announcements and the evolving circumstances of the natural gas sector. We consider that doing so would better meet the purposes of Part 4 than setting a five-year regulatory period.

We have set starting prices based on current and projected profitability

4.10 We have determined starting prices based on the current and projected profitability for each GPB.

4.11 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.[49] Stakeholders supported an approach based on current and projected profitability, highlighting that:

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

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

4.12 Attachment C provides further detail on our approach to setting price-paths for the GPBs.

Our proposed price paths for gas pipeline businesses

4.13 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.

4.14 The four-year time series of MAR for each GPB is set out in Table 4.2. The draft starting prices are the maximum allowable revenues in the first year of the regulatory period. Table 4.3 shows the starting prices and the rates of change we have determined for each business.

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[49] 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.

Table 4.2 : Proposed MAR in each year of the regulatory period ($m, nominal)

Supplier / Year	2021/22 forecast MAR	2022/2023	2023/2024	2024/2025	2025/2026
GasNet	4.384	4.839	5.284	5.681	6.093
Powerco	51.436	58.875	66.648	74.245	82.475
Vector	50.702	56.856	62.771	68.231	73.989
First Gas Distribution	24.646	28.250	32.036	35.765	39.831
First Gas Transmission	131.623	148.762	167.033	187.411	210.275

Table 4.3 : Proposed starting prices (excluding pass-through and recoverable costs) and rate of change

Supplier	Starting prices ($m)	Increase from 2021/2022 MAR	Rate of change[50]
GasNet	4.839	10%	-5%
Powerco	58.875	14%	-7%
Vector	56.856	12%	-5%
First Gas Distribution	28.250	15%	-10%
First Gas Transmission	148.762	13%	-10%

4.15 The effect of the price paths we propose setting is to allow prices for each GPB to increase annually in real terms at a constant rate, but with a cap at 10%. For our draft decision the cap applies to First Gas Distribution and First Gas Transmission.

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

4.16.1 the main drivers of starting price changes; and

4.16.2 why we propose applying alternative rates of change for the GPBs.

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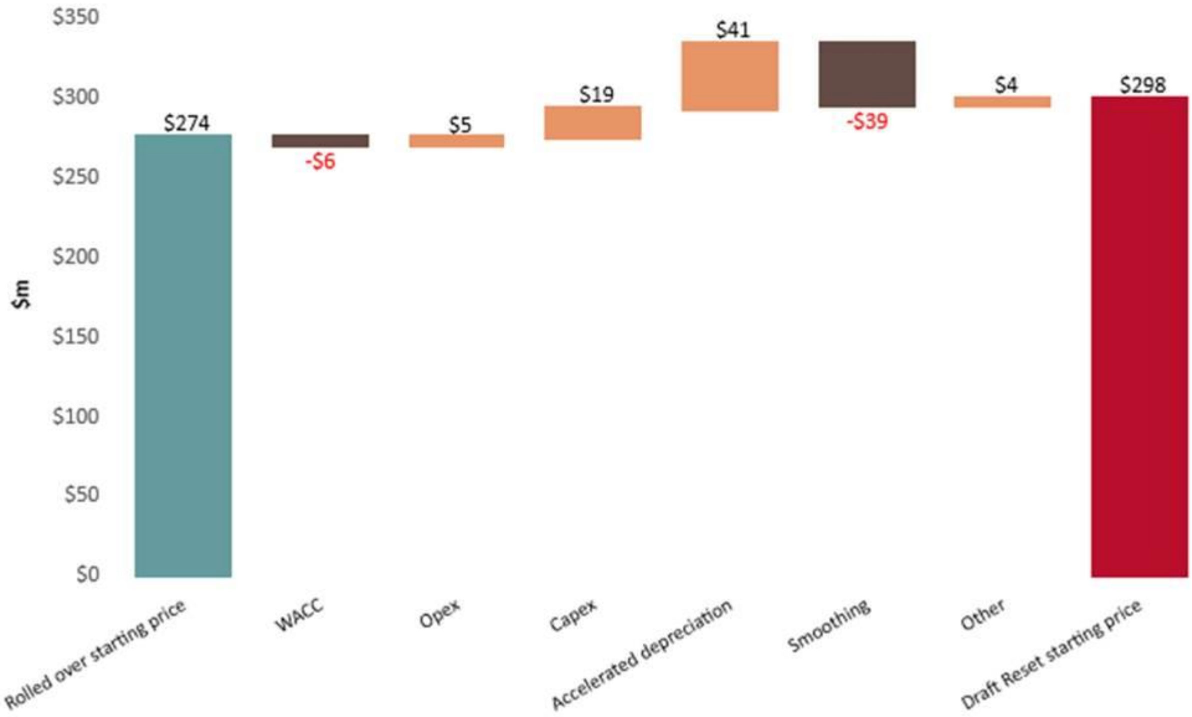
50 This figure is negative because the rate of change is expressed in "CPI minus X" terms, so the X-factor must be negative for a distributor to be allowed to increase their annual revenue at this rate. The figures for rate of change are shown as rounded here for presentation purposes. We have used unrounded figures in our financial models.

The main drivers of starting price changes

4.17 Figure 4.1 illustrates the factors influencing our proposed DPP3 starting prices, which we further discuss below.

Figure 4.1 : Drivers of change in proposed starting prices ($m)



4.18 As figure 4.1 shows, the main drivers of revenue change between rolling over prices and the draft decision are:

4.18.1 a reduction in the WACC estimate;

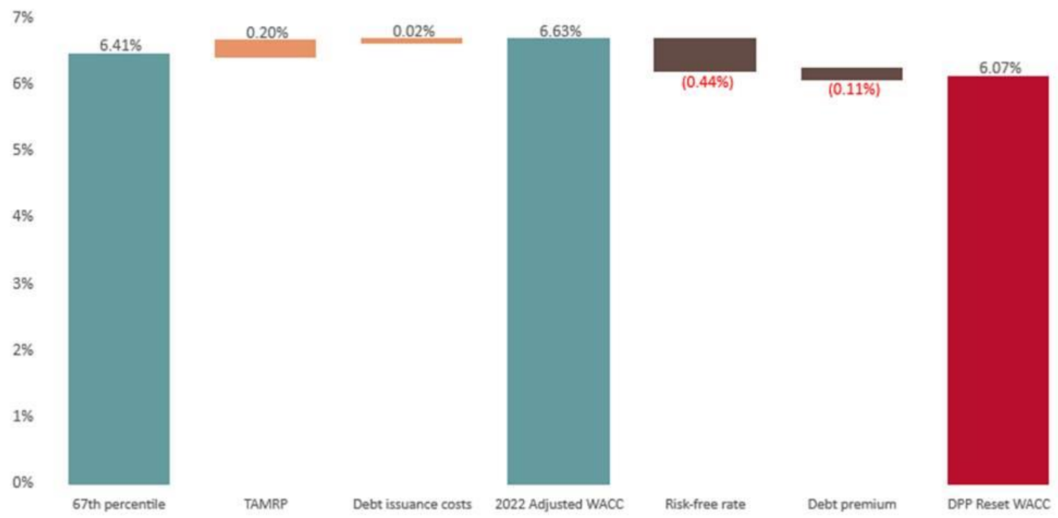
4.18.2 our opex and capex forecasts; and

4.18.3 our proposed acceleration of depreciation to help mitigate the risk of economic network stranding.

The WACC estimate has decreased to 6.07%

4.19 Our draft decision uses a vanilla WACC estimate (67th percentile) of 6.07%, compared to the WACC estimate used in DPP2 of 6.41%.

Figure 4.2 : WACC waterfall chart



4.20 In past resets we have typically used the most recently determined WACC estimate, which for DPP3 is the WACC we determined for ID purposes for First Gas and Powerco as at 1 October 2021. However, the WACC we have used to determine the draft starting prices has been estimated as at 18 January 2022.

4.21 We have observed significant changes in market conditions since 1 October 2021. This has led to changes in the parameters used to estimate the WACC, for example, the risk-free rate. Our view is that an updated WACC estimate will provide a better indication of the WACC we will determine for the final decision.

4.22 In addition to updating the parameters, we have made changes to our approach to estimating the WACC to reflect:

4.22.1 changing the tax adjusted market risk premium from 7.0% to 7.5%, reflecting the estimate we determined in the Fibre IMs; and

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

4.23 These two proposed changes require IM amendments, which we are consulting on alongside our draft DPP3 decision. We will determine the WACC for the final decision by 31 March 2022.

Operating expenditure and capital expenditure forecasts

4.24 Following our opex modelling and capex analysis we concluded that we largely agreed with the supplier opex forecasts and approximately 90% of total GPB capex that was forecast in the most recent GPB AMPs.

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: Comparison of industry total historical opex, GPB opex forecasts, DPP2 opex allowances and four-year DPP3 opex allowances (real $'000s, 2021 ID year-end)

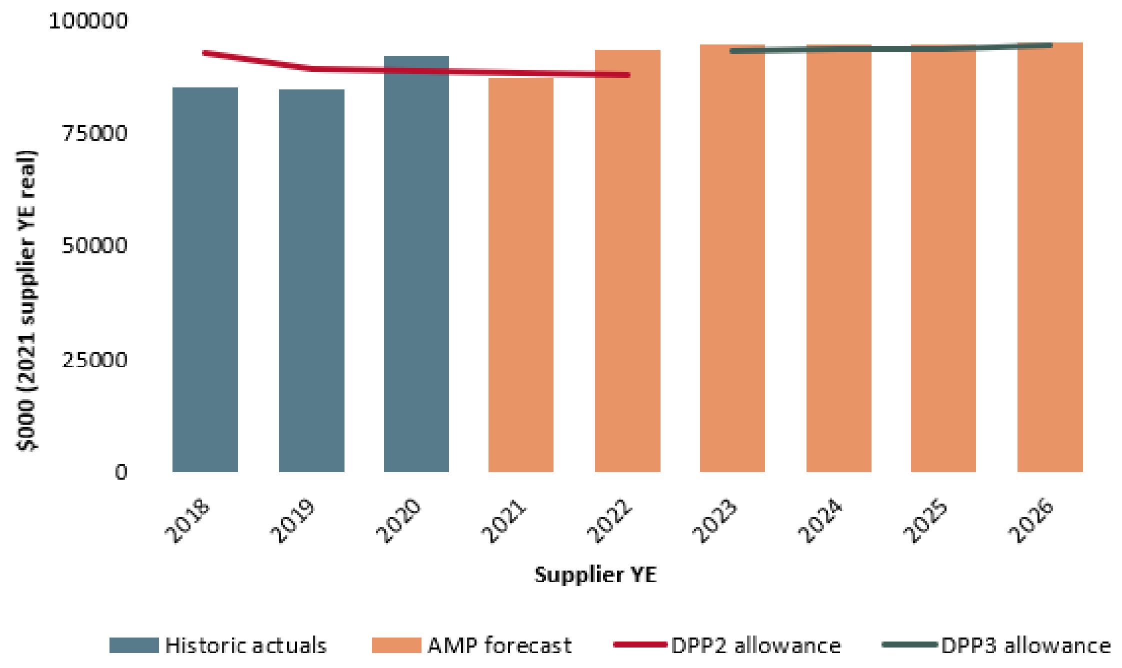
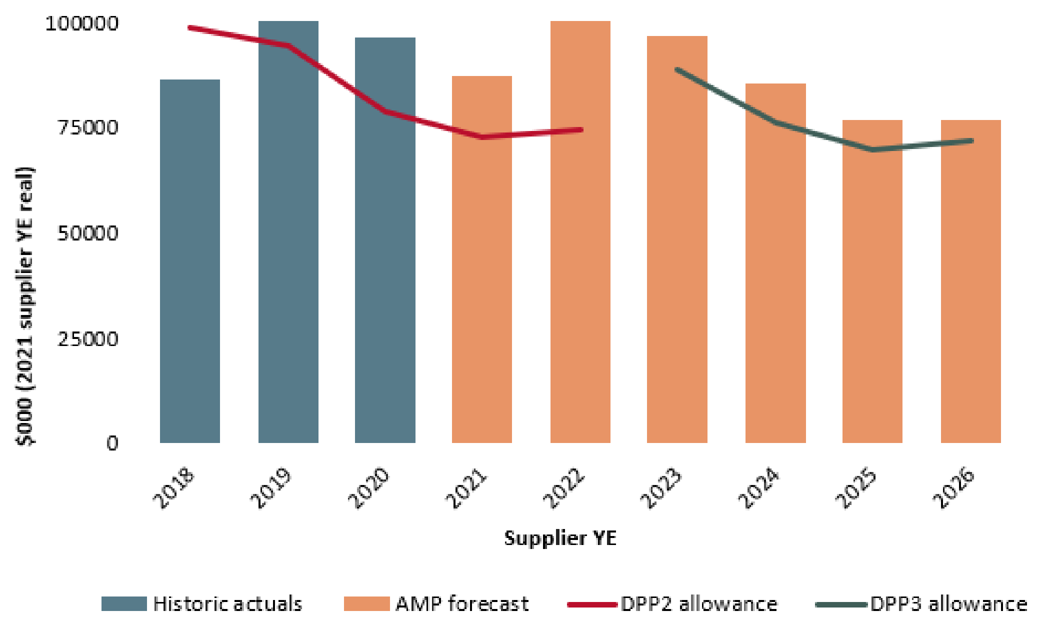


Figure 4.4 : Comparison of industry total historical capex, GPB capex forecasts, DPP2 capex allowances and four-year DPP3 capex allowances (real $'000s, 2021 ID year-end)



We are accelerating depreciation to mitigate the risk of economic network stranding

4.26 Feedback from GPBs on our process and issues paper raised concerns about increased economic stranding risk (paragraphs 6.31 to 6.36). We agree that risk of economic network stranding for GPBs has increased since we last reviewed the Gas IMs in 2016.

4.27 To address the increased stranding risk for DPP3 we propose accelerating depreciation by shortening asset lives used to set the DPP using a similar mechanism to that available for EDBs since 2016. Our proposed approach impacts on both the DPP and subsequent ID.

4.27.1 Our draft DPP decision applies a single adjustment factor tailored for each GPB to both the 45-year asset life assumption applying to new assets and the weighted average remaining asset life calculated for existing assets in the DPP3 financial model. The adjustment factor we propose for each GPB (of less than 1) shortens these asset lives used for our DPP modelling, which increases the amount of straight-line depreciation modelled during DPP3 and brings forward the expected recovery of capital represented by each GPB’s RAB.

4.27.2 We then propose requiring GPBs, after the DPP has been set, to change the asset lives of individual assets or asset classes in their ID asset registers for the corresponding first year of the DPP3 period. GPBs choose which individual depreciable asset lives to adjust for ID purposes, but must ensure that the total resulting depreciation for ID in that year equals the amount of depreciation we modelled for the first year of DPP3. Lives for new depreciable assets subsequently added under ID are shortened if the same type of existing assets have been shortened under ID. The adjusted ID asset lives affects the rolled forward ID RABs which are then used as inputs to future DPP resets. The shortened ID asset lives therefore persist across future DPP regulatory periods unless, and until, assets become fully depreciated or are disposed of, or further adjustments are made by us in future DPP resets.

4.28 Our proposed approach is further explained in Chapter 6 (paragraphs 6.79 to 6.91) and our accompanying draft IM amendments reasons paper.

4.29 Table 4.4 presents the adjustment factors we have applied for new and existing assets in DPP3.

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

Supplier	Adjustment Factor
GasNet	0.64
Powerco	0.87
Vector	0.60
First Gas Distribution	0.85
First Gas Transmission	0.75

4.30 To arrive at these adjustment factors, we have modelled a range of long-term scenarios where accelerated depreciation mitigates stranding risk. To do this we have developed a long-term (beyond 2050) financial model.

4.31 The intent of the model is to examine how the MAR could increase in DPP3 to mitigate the risk under different scenarios and sensitivities.

4.32 Our reference scenario examines a scenario where pipelines cease gas delivery in 2050. Our primary sensitivity test relates to cessation year. We have not explicitly modelled scenarios with repurposing but have considered the likelihood that there may be residual value in alternative uses when using our judgement to determine how much risk to mitigate.

4.33 A key assumption in our long-term financial model is the MAR profile. This is the revenue which we assume is effectively available as an ‘envelope’ to accommodate cost recovery, including accelerated depreciation. In profiling the MAR we allow six years of constant real annual increases, then a constant real MAR to 2029, followed by a ramp down. Our MAR profiling assumption for the first six years reflects our intent to address most but not all the assumed stranding risk in the four years of DPP3. We consider this provides GPBs with an opportunity to maintain ex-ante FCM while softening the effect of revenue increases on consumers by spreading the transition over an additional two years.

4.34 Our modelling results imply increases in the amount of depreciation needed in DPP3. As described above, this is implemented in the DPP3 financial model as a single adjustment factor applied for each GPB to the 45-year asset life assumption for forecast new assets and the weighted average remaining asset life for existing assets. Our modelling results imply that a further adjustment factor would need to be applied in DPP4 in respect of all GPBs, further shortening asset lives to achieve MAR increases for a total of at least six years. These, or any, further adjustments, however, would depend on assessing the situation facing GPBs at the time, including any new information or sector developments.

4.35 The adjustment factors we have applied for DPP3 are informed by the modelling and we have also weighted other factors including affordability and price shocks in reaching our decision. While we believe our scenarios are credible, we acknowledge that our modelling relies on uncertain long-term assumptions for key building block components.

4.36 As a starting point for arriving at our draft decision, we took the results of the Reference Scenario.

4.37 We have decided to limit real annual prices increases to 10% per annum for DPP3 to manage consumer price shocks. This is consistent with our decision to set alternative rates of change to mitigate consumer price shocks which is discussed in the following section. This cap was applied to First Gas Distribution and First Gas Transmission as the reference scenario would otherwise require real price increases of more than 10% per annum for the first six years.

4.38 Note that our decision to cap annual increases for First Gas Distribution and First Gas Transmission means we are shortening asset lives for these suppliers in DPP3 by less than we have modelled under our Reference Scenario. This implies a longer adjustment period than six years of 10% per annum increases is needed for these suppliers to address the level of risk we assume exists under the Reference Scenario.

4.39 We acknowledge these adjustments to depreciation imply significant price increases for consumers in DPP3. However, we believe that changes of this magnitude for DPP3 are consistent with outcomes likely to be produced in competitive markets in similar circumstances and therefore likely to be in the long-term interests of consumers. This is because these steps:

4.39.1 will continue to provide a reasonable expectation of FCM for the GPBs, which in turn provides incentives for investment to maintain safe and reliable networks; and

4.39.2 provide some headroom if other building block model cost components increase in future regulatory periods to better manage consumer price shocks.

4.40 We explain our approach to setting adjustment factors in more detail in chapter 6 (paragraphs 6.103 to 6.139).

We propose using alternative rates of change to mitigate consumer price shock

4.41 Under the Act, we are required to consider the price changes implied for each GPB when the rate of change in price is based on the long-run rate of productivity improvement 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.

4.42 We may set an alternative rate of change for a particular supplier, 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:

4.42.1 minimise any undue financial hardship to the supplier

4.42.2 minimise price shocks to consumers, or

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

4.43 We propose setting an alternative rate of change when the starting price adjustment would otherwise exceed 10% in real terms.

4.44 Our long-term modelling used to determine the adjustment factors for shortening asset lives (accelerated depreciation) discussed above assumes constant real annual average price increases over the four years of DPP3 (and two years beyond).

4.45 However, if we were to simply apply the adjustment factor in the DPP3 financial model, it would result in a single one-off starting price adjustment. 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

Supplier	Implied starting price ($m)	Implied real price increase for year 1 of DPP3
GasNet	5.212	13%
Powerco	65.708	20%
Vector	61.377	14%
First Gas Distribution	32.621	27%
First Gas Transmission	171.804	27%

4.46 Table 4.5 shows that the starting price increase for all GPBs would exceed 10% in real terms. For our draft decision we have limited annual real MAR increases to 10% per annum in real terms for all four years of DPP3 (including the starting price adjustment). We consider this is appropriate given the uncertainty regarding the path of the natural gas sector and to manage price shocks to consumers.

4.47 It is also our intent to deliver constant real increases over the four years of DPP3, including the initial starting price adjustment.

4.48 We are therefore proposing to use alternative rates of change ('X factors' in 'CPI-X' price paths) to increase GPBs' price in real terms at a constant rate for three years (after an initial starting price adjustment of the same real magnitude). Our proposed rates of change are set out in Table 4.6. Note that a that a negative X factor implies a price increase.

Table 4.6 : Alternative rate of change for each GPB

Supplier	Proposed rate of change (X-factor)
GasNet	-5%
Powerco	-7%
Vector	-5%
First Gas Distribution	-10%
First Gas Transmission	-10%

5. Our draft 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 forecasts of total supplier expenditure for the proposed four-year DPP regulatory period are provided in Table 5.1 and the acceptance rates of supplier forecasts in Table 5.2.

Table 5.1: Expenditure allowances for the four-year DPP (real $000, 2021 ID year-end)

Supplier	Opex	Capex	Total
GasNet	$8,150	$3,359	$11,509
Powerco	$73,405	$67,552	$140,957
Vector	$56,337	$22,727	$79,064
First Gas Distribution	$38,983	$49,441	$88,424
First Gas Transmission	$198,196	$163,528	$361,724
Industry Total	**$375,071**	**$306,608**	**$681,679**

Table 5.2: Acceptance rates of supplier forecasts

Supplier	Opex	Capex
GasNet	88%	80%
Powerco	100%	93%
Vector	100%	57%
First Gas Distribution	93%	85%
First Gas Transmission	100%	100%
Industry Total	**99%**	**91%**

5.4 Supplier forecasts were accepted where these were below our thresholds. The key points to note about the differences between supplier forecasts and the acceptance rates are:

5.4.1 a revision of GasNet's forecast step change in non-network opex following our RFI process;

5.4.2 GasNet and Powerco non-growth related network capex has been capped by the historical average capex projections we have used to limit allowances; and

5.4.3 First Gas Distribution and Vector network capex has been capped by the historical average capex projections we have used to limit allowances

5.5 The remainder of this chapter summarises the analysis approach we have taken and describes the assumptions we made, in reaching our draft decisions.

5.6 We have performed all opex and capex analysis using historical and forecast expenditure expressed in real $2021. In setting opex and capex allowances we inflated the capex and opex real $2021 forecast estimates to nominal using NZIER's:

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

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

Our approach to setting capex allowances

5.7 We have taken a top-down historical average real capex projection approach to setting real network capex allowances with targeted scrutiny of AMPs for real non-network capex. We have accepted 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.

5.8 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 four years of ID data for each GPB, apart from First Gas Transmission, where we used three years of ID data.

5.9 We noted that for First Gas Transmission, prior to 2018 and its purchase, network capex incurred by previous owners, fluctuated, and may introduce forecast error into the historical average capex projection we have used to cap allowances.

5.10 For our final decision we will incorporate DY21 ID data when calculating the historical average capex for both the GDBs and the GTB.

5.11 For GDBs we applied the historical average capex projection approach to system growth and other network capex; and for the GTB we applied this to total network capex.

5.12 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 appeared to reflect the natural gas industry's long term future. Our investigations revealed that these policies appeared to be subsidy free and met the requirements of the Gas IMs pricing principles.

5.13 We have used GDB forecasts of ICP growth and natural gas demand to form the basis of our supplier Constant Price Revenue Growth (**CPRG**) demand forecasts. Under the Weighted Average Price Cap (**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.

5.14 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 upward bias in GDB growth forecasting.

5.15 For GDB and GTB non-network capex, we sought information to support the forecasts and have accepted these forecasts based on explanations in the most recent asset management plans and following RFI responses to questions.

5.16 While GPBs largely supported our proposed top-down approach to setting capex allowances in this DPP, given the natural gas industry's future uncertainty, we will need to consider if this approach remains appropriate for future DPPs. In other words, historic expenditure may be a poor guide to inform expenditure allowances in future resets.

Why we have not added margins to historical average capital expenditure projections

5.17 The approach we have taken to set capex allowances is a simplification 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 accepted expenditure that was under the 10% margin and scrutinised expenditure above the margin.

5.18 At the time 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.

5.19 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.

5.20 In this DPP, we are not adding a margin to the historical average capex projections we have used to cap capex allowances or allowing any expenditure above the level of the historical average capex projections.

5.21 We do not consider it appropriate to allow more capex than the historic average in circumstances where growth is expected to start declining, and where there is a heightened risk of asset stranding. Suppliers may also be able to manage their capex through adjusting expenditure or capital contributions.

5.22 However, to mitigate the risk that the allowances are insufficient, we have introduced capex reopener provisions for expenditure associated with unforeseen demand growth and maintaining the safety of the networks.

5.23 Additionally, submissions from suppliers, and the work of the Gas Infrastructure Future Working Group, has signalled the increased risk of economic network stranding. To mitigate this stranding risk, we are accelerating depreciation for DPP3 (Chapter 6). We expect that suppliers will be also assess new capex investments against decisions to maintain asset for longer, to minimise the potential risk and quantum of stranding.

5.24 We noted that, following our allowance setting process, Vector's total capex allowance was 57% of what it had forecast in its 2021 AMP. We carried out further analysis to track the source of this relatively low acceptance rate when compared to other suppliers.

5.25 Vector has predicted a large uplift in system growth and asset replacement and renewals capex from DY22 when compared to the historical average capex projections, based on Vector's DY17-DY20 expenditure data.[51]

5.26 For example, on average, between DY17 and DY20 Vector has spent approximately $0.8 million per annum on system growth capex and $1.3 million per annum on asset replacement and renewals capex. However, between DY22 and DY27 Vector forecasts it will spend $2.7 million per annum on system growth capex and $3.3 million per annum on asset replacement and renewals capex. Our top-down capex allowance setting approach has not allowed these significant uplifts.

5.27 While supplier AMPs may discuss projects and programmes that explain forecast expenditure uplifts above historical levels of capex, we have not scrutinised the prudency and efficiency of these uplifts. Given the expected decline in gas use, it is our expectation that capex will not exceed historical average levels. We invite submitter feedback on this view.

[51] Vector "2021 Asset Management Plan update"

5.28 Our draft decision analysis has not used Vector's DY21 data, that was made available in December 2021, to calculate the historical average capex projections. We intend that our final decision calculation on Vector's historical average capex spend will include its DY21 actual capex spend. We anticipate this is likely increase the historical average capex projection levels and hence the capex acceptance rate for the final decision.

5.29 Finally, 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 uncertainties that GPBs may encounter.

Our approach to setting opex allowances

5.30 We have set real opex allowances using a base, step, and trend approach which we have applied in previous DPPs, and used DPP2 Year 3 (Disclosure Year 2020) opex which is the most recent disclosed opex for GPBs to set opex base values. We have removed alternative gas costs incurred by Powerco and First Gas Transmission from the historical opex we have used to calculate a base value of opex.

5.31 We have also modelled step changes in opex for First Gas Transmission and GasNet. For First Gas Transmission this step change was due to compressor fuel costs increasing and for Gasnet, a revision of its opex forecast following our investigations.

5.32 We also consider several variables when modelling opex trends. We have scaled the base opex in real terms for estimates of network length and Installation Control Point (**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 Labour Cost Index (LCI)/all-industries PPI inflator series.

We have used operating expenditure data from disclosure year 2020 to set an operating expenditure base value

5.33 In our process and issues paper we discussed several approaches to setting an opex base value in the base, step, and trend modelling.[52] This included using a multi-year average or single year of actual opex to set the base opex value. In its submission, Vector suggest that using the most recent actual opex is appropriate.[53]

5.34 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 set 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.

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[52] 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

[53] Vector "submission on Gas DPP process and issues paper" (1 September 2021), p. 34

5.35 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”.[54]

5.36 It is much less likely that opex inefficiencies exist in the opex base year for EDBs because of the Incremental Rolling Incentive Scheme (**IRIS**) in the EDB IMs. The IRIS mechanism disincentivises EDBs from inflating opex costs and means that using the 2019 opex actual costs in the EDB DPP3 base, step and trend modelling may reflect an efficient base year.

5.37 However, there is no IRIS mechanism in the Gas DPP IMs.[55] This means that, while we must make an assumption about what an efficient base level of opex may be, we are also less constrained in doing so. We investigated a number of approaches in setting a base opex value.

5.38 We considered taking a multi-year average of actual opex to set the opex base year 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. On this basis we were less confident that a multi-year opex actual average would be suitable to set a base opex value.

5.39 Following our analysis we propose using the Disclosure Year 2020 (**DY20**) actual opex to set an opex base value for all GPBs except for GasNet. The DY20 actual opex was the most recently disclosed opex data for each business at the time our analysis was carried out. For most GPBs, the DY20 opex data is very similar to their DPP2 opex allowance settings, and not an opex outlier when compared to previous years. This gives us more confidence that the DY20 opex was reflective of what each GPB needs to operates its network.

5.40 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 40% higher opex than its DPP2 opex allowance. To remove the effects of this outage from the opex forecasting, we have used GasNet’s DPP2 DY20 forecast opex allowance as the base value of opex.

5.41 Finally, we will be incorporating Disclosure Year 2021 (**DY21**) actual opex data from each GPB in our final decision base, step and trend modelling. We may use this DY21 information to update the base opex value in the final decision base, step and trend model, or we may reconsider using a multi-year average.

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

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

Our approach to modelling opex step changes

5.42 We modelled a step change in opex for the GTB First Gas Transmission related to compressor fuel costs. We sought additional information from First Gas Transmission which supported the additional opex and accepted that the cost increases are likely to be reasonable based a forecast of future natural gas prices.

5.43 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.[56] Our view is 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'.

5.44 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.

5.45 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 suppliers' pipelines and consumers' appliances.

5.46 We have not included any allowance for this in our draft decision, as we do not have evidence from suppliers as to the amount of expenditure that could reasonably be allowed for such investigations. Any amount for this purpose may also be immaterial in the context of the capex allowances.

5.47 Our view is that, while suppliers should not use funding for investigations into gas that does not meet the 'natural gas' definition or use the allowances we set for this purpose, we are open to including additional expenditure for the investigation of the conveyance of blends that would qualify as natural gas, if suppliers provide evidence of the amount of expenditure that is reasonably required for this purpose and we consider it sufficiently material to be included in the capex allowance.

5.48 Consequently, our draft decision is that we have not included any specific allowance for alternative gas investigation costs or gas blends in this DPP. Suppliers may still carry out investigations of alternative gases, but costs associated with this will need to be funded by shareholders.

Our approach to modelling operating expenditure trends

5.49 We considered several variables when modelling opex trends, namely:

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

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[56] 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

5.49.2 partial productivity (GPBs); and

5.49.3 input prices – Producer Price Index (PPI) and Labour Cost Index (LCI) costs (GPBs).

Network scale

5.50 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 Installation Control Point (**ICP**) annual growth on a real $2021 basis in each year of DPP3.

5.51 We have accepted 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.

5.52 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.

5.53 The ICP growth and network length estimates are also modified by an elasticity factor that models their non-linear impact on required opex.

5.54 In the 2013 Gas DPP draft decision modelling we used international 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.[57]

5.55 We have updated the elasticity assumption based on the OFGEM natural gas sector elasticity modelling methodology used in the 2013 Castalia report. This 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.

5.56 Our updated analysis has resulted in an elasticity factor of 0.48.

Partial productivity

5.57 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.[58]

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

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

5.58 At the time we found no evidence to indicate that the productivity of suppliers of natural gas pipeline services improved by more or less than the rest of the economy. In the absence of any new or updated information, we propose to retain a partial productivity factor of 0% for this DPP3 period

Input prices

5.59 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 GPB's control.

5.60 GPB opex allowances have been adjusted for forecast input price changes (or inflation) using the:

5.60.1 weighted average forecast change in the 'all industries' Labour Cost Index (LCI); and

5.60.2 the 'all industries' Producer Price Index (PPI).

5.61 The New Zealand Institute of Economic Research (**NZIER**) provides forecasts of these indices. We have used the same LCI/PPI weighting of 60%/40% used in Gas DPP1 and EDB DPP3 to calculate a single price index to inflate each GPB $2021 base opex and scaled opex trend to nominal opex. Note that we did not carry out base, step and trend modelling in Gas DPP2.

6. Addressing economic network stranding risk

Purpose of this chapter

6.1 This chapter describes:

6.1.1 the problem surrounding the risk of economic network stranding faced by GPBs;

6.1.2 our decision-making framework for addressing that stranding risk in DPP3;

6.1.3 our draft decision to apply an NPV-neutral mechanism for DPP3 to accelerate depreciation by shortening asset lives, thereby bringing forward the recovery of capital costs; and

6.1.4 the rationale for our decisions.

Introduction and summary of our decisions

6.2 Feedback from GPBs on our process and issues paper raised concerns about the increased risk of economic network stranding (**stranding risk**). Networks can become economically stranded if at any point in time a supplier is unable to fully recover the outstanding investment costs. Investment costs are represented by the value of the RAB.

6.3 Our view is that the stranding risk for GPBs has increased since we last reviewed the Gas Ims in 2016. Climate change initiatives are already having an impact on the supply and demand for natural gas (Chapter 3). The Government is currently considering advice from the CCC on its first three emissions budgets and there is a prospect of further policy changes that may accelerate the decline in use of natural gas pipelines for conveying natural gas and/or their closure. There is currently no mechanism available to compensate for this increased stranding risk under the Gas IMs.

6.4 The economic principle of maintaining ex-ante real FCM through our regulatory settings supports the long-term benefit of consumers by providing incentives for suppliers to invest while limiting excess profits. Increased stranding risk makes it more difficult for us to maintain expectations of ex-ante real FCM through recovery of the RAB over time.

6.5 We consider it is appropriate for DPP3 to address concerns about material risk of economic stranding and continue to support a reasonable expectation of FCM.

6.6 To address the stranding risk for DPP3 we propose accelerating depreciation by shortening GPB asset lives using a mechanism similar to that provided for EDBs since 2016, with some key differences (discussed in paragraph 6.80). Amendments to elements of the asset valuation Gas IMs are required to implement this mechanism.

6.7 We have developed a long-term financial model to inform our draft decisions on the extent of asset life adjustment factors for each GPB. The adjustment factors we have applied for DPP3 are informed by this long-term financial model and we have also weighted other factors including affordability and price shocks in reaching our decision. As a starting point for our decision, we have taken modelling results for a 'reference scenario' which assumes that gas pipelines cease operating in 2050.

6.8 It is our intent that we address most, but not all stranding risk in DPP3. Further price increases may be needed in the default price-quality path for the fourth regulatory period beginning on 1 October 2026 (**DPP4**), but this depends on how the stranding risk evolves in DPP3 and we will reassess our approach prior to DPP4.

The problem of economic network stranding risk for DPP3

Economic network stranding risk, financial capital maintenance and incentives to invest

6.9 Networks can become economically stranded if at any point in time a supplier is unable to achieve full capital recovery of its RAB. This could occur, for example, if:

6.9.1 there are insufficient consumers remaining on a network to pay high enough prices to allow the investment to be recouped; or

6.9.2 a network shuts down before the supplier has an opportunity to recover its RAB.

6.10 The stranding risk affects incentives for incremental investment. The long-term benefit of consumers is promoted by GPBs having incentives to invest to maintain safe and reliable networks.

6.11 Stranding risk is an 'asymmetric' or one-sided, downside risk for regulated suppliers under current Part 4 settings.

6.11.1 If suppliers continue to operate as regulated providers, then the regulatory settings should provide them with an opportunity to recover the cost of their investment and to make a normal return. This is because under the Gas IMs assets remain in the RAB when physically stranded or when capacity exceeds consumer demand.

6.11.2 Normally retaining the assets in the RAB would be sufficient to manage stranding risk, particularly for individual assets. However, the opportunity for suppliers to recover the cost of their investment and to make a normal return relies on an expectation that networks will remain operational for long enough to recover the costs of unused or underused assets and to earn a return on those assets. It also requires future consumers to have the willingness to pay prices high enough to do so.

6.11.3 But if operations cease prior to full recovery of the RAB, or consumers are not willing to pay the required charges, then suppliers may be unable to recover the cost of their investment and make less than normal profits.

6.12 If the supplier does not have an expectation of a normal return, it may choose not to invest.

6.13 Our ex-ante FCM maintenance principle is key to providing investment incentives and an expectation of making a normal return on investments. Ex-ante FCM requires suppliers to:

6.13.1 have an expected return on capital commensurate with their WACC; and

6.13.2 a reasonable expectation that the RAB can be recovered through return of capital (depreciation) in the long run.

Addressing economic network stranding risk through current regulatory settings

6.14 Suppliers have the option under current regulatory settings to apply to advance cash flows via a CPP to mitigate stranding risk. However, there is currently no means to take action to mitigate increased economic stranding risk within the Gas IMs applying to a DPP.

6.15 Furthermore RAB indexation exacerbates stranding risk. Under DPP settings, the RAB is indexed annually by inflation to manage inflation risk. While it preserves the real value of the RAB over time, it effectively defers recovery of revenue to the future.

6.16 Our Gas IMs already provide some compensation for stranding risk for GPBs through the parameters used to estimate the WACC.

6.17 The WACC compensate suppliers for 'systematic' risks only and stranding risk may be partly systematic for GPBs. Systematic risk refers to market-wide risks which affect all risky investments. In our 2016 statutory IM review we acknowledged it is plausible that adverse economic shocks could potentially accelerate disconnections increasing economic network stranding risk.[59]

6.18 We did not consider that stranding risk alone would justify an asset beta uplift. However, when combined with other factors, primarily the higher income elasticity of demand for natural gas, we considered there remained support for an upwards adjustment to the natural gas asset beta and allowed an asset beta uplift of 0.05 for GPBs relative to EDBs and Transpower (down from the 0.10 adjustment we allowed in 2010).[60]

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[59] Commerce Commission "Input methodologies review decisions – Topic paper 4 – Cost of capital issues" (20 December 2016) paras 423-433

[60] Commerce Commission "Input methodologies review decisions – Topic paper 4 – Cost of capital issues" (20 December 2016) paras 453

6.19 We will reconsider the WACC during the next statutory IM review which is due to commence in 2022, but which will not be completed before we make our final natural gas DPP reset decision in May 2022. This will include considering the appropriateness of the asset beta uplift and the use of the 67th percentile WACC for GPBs.

6.20 While some economic stranding risk is systematic, 'non-systematic' factors are likely to pose a more material stranding risk for DPP3. Non-systematic risk refers to risks which affect an individual company or sector of the economy. In particular there is a risk of government policy changes and shifts in consumer demand for natural gas that specifically lead to economic network stranding for GPBs. We consider that the current Gas IMs do not currently provide adequate compensation for these types of risk.

6.21 Note that the investment incentive problem for individual suppliers is not solved through investors participating in a diversified investment portfolio to hedge against non-systematic risks. Regardless of ownership, incentives to invest can be compromised when regulation does not account for asymmetric risk.

6.22 In the process and issues paper, we also noted that suppliers have the responsibility and means to mitigate at least part of the stranding risk themselves.[61] For example, suppliers can mitigate increased stranding risk by:

6.22.1 lowering expenditure on new connection and system growth; and

6.22.2 requiring larger contributions from new connections.

6.23 As discussed in Chapter 5, we have accepted the GDBs' forecasts of ICP growth and consumer connection capex for DPP3. We concluded that the GDB capital contributions policies were subsidy free in meeting the Gas IMs pricing principles (paragraph 5.12).

6.24 Most suppliers have capacity to make changes to planned capital expenditure during DPP3 to better manage stranding risk.

Future government policy changes may accelerate network decline and increase stranding risk

6.25 The main driver of increased stranding risk faced for DPP3 onwards is the potential for government policies to accelerate a decline in the use of natural gas pipelines for conveying natural gas and/or lead to their closure.

[61] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), Attachment D p. 79 para D15

6.26 Stranding risk for existing (sunk) investments is largely outside of GPBs' control. Regulatory settings determine how quickly existing assets can be depreciated thereby recovering the capital investment represented by the RAB. Changes in government policy settings and consumer demand for natural gas pipelines ultimately drive stranding risk. In contrast, suppliers have more control over stranding risk for incremental investments (paragraph 6.22).

6.27 We note that GDBs can influence natural gas demand in the short term through growing connections, or trying to maintain existing ones however, expectations are that natural gas demand will still fall in the medium to long term (paragraph 3.12).

6.28 The Government is currently considering advice from the CCC on its first three emissions budgets. DPP3 will be finalised in May 2022, around the same time as the Government expects to respond to the CCC by publishing its emissions reduction plan and the emissions budgets. There is likely to be uncertainty regarding the future for GPBs, even once the Government's response is known.

6.29 Suppliers are likely to review their own investment and operational plans following the release of the Government's emissions reduction plan and emissions budgets. This may result in further shifts in how natural gas networks are managed in coming years.

6.30 For the risks facing GPB networks as a whole, we consider that the commitment to simply retain unused or underused (stranded) assets in the RAB will not fully manage stranding risk. This is because, as customers leave, prices for remaining consumers may need to rise beyond their willingness to pay, in order to recover all of the RAB.

Economic network stranding risk is a concern for suppliers

6.31 We identified increased stranding risk as a focus for DPP3 in our process and issues paper.[62] Submissions from GPBs highlighted this risk as a primary concern for DPP3 in addition to managing uncertainty.

[62] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), pp. 35-36 para 3.62-3.63

6.32 GPBs were strongly of the view that an increased stranding risk was material and that existing DPP policy settings were inconsistent with our principle of ex-ante FCM. GasNet noted concerns that they faced increased risks which "would change what was considered excess profit moving forward".[63] First Gas, Powerco, and Vector submitted joint analysis by Frontier Economics that showed existing regulatory settings would leave more than $600 million of unrecovered capital by 2050 even if there was no further investment.[64]

6.33 Suppliers argued that existing regulatory settings are no longer fit for purpose. For example, Vector stated that:[65]

> The current settings for capital recovery – namely the current weighted average life of the existing RABs forecasting recovery timelines beyond 2050, technical lives for new system assets of 45-80 years are not fit for purpose and exacerbate stranding risk given Net Zero 2050.

6.34 GPB submissions stated that changes must be made for DPP3 to continue to provide an expectation of FCM, focusing on the risk of future price escalation for consumers and on the importance of maintaining FCM for investment incentives. For example, First Gas stated that:[66]

> The two measures that we believe the Commission should closely consider for DPP3 are to remove RAB indexation and to provide accelerated depreciation. Individually, and in combination, these measures would materially reduce exposure to unrecovered investment, mitigate consumers' exposure to future price escalation, and provide confidence to continue to invest.

6.35 First Gas, Vector and Powerco shared the view that addressing stranding risk/FCM should take precedence over other concerns for DPP3.

6.36 Other natural gas industry participants were less convinced that policy settings should change for DPP3. Methanex stated concerns were "exaggerated", particularly for the GTB and raised concerns about lack of evidence and feasibility during the scope and timeframes of a DPP reset.[67] Greymouth Gas did not support the establishment of a stranding mechanism noting that "a large proportion of this non-systematic risk must be borne by GPB owners".[68] Major Gas Users Group (**MGUG**) argued that uncertainties were "overstated" and concluded that we should "proceed with a price reset based on precedents set in DPP1 and DPP2".[69] In its cross-submission, MGUG stated:[70]

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[63] GasNet Submission on gas DPP process and issues paper" (3 September 2021), p. 4

[64] Frontier Economics "Target return for NZ GPBs report. Submission on Gas DPP 2022 process and issues paper" (27 August 2021), p. 11

[65] Vector "Submission on Gas DPP 2022 process and issues paper (August-2021), p. 10

[66] First Gas "Submission on Gas DPP 2022 process and issues paper" (30 August 2021), p. 2

Methanex "Submission on Gas DPP 2022 process and issues paper" (1 September 2021), p. 2

[68] Greymouth Gas "Submission on Gas DPP 2022 process and issues paper" (30 August 2021), p. 2

[69] Major Gas Users Group "Submission on Gas-DPP 2022 process and issues paper" (August-2021), p. 1, 2

[70] Major Gas Users Group "Cross submission Gas DPP 2022 process and issues paper" (13 September 2021), p. 1

> While we don't discount that measures proposed by GPBs to accelerate their capital recovery revenue might become necessary at some point, we don't agree that the threshold for doing so within the next DPP has been reached.

Current DPP settings imply outstanding regulated asset base out as far as 2070

6.37 We used financial modelling to assess the claim made by suppliers that current DPP policy settings imply significant unrecovered RAB in 2050. For our analysis we took current policy 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.

6.38 We looked at the extent of depreciable asset values that would be remaining in the RAB at different points in time if we were to make no policy changes in DPP3 or in any future regulatory period. We focused on depreciable assets (ie, excluding land and non-depreciable easements) as these hold an expectation of full recovery over time.

6.39 We assumed:

6.39.1 no fundamental changes in the scope of our regulation under the Act or the Gas IMs;

6.39.2 no other government interventions affecting asset recovery;

6.39.3 no changes in asset ownership for individual suppliers.

6.40 We agree that current regulatory settings imply that even with no new investment there will likely be significant unrecovered RAB across depreciable assets for all suppliers in 2040, 2050, 2060 and 2070 (table 6.1).

6.41 Our results for 2050 are of a similar magnitude to the modelling by Frontier Economics (paragraph 6.32) which relied on publicly available ID data.

6.42 There would be even greater RAB value for depreciable assets outstanding if we made reasonable assumptions about the need for ongoing additional capital investments to support a safe and reliable natural gas network in DPP3 and beyond.

6.43 This outstanding RAB under current policy settings is a function of:

6.43.1 the remaining asset lives applicable to existing (sunk) assets which determine how quickly capital costs are returned via straight-line depreciation allowances. Many existing assets, including those recently invested in, have remaining asset registry lives of greater than 60 years. This is a result of current policy settings that require suppliers to use physical asset lives in Schedule A of the Gas IMs. Schedule A specifies asset lives of greater than 60 years must be applied in most cases.

6.43.2 RAB indexation which increases the RAB annually by inflation. As mentioned above, this preserves the real value of the RAB over time, but it defers recovery of revenue to the future.

Table 6.1: RAB under current policy settings – 2020 existing depreciable assets only

Supplier / Year	2020 Existing ($m)	2040 ($m)	2050 ($m)	2060 ($m)	2070 ($m)
GasNet	24	16	10	6	2
Powerco	388	177	86	28	6
Vector	434	347	248	139	50
First Gas Distribution	174	114	81	58	30
First Gas Transmission	850	399	139	35	21
Total	1,870	1,053	565	266	109

6.44 The prospect of unrecovered depreciable RAB under current policy settings indicates that there is some stranding risk. It is credible that given the Government is targeting a net zero carbon emissions economy by 2050 that networks could shut down by 2050 or even earlier. In this case there would be unrecovered depreciable RAB even if suppliers can continue to price up to maximum allowable revenues right until network closure.

6.45 However, the materiality of this risk for achieving FCM depends on the potential residual value of the depreciable network assets. Residual value is any remaining economic value that can be realised by GPBs, even if a network ceases delivering natural gas, for example through the sale of assets. It is also possible that some part of the network may continue to be viable for some GPBs. If the residual value is expected to be equal to or greater than the remaining RAB at the date of network closure, then there will still be an expectation of FCM.

The prospect of residual network value means the risk of economic stranding is not certain

6.46 Our analysis only indicates economic network stranding at an assumed terminal date if the residual economic value for depreciable assets is less than the outstanding RAB across depreciable assets or there is no residual value.

6.47 The prospect of repurposing to carry low or no carbon gases provides a potential means for suppliers to continue operating in the long term. Networks may also convey natural gas longer than expected which would allow for greater recovery of capital. Any economic value remaining after a terminal date could be considered as residual value.

6.48 We note that under current legislation, we are:

6.48.1 limited to only considering the interest of consumers of regulated natural gas pipeline services, and only in their capacity as consumers of that regulated service;

6.48.2 constrained by the definition of gas pipeline services which means the "conveyance of natural gas by pipeline …", as in our view "natural gas", excludes hydrogen and biogas (refer to Chapter 2 for further explanation) but allows for some blending.

6.49 However, we can account for potential residual network value for GPBs under current policy settings.

6.50 The prospect of residual network value means the risk of economic stranding is not certain under current policy settings. We note that there are several economic and technical issues that would need to be resolved before repurposing becomes technically feasible or a likely outcome. However, at this stage network wind-down is not certain.

We have applied our existing framework to address the risk of economic network stranding risk in DPP3

Our decisions must promote the Part 4 purpose

6.51 Our purpose for regulating natural gas pipeline services under Part 4 is to promote the long-term benefit of consumers by promoting outcomes that are consistent with outcomes produced in competitive markets as defined in s 52A. Section 52A requires us to focus on the four objectives listed in s 52A(1)(a) to (d), balancing those outcomes and exercising judgement when doing so.

6.52 We consider that s 52A(1)(a) and 52A(1)(d) are most relevant for decisions on addressing stranding risk:

6.52.1 Section 52A(1)(a) of the Act promotes suppliers having incentives to innovate and to invest, including in replacement, upgraded, and new assets;

6.52.2 Section 52A(1)(d) of the Act promotes regulated providers being limited in their ability to extract excessive profits.

6.53 In reaching our draft decisions on addressing stranding risk, we aim to strike an appropriate balance between ss 52A(1)(a) and 52A(1)(d) to best give, or be likely to best give, effect to the outcomes in s 52A.

An expectation of real financial capital maintenance underpins our framework

6.54 For the DPP3 draft decision we have applied our existing regulatory framework which relies on a commitment to ex-ante FCM to support investment incentives under the building block model.

6.55 Part 4 of the Act and the IMs provide the basis for current regulatory settings. Under these settings suppliers have an ex-ante expectation of earning a normal return on investment such that they are incentivised to undertake efficient investment but are limited in their ability to extract excessive profits. Our ex-ante real FCM principle (and related NPV=0 principle) underpins this expectation and manages stranding risk. This supports suppliers to invest where it efficient to do so to meet the demands of consumers in the long term, for their long-term benefit.

6.56 The ex-ante FCM principle is not a guarantee of normal profits or a regulatory compact. Suppliers should have a reasonable opportunity to achieve FCM but are exposed to some stranding risk. For example, in our 2016 IM review decisions framework, we pointed to two sets of circumstances for which continuing to provide an expectation of FCM may no longer assist us in promoting the Part 4 purpose:[71]

6.56.1 if such a large number of customer disconnections mean that remaining consumers will not be willing or able to pay the prices that would be required for suppliers to achieve FCM; or

6.56.2 if the Government intervenes and amends or repeals Part 4.

6.57 Our two other key economic principles further guide our approach to addressing stranding risk.

6.58 Our risk allocation principle states that we should allocate risks to the party most able to manage the risk. In our 2016 IM review decisions framework we stated that managing risks includes:[72]

6.58.1 actions to influence the probability of occurrence where possible;

6.58.2 actions to mitigate the costs of occurrence; and

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

6.59 And our asymmetric consequences principal recognising the asymmetric consequences to consumers of regulated energy services, over the long term, of under-investment vs over-investment.

6.60 Together these principles point to the importance of ensuring that suppliers have appropriate incentives to invest in DPP3 and beyond, where it is prudent and efficient to do so.

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

[72] Commerce Commission "Input methodologies-review decisions Framework for the IM review (20 December 2016) , p. 43

6.61 Ultimately all three economics principles are a means to an outcome – the long-term benefit of consumers.

In response to increased risk of economic network stranding we could wait for more certainty

6.62 While economic network stranding may take many years to fully eventuate, it is a risk that can be reasonably anticipated now that we can begin to address through DPP3 if this would be for the long-term benefit of consumers.

6.63 There is some stranding risk now, but there is also significant uncertainty about the magnitude of the risk. Therefore, for DPP3 we need to take actions that are consistent with a high degree of uncertainty over the future need for GPBs.

6.64 Under our existing framework we can either take action now, or credibly commit to acting in a future regulatory period if the risk remains or increases eg, an early shut down becomes unavoidable.

Taking some action now best promotes the Part 4 purpose

6.65 Our view is that it is appropriate to take some actions now to provide a more credible expectation of FCM for suppliers.

6.66 We have developed a long-term financial model which supports this conclusion. Our model examines credible long-term scenarios and sensitivity analysis with no economic network stranding by changing the depreciation profile. Consumer price increases are required at some point to mitigate stranding risk under our assumptions. Our model results and assumptions are discussed in more detail below (6.119 to 6.130).

6.67 It might be possible to only begin addressing stranding risk in future regulatory periods beyond DPP3. However, we consider addressing the issue to some degree for DPP3 is consistent with outcomes likely to be produced in competitive markets in similar circumstances and therefore likely to be in the long-term interests of consumers. This is because it:

6.67.1 increases the credibility of the regime by continuing to provide a reasonable expectation of FCM for the GPBs, which in turn provides incentives for investment to maintain safe and reliable networks; and

6.67.2 provides some headroom if other building block model cost components increase in future regulatory periods to better manage consumer price shocks.

6.68 To address the increased stranding risk for DPP3 we need to make changes to the Gas IMs. In the following section we explain how we are proposing to accelerate depreciation in DPP3 to continue to support an expectation of ex-ante FCM and address stranding risk.

6.69 Some submitters asked for a full s 52Y review of the Gas IMs to be brought forward prior to setting DPP3. We considered this, but concluded it was not necessary to do this to set a fit-for-purpose DPP3. The full IM review will commence in 2022. The IM review will have the benefit of being able consider the Government's emissions reduction plan and emissions budgets.

We are proposing to accelerate depreciation for DPP3 to address the risk of economic network stranding

We considered various options for taking action in DPP3

6.70 We considered mitigating stranding risk, or leaving a material risk and providing ex-ante compensation for potential future stranding events.

6.71 In our process and issues paper we also raised the possibility of 'rolling over' starting prices as a way of addressing stranding risk.[73] We rejected this option, as setting prices based on current and future profitability is expected to be more consistent with the long-term benefit of consumers (Attachment C).

6.72 In the past for other regulated sectors, we have addressed the stranding risk by either mitigating the risk of an economic stranding event or providing ex-ante compensation, or a combination of both.

6.73 Stranding risk can be mitigated by:

6.73.1 shortening asset lives thereby accelerating the recovery of depreciation;

6.73.2 changing the depreciation methodology to reduce the value of assets subject to stranding risk more quickly; and

6.73.3 not indexing the RAB, an option which can effectively be subsumed by changing the depreciation profile

6.74 All of these methods are NPV-neutral with respect to the WACC. Suppliers would expect to receive the same amounts of revenue in present value terms over time and have an expectation of normal profits.

6.75 In the past we have considered all three of these methods to address stranding risk. For example, in the 2016 IM review we introduced a mechanism to allow shortening of asset lives for EDBs to mitigate economic stranding risk due to technological change.

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[73] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p. 43

6.76 Mitigation measures alone may be insufficient to ensure suppliers have an expectation of FCM. If so, ex-ante compensation may be appropriate. Ex-ante compensation mechanisms provide consumers with insurance against future price shocks, while explicitly exposing suppliers to the risk that assets may be economically stranded in the future.

6.77 We have previously provided ex-ante compensation for stranding risk for regulated fibre services. In Fibre, there is a risk of stranding due to partial network deregulation for 'physical' assets and there is also a Financial Loss Asset (**FLA**) which is exposed to competitive stranding risk. For the FLA, we mitigated the material risk through an accelerated depreciation profile and a relatively short asset life (14.2 years). For physical assets (sunk and incremental) we determined it was appropriate to leave a residual material risk. To support continued expansion of fibre services – we offered ex-ante compensation to maintain an expectation of FCM.

6.78 A potential advantage of ex-ante compensation mechanisms is that they can provide a clearer allocation of risk between suppliers and consumers. This is because suppliers are explicitly compensated for the risk of stranding, and consumers are explicitly protected from future price shocks.

We are proposing to accelerate depreciation by shortening asset lives for DPP3

6.79 Our draft decision is to allow an NPV-neutral (with respect to the WACC) shortening of asset lives for GPBs in DPP3. We propose maintaining straight line depreciation and RAB indexation for inflation.

6.80 The mechanism for accelerating depreciation for natural gas suppliers is based on our 2016 IM review solution for addressing increased economic stranding risk for EDBs in response to technological change.

6.81 At that time, we considered extending our decision to allow shorter asset lives for EDBs to apply to GPBs. We decided not to make any changes to the Gas IMs for GPBs given the evidence available at the time. However, we noted that if in the future emerging technology developments were to impact on natural gas networks, we could revisit the Gas IMs at that stage. Given the clear increase in stranding risk, we consider it is now appropriate to revisit that decision.

6.82 While there are other ways to bring forward cash flows (such as using a tilted annuity or other front-loaded depreciation profile), we think it is preferable in the context of a DPP to base the mechanism for GPBs off the established EDB mechanism which applies an adjustment factor to asset lives. An adjustment factor mechanism is transparent, easy to understand, and we expect it to be relatively straight forward for GPBs to implement in practice. Additionally, as noted below, it can be designed to allow for depreciation to be further adjusted as part of future DPP resets – even to the point of offsetting prior acceleration measures if required. While the EDB solution was introduced in response to technological change we consider an adjustment factor is also appropriate to deal with economic network stranding risk for GPBs under the current circumstances.

6.83 There are some differences between the adjustment mechanism for GPBs and that which applies to EDBs.

6.83.1 We will not require an application from regulated suppliers before implementing the adjustment. The EDB mechanism requires EDBs to formally request an adjustment prior to the commencement of the next DPP period and provide supporting evidence.[74]

6.83.2 There is no cap on the extent of the adjustment across existing and additional assets for each GPB for DPP purposes. The mechanism can be used to shorten asset lives (by applying a factor of less than 1) or extend asset lives (by applying an adjustment factor greater than 1), although for DPP3 we propose shortening lives thereby accelerating depreciation. For EDBs the adjustment was capped at a 15% reduction (equivalent to a factor of 0.85) to average remaining asset lives of existing assets only.

6.83.3 The mechanism is not limited to a one-time adjustment in DPP3. In our IM reasons paper for the EDB mechanism, we stated that "because of the added complications that would occur if we allowed EDBs to make multiple adjustment, EDBs will only ever be allowed to make one adjustment."[75] In contrast, it is possible that further adjustments in future regulatory periods and/or changes to how network stranding risk is mitigated and/or compensated for will occur for GPBs. Where further adjustments to asset lives are made then, as noted above, it is possible for the proposed mechanism to be used to extend lives as well as shorten them, to account for new information and changing levels of risk if necessary.

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74 Commerce Commission "Amendments to electricity distribution services input methodologies determination in relation to accelerated depreciation – Reasons paper (8 November 2018), p. 4

75 Commerce Commission "Input methodologies review decisions : Topic paper 3 The future impact of emerging technologies in the energy sector (20 December 2016), p. 26

6.84 These differences from the EDB solution allow the proposed GDB solution to better reflect the nature of the stranding risk problem facing GPBs.

6.85 We note that for DPP3 we are not proposing to explicitly change the 45-year assumption for new assets in the DPP3 financial model or asset lives for new assets specified in Schedule A of the Gas IMs that are used for ID purposes.

6.86 Rather than changing the 45-year assumption for new assets, we are using a simple adjustment factor which has the effect of reducing the 45-year assumptions for new assets in the DPP model but is tailored to the individual circumstances of each GPB.

6.87 For ID, our approach allows new assets to enter the registry with asset lives shortened commensurately with the percentage reduction 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.

6.88 For an example of how our proposal could be applied in practice for the DPP and ID see paragraphs 6.103 to 6.108.

6.89 Our proposed solution implies that if no further changes are made to depreciation in future regulatory periods, that asset lives will remain shorter. So, it implies accelerated depreciation for all future regulatory periods. This aligns with the EDB solution.

6.90 We note that most non-supplier market participants were not in favour of us taking any specific action in DPP3 to address stranding risk (paragraph 6.36). However, both suppliers and other market participants noted that accelerated depreciation mechanisms may be more appropriate than ex-ante compensation mechanisms in the context of DPP3 (paragraph 6.96).

6.91 We acknowledge that the changes made to depreciation for the draft decision affect elements of a foundational building block of the regime. Under normal circumstances, we would be hesitant to make changes to fundamental IMs outside of a seven-yearly s 52Y IM review. However, these changes are necessary for us to continue to apply our regulatory framework for DPP3, and we consider that they are necessary to best promote the long-term benefit of consumers.

Accelerating depreciation is an appropriate response given the current uncertainty

6.92 We consider that accelerating depreciation is a pragmatic measure that preserves the greatest flexibility pending the wider 2022/23 IM review.

6.93 Our modelling (paragraphs 6.119 to 6.130) shows that it is credible that we could mitigate risk by accelerating depreciation, without applying additional ex-ante compensation and still provide a reasonable opportunity for FCM.

6.94 While accelerating depreciation for DPP3 does mean price increases for current consumers, it implies relatively lower prices for future consumers. It is also NPV neutral with respect to the WACC, if stranding does not eventuate.

6.95 But more importantly, given the current uncertainty, there are much less serious implications for errors in estimation than for the main alternative of ex-ante compensation.

6.96 With respect to setting ex ante allowances Methanex noted the level of evaluation required for an ex-ante allowance "is unlikely to be feasible within the timeframe and context of a DPP reset".[76] Vector noted the much higher 'information burden' of ex-ante compensation measures and concluded that "the least regrets approach to manage the uncertain environment for demand is to tilt forward the recovery so that more investment is being recovered earlier".[77]

6.97 We favour a depreciation solution given the current uncertainty, as depreciation can be adjusted in future DPPs to account for new information and changing levels of risk. That potentially includes lengthening asset lives/slowing the rate of depreciation – even to the point of offsetting prior acceleration measures – if necessary.

It is not necessary to remove indexation to address stranding risk at this time

6.98 We have not removed RAB indexation at this time. Vector, Powerco and First Gas jointly submited a report by Frontier Economics arguing for a nominal returns framework for regulated natural gas networks in New Zealand.[78] While we considered removing RAB indexation for DPP3, there are strong practical reasons for why we have not removed RAB indexation at this time.

6.98.1 It is not necessary to remove RAB indexation to address stranding risk in DPP3. Stranding risk can be managed independently of inflation risk by accelerating depreciation.

6.98.2 There are implications for removing RAB indexation for shared assets between EDBs and GDBs, which would be difficult to work through within the constraints of the DPP process.

6.99 We can consider inflation risk allocation in the IM review.

[76] Methanex "Submission on Gas DPP 2022 process and issues paper" (1 September 2021), p. 7

[77] Vector "Submission on Gas DPP process and issues paper" (1 September 2021), p. 3

[78] Frontier Economics "Target return for NZ GPBs report. Submission on Gas DPP 2022 process and issues paper" (27 August 2021)

Accelerating depreciation has been favoured by many overseas regulators

6.100 Accelerating depreciation (eg, shortening assets lives or using a front loaded depreciation profile) is a favoured reponse by overseas regulators to address concerns about falling demand as a result of the transition to a low carbon economy.

6.101 France, Belgium, the Netherlands, and the United Kingdom have all accelerated depreciation to some extent to address concerns about uncertainty or expected decline in demand for natural gas pipelines in the future.[79] For example, in 2011 the regulator OFGEM in the United Kingdom identified that there was uncertainty about the future role of natural gas distribution in a low carbon energy sector.[80] OFGEM introduced a front-loaded depreciation profile, sum-of digits, from 2013 and more recently extended it to natural gas transmission networks.[81]

6.102 In 2021 the Australian Energy Regulator (**AER**) allowed shorter asset lives for all new natural gas pipeline assets owned by Evoenergy, based in the Canberra region. This was in response to an Australian Capital Territory Government's policy commitment to prohibit new natural gas connections in new residential developments and associated policies. Following that, the AER released an information paper in November 2021 on *Regulating gas pipelines under uncertainty*. The AER's preliminary view is some form of accelerated depreciation would be appropriate and preferred to other options such as ex-ante compensation if there is sufficient evidence to demonstrate and quantify the pricing risk and stranded asset risk arising from demand uncertainty.

Our intent is to support a reasonable expectation of Financial Capital Maintenance

We are proposing depreciation adjustment factors of between 0.60 and 0.87

6.103 Table 6.2 presents the depreciation adjustment factors we have used in our DPP3 draft decision.

Table 6.2: Adjustment Factors to be applied to asset lives for DPP3

Supplier	Adjustment Factor
GasNet	0.64
Powerco	0.87
Vector	0.60
First Gas Distribution	0.85
First Gas Transmission	0.75

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79 Oxera "Regulatory tools applied to gas networks to accommodate energy transition" (26 August 2021) considers regulatory tools applied to gas networks to accommodate energy transition in a European context.

80 OFGEM "Decision on strategy for the next gas distribution price control - RIIO-GD1" (2011) p, 44

81 OFGEM "Final Determinations – finance annex revised 002" (2011) p, 112

6.104 For our draft decision these adjustment factors apply to the 45-year asset life assumption applying to new assets and the weighted average remaining asset life calculated for each GPBs' existing assets in the DPP3 financial model. The adjustment factors shorten the asset lives for each GPB, which increases the amount of straight-line depreciation modelled during DPP3 and brings forward recovery of capital costs.

6.105 For example, for GasNet we have applied an adjustment factor of 0.64 to asset lives.

6.105.1 Before applying the proposed adjustment factor GasNet has a weighted average remaining asset life of 29.4 years for its existing assets in the base year and 26.4 years (29.4 years - 3 years) in Year 1 of DPP3.[82] After adjustment the remaining asset life is 15.8 years ((0.64 x 29.4) – 3 years) in Year 1 of DPP3.[83]

6.105.2 To determine the depreciation allowance for additional assets, the Gas IMs assume a 45-year remaining life at the time of asset commissioning for all GPBs. Our proposed adjustment factor for GasNet reduces the assumed life for new assets to 29 years (0.64 × 45 years).

6.106 As noted in paragraph 4.27.2, to reflect the DPP decision for ID purposes we propose requiring GPBs, after the DPP has been set, to change the asset lives of individual depreciable assets or asset classes in their ID asset registers for the corresponding first year of the DPP3 period.

6.107 GPBs can choose which individual depreciable asset lives to shorten for ID, but must ensure that the total resulting depreciation for ID in that year equals the amount of depreciation we modelled for the first year of DPP3. Lives for new depreciable assets subsequently added to the RAB under ID are shortened commensurately if the same type of existing assets were shortened for ID.

6.108 This means that suppliers can choose to apply a larger adjustment across some existing assets and a smaller reduction to others. For example, it may be possible to implement an adjustment factor of 0.6 (a 40% reduction) to existing depreciable assets by reducing the average asset life of more recently acquired assets by, say, 50% and not reducing the remaining lives for older assets of a different type that are almost fully depreciated.

[82] The base year for our DPP3 draft decision is Disclosure Year 2020. The formula for the weighted average remaining asset lives is as defined in the EDB IM at 4.2.2.3(a)(i) and 4.2.2.3(b).

[83] The three year deduction is due to the difference between Disclosure Year 2020 and the first year of the DPP3 regulatory period.

We considered a range of factors when determining how much to accelerate depreciation in DPP3

6.109 We have attempted to balance a range of factors when determining the extent of accelerated depreciation to apply in our draft DPP3 decision. Our primary considerations follow.

Our intent is to provide a reasonable opportunity for ex-ante Financial Capital Maintenance.

6.110 Providing a reasonable opportunity for ex-ante FCM promotes the Part 4 purpose. This is achieved by supporting incentives for efficient investment (s 52A(1)(a)) while limiting excess profits (s 52A(1)(d)).

6.111 Our view is that a reasonable expectation of FCM can be maintained for GPBs by making further adjustments to depreciation in DPP4 if required. Network wind-down is not imminent for any GPB and we consider that our decision to set a four-year rather than five-year DPP should not result in increased risk mitigation in DPP3.

6.112 However, we consider that it is appropriate to address most of the stranding risk in DPP3, given the high degree of uncertainty and the increased optionality it provides. While there is the potential for repurposing and/or residual value, we consider it is credible given the 2050 target that networks could shut down by 2050 with no residual value. Addressing most of the stranding risk in DPP3, minimises the risk that worse than expected outcomes will make it difficult, if not impossible, to continue to apply the ex-ante FCM principle in future regulatory periods.

6.113 By addressing most of the stranding risk in DPP3, we demonstrate our continued adherence to existing Part 4 frameworks including the FCM principle. Our actions are not intended to mitigate the more extreme possible scenarios within DPP3 (eg, network shut down by 2040). However, it is our intent to reconsider whether further actions are needed to address stranding risk in DPP4 and future regulatory periods if required.

6.114 Note that as mentioned above (paragraph 6.89), our proposed approach implies that adjusted asset lives will remain shorter in future regulatory periods. This means that risk is mitigated across all future regulatory periods. However, the price change impact of our adjustment occurs in the regulatory period in which the adjustment is applied. It is our intent that most of the price change adjustment required occurs in DPP3.

Our intent is to avoid unreasonable price shocks to consumers.

6.115 Rather than having large one-off starting price adjustments, we have used smoothing mechanisms to ensure that real average annual price increases are constant over DPP3 (Chapter 4).

6.116 By mostly addressing the increased stranding risk through real price increases in DPP3, we also mitigate the risk of unmanageable consumer price shocks in future regulatory periods. This provides some head room if other BBM cost components (such as the return on capital) were to increase in future regulatory periods.

We have taken actions consistent with the intent of DPPs.

6.117 Suppliers are not required to apply for accelerated depreciation. For GPBs we accept that there is increased stranding risk. In the absence of an application and approval process, we have undertaken simplified modelling of the stranding risk and used our judgement to determine the appropriate degree of risk mitigation for DPP3.

6.118 If over the course of DPP3, the risk for individual suppliers increases markedly, suppliers always have the option of applying for a CPP which already allows flexibility in how assets are depreciated. Our decision to use a four-year regulatory period for DPP3 should limit the need for a CPP.

We have examined a range of credible long term scenarios where accelerated depreciation mitigates economic network stranding risk

6.119 Assessing the magnitude of the stranding risk requires projections of the long-term profitability of GPBs, far beyond the scope of existing DPP financial models.

6.120 We have developed a long-term financial model to inform our draft decisions. With this model we have explored credible long-term scenarios and sensitivity analysis with no economic network stranding. Our model and a user guide which describes how it works is available from our website as part of the gas DPP3 draft decision consultation.

6.121 We have produced a reference scenario and sensitivities to key assumptions in that scenario. Key assumptions for our reference scenario include:

6.121.1 network closure at 2050;

6.121.2 MAR profiling to allow six years of constant real annual increases, then a constant real MAR to 2029, followed by a ramp down; and

6.121.3 taking capex allowances for the four years of DPP3 as presented in Chapter 5, but excluding further RAB additions from asset relocations, consumer connections or system growth to 2031, followed by a ramp down.

6.122 The MAR profile is the revenue which we assume is effectively available as an ‘envelope’ to accommodate cost recovery, including accelerated depreciation.

6.123 Our short-term MAR profiling assumption reflects our intent to address most but not all the stranding risk in the four years of DPP3. Real MAR increases are assumed to continue for the first two years of DPP4. The ramp down in the long run (to 20% of 2023 MAR) reflects an assumption of declining demand in the long run and a preference to avoid price escalation per unit of energy consumed.

6.124 Our capex assumptions after DPP3 imply that either suppliers all have 100% capital contributions for relocations, consumer connections and system growth, or that these types of investments cease all together.

6.125 Modelling results are summarised in Table 6.3 for our reference scenario and sensitivity to the assumed cessation year. No one scenario or sensitivity can be described as most likely.

6.126 Results are presented as real annual average increases in the MAR. These increases apply for six years under our reference scenario.

Table 6.3 : Modelled real average annual MAR increases
2050 reference scenario and sensitivity to cessation years

Supplier	2040 Sensitivity	2050 Reference Scenario	2060 Sensitivity	2070 Sensitivity
GasNet	7%	**5%**	4%	3%
Powerco	10%	**7%**	6%	5%
Vector	8%	**5%**	3%	2%
First Gas Distribution	17%	**14%**	13%	12%
First Gas Transmission	15%	**11%**	10%	8%

6.127 Under our reference scenario we would require annual increases of between 5% and 14% per annum for six years to fully address the risk.

6.128 Comparison with the 2040 and 2060 cessation year sensitivities indicates that there is significant uncertainty about the level of stranding risk in DPP3. Modelling results are particularly sensitive to the year in which full RAB recovery of depreciable assets is required.

6.129 For implementation purposes, we then calculate the implied adjustment factor for depreciation that would need to be applied in DPP3 to be consistent with the annual real MAR increases in Table 6.3. Table 6.4 presents the implied adjustment factors for our reference scenario and sensitivities.

6.130 Note these Adjustment Factors only deliver 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 MAR increases for a total of at least six years, subject to assessing the situation facing GPBs at the time, including any new information or sector developments.

Table 6.4 : Implied adjustment factors applied to asset lives 2050 reference scenario and sensitivity to cessation years

Supplier	2040 Sensitivity	2050 Reference Scenario	2060 Sensitivity	2070 Sensitivity
GasNet	0.56	0.64	0.70	0.75
Powerco	0.76	0.87	0.94	0.98
Vector	0.52	0.60	0.66	0.72
First Gas Distribution	0.61	0.69	0.73	0.78
First Gas Transmission	0.62	0.71	0.76	0.81

Significant price increases in DPP3 are likely to be for the long-term interest of consumers

6.131 For DPP3 we have decided to set the starting price adjustments and rates of change so that expected annual real price increases are between 5% and 10% per annum for all GPBs (Chapter 4 for further details).

6.132 For implementation purposes, this is equivalent to applying the depreciation adjustment factors in our DPP modelling for existing and new assets specified in Table 6.2.

6.133 As a starting point for arriving at our draft decision, we took the results of the Reference Scenario. This was a judgement call about the level of risk, considering alternative futures and the high degree of uncertainty. We then applied our judgement considering the factors discussed above (paragraphs 6.109 to 6.118).

6.134 For GasNet, Powerco and Vector, we have decided to apply the reference scenario adjustment factors directly for our DPP3 draft decision.

6.135 For First Gas Distribution and First Gas Transmission, we have calculated an adjustment factor for DPP3 that delivers 10% per annum real annual price increases for the four years of DPP3. This is consistent with our decision to limit real annual prices increases to 10% per annum for DPP3 to manage consumer price shocks (Chapter 4).

6.136 Our modelling for First Gas Distribution and First Gas Transmission illustrates that real price increases of more than 10% per annum for six years may be required to fully address the risk with a network cessation year of 2050. Our decision to limit increases to 10% per annum for DPP3 implies. This implies a longer adjustment period than six years of 10% per annum increases is needed for these suppliers to address the level of risk we assume exists under the Reference Scenario.

6.137 While we believe our scenarios are credible, we acknowledge that our modelling relies on uncertain long-term assumptions for key building block components. There is still significant uncertainty about the future of natural gas pipelines, which may have some residual value and/or alternative use to conveying natural gas which are not accounted for in our modelling.

6.138 Given the uncertainty, our draft decision is informed by modelling, but we have also weighted other factors including affordability and price shocks in reaching our draft decision. it is ultimately a judgement call. However, we are confident that:

6.138.1 the magnitude of our proposed response is commensurate with the magnitude of the problem as we have modelled it; and

6.138.2 by taking this degree of action now we are increasing optionality for the future, while continuing to support our commitment to the ex-ante FCM principle.

6.139 We acknowledge these adjustments to depreciation imply significant prices increases for consumers in DPP3. However, we believe that changes of this magnitude for DPP3 are consistent with outcomes likely to be produced in competitive markets in similar circumstances and therefore likely to be in the long-term interests of consumers. This is because these steps will continue to provide a reasonable expectation of FCM for the GPBs, which in turn provides incentives for investment to maintain safe and reliable networks. It also implies lower prices for future consumers relative to taking no action in DPP3 which provides some headroom if other building block model cost components increase in future regulatory periods. We intend to reassess our approach prior to the next reset

We have chosen to accelerate depreciation for DPP3, but are open to other long-term solutions

6.140 Economic network stranding is not imminent for any GPB, but it is something that can be anticipated now and addressed to some extent by short- to medium-term actions. Our DPP3 settings allow for other solutions to be developed over the longer-term.

6.141 We consider our approach to DPP3 is appropriate given the current policy uncertainty. We expect to have greater clarity about government climate change policy with the release of the Government's response to the CCC recommendations and the publication of its emissions reduction plan and emissions budgets in May 2022. If needed, we can consider these issues in light of that response in the upcoming comprehensive s 52Y IM review that is due to commence in 2022, including for systematic risk which is compensated through the WACC.

6.142 Depreciation-focused solutions provide additional flexibility to respond to changes in the level of risk while being NPV-neutral with respect to the WACC over the long-term. As noted above, the rate of depreciation can be slowed in the future if that were to be warranted.

6.143 We note that removing RAB indexation could go some way to achieving the same outcome. However, we think it is important that we consider RAB indexation in the wider context of inflation risk, and we intend to do this as part of the upcoming s 52Y IM review.

Our actions are consistent with the current level of uncertainty but signal change for both suppliers and consumers

6.144 Regardless of how climate change policy evolves over DPP3, New Zealand is embarking on a period of marked change in the energy sector to address climate change.

6.145 This transition will undoubtably have a profound impact on the role of GPBs and on their consumers in the long term. Suppliers will eventually either wind-down and/or repurpose to some extent towards clean gases and this may or may not result in economic network stranding. Regardless of the outcome for GPBs, consumers are likely to need to invest to some extent in alternative energy technologies.

6.146 We have continued to apply our existing frameworks for addressing stranding risk in DPP3 and maintained our commitment to ex-ante FCM. This has resulted in significant price increases for current consumers. However, it should provide incentives for suppliers to continue to invest to maintain safe and reliable networks, for the long-term benefit of consumers.

6.147 We cannot guarantee that suppliers will fully recover their RAB under any circumstance. The intent of our mitigation is to support a reasonable opportunity for FCM, but suppliers still need to be judicious in the investments they make to limit the risk of economic network stranding.

6.148 For our part, we acknowledge that we will need to continue to monitor, and may need to make further changes to regulatory settings, as the picture over the long-term use of natural gas develops.

7. Our draft decisions on quality standards

Purpose

7.1 This chapter sets out our draft decisions on quality standards; and outlines what we have considered in coming to these decisions for GDBs and the GTB.

Our draft decision

The Act requires us to set quality standards for regulated gas pipeline businesses

7.2 We set quality standards for GPBs while setting a default price-quality path as required by the Act. The provisions of the Act that are directly relevant to quality of service standards are:

7.2.1 Section 52A(1)(b) – incentives to improve efficiency and provide services at a quality that reflects consumer demand. It is the most relevant subsection of the Part 4 purpose when it comes to quality standards.

7.2.2 Section 53K – sets out the purpose of default/customised price-quality regulation. It states that default price-quality paths should be set in a relatively low-cost way.

7.2.3 Section 53M(1)(b) – requires us to set quality standards when setting a DPP. At the same time, we have wide flexibility, with s 53M(3) allowing us to set quality standards in any way we consider appropriate.

7.2.4 Section 53M(2) – price-quality paths may provide incentives for suppliers to maintain or improve quality of supply. Incentives may include, but are not limited to: penalties, rewards, consumer compensation, and reporting requirements.

We propose retaining the current quality standards

7.3 Our draft decision is to retain the current quality standards that apply to the GPBs. These quality standards are:

7.3.1 the GTB and GDBs must respond to any emergency within 180 minutes;

7.3.2 the GTB and GDBs must respond to 80% of emergencies within 60 minutes; and

7.3.3 no major interruptions for the GTB and if there was a major interruption, that the GTB must provide a detailed publicly available report.

7.4 We do not propose introducing new quality standards for the GTB and GDBs.

Our reasons for draft decision

Reliability is improving

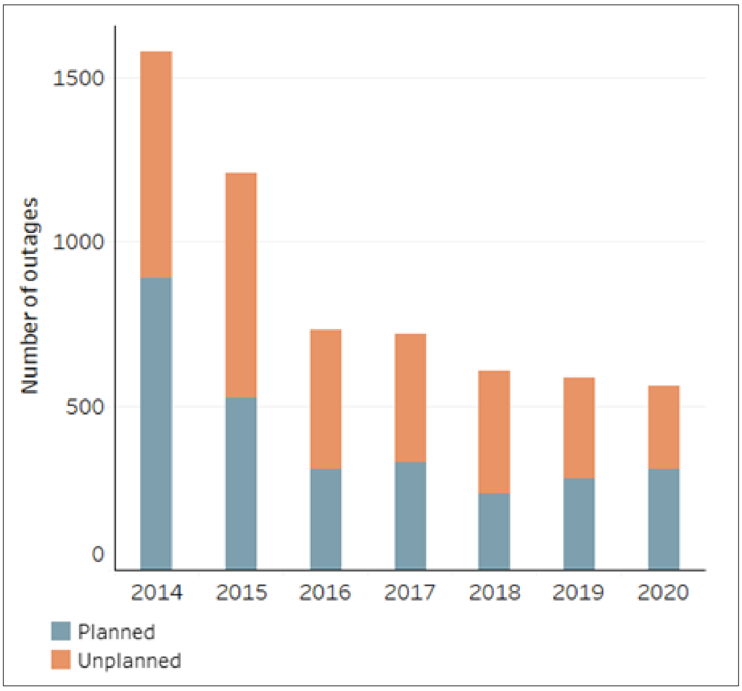
7.5 In reaching our draft decisions we have assessed a number of GPB reliability measures, including:

7.5.1 the total number of planned and unplanned outages that occurred, as shown in Figure 7.1;

7.5.2 the average number of planned and unplanned outages experienced across all customers, as shown in Figure 7.2; and

7.5.3 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 GPBs, 2014-2020 [84]



[84] Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021)

Figure 7.2 : Number of planned and unplanned outages for GPBs, 2014-2020[85]

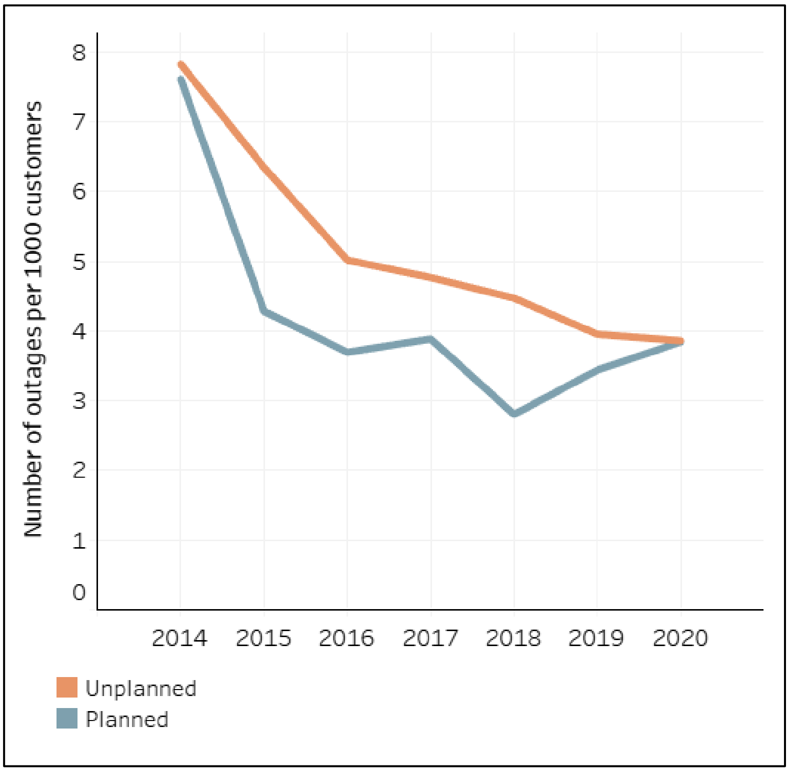
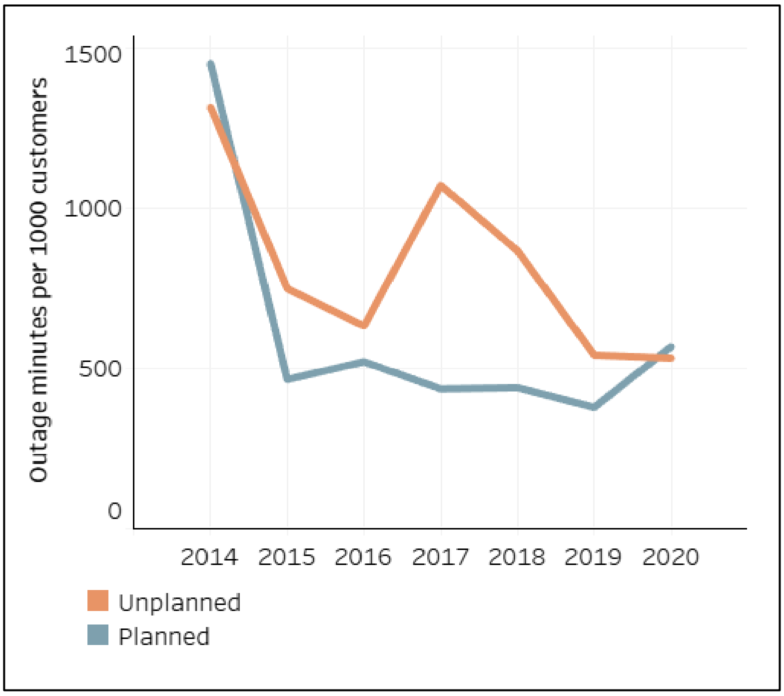


Figure 7.3 : Average length of planned and unplanned outage time per 1000 customers, 2014-2020[86]



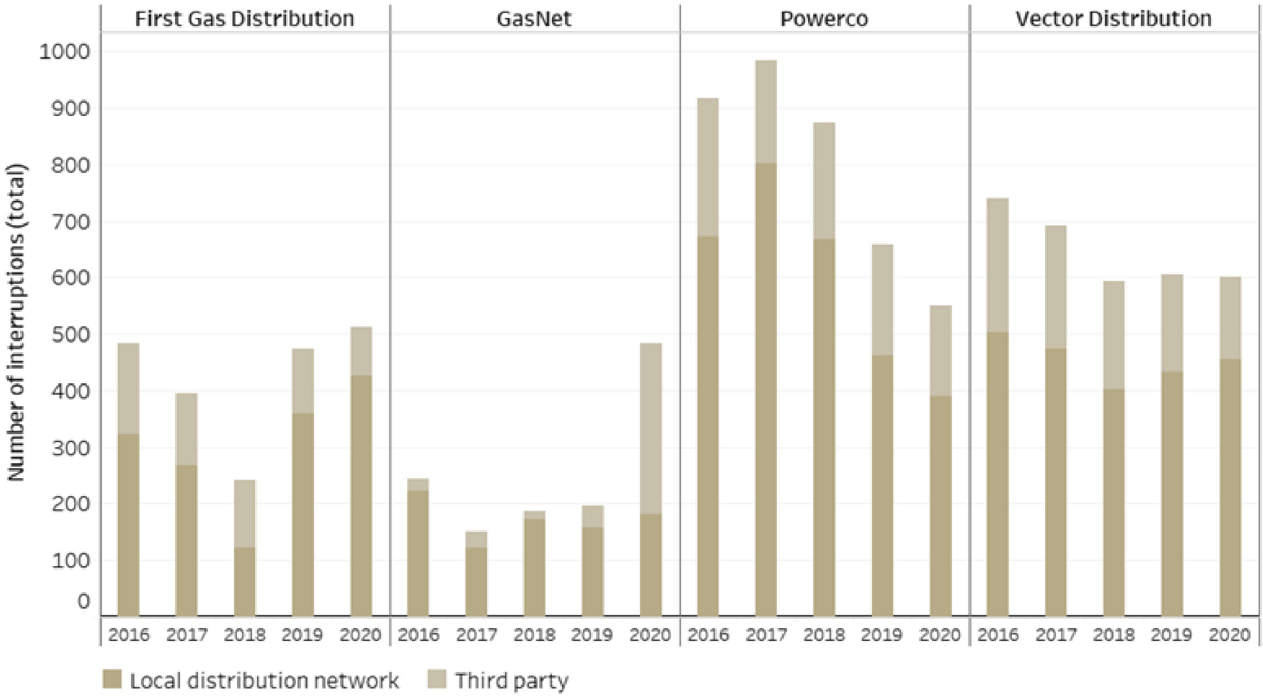
[85] Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021)

[86] Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021)

7.6 Since 2014, the total number of planned and unplanned outages and the average number and duration of outages experienced by customers has been decreasing with GasNet as an exception.

7.7 Our analysis identified that interruption results for GasNet worsened in 2018 and 2020 as shown in Figure 7.4. The high number of unplanned interruptions in 2018 was due to an event in April 2018 involving water infiltration into the natural gas mains. The high number of unplanned interruptions in February 2020 was due to an incident where approximately nine kilometres of natural gas mains and 283 gas services pipes were flooded with water.

Figure 7.4 : Breakdown of outages by origin for each GPB, 2016-2020[87]



7.8 The following metrics have also been trending downward and/or stable since 2014:[88]

7.8.1 the number of emergencies experienced on local natural gas pipeline networks;

7.8.2 the number of customer complaints associated with emergencies; and

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87 Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021)

88 Commerce Commission "Trends-in-gas-pipeline-business-performance" (15 December 2021)

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.

There are other regulatory measures and commercial incentives for quality standards

7.9 Gas pipelines are subject to a wide range of regulations, in addition to Part 4 of the Commerce Act 1986 that we administer.

7.10 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.[89] It is responsible for administering governance arrangements for the downstream natural gas industry from processing through to retail.

7.11 MBIE has a central role in governing, monitoring, and advising on the wider natural gas market, and assessing recommendations made by the GIC.

7.12 WorkSafe New Zealand is responsible for the Health and Safety in Employment (Pipelines) Regulations 1999.[90] 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).

7.13 GPBs are also incentivised to avoid problems related to quality standards because of commercial incentives like:

7.13.1 the reputational impact of quality problems;

7.13.2 the costs involved in responding to and repairing any damage; and

7.13.3 the revenue lost from undelivered services during an interruption.

Major stakeholders agreed we should keep the existing quality standards

7.14 We sought views from large natural gas consumers on whether there was merit to any additional quality standards. Their feedback was that no additional quality standards are necessary and they did not raise any concerns over current quality standards settings.

7.15 We did not receive any feedback from residential or commercial consumers and therefore do not have any direct information on whether they consider the current quality standards to be appropriate.

7.16 GPBs supported keeping the existing quality standards.

[89] Gas Act 1992

[90] Health and Safety in Employment (Pipelines) Regulations 1999

Our analysis shows that the current quality standards are fit for purpose

7.17 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.

7.18 There are other regulations and incentives that ensure that GPBs maintain quality of service as non-compliance or deterioration of quality of service could cost GPBs more.

7.19 Based on our analysis, we consider that the current quality standards are meeting regulatory requirements and do not need changes.

7.20 We acknowledge that there is some uncertainty on the future of natural gas in New Zealand. While we do not propose introducing new quality standards at this time, we recognise that natural gas consumers' preferences may change as the networks are phased out or repurposed for alternative gases. We may consider new quality standards in future DPP resets to reflect these changing consumer preferences.

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 process and issues paper submissions and the opex modelling alternatives we considered;

A2.2 a summary of the Requests for Information (**RFIs**) 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

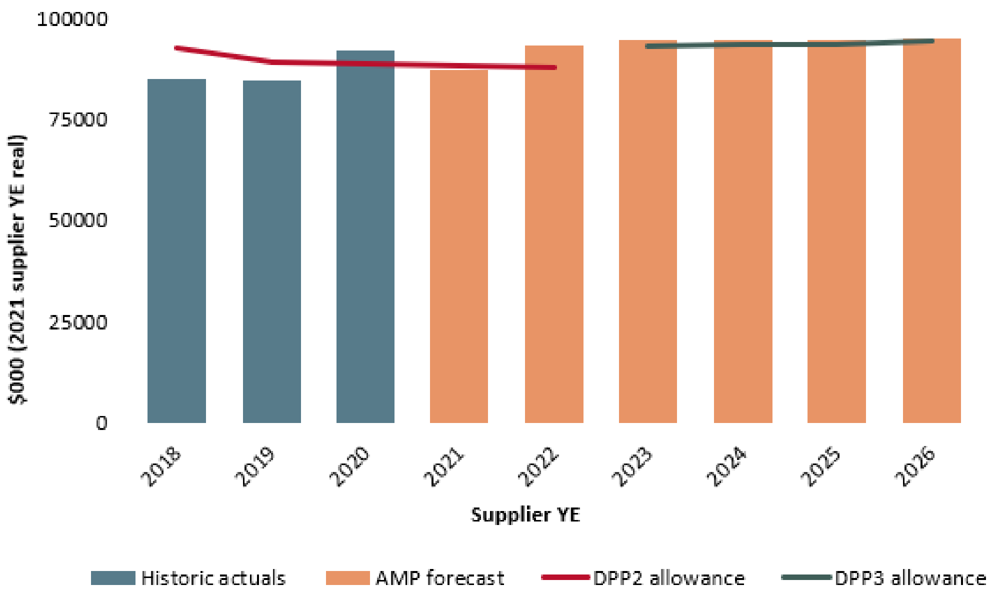
A2.4 opex allowance settings for each GPB for each year of DPP3.

Summary of allowances

Table A1 : GPB opex forecasts and DPP3 draft decision allowances for four-year DPP period (real $’000s, 2021 ID year-end)

Supplier	Opex forecast	Opex allowance
GasNet	$9,274	$8,150
Powerco	$73,405	$73,405
Vector	$56,337	$56,337
First Gas Distribution	$41,972	$38,983
First Gas Transmission	$198,196	$198,196
Industry total	**$379,184**	**$375,071**

Figure A1 Comparison of industry total historical opex, opex forecasts and DPP allowances (real $'000s, 2021 ID year-end)



How we have set opex allowances

A3 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 NZIER's all industries Labour Cost Index (LCI)/all-industries Producer Price Index (PPI) inflator series for opex with a 60%/40% weighting.

A4 We have used a base, step, and trend modelling approach to set opex allowances.

A5 To support our analysis, we have relied on supplier's historical and forecast expenditure data from their information disclosures.

A6 Following our base, step, and trend modelling, we have set allowances as the lesser of the model output or the supplier opex forecast in each year of Gas DPP3. This ensures that the allowances we set are not higher than each supplier has forecast what it needs.

A7 Our forecast of opex starts from a base value of opex that reflects what the business needs to operate its business, which is then projected forward with trends based on known cost drivers and input price inflators. We consider it is appropriate to model operating expenditure using the following three main cost drivers of:

A7.1 network scale – the scale of the network will affect operating expenditure because the volume of service provided will change;

A7.2 partial productivity – changes in operating efficiency will affect the amount of operating expenditure needed to provide a given level of service; and

A7.3 input prices – changes in input prices will affect the cost of providing a given level of service over time.

A8 We have adopted this approach because opex in the natural gas pipeline industry is typically recurring, ie, likely to be repeated regularly, and influenced by predictable factors.

A9 The base, step, and trend model also factors step change cost adjustments to reflect other cost adjustments that may not otherwise be captured by the trend modelling.

Process and issues paper submissions

A10 In our process and issues paper we signalled that we would forecast GPB opex allowances using a base, step, and trend modelling approach. We explained that this approach would be aligned with the opex modelling approach taken in EDB DPP3 and Gas DPP1. This would involve us adopting a base level of opex projected forward using trend drivers over the regulatory period.[91]

A11 Vector stated in its process and issues paper submission that the use of base, step, and trend modelling is a "practical step for setting opex",[92] while Powerco consider it is "worth considering".[93] GasNet did not have a view on how we proposed to set opex allowances,[94] while First Gas supported the proposed top-down approach to setting capex and opex allowances.[95]

A12 We also wanted to understand whether stakeholders considered the opex trend drivers of network scale, input prices and partial productivity remained appropriate for DPP3 or whether other trend drivers should be considered.

A13 On the topic of modelling partial productivity:

A13.1 First Gas considered that "Effort that would be put into estimating the productivity factor would be better put into getting the IMs right".[96]

A13.2 Vector noted that "Should the Commission embark on measuring sector productivity for setting some X-factor through historical total factor productivity (TFP) assessment will be a resource intensive exercise. It will also have less relevance on a forward-looking basis. This is because GPBs, as

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91 Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p. 67

92 Vector "submission on Gas DPP process and issues paper" (1 September 2021), p. 34

93 Powerco "submission on Gas DPP 2022 process and issues paper" (1 September 2021), p. 11

94 GasNet – submission on Gas DPP 2022 process and issues paper (6 September 2021), p. 4

95 Firstgas – submission on Gas DPP 2022 process and issues paper (1 September 2021), p. 34

96 Firstgas – submission on Gas DPP 2022 process and issues paper (1 September 2021), p. 17

foreshadowed by the Commission, must reconsider capital investment and operating level based on the impact of Net Zero 2050. The Commission's Issues Paper queried recent GPB Asset Management Plan (AMP) capital investment projections, particularly for connections and network expansion, as being reasonable in the context of Net Zero 2050".[97]

A13.3 Vector referenced the EDB DPP3 decision where a study produced for the Electricity Networks Association (concluded that "EDBs attributed the overriding feature for the change in opex productivity (for EDBs) was heightened compliance requirements" and expected that "the same drivers for EDB productivity will be shown in any analysis for GPB productivity".[98]

A13.4 Vector concluded by stating that "Any study will also be impacted by changes to asset stewardship as a result of Net Zero 2050. Indeed, the Commission itself suggests GPBs should actively adopt capex deferrals, particularly for asset replacement, by strategies that would involve more intensive opex management approaches to the extent they are able to. This type of strategic shift will not be reflected in any TPF or PPF (Total Productivity Factor or Partial Productivity Factor) study. Indeed, the context of the reset period means it is not well suited to a historical productivity approach for setting prices".[99]

A14 We also discussed in our process and issues paper how we might set base level opex and presented two possible options, namely:

A14.1 the base year opex amount is set as the most recent opex incurred by the GPB; or

A14.2 the base year opex amount is set using a multi-year average of recent opex incurred by the GPB.

A15 Vector suggested that "the benefit of the base-year approach is that we are using the most current view of the GDB's operating cost level for setting the opex base line".[100] Our view is that using actual opex to set the base value is reasonable as this is likely to reflect the ongoing costs needed to operate the business. However, there is no IRIS mechanism in the Gas IMs so the most recent opex may not necessarily be an efficient level of opex. We discuss this further when we discuss the base year value we have chosen.

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97 Vector "submission on Gas DPP process and issues paper" (1 September 2021), p. 17

98 Vector "submission on Gas DPP process and issues paper" (1 September 2021), p. 17

99 Vector "submission on Gas DPP process and issues paper" (1 September 2021), p. 18

100 Vector "submission on Gas DPP process and issues paper" (1 September 2021), p. 34

A16 In our process and issues paper we noted that businesses may change asset replacement strategies and decide to maintain assets for longer. The latter will likely increase opex need.

A17 MGUG's view is that GPBs are already adjusting capex/opex decisions stating that:[101]

> We would expect that prudent asset management would balance CAPEX/ OPEX trade-offs. For example, if GDBs anticipate asset stranding risk they would budget higher OPEX to maintain assets rather than replace them, while still retaining the option to replace them later. The evidence therefore suggests that within the timeframe of DPP3, these GPBs have all taken into account the advice of the CCC, as well as other developments surrounding the future of the gas network system.

A18 Vector's view is that maintaining assets for longer will likely increase the need for opex. Vector explained practically what would drive this, stating:[102]

> We agree with the Commission that going forward GPBs will need to consider strategies for prolonging the life of their system assets before undertaking replacement projects. This strategy will be more resource intensive as a higher volume of qualified technicians will be needed for maintenance and repair work on aging asset fleets. The hazard leaking gas pipes present to the community also require more resourcing for field crews. Opex resourcing will be needed going forward to conduct preventative maintenance with more frequent work to survey for leaks and reactive maintenance crews to respond to emergencies.

A19 Vector also noted that maintaining assets for longer would need to be balanced against the increased hazard of operating those older assets, stating:[103]

> We also recognise the Commission's suggestion that suppliers should be considering all means for managing assets to limit asset investments including asset replacement. The Commission is right that prolonging the life of system assets will create more opex as more field crews will be needed to manage older fleets. However, the hazardous nature of natural gas means the extent of any substitution will need to be carefully balanced and may not be significant. The public benefit of having reliable and safe pipeline systems will mean asset replacements will still need to be undertaken. In this sense the Commission needs to recognise its broader public purpose of facilitating effective asset stewardship.

A20 We agree with Vector in that GPBs need to balance risk in investment decisions. We consider that GPBs may need to adopt and demonstrate formal, analytical risk-based decision-making frameworks to support future capex/opex investment decisions.

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[101] Major Gas Users Group (MGUG) "submission on Gas DPP process and issues paper" (1 September 2021), p. 3

[102] Vector "submission on Gas DPP process and issues paper" (1 September 2021), p. 3

[103] Vector "submission on Gas DPP process and issues paper" (1 September 2021), p. 31

Alternatives considered

A21 We also considered using and scrutinising the opex forecasts disclosed from the latest AMPs available to set DPP opex allowances. This would be like the approach we took to setting opex allowances in Gas DPP2 in 2017.

A22 This AMP-based approach would require a significant level of scrutiny and we summarised this process in the process and issues paper.[104]

A23 Relying on AMP forecasts and explanatory material to set opex allowances would:

A23.1 be consistent with our approach to setting allowances under the previous Gas DPP;

A23.2 tailor opex allowances to the circumstances of individual suppliers, rather than applying trend factors from base, step, and trend modelling; and

A23.3 result in us scrutinising supplier asset management processes and how these are used to inform expenditure forecasts.

A24 The approach we took in setting the Gas DPP2 allowances allowed us the opportunity to test supplier asset management planning processes and to ascertain if forecasts were based on a bottom-up planning. We concluded at the time that this seemed to be the case.

A25 However, while this process allowed us to tailor allowances based on individual supplier circumstances, it was resource intensive and time consuming.

A26 The base, step, and trend approach uses historic opex performance to set opex allowances. Opex costs generally recur year-on-year so a method based on historical expenditure is likely to be a good predictor of future opex expenditure. It is also a method that sets allowances in a relatively low-cost way as opposed to the resource intensive and time-consuming bottom-up approach we took in setting allowances in the Gas DPP2.

A27 We decided that the base, step, and trend approach is more appropriate for setting opex allowances in this DPP. Base, step, and trend modelling is more in line with our framework of applying the same or similar treatment to all suppliers on a DPP and setting expenditure with reference to historical levels of expenditure.

[104] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p. 63-64

A28 We are not ruling out taking a more tailored bottom-up opex allowance setting approach in future Gas DPPs probably in conjunction with a natural gas sector efficiency study. It may also be necessary to tailor GPB opex allowances in future to assess how risk is informing capex/opex investment decisions and to factor in natural gas sector uncertainty.

Our Request for Information process and key material we have relied on

A29 We sought additional information from suppliers regarding operating expenditure items that need to be explained, accounted for in base opex calculations or modelled as opex step changes, namely:

A29.1 Gas Transmission Access Code (**GTAC**) project opex costs - First Gas Transmission;

A29.2 Operating lease costs - all natural gas pipeline businesses;

A29.3 GPB historical and forecast expenditure for the investigation of alternative gases such as biogas and hydrogen - all natural gas pipeline businesses;

A29.4 First Gas Distribution - opex uplift between DY20 and DY21;

A29.5 First Gas Transmission - forecast step change in compressor fuel costs from DY22; and

A29.6 GasNet - forecast uplift in non-network opex between DY22 and DY23.

Base opex – First Gas Transmission Gas Transmission Access Code costs

A30 We need to ensure that non-recurring project costs are not included in the base, step, and trend model variables. 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".[105]

A32 First Gas Transmission notified the Commission on 19 March 2021 that it had "permanently discontinued the project".[106] First Gas further state that:

[105] First Gas First Gas Transmission 2020 Asset Management Plan Final , p. 30

[106] First Gas Limited letter to Commerce Commission, MBIE and Energy Minister - Discontinuation of GTAC (for MBIE, Energy Minister and ComCom) 19 March 2021

> 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 First Gas Transmission confirmed that no opex costs related to GTAC had been incurred and that all project costs have been written off.[107]

Base opex – operating lease costs

A35 On 1 July 2017, the New Zealand Government announced it would adopt a New Zealand equivalent of the International Financial Reporting Standards (IFRS), New Zealand International Financial Reporting Standards, (**NZ IFRS**).

A36 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. [108]

A37 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.

A38 We sought expenditure information from all GPBs about operating lease expenditure incurred between the 2018-2020 disclosure years.

A39 GPBs responded with the following information:

A39.1 Gasnet – had no material operating leases under NZ IFRS 16;

[107] First Gas Transmission 2021 Asset Management Plan Update , p. 34

[108] https://www.xrb.govt.nz/accounting-standards/for-profit-entities/nz-ifrs-16/

A39.2 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;

A39.3 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 capitalized". Vector did not incur operating lease costs subsequent to this; and

A39.4 Powerco – stated that it had adopted NZ IFRS 16 from 1 April 2017 and had not incurred any operating leases costs since then.

A40 The GPB operating lease costs are summarised in Table A2.

Table A2 : GPB operating lease costs between disclosure year 18 and disclosure year 20

Supplier	DY18	DY19	DY20
First Gas Distribution	$34,036	$63,587	$0
First Gas Transmission	$184,060	$313,336	$0
Vector	$388,703	$0	$0

A41 For this draft decision we have decided to use a single year of opex: DY20, to set the base value of opex. No GPB has incurred operating lease costs in DY20. If we decide to use a multi-year average to calculate a base opex value then we will need to remove operating lease costs from the DY18 and DY19 historical opex.

Opex step change – alternative gas costs

A42 In our process and issues paper we signalled to the natural gas sector that we understood 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.[109]

A43 We noted 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.

[109] 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

A44 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.[110]

A45 We sought additional information from GPBs using the RFI process. We wanted to test the materiality of GPB alternative gas investigation capital and operating expenditures incurred to date and forecast to be spent.

A46 In response to our RFI question, GasNet noted that it had not incurred any expenditure related to the investigation alternative gases, but it may do so in future, stating:[111]

> To date GasNet has taken a watching brief, attending pan-industry sessions etc. with the resulting operational cost being absorbed into normal business activities for the attendees. However, as pan-industry R and D starts to ramp up, GasNet is likely to provide financial contributions, but nothing has been budgeted yet. Given the current uncertainty, made now worse by Government's deferment in applicable decision making to end of May 2022, commitment of spend at Board level is yet to be tested.

A47 First Gas stated that it had incurred approximately $0.5 million of opex in its net zero-carbon trial programme in DY20 and $0.2 million in DY21. We have removed these amounts from the First Gas Transmission opex base year calculation. First Gas also confirmed that it intends to incur capex of approximately $3 million in DY22 to carry out a Net-Zero Carbon trial. First Gas state that it would "expect to share these costs with partners who partake in the trial".[112]

A48 Recently, First Gas announced that it was planning to invest to connect its distribution network to a biogas plant in Broadlands, Central North Island, by mid-2022. First Gas state that this biogas facility could supply up to 9000 homes and businesses and may cost it between $6 million to $8 million.[113]

A49 First Gas also notes that it plans for ongoing opex in both its transmission and distribution businesses from DY23 stating:[114]

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[110] The Gas Infrastructure Working Group report – NZ Gas Infrastructure Future Findings Report (13 August 2021)

[111] RFI response to GNT-01 GasNet RFI 22 Sep 2021 provided to Commerce Commission on 6 October 2021

[112] RFI response to FG-01 First Gas RFI 22 Sep 2021 provided to Commerce Commission on 6 October 2021

[113] Stuff article (December 2021) https://www.stuff.co.nz/business/127220580/first-gas-invests-millions-to-use-biogas-but-delays-green-hydrogen-trial

[114] RFI response to FG-01 First Gas RFI 22 Sep 2021 provided to Commerce Commission on 6 October 2021

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.

A50 First Gas Transmission in its 2021 Asset Management Plan Update, describe the Future Fuels trials expenditure as:[115]

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.

A51 Powerco confirmed that it has incurred approximately $0.2 million opex to date "in developing consumer information and scenario modelling to inform the economic and regulatory implications of a transition" but did not forecast any opex for the future investigation of alternative gases. This amount appears to have been incurred since 2018, so we have divided it over three years and removed the average amount from the opex base year value in the base, step and trend modelling.

A52 However, Powerco stated that it may contribute capex to the Net-Zero Carbon trial noting that:[116]

We are assessing an opportunity to participate in a trial with Fristgas [sic], Vector, GasNet and Nova to undertake a programme of hydrogen trial work introducing a hydrogen blend gas that could be reticulated though our existing network. This work aims to establish the safety and other requirements for converting the gas distribution and transmission networks to a blend of hydrogen.

The scope of this trial will be undertaken over a number of years (ongoing since 2021 until to April 2023), at an estimated total cost of $3M. As the findings of the work will apply across all networks, we are considering whether to jointly manage and assist funding the programme alongside other GNO's. At this stage it's proposed (but has not been agreed), Powerco could potentially contribute 20% of this cost ($600K), based on our RAB.

A53 Vector stated that, to date, it hasn't incurred any capex or opex for the investigation of alternative gases, but that it has forecast to spend opex of about $0.16 million per annum from DY23 for this purpose.

115 First Gas Transmission 2021 Asset Management Plan Update , p. 50

116 RFI response to PCO-01 Powerco RFI Q2 22 Sep 2021 provided to Commerce Commission on 6 October 2021

A54 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 is 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'.[117]

A55 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.

A56 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 suppliers' pipelines and consumers' appliances.

A57 We have not included any allowance for this in our draft decision, as we do not have evidence from suppliers as to the amount of expenditure that could reasonably be allowed for such investigations. Any amount for this purpose may also be immaterial in the context of the capex allowances.

A58 Our view is that, while suppliers should not use funding for investigations into gas that does not meet the 'natural gas' definition or use the allowances we set for this purpose, we are open to including additional expenditure for the investigation of the conveyance of blends that would qualify as natural gas, if suppliers provide evidence of the amount of expenditure that is reasonably required for this purpose and we consider it sufficiently material to be included in the capex allowance.

A59 Consequently, our draft decision is that we have not included any specific allowance for alternative gas investigation costs or gas blends in this DPP. Suppliers may still carry out investigations of alternative gases, but costs associated with this will need to be funded by shareholders.

Opex step change - First Gas Transmission compressor fuel costs

A60 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.[118]

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[117] 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

[118] First Gas Transmission 2021 Asset Management Plan Update , p. 46

A61 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."

A62 We asked First Gas Transmission to provide us with more detailed compressor fuel cost increase information in order that we could model the increase in costs if we considered the increase was appropriate.

A63 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".[119]

A64 The forecast compressor cost increases are summarised in Table A3**.**

Table A3 : First Gas Transmission compressor fuel cost increases ($000's)

	DY22	DY23	DY24	DY25	DY26	DY27
Compressor fuel cost increase	$2,592	$2,592	$2,792	$2,792	$3,292	$3,292

A65 We consider that the First Gas Transmission information aligns with the gas market prices increases discussed in the latest gas industry supply/demand report produced by Concept Consulting Ltd for the Gas Industry Company.[120]

A66 However, we are unsure about the First Gas Transmission prediction that these gas price increases will be sustained over the DPP3 period. Concept Consulting Ltd predicts supply restrictions will continue into 2022 but that:

A66.1 this restriction may ease in 2023-2024; and

A66.2 there is likely to be further gas availability of around 35-40 PJ per year from 2024 due to renewable power projects coming online and planned work at existing gas fields to increase productivity.

[119] RFI response to FG-05 First Gas RFI 6 Oct 2021 provided to Commerce Commission on 12 Oct 2021

[120] Concept Consulting Ltd. "Gas demand and supply projections – 2021 to 2035" (May 2021)

A67 While we have accepted the First Gas Transmission forecast compressor fuel cost increases in our draft decision, we are seeking industry views about whether the sustained increase beyond DY24, and the additional step change in price from DY26 in price are reasonable assumptions.

Opex step change – GasNet non-network opex

A68 GasNet is predicting a step change in forecast total opex ($0.8m) between DY22 and DY23, driven mainly by a non-network opex uplift. This step change is sustained across the DPP3 regulatory period and beyond.[121]

A69 We asked GasNet to provide us with an explanation for the uplift as there was none in the 2021 AMP material. GasNet responded to our RFI question stating that:[122]

> We complete the AMP prior to completion of Annual Plan activities. GasNet is looking to better resource itself to meet business and regulatory demands which includes additional people, tools and third-party support. We are looking at tool options that have a lower capex and higher opex spend thereafter. On reflection the 2022 forecast is high given the uncertainty at this time. In addition, traditional opex costs such as insurance have increased markedly in the last twelve months and our forecast included full resourcing following filling of some existing vacancies.

A70 GasNet provided further information stating that the 2021 AMP update material was inconsistent and that the actual proposed uplift is less than $0.3 million and is due to the need to recruit two engineering staff and to improve its Asset Information Services. We consider that the need for additional resource has been reasonably explained and have modelled the opex step change of approximately $0.3 million from DY23.[123]

Operating expenditure step change – First Gas Distribution operating expenditure uplift

A71 In our review of First Gas Distribution expenditure data, we observed an expenditure step change in forecast opex between DY20 and DY21.[124]

A72 We asked First Gas Distribution to explain this expenditure increase and why the increase is sustained beyond DY21.[125]

A73 First Gas Distribution explained that the quantum of the opex uplift between DY20 and DY21 is $1.4 million and is the difference between the DY20 actual opex and the DY21 forecast opex. Originally this uplift was forecast to be $2.5 million but DY20 opex actuals were higher than forecast.

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[121] GasNet 2021 Asset Management Plan, p 59

[122] RFI response to GNT-05 GasNet RFI 12 Oct 2021 provided to Commerce Commission on 6 Oct 2021

[123] GasNet email to Commerce Commission 11 November 2021

[124] First Gas Distribution 2020 Asset Management Plan, p 42

[125] RFI response to FG-01 Q2 First Gas RFI 22 Sep 2021 provided to Commerce Commission on 6 October 2021

A74 The majority of the expenditure uplift occurs in the non-network opex categories. First Gas Distribution explained that this was due to:

A74.1 higher premiums following the latest insurance renewal process;

A74.2 increased communication and data line charges, as core information technology systems are migrated to cloud data centres;

A74.3 a lift in marketing programmes to drive new customer connections; and

A74.4 costs associated with strategic research and development.

A75 First Gas Distribution qualify the reasons for the DY20 to DY21 uplift stating that:

> We note that we expect to maintain these costs at the increased levels going forward, except for marketing costs. The expenditure on our marketing programme is under review, as we consider the environment and factors impacting our gas distribution business.

A76 The opex uplifts have been described by First Gas Distribution only at a very high level with no supporting explanatory material provided to justify the projects or programmes with a reasonable description of their need. We tested the First Gas AMP material and could find no reasonable explanation either.

A77 Given that we are treating Research and Development allowances separately, and that First Gas states that its new connection marketing programme is under review, we do not have confidence that these opex step changes in DY21 are reasonable.

A78 We did not model these step changes in First Gas Distribution opex in our base, step, and trend modelling.

Our base, step, and trend modelling approach

A79 The remainder of this attachment discusses the other individual components of the base, step, and trend model, namely:

A79.1 base level of opex;

A79.2 opex trend factors due to network scale and partial productivity; and

A79.3 input price effects.

Modelling base operating expenditure

A80 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.

A81 We considered a range of options, namely:

A81.1 the most recent opex expenditure incurred by each GPB, and for the draft decision this would be DY20 opex actuals for all GPBs;

A81.2 a multi-year opex average which would smooth historical over and under-spend effects (eg, DY18 to DY20);

A81.3 use the lowest level of historical opex between DY18 and DY20; and

A81.4 use the opex allowance from the final year of DPP2 inflated to the first year of DPP3.

A82 In the 2013 Gas DPP 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 draw on the set an average value.

A83 In the 2017 Gas DPP we took a different approach to setting opex, developing metrics to test expenditure levels then testing exceptions against AMP explanatory material or supplier responses to questions.[126]

A84 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”.[127]

A85 It is much less likely that opex inefficiencies exist in the opex base year for EDBs because of the Incremental Rolling Incentive Scheme (IRIS) in the EDB IMs. The IRIS mechanism disincentivises EDBs from inflating opex costs and means that using the 2019 opex actual costs in the EDB DPP3 base, step and trend modelling may reflect an efficient base year.

A86 However, there is no IRIS mechanism in the Gas DPP IMs. This means that, while we must make an assumption about what an efficient base level of opex may be, we are also less constrained in doing so. We investigated a number of approaches in setting a base opex value.

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[126] Commerce Commission “Default price-quality paths for gas pipeline businesses from 1 October 2017 – Final reasons paper” (31 May 2017) , p. 28-33

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

A87 We considered taking a multi-year average of actual opex to set the opex base year to smooth 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. On this basis we were less confident that a multi-year opex actual average would be suitable to set a base opex value.

A88 Following our analysis, we propose using the Disclosure Year 2020 (**DY20**) actual opex to set an opex base value for all GPBs except for GasNet, and with the DY20 alternative gas costs removed for First Gas Transmission and Powerco.

A89 The DY20 actual opex was the most recently disclosed opex data for each business at the time our analysis was carried out. For most GPBs, the DY20 opex data is very similar to their DPP2 opex allowance settings, and not an opex outlier when compared to previous years.

A90 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 40% higher opex than its DPP2 opex allowance. To remove the effects of this outage we have used GasNet's DPP2 DY20 opex allowance to set the base value of opex.

A91 Finally, we will incorporate Disclosure Year 2021 (DY21) actual opex data from each GPB in our final decision base, step and trend modelling. We may use this DY21 information to update the base opex value in the final decision base, step and trend model, or we may reconsider using a multi-year average

Modelled operating expenditure trend factors and input price effects

A92 In our base, step, and trend opex projection model we incorporate several factors that affect opex trends namely:

A92.1 network scale including elasticity effects;

A92.2 opex partial productivity; and

A92.3 input prices that inflate base opex trends calculate in real $2021 terms to nominal

A93 There were no process and issues paper submissions that discussed the opex trend factors that we proposed to use or what trends should be based on. We discuss how we have modelled each of these model variables.

Network scale

A94 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 Installation Control Point (ICP) annual growth on a real $2021 basis in each year of DPP3.

A95 We have accepted the GDB ICP growth and natural gas demand forecasts as the basis for our CPRG forecasts and this is consistent with how we have modelled opex trends related to growth.

A96 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. GDBs do not forecast network length increases in their AMPs so we have had to estimate this relationship based on historical data.

A97 The ICP growth and network length estimates are also modified by an elasticity factor that models their non-linear relationship with opex.

Elasticity

A98 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 9.0% increase in opex. In our trend modelling we have split network scale effects equally between estimates of ICP growth and network length increases.

A99 In the 2013 Gas DPP draft 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.[128]

A100 We have updated the elasticity assumption based on the OFGEM gas sector elasticity modelling methodology used in the 2013 Castalia report. This update has 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.[129]

A101 Our updated analysis has resulted in an elasticity factor of 0.48.

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[128] Vector “Submission on Revised Draft Decision on Gas Initial DPP Appendix 2 Castalia Report” (7 December 2012”

[129] Australian Gas Networks (SA) - Access arrangement 2021-26 proposal (July 2020), Attachment 7.5 – Benchmarking operating and capital costs

Opex partial productivity

A102 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.[130]

A103 At the time we found no evidence to indicate that the productivity of suppliers of gas pipeline services improved by more or less than the rest of the economy. We propose to retain a partial productivity factor of 0% for this DPP3 period

Input prices

A104 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 GPB's control.

A105 We have inflated the GPB opex allowances for forecast input price changes (or inflation) using the:

A105.1 weighted average forecast change in the 'all industries' Labour Cost Index (LCI); and

A105.2 the 'all industries' Producer Price Index (PPI), or the non-labour cost index.

A106 The New Zealand Institute of Economic Research provides forecasts of these indices. We have used 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. Note that we did not carry out base, step and trend modelling in Gas DPP2.

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

Summary of opex allowances by GPB

Figure A2 : Comparison of First Gas Transmission historical opex, AMP opex forecasts and DPP opex allowances (real $’000s, 2021 ID year-end)

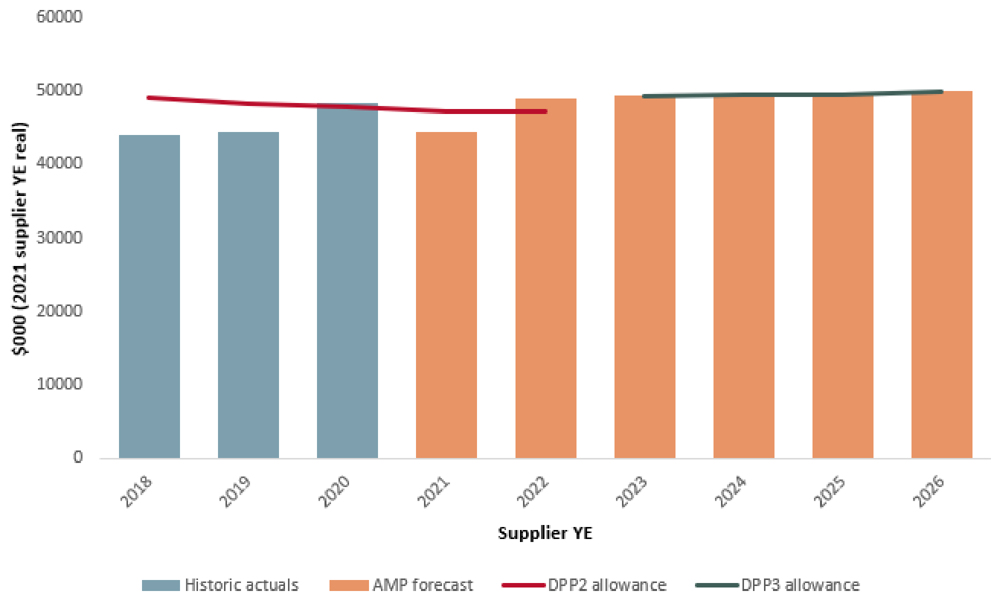


Figure A3 : Comparison of First Gas Distribution historical opex, AMP opex forecasts and DPP opex allowances (real $’000s, 2021 ID year-end)

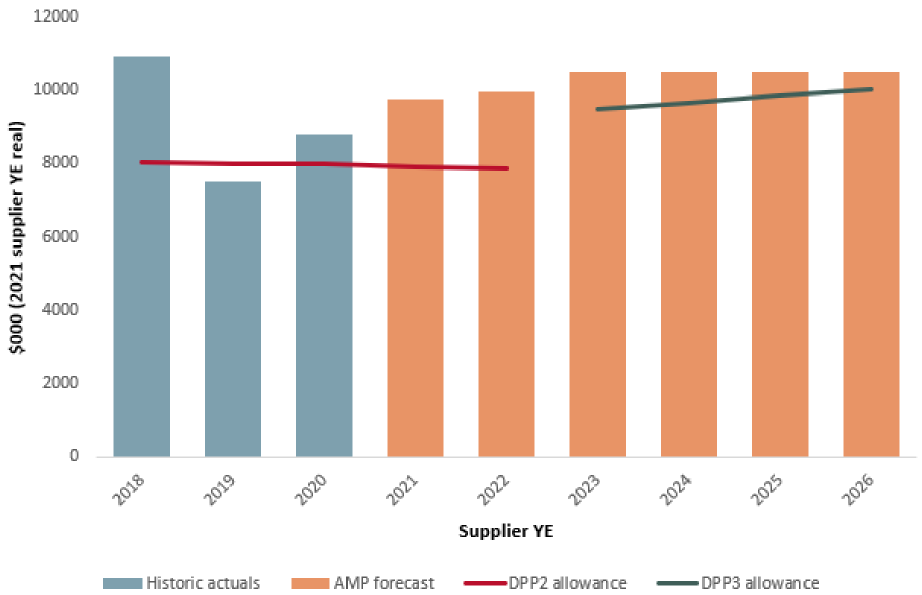


Figure A4 : Comparison of Vector historical opex, AMP opex forecasts and DPP opex allowances (real $'000s, 2021 ID year-end)

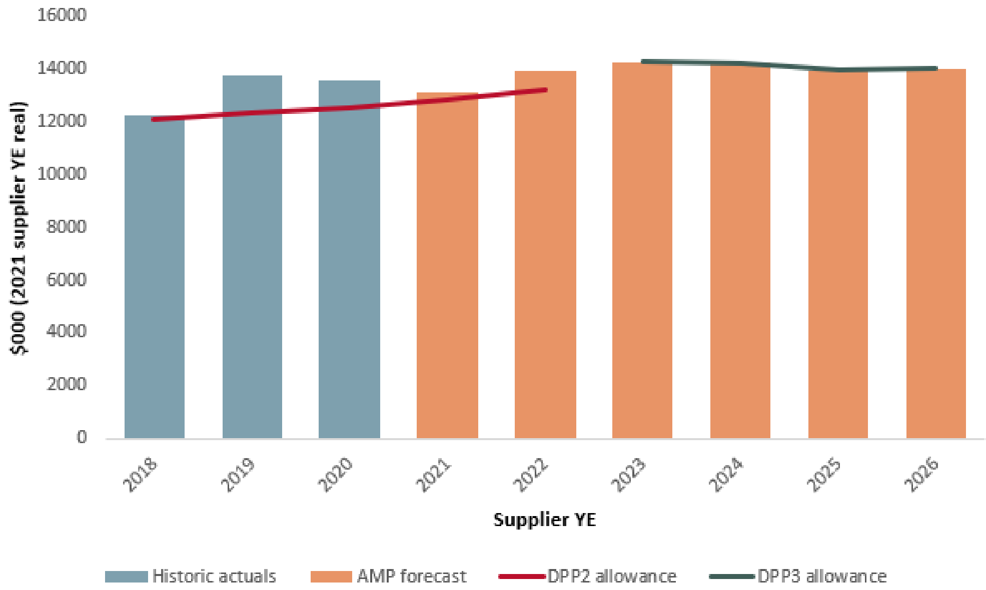


Figure A5 : Comparison of Powerco historical opex, AMP opex forecasts and DPP opex allowances (real $'000s, 2021 ID year-end)

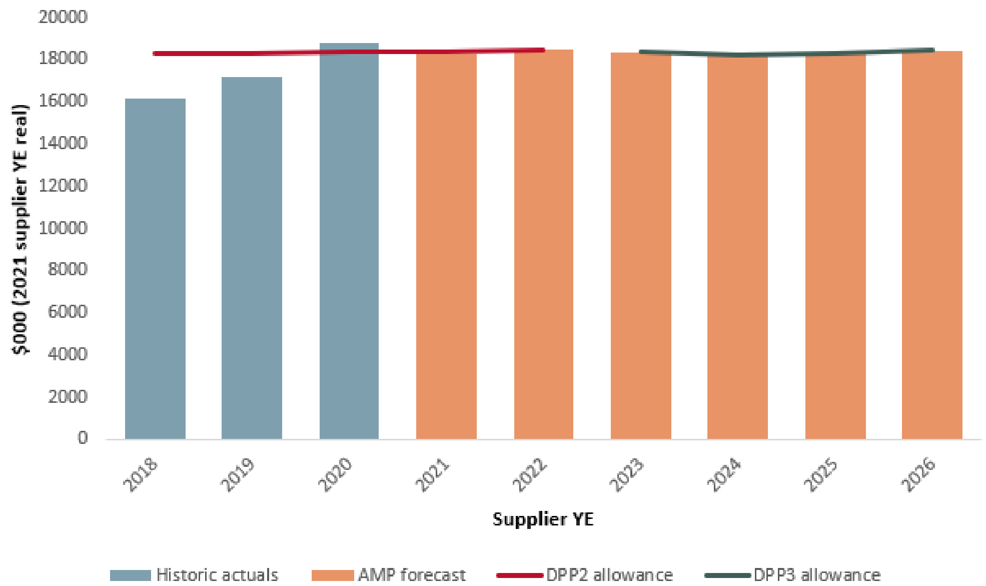
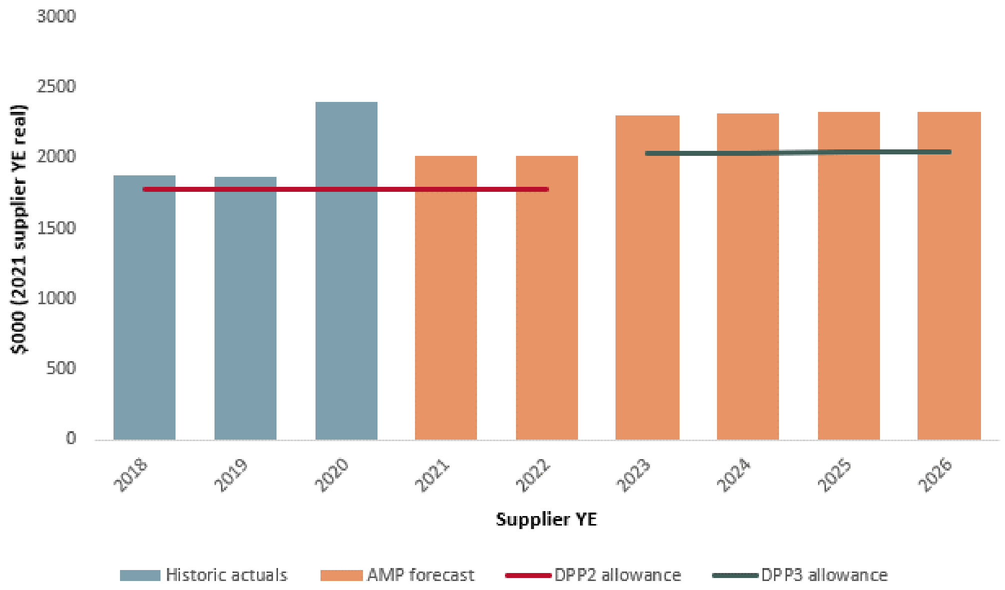


Figure A6 : Comparison of GasNet historical opex, AMP opex forecasts and DPP opex allowances (real $'000s, 2021 ID year-end)



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 process and issues paper submissions and the alternatives we considered;

B2.2 a summary of the RFI responses we used to inform our capex modelling;

B2.3 a summary of our capex modelling assumptions; and

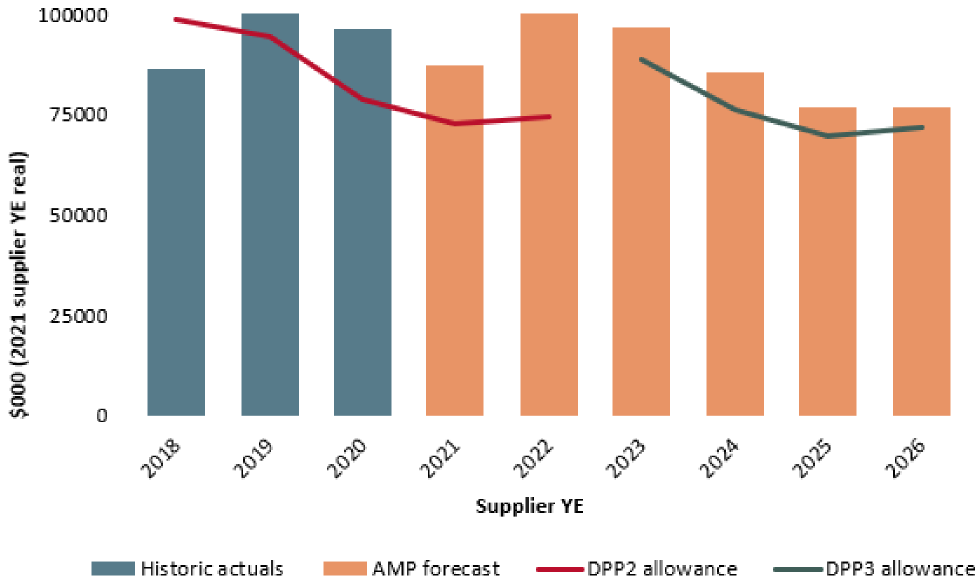
B2.4 capex allowance settings for each GPB for each year of DPP3.

Summary of allowances

Table B1 : GPB capex forecasts and DPP3 draft decision allowances for four-year DPP period (real $'000s, 2021 ID year-end)

Supplier	Capex forecast	Capex allowance
GasNet	$4,215	$3,359
Powerco	$72,694	$67,552
Vector	$38,313	$22,727
First Gas Distribution	$58,122	$49,441
First Gas Transmission	$162,090	$163,528
Industry total	**$335,434**	**$306,608**

Figure B1 : Comparison of industry total historical opex, GPB opex forecasts, DPP2 allowances and four-year DPP3 allowances (real $'000s, 2021 ID year-end)



Our approach to setting capex allowances

B3 We performed all capex analysis using historical and forecast expenditure expressed in real $2021. In setting capex allowances we inflated the capex real $2021 forecast estimates to nominal using NZIER's all industries Producer Price Index (PPI) inflator series.

B4 We have taken a top-down historical average real capex projection approach to setting real network capex allowances with targeted scrutiny of AMPs for real non-network capex. We have accepted 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.

B5 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 four years of ID data for each GPB, apart from First Gas Transmission, where we used three years of ID data.

B6 We noted that for First Gas Transmission, prior to 2018 and its purchase, network capex incurred by previous owners, fluctuated, and may introduce forecast error into the historical average capex projection we have used to cap allowances.

B7 For our final decision we will incorporate DY21 ID data when calculating the historical average capex for both the GDBs and the GTB.

B8 For GDBs we applied the historical average capex projection approach to system growth and other network capex; and for the GTB we applied this to total network capex.

B9 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 appeared to reflect the natural gas industry's long term future. Our investigations revealed that these policies appeared to be subsidy free and met the requirements of the Gas IMs pricing principles.

B10 We have used GDB forecasts of ICP growth and natural gas demand to form the basis of our supplier Constant Price Revenue Growth (**CPRG**) demand forecasts. Under the Weighted Average Price Cap (**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.

B11 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 upward bias in GDB growth forecasting.

B12 For GDB and GTB non-network capex, we sought information to support the forecasts and have accepted these forecasts based on explanations in the most recent asset management plans and following RFI responses to questions.

B13 While GPBs largely supported our proposed top-down approach to setting capex allowances in this DPP, given the natural gas industry's future uncertainty, we will need to consider if this approach remains appropriate for future DPPs. In other words, historic expenditure may be a poor guide to inform expenditure allowances in future resets.

Why we have not added margins to historical average capital expenditure projections

B14 The approach we have taken to set capex allowances is a simplification 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 accepted expenditure that was under the 10% margin and scrutinised expenditure above the margin.

B15 At the time 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.

B16 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.

B17 In this DPP, we are not adding a margin to the historical average capex projections we have used to cap capex allowances or allowing any expenditure above the level of the historical average capex projections.

B18 We do not consider it appropriate to allow more capex than the historic average in circumstances where growth is expected to start declining, and where there is a heightened risk of asset stranding. Suppliers may also be able to manage their capex through adjusting expenditure or capital contributions.

B19 However, to mitigate the risk that the allowances are insufficient, we have introduced capex reopener provisions for expenditure associated with unforeseen demand growth and maintaining the safety of the networks.

B20 Additionally, submissions from suppliers, and the work of the GIFWG, has signalled the increased risk of economic network stranding. To mitigate this stranding risk, we are accelerating depreciation for DPP3 (Chapter 6). We expect that suppliers will be also assess new capex investments against decisions to maintain asset for longer, to minimise the potential risk and quantum of stranding

Process and issues paper submissions

B21 In our process and issues paper we discussed the process we took for setting allowances in Gas DPP2 and our preference to taking a more traditional top-down analysis approach for this DPP; but that we might retain some aspects of the Gas DPP2 approach.[131]

B22 In Gas DPP2, capex allowance forecasting followed four key steps:

B22.1 Business-as-usual (**BAU**) variance tests;

B22.2 AMP evidence stage;

B22.3 GPB evidence stage; and

[131] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p. 63 Attachment B

B22.4 the use of fallbacks and alternative forecasts - at a capex category level and in an aggregate sense we applied BAU variance tests of a 10% increase above historical average capex.

B23 Powerco supports the top-down approach to setting expenditure allowances and notes that the extra effort required in carrying out bottom-up analysis is "unlikely to be of additional benefit".[132]

B24 We signalled that we would consider introducing capex re-openers. Powerco supported this by stating:[133]

> Powerco supports inclusion of capex re-openers in the DPP framework for gas businesses. The reopeners that are available in the Electricity DPP should be reviewed to ensure they capture the types of uncertainties affecting gas businesses.

B25 Vector is also supportive of the BAU top-down approach stating that:[134]

> The Commission is proposing to adopt a business-as-usual variance test for assessing expenditure forecasts of suppliers when calibrating capex and opex levels for the DPP reset. This approach has the benefit of being transparent and efficient.

B26 GasNet did not express an opinion about how we intended to set capex and opex allowances.

B27 First Gas provides a tabular summary of its views on aspect of the top-down approach.

B28 First Gas notes that past expenditures "provide a reasonable guide to safety and reliability expenditure" and that the practicality of the top-down approach is "pragmatic" since the "effort that would be put into scrutinising forecasts would be better put into getting IMs right". However, First Gas notes that the approach may not be able to "capture growing expenditure needs for hydrogen trials and biogas injection".[135]

B29 In summary we consider most GPBs support using top-down analysis to set capex allowances. We note that First Gas expressed the view that this approach is more appropriate for aspects of network capex that are aligned with maintaining the network, rather than for growth.

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132 Powerco "submission on Gas DPP 2022 process and issues paper" (1 September 2021), p. 11

133 Powerco "submission on Gas DPP 2022 process and issues paper" (1 September 2021), p. 11

134 Vector "submission on Gas DPP process and issues paper" (1 September 2021), p. 31

135 Firstgas – submission on Gas DPP 2022 process and issues paper (1 September 2021), p. 16

Alternatives considered

B30 A DPP is intended to be a relatively low-cost form of regulation and is not intended to fully tailor the price path to the supplier's specific needs. The process we undertook in 2017 for DPP2 was unusual for a DPP.

B31 In the expenditure analysis that supported Gas DPP2, we decided to take the opportunity to:

B31.1 test how GPBs were managing their assets;

B31.2 test whether forecast information was being driven by bottom-up asset considerations and expenditure needs; and

B31.3 test if forecasts were supported by asset management plan information.

B32 In 2016 we generally found that GPB forecasts were being driven by bottom-up asset considerations and that these forecasts supported the information provided in asset management plans.

B33 We also stated in our process and issues paper for the current DPP reset that we may:[136]

B33.1 use GPB forecasts for capex and apply a BAU variance test against each capex category, and for total capex, like the BAU variance test approach we took in DPP2;

B33.2 introduce capex reopeners to deal with foreseeable projects with uncertain cost and timing, and unforeseeable projects; and

B33.3 reconsider how we forecast allowances for consumer connection and system growth capex - we indicated that we would be informed by GPB capital contribution policies, factoring in potential government policy changes for new gas connections.

B34 We decided not to repeat the process we took when we set the 2017 Gas DPP. This would require a significant level of scrutiny and engagement with suppliers. Instead we have taken a hybrid approach, using top-down threshold analysis for network capex, but also carrying out targeted scrutiny of non-network capex.

B35 We are more comfortable with GPBs' AMPs following the DPP2 process and considered that GPB bottom-up asset management processes had been informing the capex and opex forecasts.

[136] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), p. 65 Attachment B

B36 Following analysis of supplier forecast information we decided that network and non-network capex, and GTB and GDB network capex category expenditures, should be considered separately. We have also applied some aspect of allowance tailoring that reflect supplier circumstances.

Our Request for Information process and key material we have relied on

B37 We sought additional information from suppliers 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:

B37.1 Whanganui sales gate capex assigned as non-network capex in DY22 - GasNet;

B37.2 GTAC project capex costs - First Gas Transmission; and

B37.3 Capital contribution policies – GasNet, Powerco and First Gas Distribution.

Whanganui sales gate capital expenditure – GasNet

B38 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.

B39 GasNet responded by declaring 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.

B40 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.

B41 We accept GasNet's explanation as reasonable and have amended its non-network forecast capex to $72,500 in DY21 and DY22, with ongoing costs of $35,000 from DY23 to DY25.

GTAC project capex costs – First Gas Transmission

B42 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.

B43 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. That is, we understand there are no forecast amounts for GTAC costs in the allowances proposed for DPP3.

Capital contributions policies and new connection growth

What we said in our process and issues paper about capital contributions

B44 In our process and issues paper we signalled that we were interested in GDB consumer connection capital contributions policies and what levels of consumer connection capex were reasonable.

B45 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 line charges.

B46 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".[137]

B47 We noted in the process and issues paper that, 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.[138]

B48 Vector, in its 2021 Asset Management Plan, discuss a changed capital contributions policy, stating that:[139]

> 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.

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137 Gas Distribution Services Input Methodologies Determination 2012 (as at 3 April 2018) Part 2 Subpart 5 clause 2.5.2 (1)(a)

138 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

139 Vector Gas "2021 Gas Asset Management Plan June 30 2021 Update", p. 5

B49 Vector also noted that it is revising its 2021 AMP forecast in December 2021 "to account for any new relevant information that may invalidate the forecasts in this AMP update and provide this to the Commission for DPP reset purposes". This revision will be too late to include in our draft decision analysis but will be included in the final decision analysis.

B50 First Gas Distribution, in its 2021 Asset Management Plan, published 30 September 2021, has stated it has modified its capital contributions policy stating that:[140]

> 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.

B51 So far as we are aware, Powerco and GasNet do not currently intend to change their capital contributions policies. Powerco stated in its submission to the process and issues paper that:[141]

> 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.

B52 Powerco's 2021 Asset Management Plan Update, published 30 September 2021, did not discuss this issue.

Request for information on capital contributions

B53 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.

B54 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 NPV=0 for the new connection.

B55 We asked GasNet, Powerco and First Gas Distribution to:

B55.1 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

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[140] First Gas Distribution "2021 Asset Management Plan Update September 30 2021", p. 37

[141] Powerco "submission on Gas DPP 2022 process and issues paper" (30 August 2021), p 7-8

B55.2 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 subpart 5.

GasNet - capital contributions policy, installation control point growth assumptions and the link to consumer connection capex

B56 GasNet responded to our RFI questions, stating that:[142]

> GasNet has no position currently linking capital contribution policy and resultant asset stranding. As such our traditional policy remains that if investment is NPV neutral at 40 years (or earlier) no contribution is requested.

B57 GasNet reviews new connections on a case by case basis and assesses the contribution required only if the connection is not Net Present Value (**NPV**) neutral over a maximum 40-year payback period for residential consumers, including a risk assessment of remaining connected, and a 20-year payback period for commercial and industrial consumers.

B58 GasNet sets different contribution rates for different customer types and its contribution analysis is guided by the by NPV neutral principle:[143]

> Where the economic investment analysis yields a positive Net Present Value, no Capital Contribution will be required from the Customer; however where the economic investment analysis yields a negative Net Present Value, the Customer will be required to pay a Capital Contribution equal to the amount required to yield a Net Present Value of zero

B59 Gasnet, in its latest AMP published on June 30, 2021, has forecast sustained connection growth out to 2031, and describes the basis of its most recent consumer connection capex forecast as:[144]

> Land development and the release of new residential properties has historically been very low in the areas served by GasNet's existing infrastructure, typically resulting in less than 1% annual growth in connections. By comparison, the rate of commercial and industrial connections is much smaller and by their nature are more difficult to predict and incorporate in any long-term forecast.
>
> GasNet's forecast…..is based on estimates for Residential and Commercial/Industrial consumer connections which reflect recent historic trends and known future developments. A step increase in 2018 was due to an increase in demand for new gas connections, which continued in 2021.

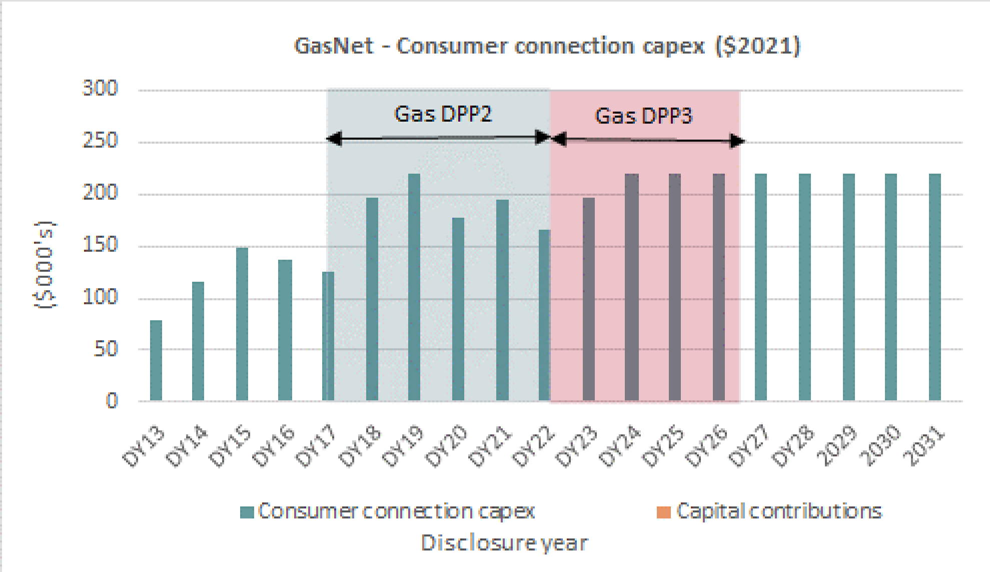
B60 GasNet has also forecast that consumer connection capex will remain steady into the DPP3 period from DY24 onwards (Figure B.2).

[142] RFI response to GNT-01 GasNet RFI Q2 22 Sep 2021 provided to Commerce Commission on 6 October 2021

[143] GasNet GNX-080 Capital Contributions Policy 20130415, p. 3

[144] GasNet 2021 Asset Management Plan, p. 62

Figure B2 : GasNet 2021 AMP consumer connection forecast



B61 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 introduce asset stranding risk in the future. GasNet's capital contributions policy may need to be revised for new residential connections as Government policy changes.

Powerco - capital contributions policy, installation control point growth assumptions and the link to consumer connection capex

B62 Powerco responded to our RFI questions with a detailed description of how it calculates the capital contributions and the payback periods to attain NVP>0 for various connection types.[145]

B63 Of note is the fact that in all cases: residential, commercial and industrial; the payback periods are generally based on a risk assessment of the connecting party remaining a customer following connection, specifically:

B63.1 Residential – no contribution is required for connections of less than 40 metres to the mains. The contribution graduates from there and the Powerco contribution is also capped. Powerco assume a payback period of about 19 years for NPV>0 that assumes most gas appliances have a life expectancy of about 15 years or longer; historical gas disconnections being less than 1% per annum.

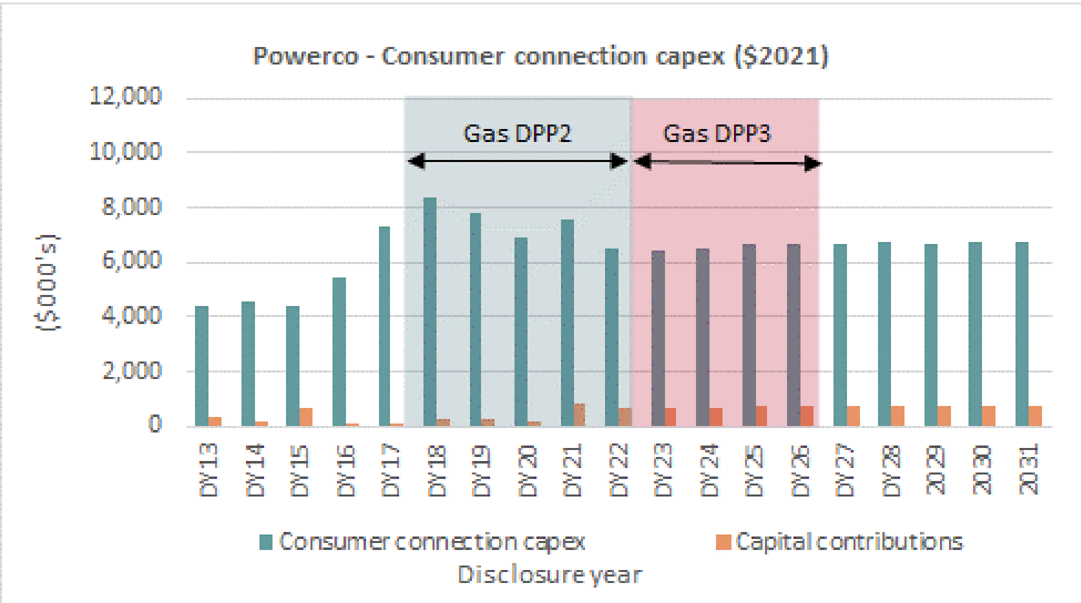
[145] RFI response to PCO-01 Powerco RFI Q1 22 Sep 2021 provided to Commerce Commission on 6 October 2021

B63.2 Commercial – the contribution is set based on connection investment payback period of 3 years because “small to medium sized commercial business as they carry a high level of risk with many failing in the first few years”.

B63.3 Industrial – the payback period for new connection NPV>0 is dependent on the customer but generally payback is achieved between 5 and 7 years because “Large industrial sites are usually less likely to fail in a short timeframe over standard commercial as they are often businesses that have operated previously and are scaling up and/or relocating to an increase in demand”.

B64 Powerco is forecasting steady ICP connection growth and consumer connection capex across the DPP3 period (Figure B.3). While new connection growth in DPP3 is forecast to be lower than in DPP2, Powerco is forecasting a modest acceleration in growth across the period.

Figure B3 : Powerco consumer connection capex



First Gas Distribution - capital contributions policy, installation control point growth assumptions and the link to consumer connection capex

B65 First Gas Distribution prefaced its response to our RFI questions by stating that it was in the process of updating its capital contributions policy and that it expected this would be published in March 2022.[146]

[146] RFI response to FG-01 First Gas RFI Q3 22 Sep 2021 provided to Commerce Commission on 6 October 2021

B66 First Gas Distribution has revised its view of the payback period for NPV>0 for new connections (where the incremental revenue of the new connection exceeds the incremental cost), stating in its RFI response to us that:

> Firstgas is revising our capital contributions policy to reflect a greater risk of asset stranding. The main changes being considered are to reduce the revenue timeframe in our models from 40 years to 30 years and to introduce customer contributions for all residential connections. 30 years is approximately two "appliance lifecycles", given that an instantaneous hot water unit is expected to last around 15 years. 30 years from 2022 also roughly coincides with the year 2050, which is the target year for net zero emissions in legislation.

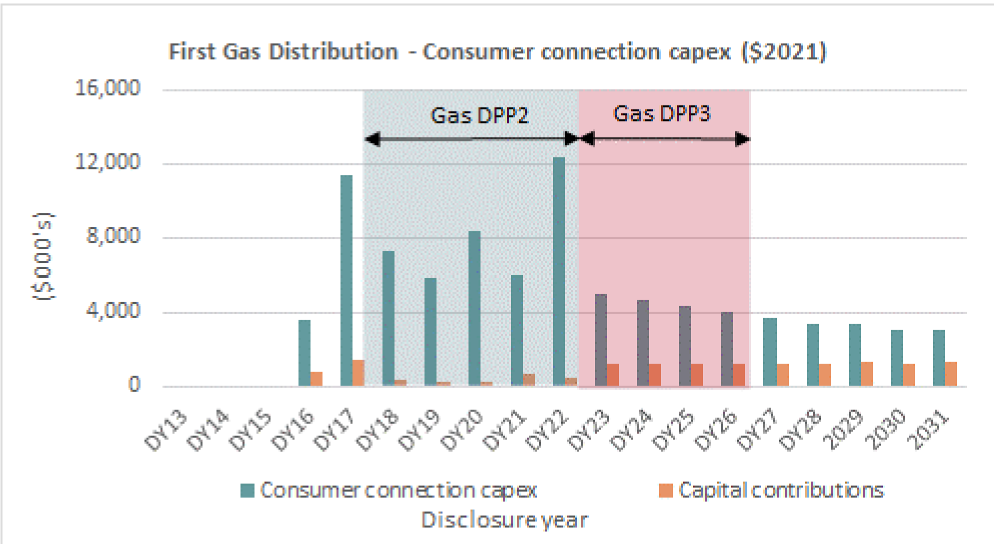
B67 First Gas Distribution also provided demonstration comparison NPV calculations for residential and commercial new connections for its provisional new capital contribution rate and payback period of 30 years and the previous policy with a 40-year payback period.

B68 In its 2021 AMP update, First Gas Distribution is predicting a decline in new connection and system growth capex requirements across regulatory control periods three and four (DY22 to DY31) stating that it is forecasting:[147]

> A significant decrease in the total combined expenditure allocated for customer connections and system growth (approximately $40 million), due to a reduction in our connection forecast and subsequent lower growth demand forecast.

B69 First Gas Distribution's historical and most recent forecast consumer capex forecast profile (including capital contributions) illustrates that it considers consumer connection capex will decline in DPP3 as capital contributions rise to over $1.2 million from DY23 (see Figure B4).

Figure B4 : First Gas Distribution consumer connection capex



[147] First Gas Distribution 2021 Asset Management Plan update, p. 10

B70 First Gas Distribution is predicting new connections will peak in DY22 and then growth to trend downwards from DY23 as the capital contributions policy starts to change new connection decisions. First Gas Distribution predict that new ICP growth will decline, on average, by about 3% per annum, from DY22.

B71 In its 2021 AMP update First Gas Distribution discussed new connections occurring on its network stating that it has seen a period of record new connection growth and some significant new major commercial projects, such as:[148]

B71.1 supply of natural gas to Winstone Wallboards site at Tauriko is a significant addition to the gas network and will make it the third largest distribution customer by gas volume; and

B71.2 a gas mains extension to Happy Valley Nutrition in Otorohanga - this dairy plant will require an estimated 3,550 scm/h of natural gas ($1.7 million); and

B71.3 a gas mains extension to OLAM International, milk powder plant in Tokoroa - this dairy plant will require an estimated of 4,300 scm/h of natural gas ($5 million).

Vector - capital contributions policy, installation control point growth assumptions and the link to consumer connection capex

B72 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. In its latest 2021 Asset Management Plan it states that:[149]

> 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.

[148] First Gas Distribution 2021 Asset Management Plan update, p 31

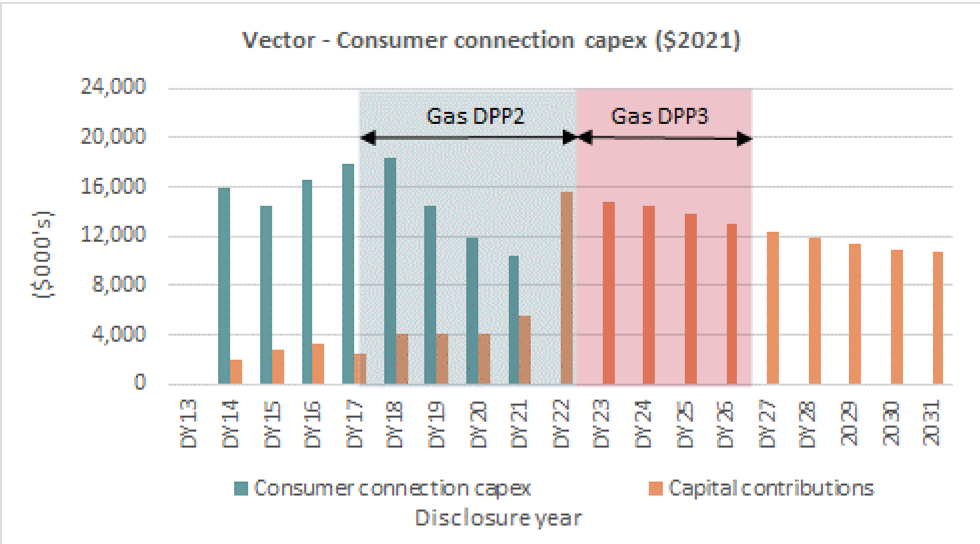
[149] Vector 2021 Asset Management Plan update, p. 5

B73 Vector also discuss the growth drivers in its region stating that:

> We are forecasting reduced growth. During the forthcoming period we are expecting a shift in the take-up of reticulated natural gas across our customer segments. 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. This policy will continue with projections for the next three years seeing this trend accelerating.
>
> The changes to our capital contribution policy will also have an impact on private developers reticulating sites with natural gas. We anticipate the impact will result in demand dropping off over the short term. We also note the current level of building activity for Auckland is forecast to level off into the next decade which is also affecting our connection growth forecast over the medium term. We are anticipating this trend to result in net residential connections growth declining for the foreseeable future.

B74 However, despite its capital contribution policy change, Vector is still predicting significant growth in new connections as evidenced by its forecast of consumer connection capex which is fully funded by capital contributions (Figure B.5).

Figure B5 : Vector consumer connection capex



B75 Vector predict that the ICP growth rate will decline, on average, by about 4% per annum, from DY22.

Summary – Capital contributions and installation control point growth rates

B76 Apart from Vector, we tested GDB capital contribution policies for new connections. We asked GDBs to provide us with information about how they set contributions in each sector and how this ensured that new connections were subsidy free.

B77 We wanted to understand the timeframes (the 'payback periods') over which each business calculated that, in conjunction with the capital contribution, the incremental cost and incremental revenue of the new connection were at least NPV=0.

B78 There were a range of 'payback periods' depending on the connection type, summarised in Table B2.

Table B2 : GDB capital contribution policy 'payback' periods

GDB	Sector	Payback period (years)
GasNet	Residential Commercial Industrial	40 years 20 years 20 years
First Gas Distribution	all sectors	30 years
Vector	N/A	N/A
Powerco	Residential Commercial Industrial	19 years 3 years 5-7 years

B79 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.

B80 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). GasNet, with its 40-year payback period for new residential consumers may need to revise its capital contributions policy to incorporate the possibility of future asset stranding risk.

B81 The payback periods indicate that suppliers will get revenues sufficient to cover the new connection costs before 2050. New connections will not be fully recovered through depreciation by 2050 as the new connection assets will be in the RAB for longer than the payback period.

B82 In allocating risk to both suppliers and consumers, suppliers need to be aware that some proportion of future growth capex may be stranded. This is due to the unpredictability of the 2050 date for gas infrastructure asset stranding occurring and the possible sector wind-down. This may create an incentive for suppliers to manage future asset stranding risk for growth-related assets.

B83 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 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.

B84 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.

B85 On balance we have accepted that the GDBs hold the best information about consumer enquiries, new consumer behaviour, and their willingness to pay to connect. For this reason, we have accepted the following forecasts and have used them to set consumer connection capex allowances in this DPP:

B85.1 ICP growth forecasts from GasNet, Vector, Powerco and First Gas Distribution; and

B85.2 consumer connection capex forecasts from GasNet, Powerco and First Gas Distribution.

B86 We have accepted the ICP growth and consumer connection capex forecasts because:

B86.1 Vector and First Gas Distribution changed their capital contributions policies and amended their growth forecasts to reflect their understanding of the gas industry's long-term future;

B86.2 Powerco's policy has payback periods that are consistent with net zero carbon emissions by 2050; and

B86.3 Powerco and GasNet appear to use risk analysis of new consumers remaining connected in setting capital contribution rates, although GasNet's residential connection policy may need to be revised.

B87 The GDB ICP and gas demand forecasts have also formed the basis of our CPRG demand forecasts for each supplier. 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.

B88 In its submission to the process and issues paper, First Gas Distribution suggested that we set the CPRG forecast to 0% which infers there would be no ICP or gas demand net growth over the DPP period. If we did take this step, then we would also likely not set any allowances for growth capex.[150]

B89 If we adopted this approach, GDBs would continue to have the option of funding new connections through capital contributions. We invite submitters views on our draft decision and this alternative.

Our approach to setting capital expenditure allowances

Non-network capital expenditure

B90 We have considered GTB and GDB non-network capex separately; accepting forecasts and seeking explanations in AMPs only for unexplained significant forecast uplifts.

B91 We have considered non-network capex separately because we have observed that non-network capex tends to contain one-off expenditure uplifts and trends that can distort historical expenditure projections.

B92 Non-network capex contains atypical non-annually recurring expenditure items such as ICT investments and building upgrades. Without carrying out in-depth 'needs' analysis of these forecast non-recurring non-network expenditure items we will be unable to form a view that they are likely to be prudent and efficient. Only a CPP analysis can provide that depth of understanding.

B93 We did not identify any uplift or expenditure exception issues with the First Gas Transmission, First Gas Distribution or Powerco forecasts of non-network capex and accepted these.

B94 We investigated the significant forecast expenditure uplift in DY23 forecast by GasNet and Vector's forecast sustained expenditure uplift from DY22.

B95 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 in FY23 and incur ongoing costs of $35,000 per annum thereafter. We could find no explanation for this expenditure in the AMP material so sought additional information using an RFI.

[150] Firstgas – submission on Gas DPP 2022 process and issues paper (1 September 2021), p. 11

B96 We tested GasNet about the uplift and were provided with an explanation in its RFI response to our Whanganui sales gate question, and that non-network capex had been incorrectly coded in ID. We accepted GasNet's explanation and revised its non-network capex forecast accordingly.

B97 Vector forecast that, in 2020, it would be spending approximately $20 million over the DY21 and DY31 periods to upgrade business areas with upgraded and linked supporting technology.

B98 In its 2021 AMP Update, Vector states that it has forecast a non-network capex forecast cost increase of $5 million over the DY22 to DY32 period due to:[151]

B98.1 increased investment in cyber security and IT network infrastructure and key system software; and

B98.2 increase in the property and leases - from changes in office lease timing and deferral of office refurbishment.

B99 Vector has 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 accepted.

B100 In summary we have accepted all GPB non-network capex forecasts, and following supporting information have accepted an amended non-network capex forecast for GasNet.

Gas Transmission Business network capital expenditure

B101 We have taken a different approach to set GTB and GDB network capex allowances. Analysis of historical and planned expenditure reveals that gas transmission network capex is dominated by expenditure for renewals, while about 60% of gas distribution network capex is to accommodate growth.

B102 We considered that applying the top-down approach to the total network capex was appropriate for gas transmission because gas transmission renewals capex is more predictable and consistent over time.

Gas Distribution Business consumer connection and system growth capital expenditure

B103 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.

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[151] Vector "2021 Asset Management Plan update", p. 29

B104 System growth capex is necessary for wider network upgrades driven by new connection growth. If we accept that GDBs have forecast 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 the system growth capex is also likely.

B105 To set system growth capex allowances we performed top-down historical capex projection analysis. First Gas Distribution, GasNet and Powerco analysis resulted in allowance settings that were generally consistent with their most recent forecasts in this expenditure category. We comment separately on Vector below.

B106 In this analysis we set the historical capex projections based on the previous four years system growth capex data (apart from First Gas Distribution where we used DY18 to DY20 data); and set allowances based on the lower of the GDB forecast or the historical capex projection.

B107 For First Gas Distribution we were not confident that the DY17 capex was representative of a level of necessary expenditure following the purchase of Vector's non-Auckland network in 2016. For the final decision, we will have an additional year of disclosed capex data (DY21), that will enable us to calculate an historical capex projection using four years of data.

Gas Distribution Business non-growth-related network capital expenditure

B108 Following separate consideration of network growth capex, we have taken a top-down historical capex projection approach for the non-growth-related network capex. The expenditure in these categories of capex is generally more predictable in nature and is comprised mostly of asset replacement and renewals expenditure.

B109 In the analysis we have set the historical capex projection levels based on the previous four years non-growth-related network capex disclosed data; and set allowances based on the lower of the GDB forecasts or the historical capex projection levels.

Cost of finance adjustment

B110 The Gas DPP IMs specify that the capital expenditure allowances we set must reflect the cost of financing capital works under construction.[152]

[152] 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).

B111 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.

B112 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. We have taken the following approach to express the cost of finance adjustments in real terms in our modelling:

B112.1 sum the forecast nominal cost of finance adjustments from each GPB AMP throughout the regulatory period;

B112.2 sum the forecast nominal capital expenditure from each GPB AMP throughout the regulatory period;

B112.3 calculate the cost of finance as a percentage of total capex; and

B112.4 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 capex allowances by GPB

Figure B6 : Comparison of First Gas Transmission historical capex, AMP capex forecasts and DPP capex allowances (real $’000s, 2021 ID year-end)

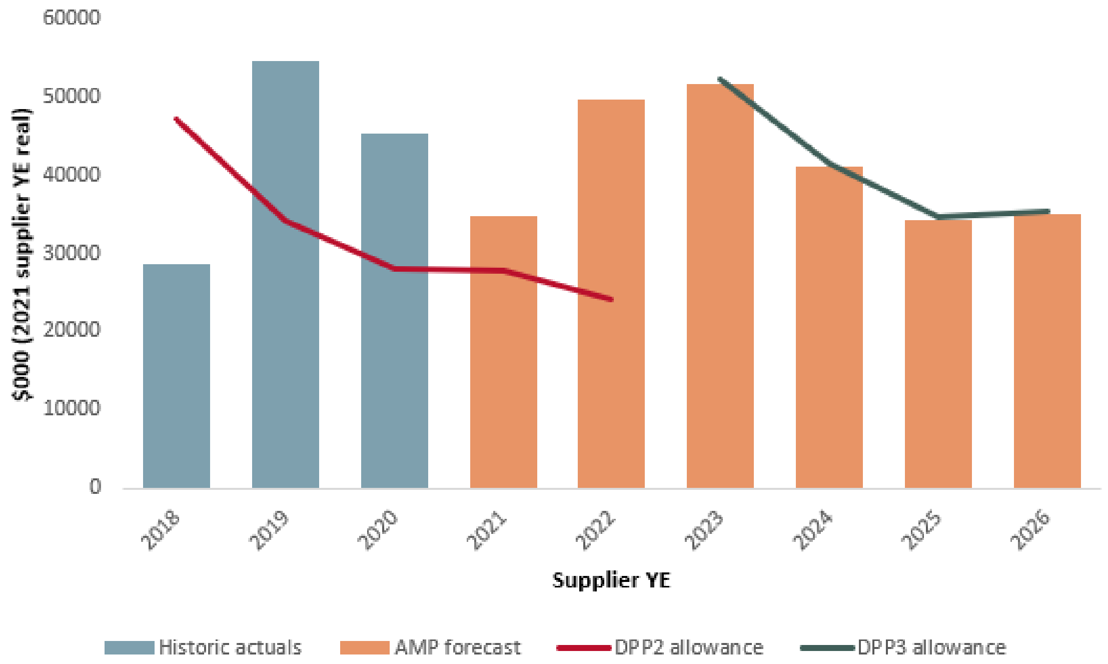


Figure B7 : Comparison of First Gas Distribution historical capex, AMP capex forecasts and DPP capex allowances (real $’000s, 2021 ID year-end)

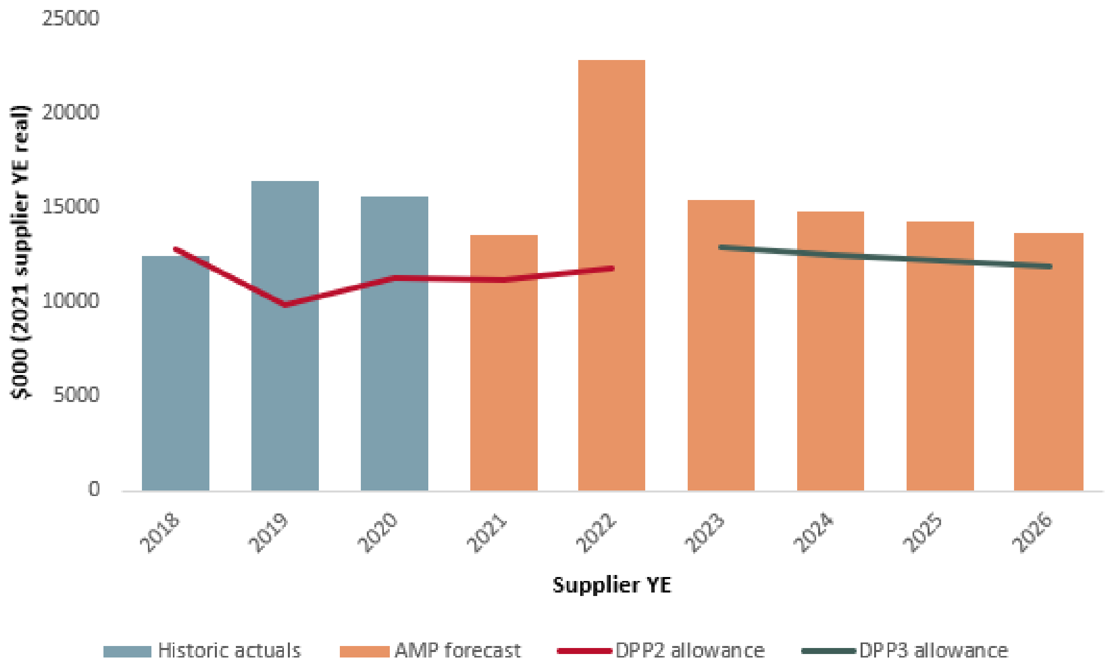


Figure B8 : Comparison of Powerco historical capex, AMP capex forecasts and DPP capex allowances (real $’000s, 2021 ID year-end)

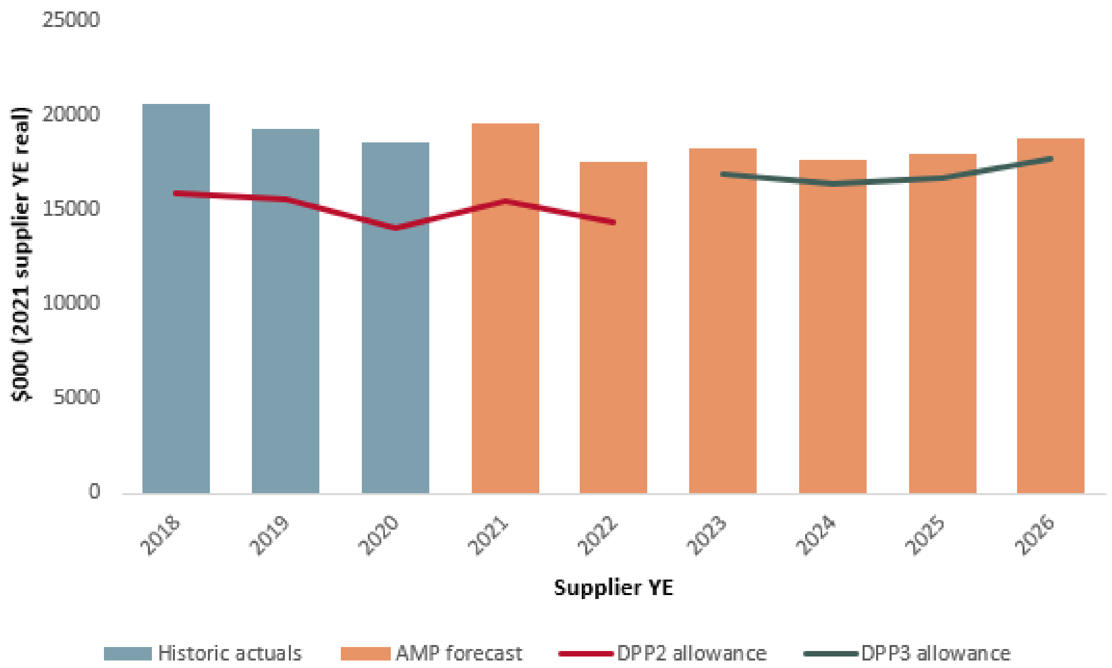


Figure B9 : Comparison of GasNet historical capex, AMP capex forecasts and DPP capex allowances (real $'000s, 2021 ID year-end)

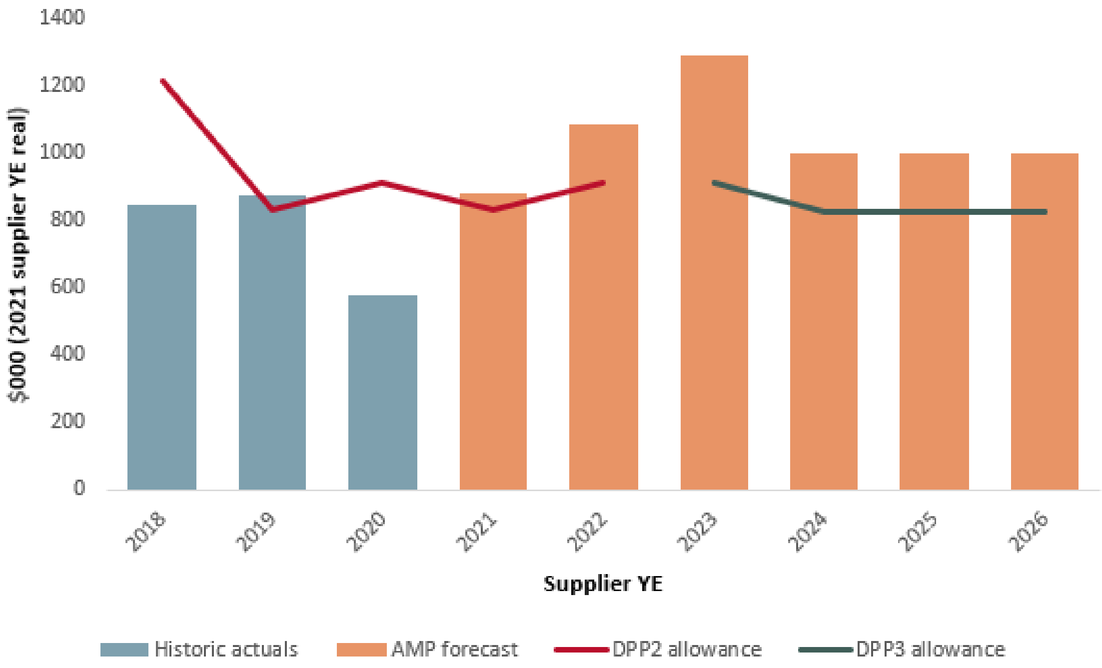
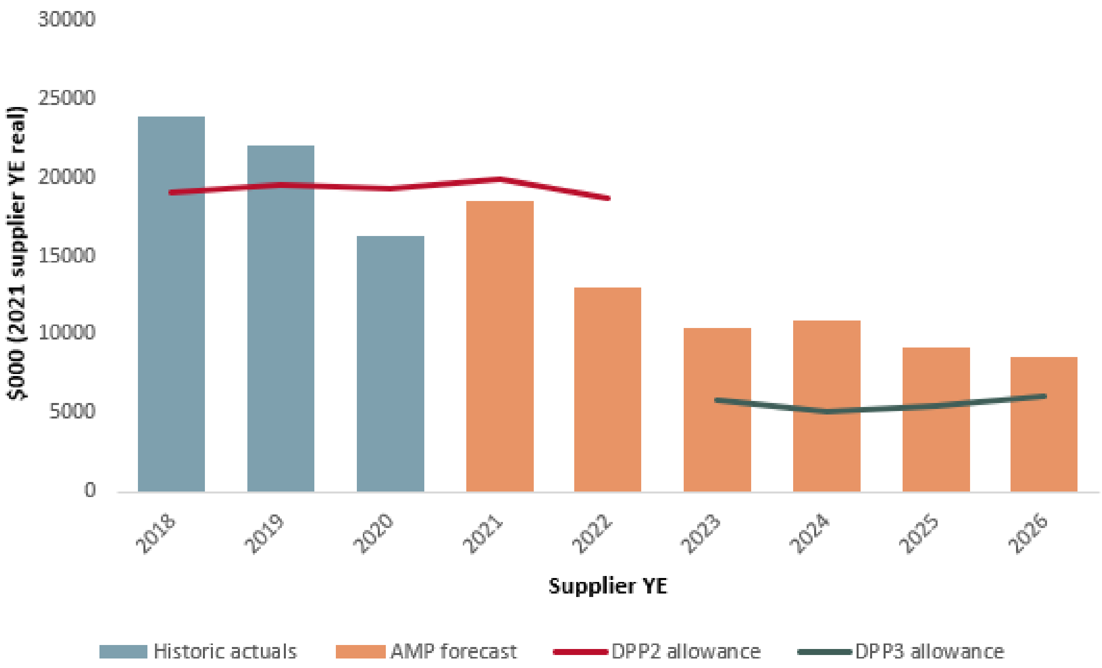


Figure B10 : Comparison of Vector historical capex, AMP capex forecasts and DPP capex allowances (real $'000s, 2021 ID year-end)



Vector's low capex acceptance rate and Vector's DPP capex allowance comparison plot

Vector's low capex acceptance rate

B113 We noted that, following our allowance setting process, Vector's total capex allowance was at 57% of what it had forecast in its 2021 AMP. We carried out further analysis to track the source of this relatively low acceptance rate when compared to other suppliers.

B114 Vector has predicted a large uplift in system growth and asset replacement and renewals capex from DY22 when compared to the historical average capex projections, based on Vector's DY17-DY20 expenditure data.[153]

B115 For example, on average, between DY17 and DY20 Vector has spent approximately $0.8 million per annum on system growth capex and $1.3 million per annum on asset replacement and renewals capex. However, between DY22 and DY27 Vector forecasts it will spend $2.7 million per annum on system growth capex and $3.3 million per annum on asset replacement and renewals capex. Our top-down capex allowance setting approach has not allowed these significant uplifts.

B116 While supplier AMPs may discuss projects and programmes that explain forecast expenditure uplifts above historical levels of capex, we have not scrutinised the prudency and efficiency of these uplifts. Given the expected decline in gas use, it is our expectation that capex will not exceed historical average levels. We invite submitter feedback on this view.

B117 Our draft decision analysis has not used Vector's DY21 data, that was made available in December 2021, to calculate the historical average capex projections. We intend that our final decision calculation on Vector's historical average capex spend will include its DY21 actual capex spend. We anticipate this is likely increase the historical average capex projection levels and hence the capex acceptance rate for the final decision.

B118 Finally, 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 uncertainties that GPBs may encounter.

[153] Vector "2021 Asset Management Plan update"

Vector's DPP capex allowance comparison plot (Figure B10)

B119 With reference to Figure B10, the differences between Vector's historical capex (in green), Vector's forecast capex (in amber), especially from DY22 onwards, and the DPP2 and DPP3 allowance settings, needs to be explained. The differences are mainly due to Vector's change in its capital contributions policy which it forecast in Vector's 2021 AMP to move fully to a 100% contribution by new connecting parties from DY22.

B120 Between 2014 and 2020, under Vector's old capital contributions policy, consumer connection capex (net of capital contributions) comprise about 70% of total capex. Vector has now moved to 100% capital contribution and this explains the difference between the DPP2 and DPP3 allowance settings in the above diagram. We set allowances that are net of capital contributions.

Attachment C Price-setting features

Purpose of this attachment

C1 This attachment sets out additional details on the core components for how we have set price-paths for DPP3. It covers:

C1.1 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;

C1.2 the length of the regulatory period; and

C1.3 our reasons for why we believe these settings best promote the long-term benefit of consumers.

How we set starting prices

C2 In accordance with s 53M of the Act and for each supplier, the DPP must specify:

C2.1 maximum price(s) or revenue for each supplier and quality standards throughout the regulatory period. The two main components of these price or revenue limits are:

C2.1.1 the 'starting price' allowed in the first year of the regulatory period; and

C2.1.2 the 'rate of change in price', or X-factor, relative to the CPI, that is allowed in later parts of the regulatory period.

We propose setting starting prices based on our assessment of current and projected profitability

C3 The Act specifies that we may set starting prices based on an assessment of current and projected profitability or roll over the starting prices from the previous DPP reset.[154]

C4 We propose setting 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.

C5 In our process and issue paper, we requested views on whether rolling over the starting prices from the previous reset would best serve the long-term benefit of consumers.

[154] Commerce Act 1986, s. 53(P)

C6 Our reasons for considering a rollover were:

C6.1 a rollover appeared to be a means of mitigating the risk of asset stranding. 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 suppliers. This would mitigate the risk of asset stranding by speeding up capital recovery;

C6.2 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.

C7 Submissions on our process and issues paper supported an approach based on current and projected profitability:

C7.1 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;[155]

C7.2 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;[156]

C7.3 First Gas supported an assessment of current and projected profitability, with suitable adjustments to accelerate capital recovery;[157] and

C7.4 MGUG believed the prevailing uncertainty is not materially different from previous DPP resets, and advocated for an assessment of current and projected profitability.[158]

C8 Having considered the matters raised in submissions, we agree with submitters that we should determine the starting prices by assessing current and future profitability. The circumstances the sector currently face have changed considerably from the prior reset, in terms of both their efficient costs, and the future outlook of the sector.

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155 Vector "Submission to the Commerce Commission's Open Letter on the Input Methodology Review, Gas Pipeline Business Reset and Information Disclosure Review" 28 May 2021

156 Greymouth Gas "Feedback on open letter: ensuring our energy and airports regulation is fit for purpose" 26 May 2021

157 First Gas "Response to Open Letter on Fit for Purpose Regulation" 20 May 2021

158 Major Gas Users Group "Open letter on priorities for energy networks and airports" 28 May 2021

C9 While a rollover might be a viable alternative for mitigating some the risks facing the sector, we consider that resetting the price path based on an assessment of current and projected profitability allows us to set a price path that better reflects the gas sector's changing circumstances.

C10 Our view is that resetting starting prices based on a projected profitability approach better promotes the long-term benefit of consumers, providing GPBs with sufficient incentives to invest in maintaining a safe and reliable network, while limiting their ability to extract excessive profits.

The building blocks allowable revenue approach

C11 We use a "building blocks" approach to determine the projected profitability. The starting prices we propose setting for both distribution and transmission are specified in terms of maximum allowable revenue (**MAR**), which is an amount that does not include pass-through costs and recoverable costs. We calculate the MAR amount through two key processes.

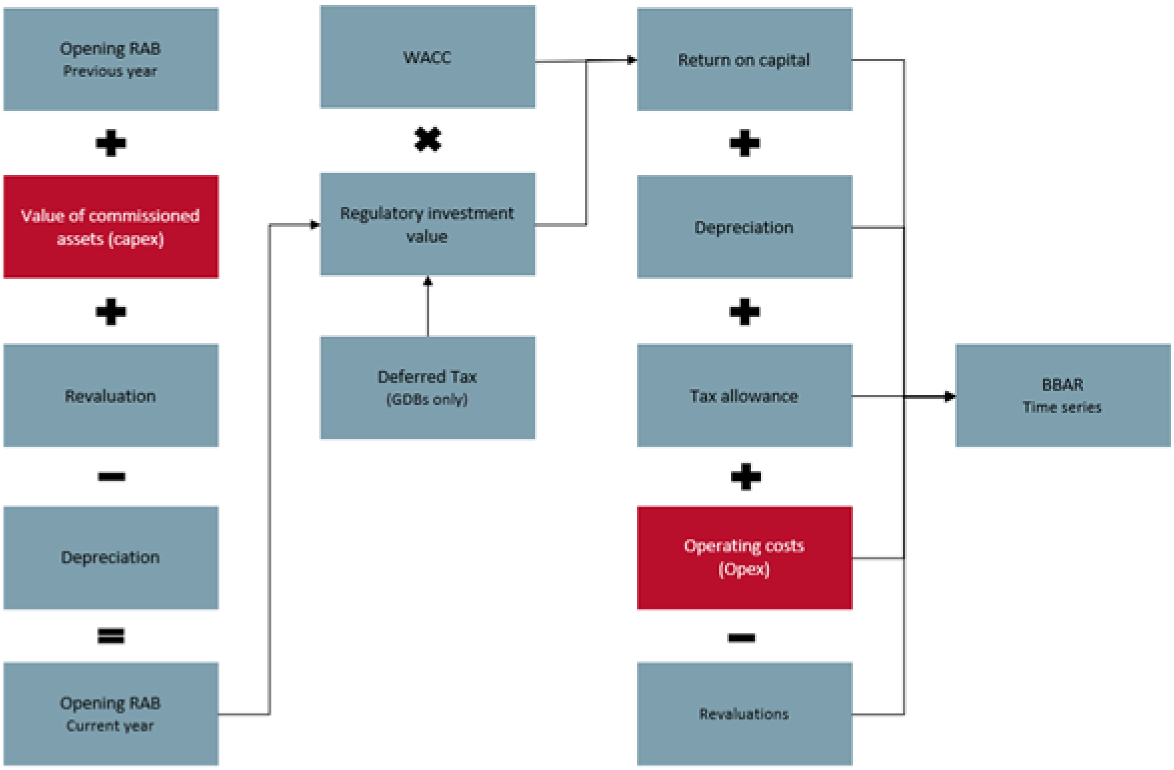
C11.1 Process 1: Determining a building blocks allowable revenue (**BBAR**) for each year of the regulatory period. At the simplest level the BBAR is calculated using separate cost ''building blocks'' as follows:

C11.1.1 Return on capital - Revaluations + Depreciation + Operating costs (opex) + Tax allowance.

C11.1.2 A high-level schematic is provided below in Figure C.1.

C11.2 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 C.2.

Figure C1 : From the regulatory asset base to building blocks allowable revenue



C12 The inputs 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.

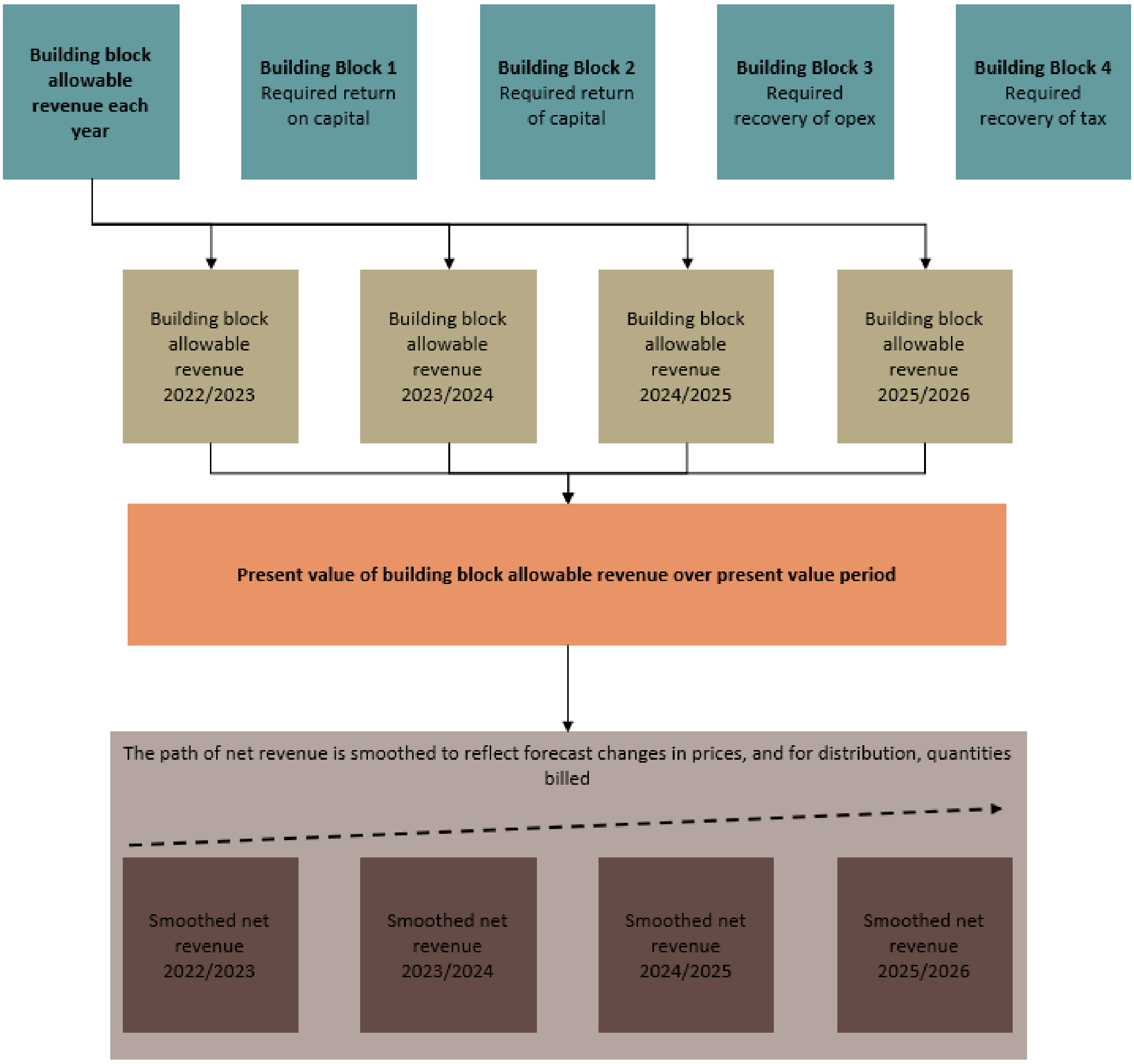
C13 Other inputs come from information disclosures. For example, forecasts of opex and capex are disclosed in AMPs and we use these as inputs into our decision on opex and capex allowances.

C14 Some inputs are wholly or largely set in the IMs. For example, the Cost of Capital IM sets out:

C14.1 how we must estimate WACC including specifying values for of most of the parameters eg: beta, leverage, TAMRP; and

C14.2 a methodology for estimating the risk-free rate and the debt premium.

Figure C2: Setting forecast revenues equal to forecast costs



C15 Certain costs that are outside of the suppliers' control are recovered through separate allowances for 'pass-through costs'. Certain other costs that suppliers have little control over are recovered through allowances for 'recoverable costs'. The items that qualify for these categories, and the criteria for inclusion that must be satisfied, are set out in the IMs.[159]

[159] Gas Transmission Services Input Methodologies Determination 2012 (consolidating all amendments as of 3 April 2018), clause 3.1.2 and 3.1.3. and Gas Distribution Services Input Methodologies Determination 2012 (consolidating all amendments as of 3 April 2018), clauses 3.1.2 and 3.1.3;

C16 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 the Electricity and Gas Complaints Commissioner Scheme by virtue of their membership. They must be associated with the supply of gas pipeline services.

C17 Recoverable costs include:

C17.1 application fees for a customised price-quality paths;

C17.2 clawback amounts if suppliers increase weighted average prices by more than the movement, or forecast movement in the CPI**;** and

C17.3 fees for audits that are necessary to meet statutory obligations.

C18 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

C19 The default price-paths that we set must specify maximum prices or revenues.

C20 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 suppliers to minimise costs.

C21 The way in which we specify price limits for distribution businesses also means that profitability depends on assumptions we make about quantity growth, such as growth in connections and throughput over the regulatory period.

C22 Distribution businesses have an incentive to outperform their given demand forecast. Under a weighted average price cap (**WAPC**), distributors 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

C23 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.

C24 For the upcoming DPP reset, we propose maintaining a WAPC for GDBs, and a revenue cap with a wash-up mechanism for the GTB.

C24.1 GDBs are subject to a WAPC, which places a limit on their maximum average prices throughout the length of the regulatory period.

C24.2 The GTB is subject to a revenue cap with a wash-up mechanism, which places a limit on its maximum revenue throughout the length of the regulatory period.

C25 Ultimately, the form of control determines who bears the within-(regulatory) period demand risk. Under a WAPC, the suppliers bear the within-period demand risk. Under a revenue cap, consumers bear the within-period demand risk.

C26 Within-period demand risk falls on GDBs under a WAPC as when volumes vary, the prices GDBs can charge remain the same. Therefore, if quantities delivered fall below the forecasted quantities, GDBs earn less revenue (until prices are set 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.

C27 Under a revenue cap, the GTB is subject to a limit on their maximum revenues. The purpose of the wash-up mechanism is to ensure that revenue is not over or under-recovered during the regulatory period. 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 except to washup previously under-recovered revenue.[160] [161]

C28 This under-recovered revenue can be carried forward to the next regulatory period. 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.

C29 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 under-recovered.

C30 In our process and issues paper, we asked for feedback on whether a change in the form of control would better promote the long-term benefit of consumers.[162]

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[160] First Gas “Vector Transmission Code” (1 October 2015)

[161] First Gas "Maui Pipeline Operating Code" (14 May 2016)

[162] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), para A1

C31 While some submitters favoured a change to the form of control, most submitters supported maintaining a WAPC for GDBs, and a revenue cap for the GTB:

C31.1 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. They were 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.[163]

C31.2 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.[164]

C32 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:

C32.1 First Gas stated that given the materiality and impact of other issues, they did not consider that changes to the form of control should be advanced at the DPP reset.[165]

C32.2 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.[166]

C33 We propose maintaining the current form of control, being a WAPC for GDBs, and a revenue cap for the GTB.

We are not proposing the introduction of demand reopeners.

C34 As noted above, Powerco suggested introducing demand reopeners to manage significant demand shocks.

C35 Under a WAPC suppliers bear the upside, and the downside, of the within-period demand risk. Maintaining a WAPC while introducing demand reopeners would shift some downside risk to consumers, while suppliers would still benefit if they were to outperform the CPRG forecast. It is our view that this would not be to the long-term benefit of consumers.

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[163] Major Gas Users Group “Open letter on priorities for energy networks and airports” 28 May 2021

[164] Powerco “Submission to the Commerce Commission’s open letter on fit-for-purpose regulation of energy networks” 28 May 2021

[165] First Gas "Response to Open Letter on Fit for Purpose Regulation" 20 May 2021

[166] Vector “Submission to the Commerce Commission’s Open Letter on the Input Methodology Review, Gas Pipeline Business Reset and Information Disclosure Review” 28 May 2021

Why we consider the current settings are appropriate

C36 Our economic principles provide for us to allocate risk to the party best placed to manage it, as we believe this best promotes the Part 4 purpose.

C37 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.

C38 Under a WAPC, the allowable revenue can change depending the actual demand of customers, compared to the GDB demand that is forecast when the DPP is set. A WAPC indirectly incentivises local GPBs to grow their customer base as they are rewarded with an increase in total revenue.

C39 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 commodity prices.

C40 We therefore propose to maintain a revenue cap for the GTB, as without exposure to the within-period demand risk, the GTB will be better placed to invest in their network.

C41 Furthermore, as we are trying to promote certainty within the DPP, maintaining the status quo may be preferable when we do not believe there is a sufficiently strong argument to be made in favour of changing the form of control.

C42 Lastly, while the sector is likely to decline in the long-term, the demand for gas is likely to remain relatively stable in the short-term, throughout the length of this regulatory period. We believe a change to the form of control is an issue that would be best addressed in later IM reviews.

We propose amending the GTB DPP3 determination to enable revenue washups from DPP2

C43 We changed the form of control that GTBs are 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.

C44 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.

C45 We have therefore amended Schedules 6,7 and 8 of the GTB DPP3 draft determination.

How we specify prices – constant price revenue growth

C46 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. 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 C1.

Table C1 : Forecast CPRG for the year ending 2023.

Supplier	CPRG forecast
GasNet	0.07%
Powerco	1.49%
Vector	1.57%
First Gas Distribution	-0.69%

Forecasting approach

C47 The CPRG model requires a forecast of the quantity of gas demanded throughout the regulatory period. These forecasts have been produced by Concept Consulting Ltd.[167]

C48 We have accepted GDBs' forecasts of ICP numbers and have directed Concept Consulting Ltd to align their forecasts of gas demand with GDBs' forecasts of ICP numbers.

Incorporating Asset Management Plan forecasts in the forecast of gas demand

C49 For the period of 2021 to 2026, Concept Consulting Ltd 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:

C49.1 data from information disclosures was used to derive historical proportions between three consumer classes: residential, commercial, and industrial;

[167] Concept Consulting Ltd, Gas demand and supply projections – 2021 to 2035 (May 2021)

C49.2 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;

C49.3 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;

C49.4 values for the years 2027 and 2028 were then projected on a continuation-of-trend basis from 2025 to 2026.

C50 The consumer allocations between 'residential', 'commercial', and 'industrial' consumer segments are slightly different when compared to the allocations from the 2017 Gas DPP reset.

C51 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.

C52 There are three reasons why we believe Concept Consulting Ltd's approach is appropriate:

C52.1 We believe GDBs have the best information on their existing consumers, enquiries from potential consumers, and their willingness to pay. They are forecasting their demand with the best possible information. We therefore consider that the forecasts of gas demand we use in the CPRG should reflect this information.

C52.2 Our price path should be internally consistent. GPB forecasts of capital expenditure for the DPP3 period are, in some part, based on forecasts of ICP growth for this period.

C52.3 The forecast growth rates in number of ICPs and gas demand throughout the regulatory period are not materially different than historic trends. Therefore, we believe these forecasts are reasonable.

Risks associated with our forecasting approach

C53 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, suppliers have a greater chance of outperforming the forecast.

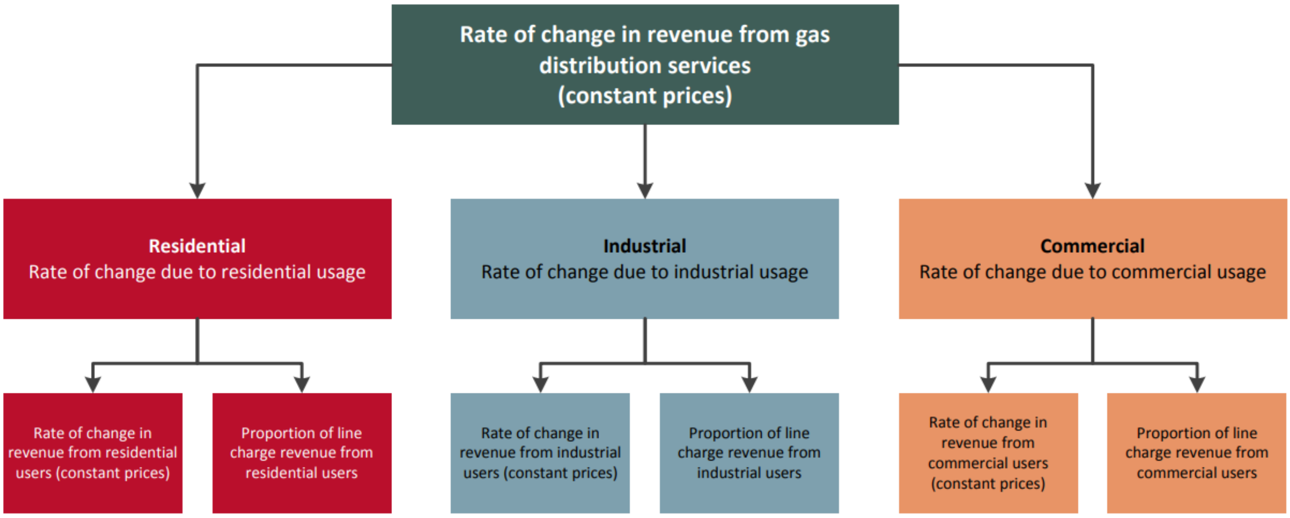
C54 We have undertaken analysis to understand the materiality of any forecast error. We examined the impact on revenue in DY20 if the rate of ICP growth was 25% greater than the historical average. Our results suggest that in this scenario, revenue for GDBs would only increase by 0.32% and 1.22%.

C55 We believe that aligning the demand forecasts with the GDBs' outlook on the sector is appropriate. As GDBs have greater information than we do on the future outlook of their own businesses, we do not believe there is an alternative approach that is likely to yield more accurate forecasts of gas demand.

Structure of the CPRG model

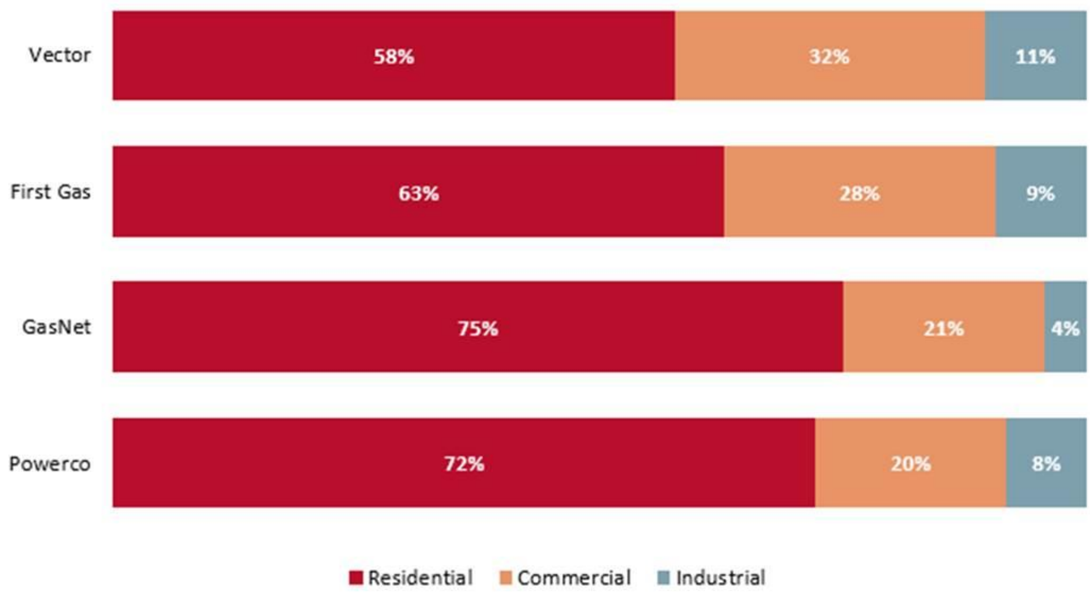
C56 In line with the previous Gas DPP, we have designated gas users into three separate classes of consumers: residential, commercial, and industrial consumers. We have modelled CPRG separately for each of the three classes of consumer. Once again, we have relied on load group information from suppliers' ID data. Figure C3 highlights this approach below.

Figure C3: Modelling constant price revenue for gas distributors



C57 We modelled each consumer class separately as each user group makes up different shares of each gas distribution businesses' user group, as detailed in figure C4.

Figure C4: User group revenue breakdown by distribution business (DY20)[168]



Length of the regulatory period

C58 We propose adopting a regulatory period of four years for the upcoming price-quality path.

C59 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.[169]

C60 In our process and issues paper, we sought views on whether shortening the length of the regulatory period would better meet the Part 4 purpose, due to the prevailing uncertainty facing the gas sector during this reset.[170]

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[168] 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)

[169] Commerce Act 1986 - Part 4

[170] Commerce Commission "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022 - process and issues paper" (4 August 2021), para 4.23

C61 There was broad support for a shortened regulatory period among submitters.

C61.1 MGUG believed the policy uncertainty was overstated but supported a four-year regulatory period to mitigate forecast uncertainty (which generally increases with the length of your forecast horizon).[171]

C61.2 First Gas[172], GasNet[173], and Nova Energy[174] supported a shortened regulatory period as they believed it would mitigate some of the impacts of policy uncertainty.

C62 Powerco[175] noted that a five-year regulatory period would allow us to account for the CCC's advice on the 2036-2040 carbon emissions budget, where the government's decision is due in December 2025, with a final decision on the subsequent price-quality path in May 2026 if a four-year regulatory period is adopted. However, on balance, they preferred a four-year regulatory period for the same reasons as First Gas, GasNet, and Nova Energy. We are resetting the DPPs for the GPBs at a time when the future direction of the gas sector is uncertain as New Zealand begins transitioning to a net-zero carbon economy. As discussed in Chapter 3, several climate change announcements are expected to be made by government in the coming years to support this transition, including an emissions reduction plan and national energy strategy to support the plan.

C63 These announcements may have material implications for the gas sector which we are unable to predict at this time.

C64 In addition to the uncertainty caused by upcoming policy decisions, there is uncertainty regarding the future of the sector in general. For example, the existing network infrastructure may be repurposed to convey hydrogen, or other low-carbon gases. On the other hand, using the existing network to convey alternative gases may prove infeasible, or not economically viable, and the sector may be dealing with a wind-down scenario.

C65 Shortening the length of the regulatory period would allow us to reset the price path to reflect further developments in the sector at the earliest point we are able to do so.

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164 Major Gas Users Group "Open letter on priorities for energy networks and airports" (28 May 2021)

172 First Gas "Response to Open Letter on Fit for Purpose Regulation" (20 May 2021)

173 GasNet "Feedback on Fit for Purpose regulation" (2 June 2021)

174 Nova Energy "Resetting default price-quality paths for gas pipeline businesses from 1 October 2022" (3 September 2021)

175 Powerco "Submission to the Commerce Commission's open letter on fit-for-purpose regulation of energy networks" (28 May 2021)

C66 Shortening the length of the regulatory period would ensure that the regulatory settings faced by GPBs are more likely to be fit for purpose.

C67 In our view, a shorter regulatory period better promotes the Part 4 purpose. As noted above, there is a lack of a clear picture of the direction of the industry in the coming years, creating a substantial amount of uncertainty.

C68 This uncertainty may dissuade GPBs from investing in maintaining a safe and reliable network, if they believe there is greater risk that they will not be able to recover their investment.

C69 By shortening the length of the regulatory period, and mitigating the effect of this uncertainty, we may provide GPBs with incentives to invest efficiently (consistent with section 52(A)1(a) of the Act).

C70 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. Assuming we retain our draft decision to set a four-year regulatory period, 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. If our draft decision on the regulatory period changes to a five-year regulatory period, the date before which any application for a customised price-quality path must be received will change to 23 October 2025.

Attachment D Forecasts of other inputs to the financial model

Purpose of this attachment

D1 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

D2 Our approach has been to largely repeat the forecasting methods used in DPP2, while checking that this remains consistent with the current IMs. We explain below where we have taken a different approach.

D3 Submissions on the DPP3 process and issues paper did not include any submissions on the forecasting methods discussed in this attachment.[176]

Cost of capital estimate

D4 As explained in Chapter 4, we have taken a different approach to determine the WACC estimate. The WACC we have used to determine the starting prices has been estimated as at 18 January 2022.

D5 In past resets we have typically used the most recently determined WACC estimate, which for DPP3 is the WACC we determined for ID purposes for First Gas and Powerco as at 1 October 2021.

D6 We have taken the different approach because we have observed significant changes in market conditions since 1 October 2021. This has led to changes in the parameters used to estimate the WACC, for example, the risk-free rate. We have also made changes to reflect changes to the TAMRP estimate and to estimate a four-year WACC. These changes require changes to the Gas IMs, which we are consulting on alongside this paper.

D7 Our view is that an updated WACC estimate will provide a better indication of the WACC we will determine for the final decision. Table D1 highlights the difference in WACC parameters between our 1 October 2021 estimate and our estimate at 18 January 2022.

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

Table D1 : Parameters used to calculate WACC estimates

Parameter	DPP2 estimate	1 October 2021 estimate	18 January 2022 estimate
Risk-free rate	2.75%	1.36%	2.22%
Average debt premium	1.81%	1.54%	1.54%
Leverage	42%	42%	42%
Asset beta	0.40	0.40	0.40
Equity beta	0.69	0.69	0.69
Tax adjusted market risk premium	7.0%	7.0%	7.5%
Average corporate tax rate	28%	28%	28%
Average investor tax rate	28%	28%	28%
Debt issuance costs	0.20%	0.20%	0.25%
Cost of debt	4.76%	3.10%	4.01%
Cost of equity	6.81%	5.81%	6.77%
Standard error of midpoint WACC estimate	0.0105	0.0105	0.0105
Mid-point vanilla WACC	**5.95%**	**4.67%**	**5.61%**
Mid-point post-tax WACC	**5.39%**	**4.30%**	**5.14%**
67^{th} percentile vanilla WACC	**6.66%**	**5.13%**	**6.07%**
67^{th} percentile post-tax WACC	**5.85%**	**4.77%**	**5.60%**

Consumer Price Index forecasts

D8 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 revalued at the rate change of CPI, we also require a forecast of CPI to determine BBAR.

D9 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 RBNZ forecasts of inflation issued as part of its Monetary Policy Statement immediately prior to the determination of the WACC for the DPP.

D10 This information will not be available until after the draft decision has been issued. The results of our approach for the draft decision, which is based on the latest available information, are set out in the table below.

Table D2 : Forecasts of CPI

Pricing year ending in calendar year	2023	2024	2025	2026
Revaluation rate, June year-end	2.50%	2.10%	2.00%	2.00%
Revaluation rate, September year-end	2.30%	2.00%	2.00%	2.00%
Inflation rate, lagged, September year-end	4.93%	3.84%	2.25%	2.02%
Inflation rate, not lagged, September year-end	2.75%	2.07%	2.00%	2.00%

D11 The final decision on the DPP will reflect the CPI estimates from RBNZ's Monetary Policy Statement due for release in February 2022.

Forecasts of disposed assets

D12 A disposed asset is an asset that is or is forecast to be sold or transferred, but is not a lost asset.[177] We are required to forecast disposed assets because disposed assets are removed from the RAB when rolling forward the RAB value.

D13 To reach our draft decision, the forecast value of disposed assets in each year of the regulatory period has been forecast 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 the table below.

[177] Gas Distribution Services Input Methodologies Determination 2012, Clause 1.1.4(2).

Table D3 : Forecasts of disposed assets ($m)

Supplier	2023	2024	2025	2026
GasNet	11.5	11.8	12.1	12.3
PowerCo	410.1	419.5	427.9	436.5
Vector	60.8	62.3	63.6	64.9
First Gas Distribution	7.4	7.6	7.7	7.9
First Gas Transmission	36.7	37.5	38.3	39.1

D14 The treatment of gains or losses on disposals as other regulated income is noted in the next section.

Forecasts of other regulated income

D15 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:

D15.1 income through prices;

D15.2 investment related income;

D15.3 capital contributions; and

D15.4 vested assets.[178]

D16 To reach our draft decision, the forecast value of other regulated income has been forecast 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 below.

Table D4 : Forecasts of other regulated income ($000)

Supplier	2023	2024	2025	2026
GasNet	39	40	41	41
PowerCo	326	333	340	347
Vector	(59)	(61)	(62)	(63)
First Gas Distribution	187	191	195	199

[178] Gas Distribution Services Input Methodologies Determination 2012, Clause 1.1.4(2)

Attachment E Assessing compliance with the price-quality path

Purpose of this attachment

E1 We are proposing to retain DPP2 GPB compliance requirements that demonstrate compliance with the price-quality path for DPP3.

E2 This attachment summarises these compliance requirements.

Our draft decisions on assessing compliance with the price-quality path

E3 We require GPBs to demonstrate whether they are complying with their price-quality paths by submitting annual compliance statements.

E4 We do not consider there is a case to change our current approach on how GPBs demonstrate compliance and how we assess compliance with the price-quality path:

E4.1 Compliance statement requirements for the price-quality path are derived from form of control and quality standard settings. We are not proposing any changes to these settings for GPBs in our DPP3 draft decisions as detailed in Chapters 4, 7 and Attachment C; and

E4.2 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.

E5 The compliance requirements from DPP2 which we propose applying to DPP3 were set out in full in Chapter 8 of the DPP2 final reasons paper and in the DPP2 determinations.[179, 180, 181]

E6 We set out in Tables F1 and F2 a summary of the key requirements for annual compliance statements for the GTB and GDBs we proposed for DPP3.

E7 The full proposed compliance requirements are included in the GTB and GDB draft determinations. We are considering, for our final decisions, instead specifying these compliance requirements in s 53N notices accompanying the determinations.

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[179] Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2017 – Final reasons paper" (31 May 2017) p. 115 - 126.

[180] Commerce Commission "Gas Distribution Services Default Price-Quality Path Determination 2017" [2017] NZCC 15, pages 11 to 14.

[181] Commerce Commission "Gas Transmission Services Default Price-Quality Path Determination 2017" [2017] NZCC 14, 29 May 2017, pages 9 to 14.

Table E1 : Compliance statement summary for the GTB

	Compliance statement for price-setting	Compliance statement for wash-up amount calculation and quality standards
Submission to us	Before 1 October, ie, the start of the assessment period	Within 50 working days of 30 September (the end of each assessment period)
Timing for publishing on the GTB's website	Within five working days after submission to us	Within five working days after submission to us
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 E2 : Compliance statement summary for GDBs

	Compliance statement for price-path	Compliance statement for quality standards
Submission to us	Within 50 working days of 30 September (the end of each assessment period)	Within 50 working days of 30 September (the end of each assessment period)
Timing for publishing on the GDBs' website	Within five working days after submission to us	Within five working days after submission to us

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

	Compliance statement for price-path	Compliance statement for quality standards
Requirement to provide signed Directors' Certificate	Yes	Yes
Requirement for auditor's report	Yes	Yes