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Financing and incentivising efficient expenditure during the energy transition topic paper

Part 4 Input Methodologies Review 2023 – Draft decision

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All above documents can be found on our website.

Commerce Commission
Wellington, New Zealand

Glossary

Abbreviation	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMP	Asset Management Plan
BBAR	Building Blocks Allowable Revenue
BBM	Building Blocks Method
BST	Base-step-and-trend
Capex	Capital expenditure
CCRA	Climate Change Response Act 2002
CEG	Competition Economist Group
CEPA	Cambridge Economic Policy Associates
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer Price Index
CPP	'Customised Price-quality path'
CRU	Commission of Regulated Utilities - the Irish energy regulator
DPP	Default price-quality path
EBSS	Efficiency Benefit Sharing Scheme
EDB	Electricity Distribution Businesses
ELS	Electricity Lines Service
ENA	Energy Networks Aotearoa
ERA	Economic Regulation Authority - Western Australia
ERP	Emission Reduction Plan
EV	Economic Value
FAR	Forecast Allowable Revenue
FCM	Financial Capital Maintenance
Fibre IMs	Fibre IMs set under Part 6 of the Telecommunications Act 2001
Framework	IM Review decision-making framework
FRP	Forecast revenue from prices
GAAP	Generally Accepted Accounting Practice
Gas IMs	Input Methodologies for gas pipeline services
GDB	Gas Distribution Business
GPB	Gas Pipeline Business
GTB	Gas Transmission Business
GTP	Gas Transition Plan
IBAT	IRIS Baseline Adjustment Term
ID	Information Disclosure

Abbreviation	Definition
IMs	Input Methodologies (refers to Part 4 IMs which are the subject of the IM Review, unless identified otherwise)
IM Review	Input Methodologies Review 2023
IPA	Innovation project allowance
IPP	Individual price-quality path
IRIS	Incremental Rolling Incentive Scheme
ISP	Integrated System Plan
LCI	Labour Cost Index
MAR	Maximum Allowable Revenue
MBIE	Ministry of Business, Innovation and Employment
MGUG	Major Gas Users' Group
MPS	Monetary Policy Statement
NERA	NERA economic consulting
NPV	Net Present Value
Ofgem	The Office of Gas and Electricity Markets
Ofwat	The Water Service Regulation Authority
opex	Operating expenditure
Oxera	Oxera Consulting LLP
Part 4	Part 4 of the Commerce Act 1986
PPI	Producers Price Index
PQ	Price-quality
Price-quality path	Refers to the maximum revenues (or weighted average prices) regulated suppliers can recover from their consumers and the minimum quality standards they must meet when delivering electricity and/or gas transmission and distribution services.
PTC	Pass-through costs
Q	Quarter
QCA	Queensland Competition Authority
RAB	Regulated Asset Base
RAV	Regulated Asset Value
RBA	Reserve Bank of Australia
RBNZ	Reserve Bank of New Zealand
RCP	Regulatory control period
RSL	Revenue smoothing limit
S&P	S&P Global Ratings
SLD	Straight-line depreciation
the Act	The Commerce Act 1986
the Zero Carbon Act	The Climate Change Response (Zero Carbon) Amendment Act 2019
TIM	Totex incentive mechanism

Abbreviation	Definition
TLC	The Lines Company
Totex	Totex regimes (total expenditure rather than treating capex and opex separately)
TPM	Transmission Pricing Methodology
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap
WE*	Wellington Electricity

Contents

Executive summary

Purpose of this paper

X1 This paper presents our IM Review draft decisions and reasons that relate to regulated suppliers' incentives to spend efficiently. The focus of this paper is on the tools and mechanisms, other than the cost of capital, that affect incentives for efficient investment and spending decisions.[1]

We invite your views

X2 We invite your submissions in response to our draft decisions on the IM Review, which are presented in our draft Report on the Review, draft topic papers, and draft IM amendment determinations. We intend to publish submissions we receive and invite cross-submissions on those submissions at that point.

X3 Submissions are due by 5pm on 19 July 2023. Cross-submissions are due by 5pm on 9 August 2023.[2]

X4 We list the components of our draft decision package for the IM Review at paragraph 1.5 below and outline how submissions and cross-submissions can be made from paragraph 1.6.

Context of this topic

X5 Our analysis and draft decisions presented in this paper are in a context where climate change and the need to electrify to decarbonise the economy are increasingly driving substantial growth in regulated suppliers' expenditure.

X6 This context and an inflation-driven higher cost of capital mean it is likely that the revenue required to pay for the cost of electricity lines services needs to increase substantially, and with it, consumer bills.

X7 Ensuring that regulated suppliers have incentives to innovate, invest and operate efficiently[3] is perhaps more important now than at any point since Part 4 of the Commerce Act 1986 (the Act) was introduced.

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1 For cost of capital decisions see: Commerce Commission “Part 4 Input methodologies Review 2023 - Draft decision - Cost of capital topic paper" (14 June 2023).

2 The Transpower IM amendment determination and the Transpower Capex IM amendment determination will be published on 21 June, one week later than the rest of the draft decisions package. As with the other amendment determinations, a seven-week consultation period will apply for these two amendment determinations.

3 s 52A(1)(a) and (b) of the Act.

X8 In an environment where suppliers of electricity lines services are expected to deliver large volumes of investments in this decade to meet New Zealand's emissions targets and transition our economy, it is important that the pace of network growth broadly matches consumers' demand for electricity lines services.

Chapter 3: Financing and incentivising efficient investment

X9 Chapter 3 presents our review of the Input Methodologies (IMs) that relate to suppliers' incentives and ability to invest efficiently. It includes discussion and draft IM decisions on cashflows and financeability, regulated asset base (RAB) indexation, new connections, gas stranding risk, and the form of control for gas distribution businesses (GDBs).

Topic 3a – RAB indexation to inflation

X10 Our draft decision is to maintain RAB indexation to inflation for electricity distribution businesses (EDBs) and gas pipeline businesses (GPBs) and change the relevant IMs to index Transpower's RAB to inflation.

X11 Submitters asked us to reconsider our approach to RAB indexation for EDBs, GPBs and Transpower. Stakeholders expressed a range of views on our approach to RAB indexation. This was an issue of high importance for many submitters.

Maintain RAB indexation to inflation for EDBs

X12 Some EDBs noted concerns about financing upcoming investment and submitted that we should allow them the option to choose to remove RAB indexation.

X13 Our draft decision is to maintain RAB indexation to inflation for EDBs. We consider that the original reasons for indexing EDBs RABs remain valid in the current context. Our current approach is consistent with providing incentives to invest and supporting a more efficient pricing profile – one that approximates constant average real prices. This is increasingly important in the context of an energy transition, where both demand for and investment in electricity lines services are expected to grow significantly, and therefore the price should encourage capacity increases to match consumer demand.

X14 EDBs that face particular challenges, including financeability risks, can apply for a customised price-quality path (CPP) that better meets their particular circumstances and provides scope for,[4] among other things, an alternative depreciation approach that better promotes the Part 4 purpose.

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[4] Section 53K of the Act.

Maintain RAB indexation to inflation for GPBs

X15 For GPBs, concerns were raised on RAB indexation in relation to how we address asset stranding risk to incentivise efficient investment.

X16 We do not propose to change to an unindexed approach for GPBs because we do not consider that changing from the status quo would better achieve our IM Review overarching objectives set out at paragraph 2.2 below.

X17 We do not consider RAB indexation is directly relevant to asset stranding risk. While removing indexation would reduce the real value of the assets over time, it would not address the fundamental asset stranding issue which relates to long-term demand uncertainty, rather than inflation.

X18 We therefore consider that asset stranding risk is better addressed independently of our approach to RAB indexation (topic 3d).

Index Transpower's RAB to inflation and allow Transpower to apply for an alternative depreciation profile

X19 Transpower submitted early in the IM Review that it favours keeping its RAB unindexed.

X20 Our draft decision is to index Transpower's RAB to inflation from RCP4 onwards and to enable Transpower to apply for an alternative depreciation approach where doing so would better promote the Part 4 purpose. We see this as a finely balanced decision, so we have put forward two (less favoured) alternatives.

X20.1 Alternative A: delay RAB indexation to start from RCP5 onwards and implement for RCP4 the RAB inflation wash-up discussed in detail in section 5b. The wash-up would cease to apply from RCP5 onwards.

X20.2 Alternative B (least favoured): retain the status quo and not index Transpower's RAB, but implement for RCP4 the RAB inflation wash-up from section 5b.

X21 In the current environment and given our understanding of Transpower's financeability, we no longer have the same concerns to match the level of revenue to Transpower's investment needs as we did in 2010. Instead, we consider that the benefits of indexation (protecting from inflation and promoting pricing profiles that are more likely to be consistent with allocative efficiency) on balance justify the change.

X22 Our draft decision is to also change the Transpower IMs, with effect at the RCP4 reset, to enable Transpower to request an alternative depreciation approach during an individual price-quality path (IPP) reset, where doing so would better promote the Part 4 purpose. This change is similar to the option currently available to EDBs and GPBs under CPPs to request an alternative depreciation approach if doing so would better promote the Part 4 purpose than the standard approach of CPI-indexed RAB straight-line depreciation.

Topic 3b – Implications of IRIS for cashflow timing

X23 Our draft decision is to not introduce any tools for altering the cashflow timing specifically for the Incremental Rolling Incentive Scheme (IRIS). We recognise that our IRIS expenditure incentive mechanism has cashflow timing implications, but in general consider it reasonable to expect suppliers to manage these implications.

X24 In situations where it is better for us to change the IRIS cashflow timing implications, we consider that assessing and smoothing all cashflow-sensitive factors as part of intra-period revenue smoothing is more effective than an IRIS specific mechanism and better promotes the Part 4 purpose, particularly 52A(1)(a).

Topic 3c – New connections volume wash-up mechanism for EDBs on a CPP

X25 Given the uncertainty in future network growth, a potential issue that has been raised by EDBs is the impact of new connections on network expenditure. New connections are outside of suppliers' direct control, but most EDBs are still responsible for part of the cost of these connections.

X26 Our draft decision is to introduce a wash-up mechanism in the EDB IMs for the outturn volume of new connections based on standard unit costs, which could be set for a CPP, but not for default price-quality paths (DPPs). Similar to the mechanism in the Fibre IMs that apply to Chorus Limited (Chorus), the mechanism would use an ex-ante 'unit cost' per connection as determined at a CPP. We do not consider the mechanism would be appropriate for a DPP currently, due to the lack of verifiable connection cost information available.

X27 The new mechanism would promote the purpose of Part 4 because:

X27.1 EDBs under a CPP would have incentives to invest to meet demand for new connections while not exposing them to overspends due to forecast error, thereby promoting s 52A(1)(a); and

X27.2 The mechanism would help control connection costs, promoting efficiency of each connection (s 52A(1)(b)). Suppliers have some control of the cost of each new connection and, therefore, specifying connection unit cost(s) in advance of a CPP provides that incentive for efficiency.

X27.3 The mechanism would be symmetrical and therefore mitigate gains or losses for suppliers (s 52A(1)(d)) and consumers. If demand is lower than forecast, allowed revenue would be consistent with that lower demand, meaning consumers would not pay higher prices than needed.

Topic 3d – Addressing asset stranding risk in the context of expected declines in gas demand for GPBs

X28 Natural gas use is expected to decline in the long-term but there is significant uncertainty about the expected pace of change and extent of decline, and the potential impact on GPBs.

X29 This context presents a transition risk[5] and has potential implications for how best to address asset stranding risk in a way that promotes the Part 4 purpose.

X30 The risk of asset stranding is a problem if it results in deferral of otherwise efficient investment or in underinvestment. This can happen where there is an expectation of losses from investment due to asset stranding risk despite there being sufficient willingness to pay from consumers (before the investment is made) to support normal returns. The magnitude of stranding risk for GPBs depends on the long-term outlook for gas pipelines, but also depends on how we regulate GPBs and specifically how we address stranding risk through the IMs.

X31 Our draft decision is to retain our current approach to addressing asset stranding risk for GPBs. The long-term benefit of consumers is promoted by ensuring GPBs continue to provide a safe and reliable supply of natural gas until they are no longer needed. Compared to alternatives, we consider our existing approach better promotes the Part 4 purpose.

X32 Keeping otherwise stranded assets in the RAB and allowing asset life adjustments in DPPs to better reflect economic assets lives supports incentives to invest and innovate in line with s 52A(1)(a). And because any adjustment to timing of cashflows resulting from asset life adjustments is net present value (NPV) neutral, suppliers remain limited in their ability to extract excessive profits (s 52A(1)(d)). Our approach is also relatively simple and low-cost.

X33 Alternative approaches that would remove stranded assets from the RAB would require ex-ante compensation to support incentives to invest, where the risk of estimation error would likely result in either under investment or excessive profits. It would also likely require a costly and contentious RAB optimisation/valuation process.

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5 Commerce Commission "IM Review 2023 - Decision-making Framework paper" (13 October 2022), para A18.

X34 By applying our existing IM provisions to adjust regulatory asset lives to better reflect economic asset lives for both existing and new investments, we can mitigate asset stranding risk for individual assets and the risk of economic network stranding of the RAB as a whole. By applying our existing IMs in conjunction with alternative rates of change we can mitigate the risk of price shocks for current and future consumers without fundamentally changing our approach.

X35 We have considered and rejected other options to address asset stranding risk.

X35.1 We have rejected allowing alternative depreciation methods in DPPs. Allowing alternative methods to straight-line depreciation in DPPs would likely add significant complexity to the DPP process, contrary to s 53K. Alternative methods remain available in CPPs where the result would better promote the Part 4 purpose.

X35.2 We are not proposing to introduce an ex-ante compensation mechanism in DPPs to address residual economic network stranding risk under our current approach (where stranded assets remain in the RAB). In addition to the challenges with estimating appropriate compensation, this would likely add significant complexity to the DPP process (contrary to s 53K) and be at odds with our IM Review overarching objective of reducing compliance costs without detrimentally affecting the promotion of the s 52A purpose.

Topic 3e – Form of Control for GDBs

X36 This section presents our review of the IMs that relate to the form of control for GDBs.

X37 Our draft decision is to maintain the weighted average price cap (WAPC) for GDBs as we consider that this best promotes the Part 4 purpose. Therefore, we propose not to change the IMs.

X38 Our draft decision promotes the long-term benefit of consumers under s 52A(1)(a) and (b) by ensuring that GDBs are incentivised to make the most efficient investment and operating decisions, while having regard to the Government's 2050 net zero emissions target (2050 target) and the expected decline of demand for natural gas.

Topic 3f - Financeability test in the IMs

X39 Our draft decision is not to adopt a financeability test in the IMs because we do not need an explicit test in the IMs to consider financeability. We can already consider, and indeed have previously considered, financeability where relevant and not inconsistent with promoting the Part 4 purpose.

Chapter 4: Our approach to incentivising efficient expenditure for EDBs and Transpower

X40 Chapter 4 outlines our draft decisions on expenditure incentive schemes that apply under EDBs' and Transpower' price-quality paths.

Topic 4a - Expenditure incentive schemes, including totex, as tools to mitigate capex bias

X41 Investment in electricity lines services is expected to significantly increase to enable electrification and decarbonisation. EDBs expect to increase their use of non-network alternatives and alternative solutions (often involving opex). In this context, we want to ensure that financial regulatory incentives do not distort investment decisions.

X42 Our draft decision is to keep the current suite of expenditure incentive schemes for EDBs and Transpower as tools to mitigate capex bias arising from financial regulatory incentives, and to not adopt a totex approach to price-quality regulation.

X43 This decision reflects our view that our existing tools to mitigate capex bias better promote the Part 4 purpose than the alternative solutions we considered.

Topic 4b - Maintain the current incentive mechanisms as they best balance considerations of effectiveness and understandability

X44 The opex and capex IRIS schemes address a range of potential issues and perverse incentives for suppliers. One of the key criticisms of these schemes is that they are complicated to understand and apply.

X45 We have assessed whether there are alternative approaches that could better achieve our objectives for incentive schemes, being:

X45.1 equal incentive rates for opex and capex;

X45.2 consistent incentive rates to make efficiency savings over time;

X45.3 ability to tailor incentive rates which determine the extent to which efficiency gains are shared with consumers; and

X45.4 removing incentives under a revenue cap to inflate costs in some key years.

X46 Our draft decision is to keep the current approach to expenditure incentive mechanisms for EDBs (opex and capex IRIS) and Transpower (opex IRIS, base capex incentive scheme and major capex incentive scheme) and no IRIS for GPBs. We have considered alternative approaches that would simplify the approach to expenditure incentives but consider that the current approach better achieves our IM Review overarching objectives. This draft decision should be considered with our proposed amendments to the current expenditure incentive mechanisms for EDBs and Transpower.

X47 We consider there have been no new 'simple' incentive mechanisms proposed in submissions or used by overseas regulators (that we are aware of) that would achieve our IM Review overarching objectives better than the current IRIS mechanisms.

X48 We have considered a totex incentive scheme (ie, applying incentives at a total expenditure level) against our current expenditure incentive mechanisms. We note that a totex incentive scheme does not equalise incentives for opex and capex (like IRIS currently does) and, without a full totex regime, the benefits of applying incentives at a totex level are reduced.

X49 Overall, we consider that all types of totex incentive schemes are unlikely to meet the objectives of expenditure incentive schemes and achieve our IM Review overarching objectives, as well as IRIS does.

Topics 4c - 4i - Specific changes to the EDB and Transpower expenditure incentive mechanisms

X50 We are proposing a range of improvements to the current expenditure incentive mechanisms. We also respond to submissions on why we have not made some changes that were recommended.

X51 Our main proposed changes to the incentive schemes include:

X51.1 Applying IRIS in real (CPI-adjusted) terms rather than nominal terms: this will remove the impact of economy-wide inflation on incentive amounts for opex and capex, which will contribute to protecting suppliers from uncontrollable economy-wide inflation risk where they cannot manage this risk.

X51.2 Applying the midpoint Weighted Average Cost of Capital (WACC) as the discount rate in the opex IRIS calculation: we do not consider that a WACC uplift is necessary for the purposes of discounting for the opex IRIS.

X51.3 Removing the Transpower baseline adjustment term: for incentive schemes to be effective, the implications of those incentive schemes must be understood in advance and there should be a clear link between a supplier's behaviour and the outcomes. Removing this term would allow Transpower to better predict its return from making opex efficiency savings under the IRIS incentive mechanism.

X52 We have considered the following issues against our IM Review overarching objectives and propose to make no changes to the IMs:

X52.1 We considered whether to allow for incentive rates to be set at a price-quality (PQ) reset rather than in the IMs. Our view is that the status quo of maintaining a retention period of five years for the opex IRIS mechanism, set in the IMs, will promote the Part 4 purpose and balance uncertainty to suppliers and changes in the external environment.

X52.2 Submitters suggested that we exclude some expenditure categories from IRIS. We do not consider that this would better achieve our IM Review overarching objectives because it would remove incentives for efficiency, and, under IRIS, suppliers only bear a proportion of any overspends (ie, they are not exposed to the total over- or underspend over the life of the solution, anyway). If these costs were treated as a recoverable cost (as suggested in submissions), it could create significant price volatility.

X52.3 We do not consider that a change is needed for the treatment of operating leases for incentive purposes.

X52.4 We do not consider that a change to IRIS is needed to account for regulated suppliers that undercharge their maximum allowable revenue (MAR).

X52.5 We continue to consider that the benefits of an IRIS mechanism for GPBs are unlikely to outweigh the costs.

Chapter 5: Inflation risk

X53 Chapter 5 presents our review of the IMs that relate to the method for forecasting inflation and exposure to inflation risk and associated compensation, including debt compensation given exposure to inflation risk.

Topic 5a – Inflation forecasting method

X54 Our draft decision is to maintain our current method for forecasting inflation. It involves forecasting the CPI for the regulatory period by using the most recently available Reserve Bank of New Zealand (RBNZ) CPI forecasts at the relevant time. This timing falls into three categories:

X54.1 for forecasting the revaluation rate and for the purposes of calculating forecast inflation for the cost of debt wash-up, this is the RBNZ forecasts available at the time we determine the risk-free rate and debt premium (used in the WACC estimate that applies for a price-quality path);

X54.2 for indexing the revenue path at the start of the regulatory period, this is the most recently available RBNZ forecasts at the time the revenue path is determined; and

X54.3 for suppliers subject to a revenue path updating their forecast net allowable revenue each year, this is the RBNZ forecasts available when suppliers set their prices for each year.

X55 The RBNZ currently forecasts CPI for 13 quarters ahead. For the remaining quarters of the regulatory period, which forecasts are not produced for, we linearly trend to the midpoint of the RBNZ inflation target band (currently two percent) by the end of the forecasting window.

X56 Our view is that, compared to alternatives, the status quo is likely to better achieve our IM Review overarching objective of promoting s 52A. For the revaluation rate, we consider it is the best estimate of the market's expectation of inflation embedded in the WACC. It therefore delivers an expectation of real financial capital maintenance (FCM), and, in doing so, provides regulated suppliers with incentives to invest, consistent with s 52A(1)(a).

Topic 5b – Inflation risk allocation and compensation

X57 Our draft decision is to amend the EDB IMs and GTB IMs to:

X57.1 wash-up allowable revenue for the first year of a regulatory period when inflation differs from expected inflation. This will make the treatment of inflation in the first year of a regulatory period consistent with the treatment in other years; and

X57.2 exclude from the annual revenue wash-up the difference between the return on debt for the year (including forecast inflation), and the return on debt for the year updated for actual inflation. This will remove revenue windfall gains and losses caused by the inconsistency between the assumption in the annual revenue wash-up, which is that nominal debt costs are variable, and the assumption in the WACC, which assumes nominal debt costs are fixed. This protects suppliers from a potential revenue shortfall (over recovery) in situations where total revenue would otherwise have been decreased (increased) by inflation and is consistent with NPV=0. No IM change is needed to provide for this in the case of Transpower and GDBs, as their IMs already permit us to do so at the IPP and DPP reset, respectively, if we decide at that point that it would promote the Part 4 purpose.

Chapter 6: Innovation incentives for EDBs and Transpower

X58 Chapter 6 presents our review of the IMs that relate to the innovation-specific mechanisms provided for in the EDB IMs. The chapter explores whether we should amend the EDB IMs to provide for regulatory sandboxes, and whether the IMs that provide for the innovation project allowance (IPA) are fit for purpose. The specific problem identified in Topic 6b has implications for Transpower as well as EDBs.

Topic 6a – Regulatory sandboxes for EDBs

X59 We consider the IMs generally enable the desired outcomes of regulatory sandboxes and do not propose to change them for this purpose. We recognise that innovative approaches may involve small scale trials or proof of concept tests that run the risk of breaching regulatory rules. However, we consider that the current mechanisms available to us in setting the price path and quality standards provide enough flexibility to enable these trials to be undertaken. Certain statutory features of Part 4 also mean that some of the ad-hoc flexibility seen in overseas regulatory sandboxes is not available in our context.

Topic 6b – Encouraging innovation and non-traditional solutions

X60 Our draft decision is to amend and expand the current innovation project allowance (IPA) into the 'innovation and non-traditional solutions allowance' to enable more scope and flexibility to set a wider range of schemes to provide better incentives for innovation and non-traditional solutions, at DPP resets or when setting a CPP.

X61 EDBs expect to increasingly use innovative and non-traditional solutions, instead of traditional lines solutions. In certain circumstances, the current regulatory settings may discourage use of these solutions.

X62 The proposed change enables a wider range of options to encourage innovation and non-traditional solutions, which better promotes the Part 4 purpose.

Chapter 1 Introduction

Purpose of this paper

1.1 The purpose of this paper is to consult with stakeholders on our IM Review draft decisions and associated reasons that relate, broadly, to regulated suppliers' incentives to spend efficiently. The focus of this paper is on the tools and mechanisms, other than the cost of capital, that affect incentives for efficient investment and spending decisions.[6] This paper focuses on price-quality regulated suppliers: EDBs, GPBs and Transpower.

Structure of this paper

1.2 This paper is structured as follows:

1.2.1 Chapter 2 addresses the relevant aspects of our decision-making framework and the context in which we are making these decisions;

1.2.2 Chapter 3 presents our review of the IMs that relate to suppliers' incentive and ability to invest efficiently. It includes discussion and draft IM decisions on regulated asset base (RAB) indexation, new connections, gas stranding risk, and the form of control for gas distribution businesses (GDBs), and cashflows and financeability;

1.2.3 Chapter 4 outlines our draft decisions on the IMs affecting the incentives that electricity distribution businesses (EDBs) and Transpower have to make efficient expenditure decisions under their price-quality paths. It includes discussion and draft decisions related to the incremental rolling incentive schemes (IRIS) and total expenditure (Totex);

1.2.4 Chapter 5 presents our review of the IMs that relate to the method for forecasting inflation and exposure to inflation risk and associated compensation, including debt compensation given exposure to inflation risk; and

1.2.5 Chapter 6 focuses on specific tools for promoting innovation under our regulatory regime, including the scope for regulatory sandboxes, the innovation project allowance provided for under the EDB IMs, and how we incentivise expenditure across regulatory periods for both EDBs and Transpower.

1.3 The table below presents all the draft decisions in this paper.

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6 For decisions related to the cost of capital see: Commerce Commission "Part 4 Input methodologies Review 2023 - Draft decision - Cost of capital topic paper" (14 June 2023).

Table 1.1 Risks and incentives topic paper – draft decisions 'at a glance'

New IM provisions | Amended IM provisions | Unchanged IM provisions

#		IM decision
Chapter 3: Financing and incentivising efficient investment		
3a	Unchanged IM provisions	Maintain RAB indexation to inflation for EDBs and GPBs
3a	New IM provisions	Introduce RAB indexation to inflation for Transpower
3a	New IM provisions	Enable Transpower to apply for an alternative depreciation profile
3b	Unchanged IM provisions	Not to introduce any tools to alter cashflow timings specifically for IRIS
3c	New IM provisions	Introduce a new connections volume wash-up mechanism for EDBs on a CPP
3d	Unchanged IM provisions	Maintain approach to address asset stranding risk in the context of expected declines in gas demand
3e	Unchanged IM provisions	Maintain the form of control for GDBs
3f	Unchanged IM provisions	Not to adopt a financeability test in the IMs
Chapter 4: Our approach to incentivising efficient expenditure for EDBs and Transpower		
4a	Unchanged IM provisions	Not adopt a totex regime. Maintain current expenditure incentive schemes as tools to mitigate capex bias
4b	Unchanged IM provisions	Maintain current incentive mechanisms as they best balance effectiveness and understandability
4c	Amended IM provisions	Adjust IRIS allowances for inflation
4d	Unchanged IM provisions	Maintain our approach to setting incentive rates
4e	Unchanged IM provisions	Not to exclude specific expenditure categories from IRIS
4f	Amended IM provisions	Use the midpoint discount rate in the opex IRIS calculation
4g	Unchanged IM provisions	Maintain our current treatment of operating leases
4h	Unchanged IM provisions	Make no change to IRIS for undercharging
4i	Amended IM provisions	Remove the Transpower baseline adjustment term
Chapter 5: Inflation Risk		
5a	Unchanged IM provisions	Maintain our current method for forecasting inflation
5b	Amended IM provisions	Introduce inflation wash-up on revenue for the first year of a regulatory period
5b	Amended IM provisions	Adjust annual revenue wash-up to reflect debt servicing costs being fixed in nominal terms
Chapter 6: Innovation incentives for EDBs and Transpower		
6a	Unchanged IM provisions	IMs generally enable the desired outcomes of regulatory sandboxes - no IM changes for this purpose.
6b	Amended IM provisions	Amend the innovation project allowance mechanism

1.4 Alongside this paper, we have published and invite stakeholders' views on the following models that support our draft decisions:

1.4.1 Demonstration model: Stylised impacts of different RAB indexation approaches. The purpose of the model is to 1) demonstrate the differences between indexation and non-indexation when outturn inflation differs from expectations; and 2) demonstrate the IM changes required to account for inflation by comparing the demonstration model to current practice.

1.4.2 Demonstration model: Financial impacts of indexation of Transpower's RAB. The purpose of this model is to demonstrate the high-level financial impacts on Transpower of changing to indexation by comparing the indexation approach to the current non-indexation approach.

Our draft decision package for the IM Review

1.5 This paper forms part of a package of draft decisions papers on the IM Review. Alongside this paper, we have published and invite stakeholders' views on:

1.5.1 our draft EDB, GDB, GTB, and Airports IM amendment determinations.[7] We will take account of submissions on these amendment determinations. These documents, with changes in response to submissions as appropriate, will be finalised and will then give legal effect to our final IM decisions;

1.5.2 our draft Summary and Context paper;

1.5.3 our other topic papers, which explain our draft IM policy decisions relevant to the following key topics:

1.5.3.1 Cost of capital;

1.5.3.2 CPPs and in-period adjustments; and

1.5.3.3 Transpower investment;

1.5.4 our draft Report on the IM Review, which summarises for every IM policy decision:

1.5.4.1 any changes we propose making;

1.5.4.2 where we have considered changes but not made them; and

1.5.4.3 where we have not found reason to consider changes.

How you can provide your views

Process and timeline for making submissions

1.6 Submissions on our draft decisions and their implementation in our draft IM amendment determinations are due by 5pm on 19 July 2023.[8] We will then invite cross-submissions by 5pm on 9 August 2023.[9] Cross-submissions should only focus on matters raised in submissions. We strongly discourage stakeholders from raising new matters via cross-submissions.

1.7 Submissions and cross-submissions can be made to the Input Methodologies Review 2023 mailbox (IM.Review@comcom.govt.nz). Please clearly indicate in your email subject line and submission which of our draft decisions your submission relates to.

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[7] The Transpower IM amendment determination and the Transpower Capex IM amendment determination will be published on 21 June, one week later than the rest of the draft decisions package. As with the other amendment determinations, a seven-week consultation period will apply for these two amendment determinations.

[8] Ibid.

[9] Ibid.

1.8 We request that submitters clearly confirm in their submission and covering email that the submission can be published on our website and does not include confidential information. If your submission does include confidential information we set out our process below.

Confidentiality

1.9 The protection of confidential information is something the Commission takes seriously. If you need to include commercially sensitive or confidential information in your submission or cross-submission, you must provide us with both a confidential and non-confidential/public version of your submission that are clearly identified. We intend to publish the non-confidential/public version of all submissions we receive on our website. This also applies to cross-submissions.

1.10 You are responsible for ensuring that commercially sensitive or confidential information is not included in a public version of a submission or cross-submission that you provide to us.

1.11 All submissions and cross-submissions we receive, including any parts of them that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we do not publish unless good reason existed under the Official Information Act 1982 to withhold it. We would normally consult with the party that provided the information before we disclose it to a requester.

Chapter 2 Framework and context

Purpose and structure of this chapter

2.1 This chapter highlights key elements of our IM Review decision-making framework (Framework) and context most relevant to our draft decisions on risks and incentives.[10]

Decision-making framework

2.2 Achieving the three overarching objectives of our Framework drives all of our decision-making in the IM Review. These objectives are:[11]

2.2.1 promoting the Part 4 purpose in s 52A more effectively;[12]

2.2.2 promoting the IM purpose in s 52R more effectively (without detrimentally affecting the promotion of the s 52A purpose);[13] and

2.2.3 significantly reducing compliance costs, other regulatory costs, or complexity (without detrimentally affecting the promotion of the s 52A purpose).

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10 We have adopted a cross-sector approach to the IM Review. Under this approach, all material we create as part of the IM Review process and material we receive from interested parties during the IM Review consultation and engagement processes will form part of the record for all of the IMs across different sectors, unless we specify otherwise. See Commerce Commission "IM Review 2023 - Process and issues paper (20 May 2022)", paras 2.13-2.14.

11 Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022)", para X20.

12 Section 52A(1) of the Act states that: "The purpose of [Part 4] is to promote the long-term benefit of consumers in markets referred to in s 52 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.

13 Section 52R provides that "The purpose of input methodologies 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]".

2.3 In applying the Framework's overarching objectives, we have had regard to whether our draft decisions promote the s 52R purpose of the IMs more or less effectively than the status quo in providing certainty for regulated suppliers and consumers in relation to the rules, requirements, and processes applying to regulation under Part 4.[14]

2.4 Several of our draft decisions (eg, our decisions on how asset lives are adjusted for GPBs in DPPs on our gas asset life adjustment tool and the innovation project allowance for EDBs) have involved tension between making IM changes to improve the regime and better promote the Part 4 purpose on the one hand, and certainty in terms of the s 52R IM purpose, on the other.[15] In such cases, we have taken account of the certainty effects, while ensuring that promoting s 52A remains at the forefront of our decision-making – both in considering which IMs to change and in reaching decisions on changing IMs.[16]

2.5 In certain contexts, such as our draft decision on GPBs' form of control, we considered it relevant and not inconsistent with promoting the Part 4 purpose to have regard to the permissive considerations under s 5ZN of the Climate Change Response Act 2002 (CCRA).[17]

2.6 We also considered it relevant and consistent with promoting s 52A to have regard to s 54Q of the Act in our draft decisions on innovation incentives. Section 54Q requires us to promote incentives and avoid imposing disincentives for suppliers of electricity lines services to invest in energy efficiency and demand-side management, and to reduce energy losses, when applying Part 4 in relation to electricity lines services.

2.7 As required under s 54V(4)(a)(i) of the Act, in coming to our draft decision to index Transpower's RAB, we also took account of the transmission pricing methodology as it applies to suppliers of electricity lines services under the Electricity Industry Participation Code 2010.

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14 Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022)", para X21.1.

15 Ibid, at para 2.22-2.25.

16 Ibid, at para 2.22-2.25.

17 Commerce Commission "Note of clarification – our Part 4 Input Methodologies Review 2023 Framework paper" (21 December 2022), p. 1.

Key economic principles

2.8 The key economic principles most relevant to this topic paper are ex-ante real FCM and FCM's practical application in the form of net present value = 0 (NPV = 0), and allocation of risk.[18]

Context for these draft decisions

2.9 This paper is concerned with regulated suppliers' incentives to invest and operate efficiently – be that investment in traditional long-lived assets, or innovative non-network solutions – in supplying services regulated under Part 4.[19] The focus of this paper is on the tools and mechanisms, other than the cost of capital, that affect incentives for efficient investment and spending decisions by price-quality regulated suppliers.[20] Given this focus, we set out below some of the issues that we understand are increasingly important to the price-quality regulated suppliers.

Investment and innovation for the energy transition

2.10 Government policy on climate change has shifted significantly since the last IM Review, with new efforts aimed at mitigating and adapting to these risks. The Climate Change Response (Zero Carbon) Amendment Act (the Zero Carbon Act) commits New Zealand to achieving net zero long-lived greenhouse gases by 2050, and the Emissions Reduction Plan (ERP) sets New Zealand on a pathway towards this target, through major government-led initiatives aimed at decarbonising the economy. The National Adaptation Plan contains Government-led proposals to adapt to the impacts of climate change and reduce the potential harm.

2.11 In this context, there is a general expectation that investment requirements for EDBs and Transpower will increase substantially in the lead up to 2030, when the next IM Review must be completed.

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[18] See Chapter 4 of Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022)".

[19] Decisions about risk allocation and compensation are a way of influencing incentives on suppliers.

[20] For decisions relating to the cost of capital see: Commerce Commission "Part 4 Input methodologies Review 2023 - Draft decision - Cost of capital topic paper" (14 June 2023).

2.12 For GPBs, the energy transition means that natural gas use is expected to reduce over the coming years and is likely to eventually be phased out. There is some potential for alternative gasses to limit the overall decline in delivered volumes for both transmission and distribution networks. However, even if repurposing is technically and economically viable, it may not replace existing uses of natural gas on like-for-like for basis.[21] If so, many existing assets will become redundant or underutilised.

2.13 The pace of this transition and the impact on GPBs remains uncertain, and presents a transition risk,[22] given the many possible pathways for the sector to decarbonise. This will be considered by the Government in the Gas Transition Plan, which is due for release at the end of 2023.[23]

2.14 So long as gas remains a widely used energy source for homes and businesses, incentives to invest efficiently are necessary to ensure the networks continue to provide a safe and reliable supply of natural gas, until they are no longer needed. The decrease in demand for natural gas is likely to correspond with an increase in demand for electricity as well.

2.15 Networks will also need to adapt to the physical risks[24] and effects of climate change. This includes investing in more resilient infrastructure and systems and responding to increasingly frequent severe adverse climatic events when they occur.

Investment needs to occur in an environment of uncertainty

2.16 There is greater than usual uncertainty around the extent of increased consumer demand and the need for investment to support this. While greater electrification is expected, it is difficult for EDBs and Transpower to forecast when and where consumers will switch products and services to more electric options. It is unlikely that all businesses will be impacted in the same way, time, or scale.

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21 See for example: Boston Consulting Group "The Future Is Electric: A Decarbonisation Roadmap for New Zealand's Electricity Sector" (2022), pp. 108-110; and Australian Energy Regulator "Regulating gas pipelines under uncertainty – Information Paper" (November 2021), pp. 13-16.

22 Commerce Commission "IM Review 2023 - Decision-making Framework paper" (13 October 2022), para A18.

23 The Gas Transition Plan will establish transition pathways for the sector to decarbonise in line with emissions budgets in the ERP, provide a framework to inform and engage with industry and stakeholders, and create a strategic view on the potential role for renewable gases. MBIE expects the GTP will be complete by the end of 2023.

24 Commerce Commission "IM Review 2023 - Decision-making Framework paper" (13 October 2022), para A18.

2.17 Advances in technology and changes in consumer preferences offer the opportunity of a new era of innovation, where regulated suppliers can meet consumers' demands at potentially much lower lifetime costs, increasing the sector's productivity and efficiency.

2.18 The impacts of high inflation add to the uncertainty facing suppliers and consumers. After almost a decade of sustained low inflation, New Zealand's annual inflation rate rose from 1.5 percent in the March 2021 quarter to 7.3 percent in June 2022, the highest level since June 1990.[25] Inflation has remained close to this level since, most recently sitting at 6.7 percent in March 2023.

Concerns about cash flows – volatility, financeability, and consumer price shocks

2.19 We have heard that some businesses are concerned about cashflow constraints that could limit their ability to invest in the current environment. These have been presented as particularly acute in light of climate change linked expenditure impacts and to enable greater electrification. Financeability refers to the ability of a business to raise and repay debt and raise equity in financial markets, readily and on reasonable terms.

   2.19.1 Some suppliers have asked us to adopt a financeability test in the IMs. Financeability depends on cashflows, which depends on the time profile of capital recovery/regulatory depreciation (amongst other things).

   2.19.2 Suppliers are also concerned about the availability of cash to fund the step change in investment that may be required.

   2.19.3 Some submitters said that elements of our regime create cashflow volatility, with the potential for flow-on impacts for consumers in the form of price shocks/volatility.

2.20 We consider that the risk of price shocks is particularly relevant in an environment where EDBs intend to significantly increase expenditure and investment in the short-to-medium term to manage decarbonisation and resilience pressures that future consumers would benefit from, but which current consumers would need to help finance.

2.21 We have heard suppliers' argument that an unindexed RAB is a better option where a significant investment profile requires support from short term cash revenue. We want to ensure businesses can fund necessary investments and reasonably withstand and react to cost pressures, while making sure that we have the right tools to help mitigate price shocks for consumers.

25 Statistics New Zealand, "Consumer price index: March 2023 quarter" (20 April 2023).

2.22 The price consumers face over time should ideally broadly reflect the flow of benefits to them over time from investment. In practice, this means that the depreciation allowance should also reflect the flow of benefits to consumers. When this is done successfully, the resulting price encourages capacity increases and consumer demand to be broadly balanced. Otherwise, we risk large increases in excess capacity and price, which can distort the demand growth that the new infrastructure is meant to serve.

Ensuring that regulated businesses retain incentives to innovate and invest

2.23 The long-term benefit of consumers is promoted by ensuring suppliers have incentives to innovate and invest efficiently. Given the likely scale of upcoming investment and the significant uncertainty around it, this means – more than ever – investing in the right things, at the right time and at the lowest lifetime cost to meet consumer demands, in line with s 52A(1)(a), (b), and (d).

2.24 In this context, this paper focuses on the appropriateness of incentives to invest to meet the changing needs of consumers and improve efficiency of spend (chapters 3 and 4), and to encourage innovation (chapter 6).

2.25 We have also considered our method for forecasting inflation for the purposes of setting price-quality paths, and how inflation forecasts and outturn inflation are applied to the RAB and price paths, thus impacting cashflows (chapter 5).

Chapter 3 Financing and incentivising efficient investment

Purpose and structure of this chapter

3.1 This chapter presents our review of the IMs that relate to suppliers' incentives and ability to invest efficiently. This is especially important in the context of the energy transition, which is widely expected to require significant investment in electrification and lead to a decline in the use of gas in the long term (see from paragraph 2.9).

3.2 This chapter covers the following topics:

3.2.1 RAB indexation to inflation;

3.2.2 implications of IRIS for cashflow timing;

3.2.3 a volume wash-up mechanism for new connections for EDBs on a CPP;

3.2.4 addressing asset stranding risk in the context of expected declines in demand for GPBs;

3.2.5 form of control for GDBs; and

3.2.6 financeability test in the IMs.

Topic 3a – RAB indexation to inflation

3.3 This section presents our review of the IMs that relate to the choice of whether to index suppliers' RAB to inflation.

Draft decisions

3.4 We have made the following draft decisions:[26]

3.4.1 maintain RAB indexation to inflation for EDBs;

3.4.2 maintain RAB indexation to inflation for GPBs;

[26] In this section, when we mention inflation, we mean CPI. When we mention RAB indexation, we mean indexation to inflation (CPI).

3.4.3 change the Transpower IMs effective from RCP4 to:

3.4.3.1 index Transpower's RAB to inflation;27 and

3.4.3.2 enable Transpower to apply for an alternative depreciation approach.[28]

Problem definition

3.5 Under the current IMs for EDBs and GPBs, we index the RAB annually by inflation. Indexing the RAB to inflation maintains the value of suppliers' RAB in real terms over time. It is also helps support a relatively flat price profile in real terms.

3.6 We do not index Transpower's RAB for inflation. This means that the real value of Transpower's RAB is unlikely to be maintained over time. It is also more likely to result in decreasing prices in real terms.

3.7 Some EDBs and GPBs have submitted that we should remove RAB indexation:

3.7.1 Some EDBs noted concerns about financing upcoming investment and submitted that we should allow them the option to choose to remove RAB indexation.

3.7.2 GPBs noted concerns relating to asset stranding and consider that we should remove RAB indexation.

3.8 Transpower submitted that we should retain the existing un-indexed approach given the extent of investment required.

3.9 Changing our approach to indexation means either bringing forward (in the case of EDBs and GPBs) or deferring (in the case of Transpower) capital recovery. All of these changes would likely have a significant impact on prices.

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[27] Same approach as for EDBs and GPBs, where we treat forecast revaluation gains as income at the reset, and the RAB in rolled forward in ID using actual inflation.

[28] In this section, when referring to 'depreciation approach' in a general sense, we mean the combined effect of the regulatory depreciation method and asset lives applied to either an indexed or unindexed asset base, which together result in an overall depreciation allowance over time (ie, the time profile of capital recovery).

3.10 We can change our approach to indexation under the IMs for a regulated service if doing so would meet our IM Review overarching objectives. The following factors are particularly relevant in this respect.

3.10.1 Changing our approach to RAB indexation has significant impacts on allowed revenues and, in turn, average prices (and price expectations) from the short to the long term. This has the potential to affect consumer demand for the service over time (s 52A(1)(b)). For example, a price that is higher than it needs to be to recover an efficient spreading of costs over time is likely to reduce consumption that consumers value above costs. Such an outcome is allocatively inefficient, and therefore would detract from s 52A(1)(b), which directs us to provide suppliers with incentives to improve efficiency.

3.10.2 Our approach to RAB indexation affects the timing, rather than the net present value, of cashflows for suppliers. To the extent that suppliers maintain an ex-ante expectation of real FCM, a change in approach would be NPV neutral, meaning that suppliers would both have incentives to invest (s 52A(1)(a)) and remain limited in their ability to extract excessive profits (s 52A(1)(d)).

3.10.3 RAB indexation is not directly relevant to addressing asset stranding risk. Taken in isolation, whether we index the RAB or not will affect the materiality of stranding risk (which may compromise incentive to invest (s 52A(1)(a))). However, the underlying risks are independent of inflation risk and can be addressed independently of inflation risk. For example, by ensuring that asset lives reflect economic asset lives.

3.10.4 Whether a different approach would promote the s 52R IM purpose more or less effectively than the status quo in providing certainty for regulated suppliers and consumers in relation to the rules, requirements, and processes applying to regulation under Part 4 (without detrimentally affecting the promotion of the s 52A purpose).

3.10.5 Whether a different approach reduces compliance costs, other regulatory costs, or complexity (again, without detrimentally affecting the promotion of the s 52A purpose).

3.11 Some stakeholders suggested changing to a non-indexed approach, or 'hybrid approach' where only the equity portion of the RAB is indexed to inflation. Not indexing the debt portion of the RAB would change the depreciation profile so that revenue would be brought forward compared to indexing the full RAB, although revenue would not be brought forward by as much as if the RAB is not indexed. In our view, the hybrid approach to indexation would not deal with the specific problem, which is the inflation risk exposure suppliers face when their revenue is adjusted for inflation each year in a way that is inconsistent with their (fixed) cost of debt. We discuss the debt compensation issue in Chapter 5, Topic 5b.[29]

Stakeholder views

3.12 Submitters asked us to reconsider our approach to RAB indexation for EDBs, GPBs and Transpower.[30] Stakeholders expressed a range of views on our approach to RAB indexation. This was an issue of high importance for many submitters.

3.13 Some submitters suggested that we should allow suppliers to choose whether the RAB should be indexed to inflation.

3.13.1 In response to the IM Review Process and issues paper, Vector recommended that we amend the EDB and GPB IMs to give suppliers the ability to choose the most appropriate indexation profile.[31]

3.13.2 Orion, and Wellington Electricity also submitted that we should consider a flexible approach to RAB indexation.[32]

3.13.3 NERA's report to the ENA highlighted that when the RAB is indexed, higher inflation has the effect of backloading the recovery of cashflows relative to lower inflation.[33]

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29 Specifically, our draft decision is to make the annual revenue wash-up consistent with the assumption underlying the WACC that firms will convert the interest rate component of their cost of debt to five-year debt. This change will address the exposure suppliers have to the risk that their revenue varies while their cost of debt remains fixed (which currently can result in windfall gains and losses).

30 For example, Aurora considered that "given the investment pressures that are likely to be placed on EDBs as a result of electrification, the issue of whether EDBs' regulatory asset base (RAB) should be unindexed should be explored" Aurora Energy "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 53.

31 Vector "Submission on the Process and issues paper" (11 July 2022), p. 4.

32 Orion "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 90; Wellington Electricity "Cross-submission on IM Review Process and issues paper, and draft framework paper" (10 August 2022), p. 2.

33 NERA "Financeability considerations under the DPP" 'Appendix D -Submission on IM Review CEPA report on cost of capital' (report prepared for Electricity Networks Association, 16 January 2023), para 6.

3.14 Unison, ENA and Wellington Electricity stated that we should consider a "hybrid approach" to indexation.

3.14.1 Unison submitted that we should consider a "shift to a hybrid approach where the RAB is indexed for inflation by the equity proportion only and nominal interest costs are financed through the MAR".[34]

3.14.2 While the ENA noted "there does not appear to be a significant issue with its [RAB indexation's] application because EDBs pay nominal interest rates on their debt, with no realistic alternative" but also state that "as part of the review, the Commission should consider a hybrid model alongside the indexed and unindexed approaches".[35]

3.14.3 Wellington Electricity also submitted that we should consider including a "hybrid RAB indexation model" in relation to concerns about debt compensation.[36]

3.15 A number of submitters stated that the same approach should apply for EDBs, GPBs and Transpower arguing that there is no justification for a different approach for Transpower.

3.15.1 Vector stated that if "the Commission declines to amend the IM to allow EDBs to remove indexation" then we should index Transpower's RAB, noting there "is no justification to maintain separate approaches between EDBs and Transpower."[37]

3.15.2 Unison stated that "we do not see how it is to the long-term benefit of consumers for Transpower to be subject to a different approach than EDBs".[38]

3.15.3 Contact noted "that the arguments for indexing the RAB of the electricity distribution business and Chorus equally apply to Transpower".[39]

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34 Unison – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 3b.

35 Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 13.

36 Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 19.

37 Vector "Submission on the Process and issues paper" (11 July 2022), pp. 4-5; Vector "Cross-submission on IM Review Process and issues paper, and draft framework paper" (3 August 2022), para 48.

38 Unison – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 3b.

39 Contact Energy "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 4.

3.15.4 Frontier on behalf of Firstgas, Powerco and Vector state that if "the Commission considers that it was appropriate in Transpower's case to remove the protection against inflation risk (given the unique circumstances that were faced by Transpower) it is unclear why similar reasoning would not justify the removal of RAB indexation for gas suppliers—given the unique circumstances faced by the gas industry at the present time".[40]

3.16 While there was some agreement that the approach should be consistent, there was differing views on what approach should apply.

3.16.1 Vector stated that "Frontier's expert report for Transpower also provides strong arguments to support an un-indexed approach for EDBs and GDBs."[41]

3.16.2 Mercury submitted the divergence in approach across suppliers needed to be reviewed to ensure the approaches are "based on sound economic principles, are reconcilable, and … do not expose the energy sector to risk."[42]

3.16.3 Contact supported indexation of Transpower's RAB noting that the "lack of indexation of Transpower's RAB has contributed to the large increase in lines costs since 2008". Contact also considered that indexing Transpower's RAB "will also help protect consumers from a potential price shock at a time when we need to encourage more electrification, not less."[43]

3.16.4 While not commenting on other sectors, The Lines Company (TLC) stated that it is "imperative that the Commission retains RAB indexation as it leads to volatile recoverable revenue for smaller EDBs and that flows on through consumer prices when assets are replaced at the end of their life".[44]

40 Frontier Economics "Options to maintain investment incentives in context of declining demand" (report prepared for Vector, Powerco and Firstgas, 9 February 2023), para 80b.

41 Vector "Cross-submission on IM Review Process and issues paper, and draft framework paper" (3 August 2022), p. 6.

42 Mercury "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p.2.

43 Contact Energy "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 4.

44 The Lines Company "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), pp. 1-2.

3.17 Transpower favours keeping its RAB unindexed, stating “our views on this matter and the context for them have not changed, if anything the need for ensuring finance is even more necessary given the impetus for electrification” and that “if a change were to be considered then substantial evidence would be required to inform any decision, including evidence that demonstrates the issues the Commission previously raised are no longer applicable”.[45]

3.18 Frontier on behalf of Transpower state:[46]

> Any move away from Transpower’s current nominal framework towards RAB indexation would reduce the speed of cash flow allowances raising the prospect of the cash flow timing issues identified above. Indeed, the need to support significant new transmission investment was one of the key reasons for the Commission maintaining the nominal framework for Transpower in the 2016 IMs review:
>
> Our lack of indexation of Transpower’s RAB means that capital recovery is front-loaded relative to an indexed approach (as applied to the EDBs). We considered this was appropriate in 2010 given their relatively large investment programme, since an un-indexed approach would likely lead to higher revenues in the near-term that better matched their investment needs. We signalled that we would re-consider the arrangement in the future once their major investment tranche came to an end. This has now happened.
>
> The need for major transmission investment, to support decarbonisation objectives, has intensified since the 2016 IMs review.

3.19 With specific reference to GPBs, suppliers Vector, Powerco and Firstgas favour removing RAB Indexation to address concerns relating to asset stranding risk.

3.19.1 Frontier on behalf of Firstgas, Powerco and Vector recommend the “removal of RAB indexation to avoid unnecessarily back-loading the recovery of costs”.[47] They state that the “Commission is correct that RAB indexation protects consumers and suppliers against inflation”, but argue that the “benefits to consumers and suppliers of protection against inflation risk are unlikely to be greater than the benefits of addressing the stranding risk and cost recovery problems identified by the Commission”.[48]

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45 Transpower NZ Ltd “Submission on IM Review Process and issues paper and draft Framework paper” (11 July 2022), p. 25.

46 Frontier Economics “RAB indexation” (Report prepared for Transpower, 7 July 2022), p .8.

47 Frontier Economics “Options to maintain investment incentives in context of declining demand” (report prepared for Vector, Powerco and Firstgas, 9 February 2023), para 21.b.ii.

48 Frontier Economics “Options to maintain investment incentives in context of declining demand” (report prepared for Vector, Powerco and Firstgas, 9 February 2023), para 80.

3.19.2 Frontier also stated that:[49]

> The Consultation paper notes that the front-loading of cost recovery could be achieved in a more precise and controlled way using alternative depreciation approaches (better reflecting the using of assets over their economic lives) than the removal of indexation. We agree with that point. However, we do not think that the Commission should view the removal of RAB indexation as an alternative to other approaches it might adopt to front-load cost recovery. Rather, we suggest that the Commission view the removal of RAB indexation as a complement to other approaches it might implement to front-load cost recovery and manage the asset stranding risk faced by suppliers by preventing the unnecessary back-loading of costs

3.19.3 Vector "do not consider retaining GPB RAB indexation can be justified in the current environment where networks face declining demand and asset stranding risk".[50]

3.19.4 Firstgas "support the removal of RAB indexation for gas pipelines" noting that other options for changes to the depreciation method are "less preferrable than removing RAB indexation as they create more complexity".[51]

3.19.5 PowerCo states that "Frontier suggest the rationale for front-loading cost recovery is aligned with removing indexation of the asset base. We agree".[52]

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49 Frontier Economics "Options to maintain investment incentives in context of declining demand" (report prepared for Vector, Powerco and Firstgas, 9 February 2023), para 81. Footnote omitted.

50 Vector "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (1 February 2023), para 26-29.

51 FirstGas Group "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), p. 2.

52 PowerCo "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), p. 3.

3.20 The Major Gas User's Group (MGUG) stated that it "seems contradictory for the Commission, to on the one hand talk down the prospect of having long lived assets, and then on the other provide incentives and settings to suppliers to invest for the long term".[53] MGUG go on state that there were "a number of inconsistencies with this approach" including the decision to "continue with RAB indexation to maintain real ex-ante FCM". While MGUG dispute the need for asset life reductions (see topic 3d), MGUG states that "if the Commission is of a mind to consider a shortened asset life as more likely than not, then it should also determine that RAB indexation can no longer [be] appropriate since maintaining the real value of asset[s] can no longer be seen in the context of asset replacement in the future".[54]

Proposed solution – Maintain RAB indexation to inflation for EDBs

3.21 Our draft decision is to maintain the status quo of indexing EDBs' RABs to inflation.[55]

3.22 In this section, when referring to 'depreciation approach' in a general sense we mean the combined effect of the regulatory depreciation method and asset lives applied to either an indexed or unindexed asset base, which together result in an overall depreciation allowance over time (ie, the time profile of capital recovery).

Our original reasons for indexing EDB RABs remain valid

3.23 In 2010, we decided that the standard depreciation approach should be a CPI-indexed RAB with straight-line depreciation (SLD). Below we present the reasons we relied on then, and our current position.

3.24 The approach protects the regulatory value of regulated suppliers' investment in real terms. We considered that the greater protection against inflation risk that RAB indexation afforded was sufficient to prefer it over an un-indexed approach for EDBs at that time.[56]

3.24.1 We consider that the inflation protection point remains valid.

53 Major Gas Users Group "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 63.

54 Major Gas Users Group "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 74.

55 Note that we are also proposing to retain RAB indexation for GPBs. We discuss our reasons for this decision below from 3.56.

56 Commerce Commission "Input Methodologies (Transpower) – Reasons Paper" (December 2010), para 4.3.13

3.25 An indexed RAB together with SLD ('standard approach') is a simple, transparent, and well-understood way of calculating depreciation.[57]

3.25.1 We consider that this point remains valid.

3.26 The standard approach supports a relatively flat aggregate pricing profile in real terms over time. Such a profile is consistent with allocative efficiency in workably competitive markets (ie, consistent with suppliers having incentives to improve efficiency and thus s 52A(1)(b)). [58] In 2010 we noted that in workably competitive markets, when the output or utilisation of an asset may reasonably be expected to vary over time, the pricing profile may be adjusted so that consumers pay the same price per unit in real terms over time.[59]

3.26.1 We consider that this point remains valid. We note that other factors in addition to a SLD- indexed RAB affect the pricing profile, such as asset lives and investment profile. Our understanding is that the extent to which a relatively stable aggregate pricing profile in real terms is efficient depends on a range of factors, such as utilisation (related to available capacity) over time, which in turn depends on demand, or the extent to which the production technology is stable.

[57] Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 4.3.69

[58] Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 5.2.6

[59] Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 4.3.85

3.26.2 We have heard–and seen evidence from AMPs–that the current context is one where investment (and therefore capacity) is likely to significantly increase ahead of demand. This suggests that, for the pricing profile to remain consistent with intertemporal allocative efficiency, and to the extent that near-term capacity increases, there should be downwards pressure in the near-term price level, and upward price pressure in the longer term as demand increases and spare capacity falls. Changing to an unindexed RAB approach for EDBs would likely create pricing outcomes that are less consistent with an efficient pricing profile, contrary to s 52A(1)(b), given the current context of increasing investment and capacity. Prices would be relatively higher in the near term when demand is lower (relative to the longer term), which would move prices away from the efficient ones, and therefore not be consistent with s 52A(1)(b). An indexed RAB depreciated in a straight line at least supports depreciation outcomes that are closer to the efficient ones, even if it may not go the full extent to deliver the most efficient price profile. We consider this is a reasonable basis for the draft decision, but note that other relevant factors may have also changed, which may affect the above discussion. We welcome evidence on this point.

3.27 The standard approach is consistent with a cashflow profile that is generally consistent with a prudently financed supplier meeting both their debt obligations and the costs of new investment. We considered there was no reason why this approach should cause a prudently financed supplier to have difficulties financing their investments, particularly given the treatment of taxation.[60, 61]

3.27.1 We consider that this point remains valid, in the absence of specific circumstances. An efficient supplier operating under our benchmark assumptions is unlikely to face financeability issues, given the way our regulatory accounting is consistent with real NPV=0 over the expected life of the assets.[62] There would need to be a specific change in circumstances, to result in a situation where an efficient supplier would have difficulty maintaining their benchmark leverage and credit rating. These circumstances are likely to be supplier specific. We note that under our draft decision, EDBs will maintain the frontloaded cashflow effects from applying our modified deferred tax approach.

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60 The modified deferred tax approach which frontloads cashflows.

61 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 4.3.76.

62 This is consistent with NERA's report for the ENA where it states: "If the regulator sets cost allowances in line with those of an efficient EDB, and a rate of return that is sufficient to provide the market rate of

3.28 The standard approach to depreciation delivers an expectation of earning normal returns over time. This is consistent with regulated suppliers having the ability—and the incentive—to invest, which is consistent with s 52A(1)(a). This is also consistent with suppliers being limited in their ability to extract excessive profits, as required by s 52A(1)(d).[63]

3.28.1 We consider that this point remains valid.

3.29 In 2010, we pointed out that if no indexation was applied to RAB values, then cashflows generated by each asset would be brought forward because depreciation in the earlier years would be higher. Such an approach would be consistent with suppliers having sufficient cashflows to finance their debt obligations, and would generally result in a more rapid recovery of the value of each supplier's investments.[64]

3.30 We noted this may help improve the financeability of investments, at the margin, for suppliers subject to default/customised price-quality regulation.[65] However, we concluded that the benefits of increased cashflows in the early years of an asset's lifetime will not, in general, outweigh the benefits associated with RAB indexation.[66] We noted that a potential issue might arise when the RAB value is inflation indexed and investment needs are increasing. Regulatory cashflows are in effect based on a real return on the value of the RAB, since revaluation gains are treated as income and therefore do not immediately result in a corresponding cashflow. We noted that since debt is usually denominated in nominal terms, it is possible that suppliers' cashflows will not match their debt obligations, potentially raising their financing costs. But noted that in these situations, suppliers that are subject to default/customised regulation will always have the option of proposing an alternative price-quality path that better meets their particular circumstances (ie, increasing investment needs).[67, 68]

return required by debt and equity holders for the profile of recovered revenues, efficient EDBs will be financeable". NERA (2023) "Financeability consideration under the DPP. Electricity Networks Association", 16 January, para 3.

63 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 4.3.70.

64 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 4.3.72.

65 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 5.2.

66 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 4.3.77.

67 See chapter 5 for our proposed solution to this issue, as it relates to inflation.

68 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 5.2.7.

3.30.1 We recognise that an important benefit of RAB indexation is intertemporal allocative efficiency, and there are other aspects of efficiency that may also be relevant, such as investment efficiency, which is related to dynamic efficiency. Potential insufficient cashflow to support investment at a point in time could undermine ability and/or incentives to invest, thus detracting from investment efficiency, contrary to s 52A(1)(a) and (b), respectively. We consider that this circumstance is likely supplier specific, and so our view remains:

3.30.1.1 in general, the benefits of RAB indexation outweigh those of frontloading cashflows; and

3.30.1.2 in specific circumstances where frontloading cashflows might be justified because doing so would better promote the s 52A purpose, there are more targeted, effective means of doing so.69

3.31 We noted that while there are several reasons for favouring CPI-indexed straight-line depreciation over alternative forms, we agreed with submissions at the time that there were likely to be certain situations in which an element of flexibility may be appropriate (including to support that consumers pay the same price per unit in real terms over time). We considered that as part of the CPP proposal process, EDBs and GPBs should be permitted some flexibility in deciding which alternative approach would better meet their particular circumstances.[70]

3.31.1 We consider that this point remains valid.

Our reasons in the 2016 IM Review to maintain RAB indexation remain valid

3.32 In our 2016 IM Review, we considered that for EDB/GPBs, our approach to RAB indexation offers an ex-ante expectation of a real return (or real FCM), and delivers an ex-post real return (or real FCM) for the effects of inflation, all other things being equal. This results in an outcome where both consumers and suppliers are protected from inflation risk.

69 The cashflow effects that a hybrid approach to RAB indexation produce could provide a reference to inform a potential future decision in this regard.

70 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 5.2.7.

3.33 We concluded that providing an expectation of, and delivering (all else equal), real FCM promotes incentives to invest (consistent with s 52A(1)(a)). This approach protects the regulatory value of suppliers' investment in real terms. We also consider that aggregate pricing that is flat in real terms over time is consistent with allocative efficiency in workably competitive markets.[71]

3.33.1 We consider that this point remains valid.[72]

Indexing the RAB to inflation is consistent with appropriate incentives to invest in the current climate

3.34 As mentioned in paragraph 3.10.2 and 3.28, indexing the RAB to inflation is consistent with the suppliers having the incentive to invest, which is consistent with s 52A(1)(a).

3.35 We have considered supplier arguments that an unindexed RAB is a better option where a significant investment profile requires support from short term cash revenue. For the reasons we outline below, our view is that removing indexation is not an appropriate way to resolve cashflow issues for EDBs at this time.

3.36 As discussed in this section, it is conceptually appropriate to consider options around regulatory depreciation to support the price path that better promotes the purpose of Part 4.

3.37 However, in general, we do not consider that depreciation should be used to address financeability concerns. We consider that financing the preferred recovery of investment (the one that best promotes the Part 4 purpose) under the price path is primarily the responsibility of suppliers. They have a range of tools for doing so, including reducing dividend payments, or raising debt and/or equity.[73] We would only bring forward capital recovery in specific circumstances where we are satisfied that doing so would better promote the Part 4 purpose.

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71 Commerce Commission " Input methodologies review decisions - Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016), para 261 and 264.

72 Only if changes to the revenue washup discussed in chapter 5 are made - particularly for debt.

73 Potential capital raising constraints from ownership arrangements are not related to our regulatory regime.

3.38 Furthermore, in the current context, we are not aware of a shortage of capital currently willing to invest in this sector. To the contrary, we continue to see transactions at RAB multiples above one,[74] and improving credit ratings.[75]

3.39 Additional reasons for not using RAB indexation to address financeability concerns for EDBs include:

3.39.1 unindexing a RAB is a 'one-size-fits-all' solution that is not appropriately targeted in scope, because it affects suppliers that may not have financeability risks;

3.39.2 unindexing a RAB is not an appropriately targeted solution in terms of impact, because we cannot calibrate the front/backloading of cashflows. This is because the impact on cashflow timing of an indexed RAB approach is determined by forecast inflation and the size of the RAB, rather than by the financing needs; and

3.39.3 we can already vary depreciation for price-quality regulated EDBs under CPPs to alter the timing of cashflow in a much more targeted way, where doing so would better promote the purpose of Part 4 than the result of applying the standard depreciation method.[76]

3.40 A decision to frontload cashflow for financeability reasons should be informed by specific evidence (eg a supplier-specific financeability assessment). As outlined in the financeability section 3f, we can already consider financeability in our decision making under Part 4 where it is relevant and not inconsistent with promoting the Part 4 purpose.

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74 Eastland Group "Eastland Group and shareholder Trust Tairāwhiti announce sale of Eastland Network to Firstgas Group, owned by Igneo Infrastructure Partners, for $260 million" (press release, 22 November 2022). See also Chapter 7 of Commerce Commission "Part 4 Input methodologies Review 2023 - Draft decision - Cost of capital topic paper" (14 June 2023).

75 https://www.spglobal.com/ratings/en/research/articles/230426-research-update-vector-ltd-upgraded-to-bbb-on-strengthening-business-mix-outlook-positive-12710994.

76 Christchurch Airport's application of a backloaded tilted annuity depreciation method, intended to approximately result in constant real prices, demonstrates the use of depreciation to support an efficient pricing profile. This was in the context of increased spare capacity (ie, the Airport completed a new integrated terminal), and application of the standard (straight line) depreciation would have generated a material increase in prices and an inefficient spreading of costs over time. Instead, the alternative depreciation aimed to target a more constant recovery of capital costs per unit of demand over time, and aggregate capital recovery growing with demand. Christchurch Airport "Disclosure relating to the reset of aeronautical prices for the period 1 July 2017 to 30 June 2022" (14 August 2017), pp. 22-24.

3.41 We note that some EDBs submitted that they should be given the ability to choose the approach to implement in their regulatory accounting, whether this is an indexed or unindexed RAB.[77] For the reasons above, we do not consider that this would better achieve the overarching objectives of the IM Review compared to the status quo. Specifically:

3.41.1 in the current context of investing ahead of demand, s 52A(1)(b) is most likely better promoted by constant real depreciation, as supported by an indexed RAB depreciated in a straight line, as long as the required prudent and efficient investment occurs; and

3.41.2 turning RAB indexation on or off as a cashflow management tool at price-quality resets would materially decrease the certainty of our rules, contrary to the s 52R IM purpose, without a corresponding benefit in achieving the Part 4 purpose, when there are more appropriate tools to manage cashflows.

Removing indexation risks price shocks

3.42 We note TLC's submission opposing the removal of RAB indexation. TLC submitted that, "the electricity industry is expected to see a sharp increase in demand… [r]emoving RAB indexation would have a material impact for smaller electricity distribution businesses (EDB's) with smaller customer bases, because it can potentially result in price shock for the customers."[78]

3.43 In the present economic context, we consider that unindexing EDBs' RABs would have a likely disproportionate impact on cashflows relative to a potential financeability problem. Frontloading cashflows in this manner would in turn increase the risk of price shocks for consumers of all network businesses.

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[77] See, for example, Orion "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 17; Vector "Submission on the Process and issues paper" (11 July 2022), p. 4.

[78] The Lines Company "TLC Submission: IM review - Options to maintain investment in the context of declining demand" (10 February 2023), p. 1.

Indexing the RAB to inflation likely better promotes allocative efficiency in the current context where future electricity demand is expected to be significantly greater

3.44 An inflation-indexed RAB that is depreciated using the straight-line method, under certain assumptions,[79] is more likely to be consistent with constant real prices, which is likely closer to an allocatively efficient pricing profile.[80]

3.45 The current environment of significantly higher investment requirements is likely to create near-term spare capacity on regulated suppliers' networks because investment tends to precede demand growth. This is consistent with what submitters have said and the evidence we see emerging.[81] In this context, an indexed RAB approach is more likely to produce depreciation—and therefore pricing—outcomes that are closer to the more efficient pricing profile of constant real prices, in line with providing suppliers with incentives to improve efficiency under s 52A(1)(b).[82]

3.46 That is because, in the presence of spare capacity and other things being equal, achieving constant real prices requires lower real depreciation amounts in the short term, when demand is relatively low, and higher ones in the longer term, when demand is higher and the network is closer to congestion. An unindexed RAB produces the opposite depreciation outcomes, while an indexed RAB depreciated in straight line at least supports depreciation outcomes that are closer to the efficient ones, even if it may not go the full extent to deliver constant real prices.

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79 Constant aggregate consumer demand and capacity utilisation, consumer preferences for service quality do not change, real input costs do not change, demand elasticity does not change. Note that if prices were based on the use of a single asset, rather than an aggregation of assets in the RAB, constant real prices would require a back-loaded depreciation profile compared to real straight-line depreciation.

80 This is because the efficient Ramsey prices for a regulated monopolist subject to a normal profit constraint will be constant prices in real terms: Baumol, Optimal depreciation policy: Pricing the products of durable assets, Bell Journal of Economics and Management Science Vol 2, 1971, 638-656; and W. Rogerson, Optimal depreciation schedules for regulated utilities, Journal of Regulatory Economics Vol 4, 1993, pp. 5-33 as cited in: Commerce Commission (2009) "Input Methodologies Discussion Paper" 19 June, paragraph 6.192 and footnote 249; and Commerce Commission (2010) "Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper" December, para 5.2.6. See also Australian Energy Regulator "Draft Decision AusNet Services transmission determination 2017-18 to 2021-22 - Attachment 5 - Regulatory depreciation" (July 2016), pp. 5-54 - 5-56.

81 See for example: Frontier Economics "Efficient investment in a decarbonising economy" – 'Submission on IM Review CEPA report on cost of capital' (report prepared for Vector, 3 February 2023), chapter 6; Wellington Electricity (2023) "Wellington Electricity 10 year Asset Management Plan: 1 April 2023 – 31 March 2033", pp. 22-23.

82 This is well established in the economics literature. See for example: Burness & Patrick (1992) "Optimal depreciation, payments to capital, and natural monopoly regulation" Journal of Regulatory Economics; The Allen Consulting Group "Principles for determining regulatory depreciation allowances" (Note to the Independent Pricing and Regulatory Tribunal of NSW, September 2003)

3.47 An unindexed RAB results in depreciation amounts—and therefore revenues and prices—that are larger in the near term compared to the longer term. The short-term risk in the context of significant investment ahead of demand is that of significantly higher short-term prices to consumers. These potentially less efficient higher prices could cause efficiency losses to consumers, detracting from s 52A(1)(b).

3.48 Given that it is likely to be optimal to have some spare capacity, intertemporal economic efficiency considerations imply smaller real prices in the early periods of network asset lives, reflecting the low marginal cost of usage, and encouraging asset use. Then these prices progressively increase as demand on the network increases.[83]

3.49 A CPI-indexed RAB depreciated in a straight line is likely the best choice for a standard approach to the time profile of depreciation. Other factors may, at times, indicate when lower or higher prices may better promote the Part 4 purpose under specific circumstances, and therefore how the time profile of depreciation could change to support that. This can be considered in a CPP.

3.50 Indexation that supports a more efficient pricing profile is also consistent with efficient electrification. We note Contact's view on this point in relation to Transpower, that indexing Transpower's RAB "will also help protect consumers from a potential price shock at a time when we need to encourage more electrification, not less."[84]

3.51 Making efficient electrification attractive to consumers is consistent with the 2050 target,[85] which we can take into account where relevant and not inconsistent with promoting s 52A.[86]

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83 For example, refer: E. Diewert, D. Lawrence, and J. Fallon "Asset valuation and productivity-based regulation taking account of sunk costs and financial capital maintenance", (Report prepared for Commerce Commission, June 2009), pp. 33, 35 and 37.

84 Contact Energy "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 4.

85 Section 5ZN(a) of the Climate Change Response Act.

86 Commerce Commission "IM Review 2023 - Decision-making Framework Clarification note- s5ZN of the CCRA" (21 December 2022).

3.52 Taking the 2050 target into account in our decision on indexation is not inconsistent with promoting the Part 4 purpose because doing so does not detract from promoting the long-term benefit of consumers by promoting the s 52A(1)(a) to (d) outcomes of the Part 4 purpose.[87]

We considered and rejected an option of depreciation loadings in DPPs to address financeability concerns

3.53 We considered introducing the option of depreciation loadings in DPPs. Specifically, we considered a tool that would enable us to amend the current depreciation method to allow depreciation loadings of less than or greater than 100 percent.

3.54 Such a tool could be confined to circumstances where certain criteria were met. For example, instances where the default depreciation settings would result in price shocks to consumers, or where a supplier(s) demonstrated that these settings would result in undue financial hardship for them (which are factors we may take into account already when setting alternative rates of change for a DPP).

3.55 However, the tool would likely entail further material changes to how depreciation is adjusted over time in DPPs. Changing the EDB IMs to provide for the tool would be unlikely to better achieve our IM Review overarching objectives because:

3.55.1 We consider that in the absence of evidence of a widespread, industry-wide financeability problem,[88] CPPs remain the preferred means of enabling a price-quality path that better meets an individual supplier's particular circumstances, in line with s 53K; and

3.55.2 The additional tool would materially increase the complexity and compliance costs of the DPP reset by requiring specific analysis for each EDB. Depending on the extent and complexity of the analysis, this could be inconsistent with the purpose of DPP/ CPP regulation under s 53K and be at odds with our IM Review overarching objective of reducing compliance costs (without detrimentally affecting the promotion of the s 52A purpose).

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[87] Concept Consulting recently found that one impact of 100 percent renewables was "increased rest-of-economy emissions from the higher electricity prices reducing the rate of electrification." See Concept Consulting "Which way is forward? Analysis of key choices for New Zealand's energy sector" (21 October 2022), p. 26.

[88] We note the submissions from CEG and NERA, which provided the results of analyses relating to EDB financeability.

Proposed solution – Maintain RAB indexation to inflation for GPBs

3.56 We propose to maintain RAB indexation for GPBs because, as we outline below, we do not consider that changing from the status quo would better achieve the IM Review overarching objectives.

3.57 The concerns that submitters raised on RAB indexation for GPBs were related to how we address asset stranding risk to incentivise efficient investment.[89]

3.58 We do not consider that RAB indexation should be removed to address asset stranding risk or economic network stranding risk. Our approach to RAB indexation is not directly relevant to how we address asset stranding risk and maintain incentives to invest in the context of declining demand (s 52A(1)(a)). While removing indexation would reduce the real value of the assets over time, it would not address the fundamental asset stranding issue which relates to long-term demand uncertainty, rather than inflation.

3.59 We therefore consider that asset stranding risk is better addressed independently of our approach to RAB indexation. In our view, our proposed approach to addressing asset stranding risk in the context of declining demand for GPBs in Topic 3d would better achieve our IM Review overarching objectives than removing RAB indexation.

Proposed solution – Change the IMs to index Transpower's RAB for CPI inflation and allow Transpower to apply for an alternative depreciation profile, with effect at the RCP4 reset

3.60 Our draft decision is to change the Transpower IMs, with effect at the RCP4 reset, to:

3.60.1 index Transpower's RAB to inflation; and

3.60.2 enable Transpower to apply for an alternative depreciation profile, where doing so would better promote the Part 4 purpose.

3.61 As we explain in this section, our present view is that making these changes to Transpower's IMs is likely to better achieve the overarching objectives of the IM Review than maintaining the status quo. We do, however, see this as more finely balanced than in relation to EDBs and GDBs, because there are implementation and compliance costs associated with the change. We outline below two (less favoured) alternatives to our draft decision: Alternative A and Alternative B.

89 See for example : Vector "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (1 February 2023), para 26-29, and, Frontier Economics "Options to maintain investment incentives in context of declining demand" (report prepared for Vector, Powerco and Firstgas, 9 February 2023), paras 21.b.ii, 80, and 81.

3.62 Specifically, we consider that, while the three options (our draft decision, Alternative A, and Alternative B) equally protect both Transpower and consumers from inflation forecast risk (consistent with s 52A(1)(a)), for the reasons we discuss in this section, our draft decision is more likely to better promote s 52A(1)(b) in supporting a more efficient price profile, followed by Alternative A and then Alternative B.[90]

3.63 Therefore, as we outline below, if after considering submissions we decided not to adopt our draft decision, then our current view is that Alternative A would be the better of the two alternatives.

3.64 We welcome evidence and submissions on our draft decision and the alternatives.

3.65 Our draft decision is to index Transpower's RAB from RCP4 onwards, reflecting that our final decision on the IM Review will precede the due date for our final decision on the RPC4 reset by just under a year. We welcome evidence on the workability of this.

3.66 Two alternatives to our draft decision that we welcome submissions on are:

3.66.1 Alternative A (more favoured): if, after taking account of submissions, we decided to index Transpower's RAB but delay this until the RCP5 reset, our next favoured alternative in terms of achieving our IM Review overarching objectives would be to implement RAB indexation from RCP5. In RCP4, the RAB inflation wash-up discussed in detail in section 5b could be implemented. This would no longer be required once indexation was implemented in RCP5.

3.66.2 Alternative B (less favoured): if, after taking account of submissions, we decided to retain the status quo and not index Transpower's RAB, then our less favoured alternative would be to implement for RCP4 the RAB inflation wash-up discussed in section 5b.[91] This alternative would therefore be the status quo (no RAB indexation) but with the RAB inflation wash-up for RCP4, if we decided to adopt it at the RCP4 reset.

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[90] Revenues (and therefore cashflows) would likely be affected the most under our draft decision and the least under Alternative B.

[91] For either alternative, proceeding with the RAB inflation wash-up would not require a change to the Transpower IMs, but would instead be something we would consult on and decide as part of the IPP reset for RCP4, if we considered in that context that doing so would better promote s 52A.

3.67 Of the two alternatives, we favour Alternative A because, for the reasons we outline in this section, we consider that while it represents a delay for consumers, it is preferred to maintaining the unindexed approach indefinitely in terms of better achieving the IM Review overarching objectives.

3.68 The balance of this section discusses the reasons why our draft decision is to index Transpower's RAB, with effect at the RCP4 reset.

Our 2010 decision to not index Transpower's RAB was based on factors that have become less significant

3.69 In our initial setting of the Transpower IMs in 2010, we considered that, among other things, an unindexed approach was appropriate for Transpower because:[92]

> Transpower is planning to invest over $3 billion in upgrading and renewing the transmission network over the next five years, which will more than double the value of Transpower's RAB. This level of proposed investments is significantly larger than any of the EDBs in both an absolute and relative sense. In addition, unlike the EDBs, a significant portion of Transpower's planned investment programme involves expenditures being incurred a number of years in advance of commissioning. The level of Transpower's investments will result in it having, relative to other lines businesses, high investment programme funding requirements…
>
> updating the RAB value using an un-indexed approach will, given the likely age structure of Transpower's asset base, be likely to lead to higher revenues for Transpower over the near term. This level of revenue will be likely to be better matched to Transpower's investment needs…
>
> Some of the above factors might be more relevant over the short to medium term than over the long-term (e.g. because of Transpower's current tranche of investment). In the case of EDBs, the Commission considers the greater protection against inflation risk that is afforded by CPI-indexation is sufficient reason to prefer such an approach over an un-indexed approach. In Transpower's case this factor is currently outweighed by the factors discussed above. In the longer term, some of the differences between Transpower and EDBs might become less significant, in which case consideration of greater alignment in some of the approaches for electricity distribution services and electricity transmission services might be warranted.

3.70 As we noted in the process and issues paper,[93] in 2010 when we set the IMs, Transpower had significantly underinvested as a result of the 'glide path' strategy in the late 90s and early 2000s. This strategy minimised spending on the grid and renewing assets, on the premise that distributed generation would increase, thus reducing the need to expand and maintain the grid. This strategy became unsustainable and Transpower embarked on a significant investment programme.

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92 Commerce Commission "Input methodologies (Transpower): Reasons paper" (December 2010), para 4.3.12 - 4.3.13.

93 Commerce Commission "IM Review 2023 - Process and issues paper" (20 May 2022), para 10.34.

3.71 Our reading of the evidence is that Transpower was at that time investing to catch up with demand, rather than investing ahead of demand. As the Auditor-General's findings note:[94]

> By 2003, it had become clear that the glide path was unsustainable. Many of the grid assets were approaching the end of their useful life, and were required to deliver more power for a growing economy and population. Transpower identified that the grid backbone was nearing its capacity and that investment was needed in many other parts of the grid. Transpower made the strategic decision to focus at this time on increasing the capacity of the grid, and began a programme to advance significant investment in capacity. This programme is under way. It includes work on the Cook Strait links, the North Island grid upgrade, and the North Auckland and Northland project.
>
> In 2008, Transpower turned its attention to the necessary replacement and refurbishment of the ageing grid assets.—

3.72 Our understanding is that the current environment for Transpower is different. As noted in the Process and issues paper, between 2008 and 2020, the value of Transpower's RAB has more than doubled—increasing by around $2.5 billion in nominal terms.[95] While demand is expected to increase in the future as electrification gains momentum, we understand that there is adequate transmission capacity in the grid as a whole, to meet most short-term demand increases.

3.73 Transpower is planning—and has started—grid upgrades to meet forecast demand, including beyond the short term. For example, Transpower's currently planned capex nearly doubles between now and 2030,[96] enhancement and development capex more than doubles in RCP4, while electricity demand takes longer to ramp up, increasing by around 70 percent but not until 2050.[97]

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94 Lyn Provost "Transpower New Zealand Limited: Managing risks to transmission assets" (28 September 2011)

95 Commerce Commission "IM Review 2023 - Process and issues paper" (20 May 2022), para 10.33.

96 https://www.transpower.co.nz/our-work/industry/our-grid/asset-management. Refer to 'ITP schedules' p.3.

97 Transpower "RCP4 Consultation" (September 2022), p. 101

3.74 This suggests that increasing spare capacity is likely in the near term, which means that the efficient price trajectory for Transpower in this context is more likely one that has a flatter profile compared to the current one (ie, lower near term and higher longer term average price). Delivering lower near-term prices and higher longer-term ones is likely to better promote s 52A(1)(b), and is why our draft decision is to index Transpower's RAB from RCP4, rather than delay the change to RCP5 (Alternative A).[98]

3.75 Even if spare capacity did not materially increase in the near term, we consider that an indexed RAB that supports a more constant real price over time is likely to better promote efficiency than the status quo, because such a price profile is likely more allocative efficient, as explained in this section.

3.76 Overall, in the current environment and given our understanding of Transpower's financeability under benchmark assumptions (see relevant sub-section below), we no longer have the same concerns to match the level of revenue to Transpower's investment needs as we did in 2010. Instead, we consider that the benefits of indexation (protecting from inflation and promoting pricing profiles that are more likely to be consistent with allocative efficiency) justify the change.

3.77 Therefore, our view is that indexing Transpower's RAB is likely to better promote the Part 4 purpose in the current circumstances.

Some of our reasons in the 2016 IM review to maintain an unindexed RAB have changed

3.78 In the 2016 IM review, we noted that the uncertainty around capital recovery resulting from emerging technologies meant that indexing Transpower's RAB was not consistent with our approach to possibly shortening asset lives for EDBs. To be consistent, we would have had to allow an equivalent treatment for Transpower, but this would have added complexity for a similar outcome to that achieved under no RAB indexation.[99]

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98 Alternative A also involves implementing the RAB inflation wash up during RCP4 as a transitory solution for protecting both Transpower and consumers from inflation risk. Since indexing the RAB equivalently protects from inflation risk, both solutions are equally consistent with s 52A(1)(a). We discuss alternative A in section 5b.

99 Commerce Commission "Input methodologies review decision. Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016), para 311.

3.79 The above view is consistent with the literature, which finds that technological change leading to competition for the monopoly service may require front-loading of depreciation in order for the regulated supplier to achieve full recovery of capital.[100]

3.80 This reason no longer applies in the current context, where there is an expectation of substantially increasing demand for electricity lines services in the following decades. We understand that the uncertainty around the risk that competition poses to capital recovery has diminished relative to the 2016 IM Review.

Our present view is that the compliance and regulatory costs of indexation are likely lower than the benefits

3.81 We acknowledge that a decision to index Transpower's RAB would likely add compliance and regulatory costs for Transpower, particularly in making the initial transition.

3.82 In the 2016 IM Review, we noted that if we were to change our approach there would be complexity and compliance costs of an unknown magnitude, given Transpower's regulatory approach is consistent with GAAP to the extent practicable, and indexing the RAB would not be able to be achieved in a GAAP consistent manner.[101]

3.83 We recognise that indexing the RAB would be a move away from GAAP-consistent regulatory reporting, which may require internal accounting/system changes. We welcome specific evidence and details of the costs of these changes.

3.84 Although there will also likely be cost and timing implications in respect of Transpower's operational implementation of the Transmission Pricing Methodology (TPM), the Electricity Authority has advised that, in terms of implications for the Code's TPM, it would be comfortable with a change to the IMs to index Transpower's RAB. That is because the TPM is 'future-proofed' so that the calculation of Transpower's transmission charges aligns to the time profile of cost recovery that we specify under Part 4.[102]

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[100] M Crew and P Kleindorfer, Economic depreciation and the regulated firm under competition and technological change, Journal of regulatory economics, Vol. 4, Iss. 1, March 1992, pp. 51–61. As referred to in AER "Draft determination - AusNet Services transmission determination 2017-18 to 2021-22 Attachment 5 - Regulatory depreciation" (July 2016), p.55.

[101] Commerce Commission "Input methodologies review decision. Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016), para 310.

[102] Section 54V(4)(a)(i) of our Act requires us to take the TPM (as it applies to Transpower and EDBs) into account before exercising our Part 4 functions/powers. See: Letter from Tim Sparks (Director, Network Pricing, Electricity Authority) to Andy Burgess (General Manager, Infrastructure Regulation, Commerce Commission) responding to request to consider the potential implications for the TPM, under the Code, should we decide to index Transpower's RAB to inflation (30 May 2023), published on our website.

3.85 As outlined above (and discussed later in this document at section 5b), if, after taking account of submissions, we decided that Alternative A or Alternative B would better achieve the overarching objectives of the IM Review than our draft decision, we would propose rebasing the RAB at resets to wash-up departures of actual from forecast inflation.[103] This would protect Transpower and consumers from inflation risk, but would have a more limited impact on depreciation and cashflows.

3.86 However, RAB indexation would also protect Transpower and consumers from inflation risk, and therefore the RAB inflation wash-up outlined in section 5b would not be required, under our draft decision. The wash-up has lower implementation costs but lower benefits in terms of depreciation profile than indexing the RAB.

3.87 Some submitters suggested the approaches to RAB indexation for Transpower and EDBs should be aligned for consistency.[104] Consistency in and of itself is not a reason to change the status quo if it would not better achieve our IM Review overarching objectives, for example, by reducing compliance costs, other regulatory costs, or complexity (without detrimentally affecting the promotion of the s 52A purpose). While it does not underpin our draft decision which is based on the reasons outlined above, we welcome evidence on whether, and if so, how aligning the approaches to RAB indexation for Transpower and EDBs for consistency would (or would not) better achieve our IM Review overarching objectives.

Allowing Transpower to apply for an alternative depreciation profile

3.88 As is the case with EDBs and GPBs, there may be certain situations in which an alternative depreciation approach may be appropriate.

3.89 When we set the IMs in 2010, we did not introduce an alternative depreciation option for Transpower on the basis of the cashflow advantages from the lack of RAB indexation to inflation.[105]

3.90 We recognise that an indexed RAB, while NPV neutral from the suppliers' perspective, decreases cashflow in the short term, but note that this does not necessarily imply financeability issues.

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103 As noted above, proceeding with a RAB inflation wash-up would not require a change to the Transpower IMs, but would rather be something we would consult on and decide as part of the IPP reset for RCP4, if we considered in that context that doing so would better promote s 52A.

104 Vector "Submission on the Process and issues paper" (11 July 2022), pp. 4-5; Vector "Cross-submission on IM Review Process and issues paper, and draft framework paper" (3 August 2022), para 48, and, Unison – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 3b.

105 Commerce Commission "Input methodologies (Transpower): Reasons paper" (December 2010), para X18 and 4.3.15.

3.91 We note Transpower's submission of a Frontier Economics report on the topic of RAB indexation. In it, Frontier presents an example of an Australian transmission project. We understand that the intention of this is to show how RAB indexation[106]

> has impacted the commercial viability of major new transmission projects. Under the Australian framework, full RAB indexation has resulted in the speed of cash allowances being so slow that investment in major new projects would cause a significant credit rating downgrade.

3.92 The specific example is the Australian Energy Market Commission's (AEMC) rejection of TransGrid's rule change request aimed at improving financeability of Integrated System Plan (ISP) projects.[107] Frontier mentions that:

> Transgrid is on the record stating that the project would not go ahead due to the impact on its credit rating. A government agency, the Clean Energy Finance Corporation, then provided $295 million of subsidised mezzanine financing to enable the project to proceed under the existing regulatory rules.
>
> The AEMC has since commenced a consultation process on 'financeability issues' – not conceding that there was an issue in relation to PEC, but recognising that cash flow timing issues might arise in relation to future major transmission projects. As part of this process, the AEMC has proposed that the Australian Energy Regulator should be able to accelerate depreciation allowances to the extent required to ensure that such approved projects are 'financeable' and able to proceed as commercially viable investments.

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106 Frontier Economics "RAB indexation: Report for Transpower" (report prepared for Transpower, 7 July 2022), pp. 8 and 10.

107 AEMC "Rule Determination: Participant derogation - financeability of ISP projects (TransGrid). Proponent: TransGrid" (8 April 2021).

3.93 We make the following observations on this Australian development:

3.93.1 part of TransGrid's case rested on the view that cashflows would be insufficient to support the benchmark leverage (60 percent debt) and credit rating (BBB+ on the S&P scale). As we mention below, we are not aware that Transpower faces capital raising (financeability) issues;

3.93.2 Frontier notes that the government had to provide additional finance to support the project going ahead. We consider that raising additional finance (equity and/or debt) is appropriate to support investment. As we mention below, we are not aware that Transpower faces capital raising (financeability) issues;

3.93.3 we agree with the AEMC's view (supported by its advisor Cambridge Economic Policy Associates (CEPA)) that the proposed changes (that cashflow be brought forward by providing a nominal rate of return on an unindexed RAB and allowing for depreciation as incurred) would not result in an efficient profile of prices;[108] and

3.93.4 the final AEMC final rule introduces greater flexibility to address the risk of financeability challenges that may arise for ISP projects. In particular, that the "Australian Energy Regulator (AER) be given the explicit ability to vary the depreciation profile for actionable ISP projects to address financeability challenges, where it considers this would better meet the National Electricity Objective."[109] The AEMC further recommends that the AER have regard to the following:[110]

3.93.4.1 Principle 1: the relative consumer benefits from the provision of network services over time;

3.93.4.2 Principle 2: the capacity of the network operator to efficiently finance its overall regulatory asset base, including efficient capital expenditure; and

3.93.4.3 Principle 3: any other factors the AER considers relevant, having regard to Principles 1 and 2.

108 AEMC "Rule Determination: Participant derogation - financeability of ISP projects (TransGrid). Proponent: TransGrid" (8 April 2021), p.54.

109 AEMC "Transmission Planning and Investment - stage 2: Final report" (27 October 2022), para 7.

110 AEMC "Transmission Planning and Investment - stage 2: Final report" (27 October 2022), p.11.

3.93.5 Under the principles, a decision to vary depreciation must have regard to inter-generational equity (principle 1). Principle 2 in turn favours a targeted, supplier-specific approach to considering financeability (principle 2).[111]

3.94 We have published a model of Transpower's regulatory and financial accounts for the period until 2055 based on the assumption in our draft decision to index Transpower's RAB for inflation at the RCP4 reset. The model is not of Transpower's actual financial position, but rather assumes Transpower operates according to our benchmark financing assumptions. For example, we assume Transpower maintains leverage at the benchmark value of 41 percent.

3.95 Our model uses inputs from Transpower's 2022 asset management plan. This plan includes a 71 percent increase in demand for the 30-year period ending 2050. Real capital expenditure is assumed to increase by 98 percent in the RCP4 period compared to the forecast used for RCP3 and remain at these elevated levels throughout RCP5. This increase in capital expenditure, relative to the size of Transpower's RAB, reinforces the importance of ensuring Transpower's future price path is efficient.

3.96 Other things equal, our draft decision to index Transpower's RAB to inflation would reduce Transpower's allowed revenues, and therefore the transmission prices that they charge consumers. In the longer term, allowed revenues under an indexed RAB would eventually be higher than under the status quo, since the change is NPV neutral over the life of the assets. We estimate this reduction in revenue to be around $100 million per year in real terms between 2026 and 2035, or just over a 10 percent decrease. The estimate is based on an assumption of 2 percent forecast inflation, and the actual reduction will depend on the inflation forecast used at the relevant IPP reset when the IM change takes effect.[112]

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111 This is consistent with how we are approaching financeability, as explained in the financeability section in this paper.

112 This estimate is broadly in line with the estimates that Frontier Economics produced for Transpower, noting that Frontier's estimates are backward looking (relate to RCP3). Frontier Economics "RAB indexation: Report for Transpower" (Report prepared for Transpower, 7 July 2022), p.12.

3.97 We note that, assuming Transpower operates according to our benchmark assumptions, Transpower's capital expenditure plans would likely require the suspension or reduction of dividends and equity injections under either indexation or non-indexation. The lower revenue from RAB indexation would imply a need for greater equity injection and a longer suspension of dividends compared to continuing the status quo. We welcome comments on whether Transpower's (benchmark) cash flows would create concerns for its (benchmark) credit rating position. Our modelling at this point indicates indexation may not lead to a financeability problem.[113]

3.98 While we consider it unlikely that Transpower faces financeability issues as a result of this decision, and that it has strong incentives to continue supply at a quality (including reliability and security) reflecting consumer demands, we also consider that it is appropriate to introduce the ability to set an alternative depreciation approach if that would better meet the Part 4 purpose.

3.99 Therefore, our draft decision is to change the Transpower IMs, with effect at the RCP4 reset, to enable Transpower to request an alternative depreciation approach during an IPP reset, where doing so would better promote the Part 4 purpose. This request would work similar to the option currently available to EDBs and GPBs under CPPs to request an alternative depreciation approach if doing so would better promote the Part 4 purpose than the standard approach of CPI-indexed RAB straight-line depreciation. As for EDBs and GPBs, for this purpose, alternative depreciation might involve the use of a different depreciation method from straight-line depreciation and/or the use of economic asset lives rather than physical asset lives.[114]

3.100 We note that the tax approach applied to Transpower (tax payable) is different to that applied to EDBs (modified deferred tax). The EDB approach delivers front-loaded recovery of tax obligations for EDBs relative to Transpower, which also brings forward revenue. We are not proposing to change the EDB tax approach, so this specific cashflow timing effect for EDBs will continue. But this provides support to introducing flexibility via the Transpower IMs to alter depreciation in the specific circumstances where an alternative approach better meets the Part 4 purpose.

113 We note that, in times where Transpower has faced significant increases in investment, as is likely to be the case again for RCP4 and RCP5, it has suspended dividend payments.

114 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para E10.61.

Topic 3b – Implications for IRIS for cashflow timing

3.101 Our IRIS expenditure incentive mechanism has cashflow timing implications. Whenever a business chooses to spend a different amount to the opex and capex allowances (more or less), there is a cashflow implication in the year itself, and then again several years later ('carry forward amounts'). Some submissions suggested that the IRIS cashflow timing implications may distort EDBs' investment decisions.

Draft decision

3.102 Our draft decision is to not introduce any tools for altering the cashflow timing specifically for IRIS.

3.103 We note that cashflow timing adjustments to address undue financial hardship or price shock could occur at the aggregate level as part of in-period revenue smoothing. Compared to introducing a specific tool for IRIS, we consider that assessing and smoothing all cashflow-sensitive factors as part or revenue smoothing better promotes the Part 4 purpose, particularly 52A(1)(a).

Problem definition

3.104 Incentive regulation creates incentives for cost reduction by temporarily decoupling allowed revenue from actual costs. Compared with a regulatory compensation approach where allowed revenue matches incurred costs incurred every time period (eg, every year), incentive regulation alters the timing of costs and revenue.

3.105 Incentive regulation therefore creates financial line items that EDB finance functions need to monitor and manage. IRIS cashflow timing may cause the following potential issues:

3.105.1 in general, it may exacerbate cashflow problems for businesses (undue financial hardship) that therefore distort suppliers' investment decisions, or IRIS related cashflows may result in price shocks for consumers; and

3.105.2 the mismatch between opex and capex IRIS cashflow timing may distort suppliers' investment decisions, more specifically to favour solutions that (from a business' point of view) have better cashflow implications.

3.106 For further analysis supporting this problem definition, refer to Attachment A.

Proposed solution

3.107 We propose no IM changes to change the cashflow timing of IRIS. We consider that IRIS cashflow timing consequences can be appropriately dealt with, if deemed necessary, through general in-period cashflow timing tools (smoothing).

IRIS cashflow timing implications can generally be expected to be managed by EDBs

3.108 Wellington Electricity submitted:

> IRIS adjustments often continue for years after allowances were under or overspent. The revenue volatility can cause EDBs to avoid an efficient investment decision because of the impact on financial stability.

3.109 Wellington Electricity correctly points out that the IRIS has multi-year cashflow implications.[115] However, we consider that these cashflow implications:

3.109.1 at any given point in time, are accurately predictable five years in advance;

3.109.2 are within the control of EDBs. Ultimately whether businesses spend more or less than the expenditure implicit in their allowances is a businesses' choice (including the choice to apply for CPP where this better meets a businesses' circumstances); and

3.109.3 can reasonably be expected to be understood by EDBs and any implications managed by their treasury functions.

3.110 Arguably, if a cashflow swing were sufficiently large and negative, it could cause debt covenant issues in any one particular year. However, given it is predictable, an EDB's treasury function ought to have sufficient time to work out how to address it.

3.111 Due to the relative size of the IRIS related cashflows (refer to Attachment A) the likelihood of IRIS creating cashflow issues and distorting decisions on its own is likely low. We welcome submissions with further evidence.

3.112 As we discuss in chapter 4, we consider our incentive mechanisms are an important part of our regulatory regime. In general, the cashflow implications are in our view an acceptable result of providing better expenditure incentives.

Cashflow timing is best considered in aggregate

3.113 Whether or not IRIS is expected to result in cashflow issues would depend on an individual EDB's circumstances and would depend on other factors impacting cash flows. To manage it therefore also requires consideration of other factors with cashflow implications.

[115] For the purpose of this analysis we assume the issue is not a general cashflow insufficiency, which may arise from persistent differences between the amount cash needed or the amount spent, and the revenue allowance we set. Our expenditure incentive incentives are concerned with providing marginal incentives, not with the level of allowances.

3.114 For example, if a smooth intra-period revenue profile is desirable to mitigate undue financial hardship or avoid price shocks for consumers, this is best considered in the round with other cashflow-sensitive factors. At the DPP3 reset, in our final reasons paper we stated: [116]

> In our draft decision we considered whether the IRIS opex incentive amounts themselves could be smoothed over the period. We decided that this would involve distributors forecasting the incentive amount values for the remainder of the period and smoothing to ensure NPV neutrality and would require an IM change and introduce additional complexity to the regime. Therefore, we decided not to pursue the option.
>
> […]
>
> We consider that the current mechanisms in place to smooth certain IRIS amounts as well as general revenue smoothing are appropriate to reduce the risk of price shocks to consumers or revenue shocks to distributors.

3.115 The DPP3 approach is also consistent with the treatment of incentive amounts in the Aurora CPP where we smoothed revenue at an aggregate level, rather than just specifically for IRIS, and provided similar reasoning.[117]

3.116 The current IMs already provide for the flexibility to smooth IRIS cashflow implications, if deemed necessary, as part of smoothing revenue overall. As discussed in Attachment D, we have proposed workability enhancements to these smoothing mechanisms. Smoothing all cashflow-sensitive factors as part of revenue smoothing is more effective than with an IRIS specific mechanism. Smoothing all cashflow-sensitive factors as part of revenue smoothing therefore better promotes the Part 4 purpose, particularly 52A(1)(a).

Understanding of IRIS cashflow timing as a potential barrier to effective cashflow management

3.117 Another issue could be that businesses do not proactively identify differences in timing so that, despite predictability and manageability (in theory), IRIS adjustments may be unexpected (in practice) and cause or exacerbate financial hardship. We also acknowledge that the *detailed* workings of the incentive mechanisms that gives rise to annual cashflows are not intuitive and may therefore be hard to understand intuitively. This may compound any issues caused by IRIS cashflow timing.

3.118 If this means businesses do not regularly reflect the IRIS implications in their financial planning, it is conceivable that they may be surprised, requiring reactive (ie, less deliberately considered and managed) responses.

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116 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), p.280.

117 Commerce Commission "Decision on Aurora Energy's proposal for a customised price-quality path – Final decision" (31 March 2021), p.394.

3.119 We currently do not require EDBs to calculate and disclose IRIS carry-forward amounts as they occur in their disclosures. This means stakeholders (including the Commission) are unable to assess annually how EDBs perform against their expenditure allowances and must wait until the second year of the following DPP to understand the revenue implications of the expenditure incentive mechanisms. If EDBs do not sufficiently understand the implications of IRIS in advance, by assessing incentive scheme financial implications at the end of each year for future years, and planning for these implications financially, cash-flow problems may arise.

3.120 As part of a separate process, we intend to consult on proposed ID requirements to require EDBs to disclose opex IRIS carry-forward amounts, and other relevant IRIS information, in their annual information disclosures. Such requirements would aim to assess and mitigate the risk that EDBs do not sufficiently engage with the cashflow implications of IRIS and provide additional information to interested persons on under- or over- spends of EDBs' allowances.

Mismatch between opex and capex IRIS cashflow timing

3.121 Opex and capex incentive amounts are recovered differently over time. Capex incentive amounts are recovered through the return of and return on capital that can be charged to customers. Opex IRIS is a rolling mechanism where incentive amounts are recovered via recoverable cost for the five years following an over- or under- spend.

3.122 Wellington Electricity submitted:[118]

> IRIS adjustments often continue for years after allowances were under or overspent. The revenue volatility can cause EDBs to avoid an efficient investment decision because of the impact on financial stability.
>
> Often a long wait to receive the benefits of an investment – for example, a network may have to wait seven years to see Capex IRIS benefits (the time difference between the firsts year of a determination and to when the capex IRIS is calculated).
>
> The IRIS adjustments for opex/capex substitutions are years apart – EDBs have to balance the decision to substitute expenditure with whether they can also find ways of offsetting short terms reductions in revenue and return.

3.123 EDBs expect the scope for opex/capex substitution to increase (refer to paragraphs 4.38 to 4.42). The question is whether the difference in cashflow timing between two potential solutions could result in EDBs adopting a solution that results in worse outcomes for consumers (eg, relatively higher whole-of-life costs).

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118 Wellington Electricity – "Submission on IM Review Process and Issues paper and draft Framework paper" (11 July 2022), p. 15.

3.124 This is a subset of the more general issue discussed above. If EDBs manage their cashflows effectively and IRIS does not cause or exacerbate cashflow issues (eg, undue financial hardship), then it is unlikely that this subset issue would cause behavioural changes. However, if an EDB experiences undue financial hardship, then it might impact investment choices if the cashflow timing between the two solutions is significantly different.

3.125 As we explain in chapter 4, the current scope for capex/opex substitution is likely limited but is expected to increase over the next decade. Related to this, in chapter 6 we set out our proposed solutions to certain situations where opex is used to defer capex to the next regulatory period, but where an EDB may be financially penalised for such an efficient deferral. The proposed solution, in addition to addressing the (primary) issue of removing potential barriers to efficient investment, also deals with the (secondary) issue of IRIS cashflow implications by reducing the likelihood of a supplier needing to exceed its allowance.

3.126 Given this, the most likely (but still likely immaterial) distortionary effect might be on businesses considering intra-regulatory period opex/capex substitutions (if they have cashflow issues). Some opportunities for shorter term substitution may arise (eg, with shorter lived assets, in particular non-network assets) or businesses may treat opex and capex as a fungible pool of totex and change the required expenditure mix to adapt to need.

3.127 For an illustration of IRIS cashflow timing under the DPP refer to Attachment A.

3.128 We consider that IRIS cashflow timing consequences can be appropriately dealt with, if deemed necessary, through general in-period cashflow timing tools. We discuss our decisions in relation to smoothing (IRIS carry-forwards may be included when smoothing the revenue path) and wash-ups (IRIS carry-forward amounts may not be included in wash-ups) in Attachment D.

Alternatives considered

3.129 We also considered whether cashflow implications from IRIS should be dealt with through an IRIS specific cashflow timing tool. Our reason for rejecting this alternative solution is the same as when we considered it at the DPP3 reset and the Aurora CPP, refer to paragraphs 3.114 to 3.115 above.

3.130 Smoothing revenue (and consequentially the effect of all cashflows) is more effective than with incentive scheme specific mechanisms. Smoothing all cashflow-sensitive factors as part of revenue smoothing therefore better promotes the Part 4 purpose, particularly s 52A(1)(a).

Topic 3c – New connections volume wash-up mechanism for EDBs on a CPP

3.131 Given the uncertainty in future network growth, a potential issue that has been raised by EDBs is the impact of new connections on network expenditure. New connections are outside of suppliers' direct control, but most EDBs are still responsible for part of the cost of these connections.

3.132 This is also related to how we set the form of control for EDBs. We currently apply a revenue cap for EDBs but note that price caps have favourable incentive properties in terms of removing demand risk (see, for example, the form of control for GDBs).

3.133 However, given the scale of tariff reforms potentially facing EDBs, quantity forecasting risk and potentially detrimental impacts on incentives to incur expenditure efficiently, we changed to a revenue cap in 2016.[119] This mechanism that we are proposing aims to capture some of the positive incentive properties of the price cap such that EDBs are not exposed to demand risk from new connections.

3.134 Attachment D discusses the improvements to the wider wash-up mechanisms.

Draft decision

3.135 Our draft decision is to provide for a 'new connections volume wash-up mechanism', applying only to new connections, in the EDB IMs for CPPs, but not for DPPs.

Problem definition

Connections volume uncertainty

3.136 A theme in submissions on our Process and issues paper was that suppliers should not be penalised for costs that are not within their control. This was considered an issue by suppliers in terms of expenditure on new connections and system growth. The context of decarbonisation and electrification means that the extent and pace of future demand growth for electricity lines services (ELS) is likely uncertain.

3.137 This could mean that, if demand for new connections exceeds those forecast in a price path, EDBs are penalised for the associated additional expenditure through IRIS.

[119] For more information see Commerce Commission "Input methodologies review decisions - Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016), Chapter 2: Form of control for EDBs.

3.138 There are currently reopener provisions in the IMs for 'unforeseeable major capex projects' (clause 4.5.5A) and 'foreseeable major capex projects' (clause 4.5.5B) that have a primary driver of meeting demand for:[120]

3.138.1 connection capex;

3.138.2 system growth capex;

3.138.3 asset relocation capex; or

3.138.4 a combination of connection capex and system growth capex.

3.139 These reopener provisions cover large connection-driven projects that have a materiality of either the lesser of 1 percent of that EDB's forecast net allowable revenue or $2 million. For example, see the Tauhara project reopener for Unison Networks.[121] We are also proposing some improvements to these existing reopeners and proposing another new mechanism to help with large connections (the large customer investment contract mechanism). These are discussed in Chapter 8 of our CPP and In-period Adjustment Mechanisms Topic Paper.

3.140 However, there is currently no wash-up in the IMs for the risk that the forecast volume of other connections (ie, those not included in the above reopeners or proposed large connection mechanism) is different from actual.[122] Examples could include system growth of the network associated with an increased demand from electronic vehicle uptake or general connection growth.

3.140.1 Depending on the assumptions underpinning the forecasts used to set price paths, this could result in gains or losses for suppliers and consumers (which would not be consistent with s 52A(1)(a) and (d)). There is little-to-no control over customer-initiated demand, and the numbers and types of connections may be difficult to accurately forecast relative to other categories of expenditure.

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120 Commerce Commission "Electricity distribution services input methodologies determination 2012 – consolidated 20 May 2020" (20 May 2020), clauses 4.5.5A, 4.5.5B.

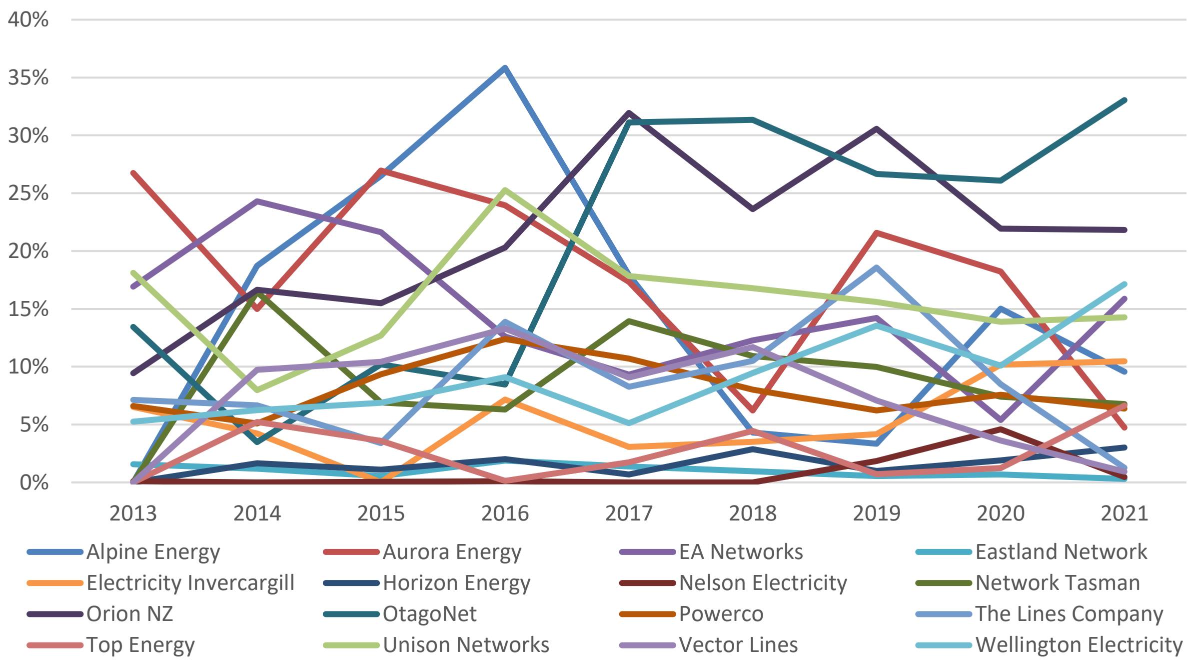
121 For more information see Commerce Commission "Reconsideration of default price-quality path for Unison Networks Limited – unforeseeable major capex project to supply Tauhara geothermal power station – Final decision" (4 March 2022).

122 Separate to this decision on the connection capex wash-up, we also note that we are proposing to introduce large connection contracts for EDBs which take new connections that meet certain criteria outside of the regulatory asset base and revenue. This is related to the discussion of connection capex.

3.140.2 If EDBs are exposed to material overspends, this could weaken their incentives and potentially their ability to invest (s 52A(1)(a)). If they reacted by significantly ramping up capital contributions, this could result in them inefficiently limiting connections growth and providing services below a quality reflecting consumer demand (s 52A(1)(b)). In addition, EDBs may potentially be incentivised to divert money from necessary network expenditure to cover the costs of connections, which would also compromise quality of service for a greater number of consumers, contrary to s 52A(1)(b).

3.141 Figure 3.1 shows that consumer connection expenditure (net of capital contributions) is a significant proportion of overall capex for some price-quality regulated EDBs. Therefore, large deviations from forecast connections could have a material impact for price-quality regulated EDBs.

Figure 3.1 Consumer connection expenditure (less capital contributions) is a significant proportion of total capex for price-quality regulated EDBs



3.142

Stakeholder views

3.143 In response to the Process and issues paper, multiple submitters suggested that connection capex should be excluded from IRIS due to the uncertainty surrounding it. EDBs' considered that they should not be penalised for meeting the needs of consumers.[123]

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123 See for example Horizon Network – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 20; Aurora Energy "Submission on IM Review Process and issues.

3.144 In November 2022, we published a staff working paper discussing the equivalence of the IRIS mechanism, a model demonstrating the intended equivalence of the opex and capex incentive rates, and some follow-up questions from our expenditure workshop.[124]

3.145 In response to the questions that we published alongside the staff working paper, multiple submitters continued to suggest that either lowering the incentive rate applied to connection capex or carving it out from IRIS was desirable due to the uncertainty surrounding volumes.[125]

3.146 Not all submissions were supportive of this approach. Some submitters considered that this would add complexity to a system that was already poorly understood and that there were other mechanisms, such as reopeners, that were better suited to dealing with the uncertainty surrounding connection capex.[126]

3.147 A ‘connection capex volumetric uncertainty mechanism’ was also raised as a potential IM change by Frontier in a report for the Big 6:[127]

> Mechanism similar to the connection capex mechanism that applies to Chorus under the fibre regime.
>
> O Baseline allowance, including connection capex than is relatively certain. Connection capex unit costs and connection types.
>
> O Variable adjustment, representing the difference between the baseline allowance (based on forecast volumes) and actual connection volumes. Variable adjustment based on same connection capex unity costs used to determine the baseline allowance.
>
> Note that this mechanism is similar to those applied by Ofgem and CRU (below).

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paper and draft Framework paper” (11 July 2022), para 75; Electricity Networks Association “Submission on IM Review Process and issues paper and draft Framework paper” (11 July 2022), p. 9.

124 See Commerce Commission “IM review 2023: Incremental rolling incentive schemes equivalence staff discussion paper” (22 November 2022); Commerce Commission “IM review 2023: Incremental rolling incentive schemes equivalence model” (22 November 2022), and Commerce Commission "IM review 2023 - Incentivising efficient expenditure - Workshop follow up questions" (22 November 2022).

125 For example Vector “Submission on Expenditure incentives EDB workshop” (6 December 2022), p. 6; PowerCo “Submission on Expenditure incentives EDB workshop” (6 December 2022), p. 7.

126 For example Wellington Electricity “Submission on Expenditure incentives EDB workshop” (6 December 2022), p. 9; Horizon Energy Group “Submission on Expenditure incentives EDB workshop” (8 December 2022), p. 7.

127 Frontier Economics “The IM review: Investing to enable decarbonisation and realise the benefits of electrification – A report for the B6” (18 November 2022), Table 13.

Proposed solution

Introduce a new connections volume wash-up mechanism in the EDB IMs for CPPs, but not DPPs

3.148 Our draft decision is to introduce a wash-up mechanism in the EDB IMs for the outturn volume of new connections based on standard unit costs specified at a price-path, which could be set for CPPs, but not for a DPP.

3.149 Under this approach, the IMs would allow for the mechanism, but the decision to apply the mechanism would occur when setting a CPP, along with the other decisions on how the price path will be set.

3.150 Based on the characteristics of connection capex, the forecast and actual outputs (number of connections) can be objectively quantified and specified in advance of the activity taking place in the regulatory period. Therefore, a wash-up mechanism could work as follows:

3.150.1 the number of new connections would be forecast ex-ante for a CPP;

3.150.2 we would determine a unit cost per connection, ex-ante, for the CPP; and

3.150.3 the wash-up mechanism would provide for the difference between the forecast number of connections and actual number of connections based on the assumed unit cost.

3.151 In practice, the difference between baseline connection capex and actual connection capex (based on outturn volumes) would be applied automatically each year through the wash-up mechanism (more information on the treatment of the wash-up amounts in the following section).

3.152 We apply a similar scheme to Chorus for connection capex specified under the Fibre IMs. This involves a variable adjustment based on unit costs of each connection type. We could base our implementation on this mechanism and apply learnings from the fibre approach so far.[128]

3.153 We propose for the wash-up mechanism to be symmetrical for over- and under-forecast connection volumes. Therefore, if connections are over-forecast, there will be a negative adjustment to reflect that the EDB will have lower costs due to the lower than forecast number of connections. This balances the allocation of this risk between suppliers and consumers and encourages accurate forecasting at a CPP.

[128] For more information on the implementation of the mechanism, see Commerce Commission "Chorus' price-quality path from 1 January 2022 – Final decision Reasons paper" (16 December 2021), para 4.287–4.347.

3.154 There is also a question around whether this mechanism would apply to new connections only, or new and existing connection expenditure. Expenditure on existing connections also depends on outturn demand but is not likely to be subject to the same uncertainty as new connections and the driver is also not as discernible.[129] We therefore consider that the wash-up mechanism should only apply to new connections.

3.155 We would need unit cost data for each standard new connection to apply this mechanism. We consider this would only be possible under a CPP, given the scrutiny applied and information requirements. We consider that this mechanism would not currently be appropriate for a DPP due to a lack of sufficiently reliable and verifiable data on connection unit costs to achieve this in a relatively low-cost way.[130]

3.156 Below we discuss how our proposed mechanism promotes the purpose of Part 4.

3.156.1 EDBs under a CPP would have incentives to invest to meet demand for new connections while not exposing them to overspends due to forecast error, thereby promoting s 52A(1)(a).

3.156.2 The mechanism would help control connection costs, promoting efficiency of each connection (s 52A(1)(b)). Suppliers have some control of the cost of each new connection and, therefore, specifying connection unit cost(s) in advance of a CPP provides that incentive for efficiency.[131]

3.156.3 The mechanism would be symmetrical and therefore mitigate gains or losses for suppliers (s 52A(1)(d)) and consumers. If demand does not occur as forecast, consumers would not pay higher prices to cover the connections that were not required.

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129 Expenditure on existing connections could be for a range of different reasons. EDBs could also potentially manage investment through managing demand on the network.

130 See the 'alternatives considered' section for the alternative approaches that we considered for this issue.

131 Under the status quo, these costs would fall under the IRIS mechanism which would provide an overall incentive to control costs at an aggregate level.

Treatment of connection capex wash-up amounts

3.157 Given our draft policy decision to introduce a connection capex wash-up mechanism for CPPs, we next must consider how best to implement the wash-up amounts. We consider that there are two main options for the treatment of the difference from the baseline connection capex allowance.

3.157.1 As part of the wider price-path wash-up – make the adjustment the baseline allowance through the EDB wash-up provisions to update the revenue allowance ex-post for actual connection numbers based on the unit cost.

3.157.2 Recoverable cost – the difference between the baseline number of new connections and actual connections would be a recoverable cost based on the unit cost per connection (set ex-ante).

3.158 The benefits of operating through the wash-up provisions are that the cost difference from the baseline new connection allowance will enter the RAB and will be recovered over time like the rest of the capex allowance. These costs would then be part of the overall capex allowance and subject to IRIS. This is generally consistent with how we have applied the connections wash-up for Chorus under Part 6, noting that an IRIS mechanism does not apply to Chorus' PQ path and so is subject only to the natural incentive.

3.159 The benefits of a recoverable cost approach are that it is simple to automatically apply every year and efficient performance is already incentivised through the ex-ante unit cost per connection. However, the downside of this approach is that the cost difference from the baseline new connection allowance will not enter the RAB and will be recovered in the year incurred (which can create volatility and potential price shocks). In addition, any cost efficiencies (or overspends) compared with the unit cost will not be shared with consumers.

3.160 We consider that the wash-up approach to treating the difference in new connections would best meet the objectives of the review. For more information on our approach to wash-ups for EDBs, see Attachment D.

3.161 For consistency with the capex IRIS, the practical implementation of the wash-up mechanism will correct the capex allowance (as the mechanism will already adjust actual capex and revenue for volume differences).[132]

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[132] Therefore, if we were not to make a change to the capex allowance then, for the IRIS calculation, actual capex would be updated for the actual number of connections, but the capex allowance would not.

Alternatives considered

Introduce a new connections volume wash-up mechanism in the EDB IMs for DPPs and CPPs

3.162 We considered introducing this mechanism for DPPs as well as CPPs. We concluded that this would not be appropriate or proportionate for a DPP. This is due to a lack of sufficiently reliable and verifiable data on connection unit costs to achieve this in a relatively low-cost way for each of the 16 price-quality regulated EDBs, as anticipated by s 53K. In addition, identifying 'standard' new connection cost information from non-standard connection costs in a DPP would likely be difficult without the level of scrutiny applied in a CPP.

3.163 Setting explicit unit costs based on limited information could result in inflated and/or inaccurate forecasts by EDBs. We would also need to take capital contributions into account.

3.164 EDBs can change capital contribution policies to address the risk of overspending on connection capex or make gains due to changing policies during a regulatory period. EDBs concerned about overspending on connection capex have the option of putting a higher proportion of the cost onto the connecting party. However, there may be constraints on EDBs shifting all of the costs to connecting parties.

3.165 We can collect more data through ID on, for example, costs of new connections and types of connections, to give us more information to consider and use to calibrate these types of mechanisms in the future for use in a DPP. This is separate from the decisions on the IMs but can be relevant to future resets.

Treat connection capex as a recoverable cost

3.166 We also considered treating new connection expenditure as a recoverable cost (rather than applying a volume wash-up mechanism), as suggested by some submitters. This would mean that there are limited incentives on suppliers to control costs and the risk will be solely borne by consumers.

3.167 Additionally, if connection expenditure was a recoverable cost, it would be recognised immediately (rather than going through the RAB and being recovered over time) and have significant price impacts and increased volatility.

Topic 3d – Addressing asset stranding risk for GPBs in the context of expected declines in demand

3.168 Natural gas use is expected to decline in the long-term but there is significant uncertainty about the pace of change and extent of decline, and the potential impact on GPBs. This has potential implications for how best to address asset stranding risk in order to promote the Part 4 purpose.

3.169 This section describes our draft decisions and reasons for IMs relating to how we address asset stranding risk for GPBs.

Draft decision

3.170 Our draft decision is that our current approach to addressing asset stranding risk appropriately incentivises continued investment in gas pipelines for the long-term benefit of consumers.

3.171 Keeping assets in the RAB that would otherwise be economically stranded addresses asset stranding risk, incentivising investment (s 52A(1)(a)) while limiting suppliers' ability to extract excessive profits (s 52A(1)(d)).

3.172 Alternative approaches that would remove stranded assets from the RAB would require ex-ante compensation to support incentives to invest, where the risk of estimation error would likely result in either under investment or excessive profits. It would also likely require a costly and contentious RAB optimisation/valuation process.

3.173 By applying our existing IM provisions to adjust regulatory asset lives to better reflect economic asset lives for both existing and new investments, we can mitigate asset stranding risk for individual assets and the risk of economic network stranding of the RAB as a whole. Doing this in conjunction with alternative rates of change, we can mitigate the risk of price shocks for current and future consumers without fundamentally changing our approach.

3.174 In making our draft decision, we have considered and rejected other options to address asset stranding risk that are consistent with the ex-ante FCM principle.

3.174.1 As discussed in topic 3a above, we do not consider that RAB indexation should be removed to address asset stranding risk or economic network stranding risk (3.58).

3.174.2 We have rejected allowing alternative depreciation methods in DPPs. Allowing alternative methods to straight-line depreciation in DPPs would likely add significant complexity to the DPP process (contrary to s 53K). Alternative methods remain available in CPPs where the result would better promote the Part 4 purpose.

3.174.3 We are not proposing to introduce an ex-ante compensation mechanism in DPPs to address residual economic network stranding risk under our current approach (where stranded assets remain in the RAB). In addition to the challenges with estimating appropriate compensation, this would likely add significant complexity to the DPP process (contrary to s 53K) and be at odds with our IM Review overarching objective of reducing compliance costs (without detrimentally affecting the promotion of the s 52A purpose).

3.175 We have also rejected writing down suppliers' assets from the RAB and/or restricting asset life adjustments to new assets only without prior ex-ante compensation. These options would undermine incentives to invest (ie, not consistent with ex-ante FCM) at a time when continued investment remains in consumers' long-term interest.

Problem definition

3.176 The long-term benefit of consumers is promoted by ensuring GPB networks continue to provide a safe and reliable supply of natural gas until they are no longer needed. This means GPBs require incentives to invest and innovate in line with s 52A(1)(a).

3.177 The risk of 'asset stranding' is a problem if it results in deferral of otherwise efficient investment or in underinvestment. This can happen where there is an expectation of losses from investment due to asset stranding risk despite there being sufficient willingness to pay from consumers (before the investment is made) to support normal returns. The magnitude of risk for GPBs depends on the long-term outlook for gas pipelines, but also depends on how we regulate GPBs and specifically how we address stranding risk through the IMs. 'Asset stranding' occurs when the returns a firm makes on an investment are less than necessary to compensate for the initial investment cost. For example, this could occur if an asset is permanently underutilised or shut down early.

Current IMs incentivise investment by keeping otherwise stranded assets in the RAB

3.178 Under the current IMs, assets remain in the RAB when capacity exceeds consumer demand rather than becoming economically stranded. The expectation that individual assets will stay in the RAB addresses asset stranding risk thereby supporting incentives to invest and innovate in line with s 52A(1)(a) and the ex-ante FCM principle.[133]

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[133] See Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022), para 4.7-4.11. for an explanation of the ex-ante FCM principle and its application.

3.179 When setting a DPP, we allow suppliers to recover these costs from consumers over the lifetime of the assets. This is achieved through straight-line depreciation indexed for the consumer price index (CPI) to maintain real (depreciated) asset values over time.

3.180 Under our regulatory approach to date, consumers have always largely borne the risk of asset stranding. However, suppliers ultimately bear some risk as our framework only provides for an expectation of FCM where it assists us in promoting the Part 4 purpose.[134]

Declining demand may increase the risk of stranding of the RAB as a whole

3.181 Keeping individual assets in the RAB does not address the asymmetric risk of economic network stranding.

3.181.1 Networks can become fully or partially economically stranded if at any point in time a network owner can no longer expect to recoup their investment.

3.181.2 The risk is asymmetric because GPBs profits are constrained on the upside, but not the downside. The commitment to keep assets in the RAB should be sufficient to provide GPBs with an opportunity to recover the cost of their investment including a normal return. But if operations cease prior to full recovery of the RAB, or consumers are not willing to pay the required charges, then GPBs may be unable to recover the cost of their investment and may make less than normal profits.

3.182 In the case of GPBs there are risks of economic network stranding as a result of changes in climate change policies or consumer preferences. For example:

3.182.1 the risk that future governments close or place restrictions on gas pipeline usage which would limit which consumers have access to gas pipelines;

3.182.2 that in the future the cost of alternative fuels declines relative to delivered natural gas, which essentially caps individual consumers' willingness to pay for natural gas;

3.182.3 that consumers place less value on gas because of environmental or other concerns relating to climate change; or

134 For example, ex-ante FCM may not promote the Part 4 purpose if - in the future - such a large number of customer disconnections means that remaining consumers will not be willing or able to pay the prices that would be required for suppliers to achieve FCM.

3.182.4 that consumers anticipate potential network wind-down and when they need to replace existing assets with new assets, choose energy alternatives that do not use natural gas and/or are not dependent on gas pipelines to avoid the risk that their own investments may become stranded.

3.183 While the prospect of asset-related costs not being recovered may not be imminent (ie, under-recoveries are unlikely to occur in the current regulatory period or the next), it is the uncompensated risk that under-recoveries may eventuate in the future that can signal a potential economic stranding event and threaten current investment incentives.

3.184 If economic network stranding risk is material, it needs to be addressed to provide for ex-ante FCM. Stranding risk may be partly systematic, given the relatively low penetration of gas infrastructure in New Zealand. To this extent, it is one of many factors we have recognised in calculating the asset beta of the WACC. However, the gas sector faces specific non-systematic risks (such as those listed in paragraph 3.182 relating to decarbonisation which are not accounted for in the parameters that determine the WACC.

3.185 Non-systematic risk of stranding needs to be specifically addressed. Ex-ante FCM can be supported through measures that bring forward cash flows in a way that would be NPV neutral if stranding did not occur (meaning consumers continue to bear most of the risk) or compensated for through an ex-ante risk premium which consumers pay (meaning suppliers are paid for bearing the risk – or more risk – going forward).[135]

3.186 Under current IMs economic network stranding risk can be mitigated.

3.186.1 Asset lives can be adjusted at DPP price-quality path resets if doing so would better reflect economic asset lives and promote the Part 4 purpose. Our DPP3 decision to adjust asset lives to better reflect economic asset lives mitigated asset stranding risk for individual assets as well as the risk of economic network stranding.

3.186.2 Asset lives and the depreciation method can be adjusted in CPPs if doing so would better promote the Part 4 purpose. This could include bringing revenues forward to mitigate economic network stranding risk and maintain incentives to invest.

[135] Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022), para 4.9.2.

3.187 Changing asset lives or depreciation method does not lead to excessive profit (ie, it is NPV neutral) because it changes the timing but not the total real value of revenue received by GPBs. Suppliers continue to bear the residual stranding risk, if the risk mitigation is insufficient.

3.188 Under current IMs we do not have provisions that allow for ex-ante compensation at the time of a price-quality path reset and suppliers have not received ex-ante compensation in the past for non-systematic asset stranding risk.

Managing the risk of consumer price shocks

3.189 Our approach to addressing asset stranding risk affects how consumer prices adjust at price-quality path resets and how they are expected to adjust at future resets.

3.189.1 In a general sense, allocating asset stranding risk to consumers supports relatively stable long-term consumer price expectations if there are expectations of stable demand.

3.189.2 But with increased demand uncertainty, there is now increased risk of sharper price movements in future regulatory periods.

3.190 In the context of expected declines in demand, price shocks or the expectation of price shocks could affect consumer confidence to continue to invest in and use gas. This could accelerate the decline in demand for gas pipeline services, and result in early closure of the GPBs' networks (or parts of the networks) in the future. This could in turn result in unmet demand, despite consumers otherwise being willing to pay for continued investment, which would be at odds with s 52A(1)(b).

3.191 In general, we can manage the risk of consumer price shocks independent of how we address asset stranding risk. This includes smoothing price increases over multiple years by setting an 'alternative rate of change' for a particular supplier if we consider it necessary or desirable to minimise price shocks to consumers.[136]

3.192 Applying the current IMs to update regulatory asset lives to reflect economic asset lives in conjunction with alternative rates of change can also mitigate the risk of larger price movements. For example, we considered both short- and longer-term price effects in DPP3 and the asset life reductions we applied in DPP3 somewhat mitigated the risk of consumer price shocks in future regulatory periods. We also capped increases in DPP3 to reduce the impact on current consumers, noting there is a trade-off between how much we can cap increases while we maintain an ex-ante expectation of normal returns.

[136] Section 53P of the Act.

Other concerns raised by stakeholders

3.193 A number of other concerns were raised in relation to the current IMs addressing stranding risk. This included that current IMs:

3.193.1 result in price outcomes which are inconsistent with outcomes in competitive markets where stranding risk is borne by suppliers;[137]

3.193.2 negate "normal supply/demand curve incentives toward efficient consumer decisions about gas assets and use, by prematurely increasing gas delivery costs, instead of reducing them";[138]

3.193.3 "may incentivise wasteful investment in assets by suppliers who should be reducing investment";[139]

3.193.4 are "directly contrary to limiting excessive profits" and that stranding risk is already compensated for in the WACC;[140,141]

3.193.5 mean that present consumers are subsidising future consumers and not delivering fairness or equity for current consumers;[142]

3.193.6 will result in unsustainable price increases;[143] and

3.193.7 are too discretionary with respect to asset life adjustments to "constitute or properly form part of input methodologies".[144]

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137 For example Major Gas Users Group (MGUG) "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (9 February 2023), para 103.a.iii; Major Gas Users Group "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 59-62.

138 Major Gas Users Group (MGUG) "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (9 February 2023), para 3c.

139 Major Gas Users Group (MGUG) "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (9 February 2023), para 3d.

140 Major Gas Users Group (MGUG) "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (9 February 2023), para 3b.

141 For example Major Gas Users Group – "Submission on IM Review Process and issues paper and draft Framework paper" – Attachment 2: IM Notice of Appeal (29 June 2022), para 31c.

142 For example Greymouth Gas "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 5 and para 23.

143 For example Greymouth Gas "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 11 states that "Classical application of the ex-ante FCM principle will create an unsustainable death spiral of price increases".

144 For example Major Gas Users Group – "Submission on IM Review Process and issues paper and draft Framework paper" – Attachment 2: IM Notice of Appeal (29 June 2022) from para 33 which considers the IMs do "constitute or properly form part of input methodologies".

3.194 Some stakeholders expressed the view that our current approach of keeping assets in the RAB is inconsistent with what would occur in workably competitive markets.

3.195 Where appropriate, we can draw relevant insights from workably competitive markets. However, our task under the Part 4 purpose is to promote the specific competitive outcomes under s 52A(1)(a)-(d) in the market for the regulated service.

3.195.1 Keeping assets in the RAB to address stranding risk supports incentives to invest and innovate in line with s 52A(1)(a).

3.195.2 Concerns about dynamic efficiency and the strength of incentives for suppliers to make efficient investment choices in line with s 52A(1)(b) are relevant considerations that we have balanced with concerns about underinvestment or excessive profits (s 52A(1)(c)) in forming our draft decision (see, for example, para 3.220).

3.196 We note that under current IMs, consumers as a whole – including major gas users, other businesses, and households – bear asset stranding risk.

3.197 While we acknowledge that changes to asset lives that affect depreciation have varied impacts on individual consumers,[145] such changes reduce the likelihood of asset stranding occurring in the first place. This means that consumers pay more cost-reflective (and in turn more equitable) charges over time which mitigates the risk of consumer price shocks in future regulatory periods.

3.198 We reiterate our view that our current approach limits excessive profits, consistent with s 52A(1)(d).

3.198.1 Changes to the timing of cash flows are NPV neutral and cannot all-else-equal lead to excessive profits for suppliers or impose additional costs on consumers they did not already expect to bear in aggregate.

3.198.2 With respect to the WACC, we reiterate that the gas sector faces specific non-systematic risks relating to decarbonisation which are not accounted for in the parameters that determine the WACC.

3.199 We note that any changes we make to IMs now will only directly affect consumer prices at future price-quality path resets (DPP4 is due in 2026). Given that context, for the IM Review we must ensure the IMs enable us to appropriately address asset stranding risk at future resets, in a manner that promotes our IM Review overarching objectives.

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145 For example, if demand is forecast to decline, consumers expected to remain on the network longer are better off, while consumers who are expected to cease using gas pipeline services in the nearer term are worse off as a result of asset life reductions for existing assets.

3.199.1 Our ex-ante FCM principle underpins how we address asset stranding risk for regulated suppliers. As we discussed in our IM Review decision-making framework, this means that suppliers expect to be appropriately compensated (ex-ante) for risks they are required to bear.[146]

3.199.2 Stakeholders expressed differing views on the materiality of asset stranding and economic network stranding risk and the resulting need for it to be able to be addressed through the IMs.[147]

3.199.3 However, we do not consider that it is possible to quantify now the extent that stranding risk could undermine incentives to innovate and invest at the time of the next reset (let alone future resets beyond DPP4 to which the IMs would apply if unchanged).[148]

3.199.4 This means that we need IMs that enable us to set appropriate inputs at the time of price-quality path resets that reflect the actual risk suppliers and consumer face at that time.

Proposed solution

3.200 We propose to maintain our current approach to addressing asset stranding risk.

3.200.1 Assets can remain in the RAB until fully depreciated, even if the assets are permanently underutilised, redundant, or decommissioned.

3.200.2 Asset lives can be adjusted in DPPs if doing so better reflects economic assets lives and promotes the Part 4 purpose, with no further constraints.

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146 Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022), para 4.9.2.

147 For example Methanex "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 3 and para 12-13; Major Gas Users Group (MGUG) "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (9 February 2023) para 54-58, para 72, and para 116; and Greymouth Gas "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 3.

148 We note the suggestions by Frontier Economics on behalf of Powerco, Vector and Firstgas (FirstGas, PowerCo & Vector "Joint submission on IM Review Options to maintain investment incentives in context of declining demand paper" (10 February 2023), para 101.) that we should consider the use of willingness to pay studies and extended long term price modelling at future price-quality path resets. To the extent these are relevant in deciding whether to adjust asset lives, the IMs do not prevent us (or submitters) from considering these factors in the context of future price-quality path resets.

3.200.3 Alternative depreciation methods are allowed as part of a CPP if this would better promote the purpose of Part 4 than applying the standard depreciation method.[149]

3.201 As noted above, the long-term benefit of consumers is promoted by ensuring GPBs continue to provide a safe and reliable supply of natural gas until they are no longer needed. Compared to alternatives, we consider our existing approach better promotes the Part 4 purpose.

3.202 Keeping otherwise stranded assets in the RAB and allowing asset life adjustments in DPPs to better reflect economic assets lives supports incentives to invest and innovate in line with s 52A(1)(a). And because any adjustment to timing of cash flows resulting from asset life adjustments are NPV neutral if stranding does not occur, suppliers remain limited in their ability to extract excessive profits (s 52A(1)(d)). Our approach is also relatively simple and low-cost.

Alternatives considered

3.203 In response to the IM Review Process and Issues paper we received a number of suggestions for changes to IMs relating to how we address asset stranding risk. Following that, we consulted on a range of potential options for IM changes in a discussion paper on Options to maintain investment incentives in the context of declining demand (the Options paper).

3.204 The Options paper was primarily focused on ways to address asset stranding risk for GPBs, while continuing to provide for ex-ante FCM to maintain incentives to invest. It presented analysis of a number of possible changes to IMs.[150] These included:

3.204.1 further changes to IMs to better align regulatory asset lives with economic asset lives;

3.204.2 changes to IMs to support the use of alternative depreciation methods; and

3.204.3 tools to support reallocation of asset stranding risk to suppliers.

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149 See *Commerce Act Gas Distribution Services Input Methodologies Determination 2012* [2022] NZCC15 cl 5.3.8

150 For an overview of the five main options discussed, see Table 1, page 12 (Options A and B); Table 2, page 15 (Option C); and Table 3, page 17 (Options D and E) of the Options paper: Commerce Commission "Input methodologies review 2023 - Options to maintain investment incentives in the context of declining demand” (20 December 2022).

3.205 In the Options paper we noted that current IMs allocate stranding risk largely to consumers; but they may not always be best placed to manage these risks. For example, the choice of what and when to invest in new assets is (largely) in the control of GPBs, subject to any capital expenditure approval rules we implement.

3.206 The main advantage of allocating more asset stranding risk to suppliers is that it may provide an additional financial incentive for suppliers to better manage the risk, to the extent they can. This could result in stronger incentives to innovate and improve efficiency. It would also reduce the chance of larger price movements for consumers. Allocating more asset stranding risk to suppliers would be the desirable thing to do, where suppliers are better placed than consumers to manage that risk (considering the wider suite of tools available to manage consumer price impacts over time). If suppliers were allocated this risk, they would expect to be compensated, in order to maintain an expectation of a normal return on capital.

3.207 The first alternative option we have considered is transitioning to a regulatory model where we would address asset stranding risk prior to investment through ex-ante compensation and assets would be regularly revalued and removed from the RAB if deemed economically stranded. This would mean that in the future, consumers would pay an ex-ante risk premium and suppliers would bear the risk of asset stranding. We explain below why we do not consider this alternative would better promote the Part 4 purpose than the current approach of keeping assets in the RAB.

3.208 We have then considered a range of alternative options that could be implemented while retaining our current approach where assets remain in the RAB (in ways that are consistent with the ex-ante FCM principle).

3.208.1 Changes to our approach to adjusting asset lives. This includes:

3.208.1.1 options raised in the Options paper to better align regulatory asset lives with economic asset lives; and

3.208.1.2 changes that restrict or remove our ability in DPPs to adjust asset lives to better reflect economic asset lives.

3.208.2 Changes to the depreciation method. This includes:

3.208.2.1 the option raised in the Options paper to allow alternative depreciation methods for individual assets; and

3.208.2.2 a new tool that we have considered that would allow front and back loading of depreciation at DPPs without changing the underlying depreciation method.

3.208.3 Changes to introduce an ex-ante compensation mechanism in DPPs to address residual economic network stranding risk under our current approach (where stranded assets remain in the RAB). We discussed this as Option D in the Options paper.

3.209 We note that some stakeholders also submitted that we should also consider writing down suppliers' assets from the RAB without compensation. We have rejected that option as it would not be in consumers' long-term interest.

3.209.1 The current IMs do not allow for stranded assets to be removed from the RAB, unless they have been fully depreciated.[151] We have not provided ex-ante compensation in the past.

3.209.2 Removing stranded assets from the RAB without prior compensation would undermine the credibility of the regime to provide an ongoing expectation of ex-ante FCM. This would deter further investment at a time when continued investment remains in consumers' long-term interests and they are willing to pay for that investment.

3.210 Similarly, the option of restricting asset life adjustments to new assets only without also making provisions to offer ex-ante compensation for residual material economic network stranding risk in DPPs, would not be in consumers' long-term interests.

3.210.1 Ex-ante compensation would be needed at future resets to provide an expectation of ex-ante FCM, given the risk that regulatory asset lives for existing assets could be materially longer than economic asset lives.

3.210.2 Ignoring this risk at resets would not provide an ongoing expectation of ex-ante FCM, undermining incentives to invest.

3.211 We have also rejected the suggestion by Greymouth Gas that we require payments from GPBs to consumers to stop "the unsustainable death spiral in the context of declining demand" and for "historical material asset stranding risk that consumers have borne".[152] Again, this would not be consumers' long-term interests as it would undermine credibility in the regime to provide an ongoing expectation of ex-ante FCM, undermining incentives to invest.

[151] With the exception of "Disposed" assets. See IM definition for disposed assets. In general, economically stranded assets are not disposed assets.

[152] Greymouth Gas "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 12.

3.212 In the current context, we have not been provided with any plausible alternative that would promote the s 52A outcomes better than continuing to have IMs that are underpinned by the ex-ante FCM principle, and so we have rejected options that are inconsistent with that principle. Amending the IMs so as to depart from the ex-ante FCM principle would have immediate consequences on suppliers' incentives to continue to invest at time when continued investment – including in ensuring a safe and reliable network – remains in consumers' long-term interest.

3.213 This does not amount to an ex-post assurance of FCM for sunk investment. While we consider that in the current context it is appropriate that stranded assets remain in the RAB with asset lives that reflect remaining economic asset lives, we do not guarantee that suppliers will always be able to recoup their historical investments from consumers.[153]

3.214 Finally, we note that suppliers submitted that we should remove RAB indexation which would bring forward cashflows for GPBs. RAB indexation is not directly relevant to how we address stranding risk, and our reasons for proposing to retain a CPI-indexed RAB for GPBs are discussed in topic 3a.

Stakeholder views

3.215 We received a wide range of views on whether we should make material changes to these IMs. In general, there was very limited support for any of the specific options for IM changes discussed in the Options paper, with complexity a key concern.[154]

3.215.1 Powerco and Vector supported further changes to how we adjust asset lives to incorporate Generally Accepted Accounting Practice (GAAP) for new (Option A) and existing assets (Option B).[155,156]

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153 For example, if demand were to drop quickly, or if the Government were to enforce restrictions or an early phase-out of natural gas use, GPBs may be exposed to unmitigated economic network stranding risk for the RAB as a whole.

154 See for example: Methanex "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 18(iv); FirstGas Group "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), table 1; and Orion "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023) pp. 5-6.

155 PowerCo "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), p. 3.

156 Vector "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (1 February 2023), para 11-12.

3.215.2 Vector supported allowing changes to the depreciation method for individual assets (Option C).[157] Powerco agreed in principle but had concerns about complexity.[158] Methanex noted there was logic in having a depreciation method that matches long term demand expectations but was concerned about complexity of Option C and considered it "unlikely that alternative depreciation types will assure a better match to the long-term demand profile".[159]

3.215.3 Firstgas did not want to adopt any of the options discussed in the Options paper at this time, given the recent DPP3 IM amendment and the merits appeal.[160] Firstgas expressed concern about complexity of the options presented.[161]

3.215.4 MGUG and Greymouth Gas wanted stranded assets removed from the RAB (Option E), but absent any ex-ante compensation (Option D).[162]

3.215.5 Suppliers (Firstgas, Vector and Powerco) favour removing RAB indexation which would front-load cash flows relative to current IMs.[163]

3.215.6 MGUG and Greymouth Gas submit that we should remove existing provisions to adjust asset lives.[164,165]

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157 Vector "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (1 February 2023), para 11-12.

158 PowerCo "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), p. 3.

159 Methanex "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 22-25.

160 FirstGas Group "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), p. 2.

161 FirstGas Group "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), table 1.

162 For example Major Gas Users Group (MGUG) "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (9 February 2023) p. 32; and Greymouth Gas "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 18-20.

163 FirstGas Group "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), table 1; PowerCo "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), p. 2.; Vector "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (1 February 2023), para 11-12.

164 Major Gas Users Group – "Submission on IM Review Process and issues paper and draft Framework paper" – Attachment 2: IM Notice of Appeal (29 June 2022), para 3a.

165 Greymouth Gas "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 37.

3.215.7 MGUG submit that we should otherwise restrict asset life adjustments to new assets only; and specify asset life reductions for specific new assets through the IMs rather than making adjustments in DPPs.[166]

3.215.8 Nova supported the use of economic asset lives for new assets only noting that "these might be reasonably determined by each regulated party using GAAP".[167]

3.215.9 Methanex also submitted that we should reconsider why the IMs allowing asset life adjustment for GPBs differ to those which apply for EDBs which require suppliers to apply for any adjustments.[168]

3.215.10 There was very limited support for introducing an ex-ante compensation mechanism (Option D) as a tool in DPPs for managing economic network stranding risk. An exception was Aurora that generally supported having all tools available in DPPs.[169]

3.215.11 While not commenting on specific options for IM changes, Energy Resources Aotearoa stated that the "priority should be preserving flexibility to avoid path dependencies and to maximise option value".[170]

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166 For example, Major Gas Users Group – "Submission on IM Review Process and issues paper and draft Framework paper" – Attachment 2: IM Notice of Appeal (29 June 2022), para 3c-3d.

167 Nova Energy "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), p. 5.

168 Methanex – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 6.i; Methanex "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 8.

169 Aurora Energy "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 11.

170 Energy Resources Aotearoa "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), p. 1.

3.216 With regard to whether stranded assets should remain in the RAB and general application of the ex-ante FCM principle, Frontier on behalf of Powerco, Vector and Firstgas stated that:[171]

> …none of the limbs of section 52A would be promoted by reallocating risk from suppliers to consumers or abandoning the ex-ante FCM principle. Hence, there is no trade-off between the application of the ex-ante FCM principle to promote incentives to invest in regulated assets and some other consideration that would promote the Part 4 purpose.

3.217 Frontier go on to state that:[172]

> As the Consultation paper explains, the current regulatory arrangements allocate most of the long-term demand risk to consumers. The benefits that consumers receive in exchange for bearing this risk are:
>
> a. the preservation of strong incentives for suppliers to invest prudently and efficiently in regulated assets to deliver secure and reliable regulated services; and
>
> b. lower allowed revenues than would be required if suppliers were bearing additional risk

We propose not transitioning to a regime where stranded assets are removed from the RAB

3.218 As we noted above, there is the option of moving to a regulatory approach that compensates suppliers for asset stranding risk in advance and removes stranded assets from the RAB, while still promoting s 52A(1)(a).

3.219 There are pros and cons to this approach. Changing IMs to allow stranded assets to be removed from the RAB may partly address some of the issue raised above, but not without costs. If assets were removed from the RAB, it would be a fundamental departure from our current regulatory approach and require developing IMs to support ex-ante compensation and developing processes and IMs relating to when and how stranded assets would be identified and removed from the RAB.

3.220 Potential benefits of such an approach include:

3.220.1 stronger incentives to improve efficiency in line with s 52A(1)(b);

3.220.2 reduced risk of substantial price increases for current and/or future consumers if it became clear that long-term demand for gas pipelines would decline at an even faster rate than previously expected; and

[171] Frontier Economics on behalf of FirstGas, PowerCo & Vector "Joint submission on IM Review Options to maintain investment incentives in context of declining demand paper" (10 February 2023), para 33.

[172] Frontier Economics on behalf of FirstGas, PowerCo & Vector "Joint submission on IM Review Options to maintain investment incentives in context of declining demand paper" (10 February 2023), para 34.

3.220.3 reduced risk that resulting price shocks, or the expectation of price shocks in the future, could undermine consumer confidence in continuing to invest in and use gas, leading to inefficient disconnections.

3.221 But the certain costs of changing include:

3.221.1 there are significant issues with estimation of ex-ante compensation and consequently a risk of windfall gains or losses. The result is either excessive profits or under investment, respectively. Information asymmetries that favour suppliers when estimating appropriate ex-ante compensation would mean that over-compensation is more likely than under-compensation increasing the risk of suppliers extracting excessive profits (contrary to s 52A(1)(d));

3.221.2 it would likely require a costly and contentious RAB optimisation/valuation process. As we noted in the Options paper, it would not be possible to simply rely on suppliers to remove stranded assets from the RAB, as they would be incentivised to not reveal when an individual asset (or part of an asset) has become stranded. The gains from doing so would be an increase in long-term profits. This contrasts with asset life adjustments which can be implemented in a way that is NPV neutral with respect to the WACC; and

3.221.3 it is unclear how uncertainty created by such a significant change in regulatory approach would affect investment in other regulated sectors. In contrast, retaining a regulatory approach that we know works provides predictability to the entire Part 4 regime, and therefore certainty to stakeholders.

3.222 We also note that we can continue to mitigate the risk of price shocks for current and future consumers without fundamentally changing our approach (3.191).

3.223 We have assessed this option and concluded that such a change is highly unlikely to better achieve our IM Review overarching objectives. The potential benefits of changing approach are outweighed by the certain costs of changing. These costs would exist even if a change in approach only applied to a subset of assets.

We propose retaining our existing approach to adjusting asset lives at this time

3.224 We have reviewed the existing asset life adjustment IMs. These IMs were introduced prior to DPP3 and applied in DPP3 to reduce asset lives to better reflect expected economic asset lives.

3.225 In the Options paper we discussed two potential options that may better align regulatory asset lives with economic asset lives than is possible under the current IMs.

3.225.1 Amend the current approach to asset life adjustments to give suppliers discretion to set economic asset lives for new assets consistent with GAAP (retain the current approach for existing assets) (Option A).

3.225.2 Allow suppliers to propose updated economic asset lives (consistent with GAAP) for all existing assets at a DPP reset. (Option B).

3.226 We also discussed the implications of potential changes raised by submitters that might restrict or remove our ability in DPPs to adjust asset lives to better reflect economic asset lives.

3.227 Considering the feedback received on the Options paper, and noting limited support for the specific proposed changes at this time, our draft decision is not to change asset life adjustment IM provisions.

3.228 Further refinements to how default asset lives are determined for new assets entering the RAB (e.g. Option A) may be appropriate prior to future resets. However, we consider that it is preferable to wait until ID data from the adjustment factors applied in the DPP3 reset is available, before further amending IMs affecting default asset lives for new assets entering the RAB. It may turn out the current default ID assumptions are appropriate, and changes prove unnecessary.[173] Changing IMs now in these circumstances would not promote certainty in terms of the IM purpose under s 52R.

3.229 We also consider that our current approach to adjusting asset lives for existing assets remains appropriate. Option B as proposed in the Options paper would have added complexity to how we forecast depreciation allowances in DPPs with no material benefits over the status quo. We can still seek suppliers' views on appropriate asset lives at DPP resets (informed by GAAP) and adjust aggregate depreciation accordingly. This means that the benefits of this alternative approach can be gained without changing current IMs and adding unnecessary complexity.

[173] Note that under the current IMs we are required to apply the same adjustment factor for new and existing assets. Applying the same factor in DPP3 allowed asset lives for forecast new and existing assets to better reflect economic asset lives. However, for future resets, it may be appropriate to apply different adjustment factors for new and existing assets. For example, the weighted average asset life for existing assets may remain appropriate, but the 45-year assumption for new assets may be too long. Under the current IMs we would need to shorten both assumptions by the same amount. We can address this minor technical issue after we have received ID data from the adjustment factors applied in the DPP3 reset.

3.230 Removing our ability in DPPs to adjust asset lives (by revoking the amendments made in DPP3), as some stakeholders suggest, would not allow regulatory asset lives to reflect assets' economic lives.

3.230.1 As discussed above, the use of economic asset lives mitigates economic network stranding risk (as well as the risk of long-term price shocks for consumers). If we use regulatory asset lives that are longer than expected economic asset lives, we would be exposing suppliers to unmitigated economic network stranding risk. That would not be consistent with applying ex-ante FCM using the Building Blocks Method (BBM).

3.230.2 The current mechanism allows for further adjustments as part of future DPP resets – to decrease or increase asset lives. While in DPP3 it was used to shorten lives, it may be appropriate to use it to lengthen lives in subsequent DPPs, depending on the circumstances. For example, if it became clear that long term demand for gas pipelines would decline at a slower rate than currently expected.

3.231 We noted in the Options paper that we could consider applying the BBM consistent with ex-ante FCM, in ways that treats asset lives differently for sunk versus incremental investments. However, we do not consider that IM changes to support such decisions at resets would better promote the Part 4 purpose.

3.231.1 While we could, for example only apply economic asset lives for new assets entering the RAB, to implement such a decision in a DPP we would need to offer ex-ante compensation for existing assets to support ex-ante FCM and promote the Part 4 purpose.

3.231.2 We discuss below why we have rejected the option of introducing an ex-ante compensation mechanism in DPPs including the challenges with estimating appropriate compensation (3.241).

3.231.3 Consequently, we would be limited in our ability to support ex-ante FCM, undermining promotion of s 52A(1).

3.232 We note Methanex's specific request that we reconsider why we have taken a different approach for adjusting asset lives for EDBs compared with GPBs.[174] We consider that given the context for GPBs, our current approach is likely to better promote the Part 4 purpose than an approach that would require suppliers to individually apply for asset life adjustments. We consider that the adjustment mechanism for GPBs appropriately reflects the sector-wide nature of the drivers for the adjustment, but also the need to be responsive to the different and changing circumstances of individual suppliers for the long-term benefit of their consumers.

3.233 We agree that any adjustments should be based on a strong evidential basis and be consulted on with stakeholders as part of resetting a DPP. The current IMs allow this and it reflects our intended approach to adjustments.

3.233.1 We note that putting an evidential threshold in the IMs is unlikely to provide the certainty that major users seek, unless it is very prescriptive. A prescriptive tool may not be usable (or its effectiveness constrained) when an adjustment would otherwise promote the Part 4 purpose.

3.233.2 We can obtain the evidence necessary to justify asset life adjustments under the current IMs and have the ability to restrict adjustments to specific circumstances or limit the extent of adjustment if appropriate evidence is not provided.[175]

3.233.3 Stakeholder consultation and engagement is a central element of our DPP and IM Review processes.

We propose retaining our existing depreciation method for DPPs at this time

3.234 We have reviewed our depreciation method that applies in DPPs (currently straight-line depreciation for all assets). We considered two options for changing the depreciation method in DPPs.

3.235 In the Options paper we discussed how we could apply a front-loaded depreciation method (eg diminishing value) to individual assets (Option C).

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174 Methanex – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022) para 6.i; Methanex "Submission on IM Review Options to maintain investment incentives in the context of declining demand paper" (10 February 2023), para 8.

175 We note Methanex's request that we give consideration to the approach taken by the Australia Energy Regulator in respect to regulation of the APA Victorian Transmission System (Methanex – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 7-11). While the regimes differ, current IMs do not prevent us from adapting elements of the AERs approach if doing so promotes the Part 4 purpose at the next reset.

3.236 Following the release of the Options paper we also considered whether to allow depreciation loadings in DPPs.[176]

3.236.1 Loadings of less than or greater than 100 percent could apply to the depreciation allowance after it is calculated using straight-line depreciation if doing so would promote the s 52 A purpose.

3.236.2 Suppliers would then be required to pass through the same depreciation loading to depreciation for individual assets in the RAB for that regulatory period, so that adjustments are NPV neutral with respect to the WACC.

3.237 Our draft decision is not to implement either Option C or depreciation loadings in DPPs as either option would add significant complexity at DPP resets (contrary to s 53K).

3.237.1 With respect to Option C there is significant complexity with changing the underlying depreciation method for individual assets in DPPs.

3.237.2 While depreciation loadings would have lower compliance costs than changing the underlying method for individual assets, it would still add significant complexity to our price-quality path resets (contrary to s 53K).

3.237.3 For either option we would have to consider whether to adjust assets lives and/or the depreciation method and consult on both decisions.

3.238 Alternative methods remain available in CPPs where the result would better promote the Part 4 purpose. For example, there may be circumstances where regulatory asset lives reflect economic asset lives, but due to residual economic network stranding risk, front loading of depreciation is appropriate. Suppliers can apply for CPPs and must provide evidence to support their application.

We propose not introducing an ex-ante compensation mechanism for DPPs

3.239 Ex-ante compensation could be used to address economic network stranding risk resulting from keeping individual stranded assets in the RAB in the context of declining demand.

3.240 We considered whether we should add a mechanism into the IMs that provides for ex-ante compensation in DPPs if necessary to support an expectation of ex-ante FCM. We discussed this as Option D in the Options paper.

3.240.1 The mechanism would only specify that we could provide compensation, not the level of compensation.

176 We also considered whether to allow depreciation loadings for EDBs in DPPs (see section 3a).

3.240.2 For GPBs subject to DPP regulation, the level of compensation would be specified at the time a price path is set, given the risk assessment at that time. This could be done through the price path determination.

3.241 Our draft decision is not to implement this tool for managing economic network stranding risk in the current context.

3.241.1 When setting a price-quality path, we would still need to decide whether to provide compensation and the level of compensation that is being provided. This would likely add significant complexity to the DPP process (contrary to s 53K) and be at odds with our IM Review overarching objective of reducing compliance costs (without detrimentally affecting the promotion of the s 52A purpose).

3.241.2 There are significant consequences of estimation error for ex-ante compensation (ie, under investment or excessive profits) (discussed in paragraph 3.221 above).

Topic 3e – Form of control for GDBs

3.242 The form of control refers to how the price path is implemented, either by capping the allowed revenues a supplier can earn or the weighted average price a supplier can charge. The major factor in determining which form of control to apply is whether consumers or suppliers should bear the risk of demand being lower or higher than anticipated within a regulatory period.

3.242.1 Under a WAPC, the within-period demand risk falls on suppliers. If volumes vary, the maximum weighted average price that suppliers are allowed to charge remains the same, which means that the revenue they recover varies, until prices are reset in the next DPP reset.

3.242.2 Under a revenue cap, consumers bear the within-period demand risk. If volumes vary, suppliers can change prices during the regulatory period to recover their allowed revenue.

3.243 The current form of control for GDBs is a WAPC. We have reviewed whether the WAPC best promotes the objectives of the IM Review as the form of control for GDBs.[177]

[177] We discuss the form of control for Transpower, EDBs and the GTB in part 3 of Commerce Commission "Part 4 Input methodologies Review 2023 - Draft decision - Report on the Input Methodologies Review 2023 paper" (14 June 2023).

Draft decision

3.244 Our draft decision is to maintain the WAPC for GDBs – the status quo – as we consider that this best promotes the Part 4 purpose.

Problem definition

3.245 The issue we face in this IM Review is whether the current form of control for GDBs is the right one in the context of the expected decline in demand for gas in the long term. There is considerable uncertainty about the pace and extent of this decline.[178]

Stakeholder views

3.246 First Gas and Vector both support reviewing the form of control and moving to a revenue cap due to a significant quantity forecasting risk in the current environment, and as incentives to grow connections are not consistent with the ERP and 2050 target.[179]

3.247 MGUG, on the other hand, did not support the proposed change to a revenue cap. It stated there is no evidence that consumers are not choosing to connect to gas where they have the option to do so. Furthermore, MGUG stated that growth forecasts seem to demonstrate stability.[180, 181]

3.248 Greymouth Gas submitted that rather than focusing on the form of control, we should consider more fundamental arguments related to ex ante FCM, accelerated depreciation and asset values (see discussion on these topics in chapter 3, Topic 3d).

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178 As part of New Zealand's transition towards a net zero emissions economy by 2050 under s 5Q of the Climate Change Response Act 2002 (CCRA), the Government has signalled it wants to phase out the use of fossil fuels such as natural gas, while ensuring energy is accessible, affordable, secure, and supports economic development and there is an equitable transition. No end date has been indicated for this phase out, but demand for natural gas is likely to decline and eventually be phased out. Ministry for the Environment "Te hau marohi ki anamata. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan" (16 May 2022), p. 48.

179 First Gas Limited "Submission on IM Review Process and issues paper and draft Framework paper" (13 July 2022), p. 20; Vector "Submission on the Process and issues paper" (11 July 2022), p. 14.

180 Major Gas Users Group "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 4.

181 MGUG proposed we broaden the definition of 'gas pipeline services' to include lower carbon gases to maintain the relevance of the current form of control for GPBs. We note that we cannot amend the definition of 'gas pipeline services' which sits in s 55A of the Act.

Proposed solution

3.249 Our view is that the status quo is preferable because there is not a sufficiently strong argument, in terms of our IM Review overarching objectives, in favour of changing the form of control. Specifically, changing GDBs' current form of control is not likely to result in better s 52A outcomes for consumers of gas distribution services or reduce compliance costs, other regulatory costs, or complexity.

3.250 Consistent with s 52A(1)(a) and (b), we consider that our draft decision will ensure that GDBs are incentivised to make the most efficient investment and operating decisions so that consumers benefit from the continued supply of natural gas, while having regard to the Government's 2050 target and the expected decline of demand for natural gas.

3.251 If circumstances change as we approach the next gas DPP reset, we can reassess our decision on the form of control for GDBs at that point.

3.252 In the remainder of this section, we explain:

3.252.1 why a WAPC better promotes the s52A purpose, considering efficient investment and allocation of risk;

3.252.2 consideration of inter-regulatory period price stability and tariff structuring under a WAPC;

3.252.3 consistency with the GTB form of control; and

3.252.4 growing demand through new connections.

A WAPC would better promote s 52A(1)(a) and (b) of the Part 4 purpose

3.253 Our main reason for retaining the current GDB form of control is that the WAPC provides incentives for a GDB to spend to deliver safe and reliable services for its consumers (at a quality they demand) while there is still demand for gas, in line with s 52A(1)(a) and (b). A WAPC also better minimises the risk of inefficient expenditure (both capex and opex), consistent with s 52A(1)(b). We consider this to be an important factor for GDBs in the current environment, having regard to the ERP, emissions budgets, and the 2050 target, under s 5ZN of the CCRA.

3.254 We consider the s 5ZN considerations (particularly the ERP and 2050 target) are relevant and taking account of them in our decision on GDBs' form of control would not be inconsistent with promoting s 52A.[182] This is because our form of control decision can help promote incentives to invest efficiently, in line with s 52A(1)(a) and (b). While natural gas use is expected to decline over time, enabling efficient investment (for example, in ensuring the safety and reliability of a network) while gas is still used promotes the Part 4 purpose – s 52A(1)(a) and (b), in particular.

3.255 The 2050 target, ERP, emissions budgets, and government energy policy strongly influence the timeframe for the decline of gas use, and therefore, what efficient investment looks like while gas is still used.[183] Taking these into account makes incentivising efficient expenditure more important in determining the right form of control for GDBs.

3.256 In line with promoting s 52A(1)(a) and (b), the WAPC provides suppliers with a stronger incentive to tailor expenditure to changes in demand, such that consumers that value gas supply enough can continue to benefit from it. This may be more efficient than the incentives to minimise expenditure under a revenue cap, which could result in some consumers no longer having access to gas supply.

3.257 Under a revenue cap, once the price-quality path is set, suppliers have no incentives to spend to retain customers or provide services at a quality they demand. They rather have incentives to reduce costs. With a falling demand, and reduced costs related the fall in demand, a supplier under a revenue cap will have strong incentives to reduce expenditure, for example, by reducing the volume of sales by setting prices above marginal cost and/or degrading the quality of services, at least in the short term.[184]

3.258 Although suppliers can manage expenditure on a revenue cap, the incentives to spend efficiently to provide services at a quality consumers demand, and to reconsider the appropriateness of existing expenditure plans during a DPP, are likely to be stronger under a WAPC. For example, if the actual demand turns out to be lower than the forecast, under a WAPC, suppliers recover less money and therefore have a strong incentive to reprioritise expenditure to find efficiencies and make savings.

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182 Commerce Commission "IM Review 2023 - Decision-making Framework Clarification note- s5ZN of the CCRA" (21 December 2022).

183 Commerce Commission "Default price-quality path for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para X14.

184 Regulatory Policy Institute "Characteristics of alternative price control frameworks" (report prepared for Ofgem, February 2009), p. 7.

3.259 Under a revenue cap the incentives to look for efficiencies are not as strong as suppliers can recover up to the revenue cap regardless of the demand being lower than forecasted. This can be done, for example, by charging higher prices or reducing costs by not pursuing new connections.

3.260 We consider for reasons discussed above, a WAPC gives suppliers a stronger incentive to improve efficiency to maintain or improve profitability, in line with s 52A(1)(a) and (b).

3.261 Our risk allocation principle is also relevant to our draft decision.[185] Under that principle, we ideally allocate risks to suppliers or consumers depending on who is best placed to manage them. Managing risks includes:

3.261.1 where possible, taking actions to influence the probability of risks eventuating;

3.261.2 taking actions to mitigate the costs of occurrence; and

3.261.3 having the ability to absorb the impact where it cannot be mitigated.

3.262 Having regard to this principle, we consider that suppliers can mitigate the cost and/or absorb the impact on profitability of the demand risk by adjusting their expenditure (opex and capex).[186] GDBs are better placed than consumers to manage the consequences of forecast error (the difference between forecast and actual quantities supplied) rather than the actual change in demand. Exposure to this risk gives suppliers increased incentives to spend efficiently.

3.263 Vector, First Gas and Powerco submitted that a revenue cap would better deal with the quantity forecasting risk that was raised as a significant issue in the submissions on our Process and Issues paper.[187] The suppliers stated that there is a significant quantity forecasting risk in the current environment which provides a strong disincentive for efficient investment.

185 We describe our risk allocation principle and how it works with the Part 4 purpose in Commerce Commission “IM Review 2023 - Decision-making Framework paper” (13 October 2022), para 4.12-4.19.

186 Suppliers can also manage risks through capital contribution policies and payback period policies.

187 See for example First Gas Limited “Submission on IM Review Process and issues paper and draft Framework paper” (13 July 2022), p. 20, section 4.4.1. and Vector “Submission on the Process and issues paper” (11 July 2022), p. 14; Powerco – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 7.

3.264 Despite the quantity forecasting risk, we consider a WAPC would better promote the Part 4 purpose compared to a revenue cap. We consider GDBs (under a WAPC) are better placed than consumers (under a revenue cap) to manage the risk and consequences of demand forecast error rather than the actual change in demand. Under the WAPC, suppliers are exposed to manageable risk that is likely to provide stronger incentives to invest and operate efficiently than a revenue cap. Under a WAPC GDBs can, to some extent, manage the demand risk by adjusting spending on opex and capex.[188]

3.265 GDBs can also manage connection numbers (influence demand through connections and reconnections), but not volumes from existing connections.

3.266 We acknowledge that quantity forecasting under a WAPC could become more difficult in the short-to-medium term due to the uncertainty regarding the uptake of emerging technologies (eg, repurposing gas pipelines to carry hydrogen/low carbon gases), or users switching to using electricity instead of gas, and the resultant impact on gas volumes.

3.267 We also note that revenue caps do not eliminate the need for demand forecasts. When assessing expenditure, we are implicitly assessing suppliers' own forecast of demand. Long-term demand forecasts will be necessary for assessing economic network stranding and whether it is appropriate to mitigate the risk through changes to assets and/or the depreciation method.

3.268 While a WAPC exposes suppliers to demand (quantity forecasting) risk, we do not consider there is a risk of GDBs not investing in the network as a result of our choice of form of control.[189]

Price stability and tariff restructuring

3.269 A WAPC provides consumers with more price stability within period, on average, but a higher likelihood of between-period instability if large revenue corrections are needed.[190]

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[188] Suppliers can also manage risks through capital contribution policies and payback period policies.

[189] In addition to the form of control, our regulatory approach incentivises investment, including by adhering to the principle of ex-ante financial capital maintenance (FCM), which provides an expectation of earning a 'normal return'. Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022).

[190] As we noted in Commerce Commission " Input methodologies review decisions - Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016), para 65, price stability is a factor consumers tend to value.

3.270 A change to a revenue cap would shift some demand risk (ie, price volatility) to consumers within each regulatory period and would likely result in lower between-period price stability.

3.271 We are not aware of any evidence that shows a WAPC creates problems about tariff restructuring or efficient pricing for GDBs.

3.272 We consider that it is unlikely that GDBs might restructure tariffs to the same extent that EDBs can. For EDBs, moving to a revenue cap removed potential compliance barriers for suppliers to restructure their tariffs to be more efficient. By contrast, the ability to store gas through the line pack of distribution networks means that introducing peak charging signals is less valuable in gas than electricity.[191]

Consistency with the GTB form of control

3.273 Some suppliers submitted that the WAPC is inconsistent with the approach to the form of control for the GTB.

3.274 We note that consistency with the GTB form of control is not persuasive under our Framework if it does not result in the revenue cap better achieving the IM Review overarching objectives as the form of control for GDBs. We have no evidence that it would do so.

[191] First State Investments "Input Methodologies Review: Form of Control" (24 March 2016).

Growing demand through new connections

3.275 Some suppliers submitted that the WAPC provides incentives to grow demand through new connections, which is no longer relevant in the transition to net zero emissions. While demand for gas is expected to decline in the longer term, for the reasons outlined above, we consider promoting incentives to invest efficiently (for example, in ensuring the safety and reliability of a network) is important while gas is still used. We consider a WAPC form of control is better suited to this than a revenue cap.

Topic 3f – Financeability test in the IMs

Draft decision

3.276 Our draft decision is to not adopt a financeability test in the IMs.

Problem definition

3.277 In the IM Review process to date several suppliers have submitted that we should adopt a financeability test in the IMs. Their submissions have been accompanied by expert reports.

Stakeholder views

3.278 In their submissions on our Process and Issues paper, our draft IM Review Decision-Making Framework paper, and on the report by Cambridge Economic Policy Associates Pty Ltd on aspects of the cost of capital IMs (CEPA report), several suppliers recommended we adopt a financeability test in the IMs.

3.279 This section summarises the main points submitters made to us on this matter.[192] This section only covers suppliers' view that we adopt a financeability test in the IMs to use when setting a price path. It does not address specific IM policy decisions and mechanisms that may be relevant to the financeability of regulated services.

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192 In response to Commerce Commission "IM Review 2023 - Draft Framework paper" (20 May 2022), some suppliers (eg, Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 11; Vector "Cross-submission on IM Review Process and issues paper, and draft framework paper" (3 August 2022), para 22) also advocated the addition of a new key economic principle in the IM Review framework in the form of a financeability test. We do not revisit those submissions in this paper as we commented on them in deciding against adopting a new key economic principle in Commerce Commission "IM Review 2023 - Decision-making Framework paper" (13 October 2022).

3.280 In response to our Process and Issues paper and draft IM Decision-Making Framework paper, Aurora, the ENA, Powerco, Vector, and WE* all advocated for the introduction of a financeability test, for example, to enable an EDB to finance obligations imposed under price-quality regulation and decarbonisation – in line with equivalent tests from overseas jurisdictions.[193],[194]

3.281 In particular, Vector requested an amendment to the IMs to provide for such a financeability test, arguing that doing so "would better support the Part 4 purpose by ensuring regulated businesses can finance their networks efficiently."[195]

3.282 Transpower cross-submitted "EDBs emphasised that the principle of "financeability" should be applied in the IMs. If material changes are made to the IMs that affect regulated businesses' ability to finance investment, then we support consideration of introduction of a financeability test."[196]

3.283 In response to the CEPA report, the ENA referred us to a report from NERA and submitted that "the enablement of the electrification and decarbonisation of the New Zealand economy will result in increased expenditure by EDBs. [197] The funding of this expenditure will put pressure on EDBs' cash flows." The ENA recommended:[198]

3.283.1 we incorporate financeability tests into the regulatory regime as a cross-check to ensure the internal consistency of our credit rating assumptions with the revenue allowance for the benchmark efficient entities; and

193 See Aurora, "Commerce Commission Part 4 Input Methodologies Review 2022 - Process and issues paper" (11 July 2022),para 47; Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 11; Powerco – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022)),p. 2; Vector, "Vector submission on IM review 2023: Draft Framework Paper" (11 July 2022), para 130-133; Vector "Cross-submission on IM Review Process and issues paper, and draft framework paper" (3 August 2022), para 22-23; and Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 11.

194 As examples of financeability tests, Aurora, above n 193, at n 47, pointed us to the duties imposed on Ofgem by section 3A of the Electricity Act 1989 (UK) and section 4AA of the Gas Act 1986 (UK). Section 2 of the Water Industry Act 1991 (UK) imposes a similar duty on Ofwat. When the Infrastructure Pricing and Regulatory Tribunal (**IPART**) determines prices under its regulatory regime, it tests the ability of the regulated business to finance its ongoing operations using non-statutory financeability tests that IPART has developed, applied, and reviewed in 2018.

195 Vector, "Vector submission on IM review 2023: Draft Framework Paper" (11 July 2022), para 130.

196 Transpower, "Input Methodologies Review 2023: Cross submission – Draft Framework Paper and Process and issues paper" (3 August 2022), p. 2.

197 NERA "Financeability considerations under the DPP" 'Appendix D -Submission on IM Review CEPA report on cost of capital' (report prepared for Electricity Networks Association, 16 January 2023).

198 ENA, "Rate of Return Issues – Submission on IM Review CEPA report on cost of capital" (3 February 2023), p. 20.

3.283.2 the cross-check should adopt the quantitative metrics used by rating agencies S&P Global Ratings and Moody's and be conducted at each price-quality determination and review of the IMs.

3.284 Vector recommended introducing a financeability assessment in line with the approach set out in Oxera Consulting LLP's (Oxera) report for six EDBs.[199] Vector contended that:

> it would be a perverse outcome if a regulated businesses could not, in practice, fund an efficient investment programme allowed under the regulatory framework. We consider introducing a formal financeability assessment in the IMs would defend against this. This would support the Part 4 purpose by–
>
> Supporting the ability of regulated business to innovate and invest and support efficiency gains. We note cashflow and financing issues could result in inefficient deferrals that would otherwise result in higher costs to consumers over time.
>
> Supporting stakeholder, including investor, confidence that the regime is delivering appropriate outcomes for regulated businesses and consumers.
>
> "Supporting regulated businesses to obtain financing on efficient terms thereby reducing financing costs to consumers.

3.285 NERA for the ENA noted several considerations under price control regulation that could create financeability concerns, notably using benchmark costs of debt, inflation indexation of the RAB, and adoption of incentive regulation (rather than a cost pass-through regime). NERA considered two specific features of the Part 4 regime could also lead to financeability concerns: use of alternative X-factors and the within-period limit on annual revenue increases. NERA noted three environmental factors that could further raise financeability concerns: high inflation, low interest rates, and increased capex needs.[200]

3.286 NERA therefore advocated we:[201]

> implement financeability testing as the benefits to consumers of implementing financeability testing outweigh the costs. In particular, the costs are trivial as the [Commission] already has the information needed to calculate the core financial ratios used by Moody's and S&P (we have done so using the [Commission's] financial models as part of preparing this report);
>
> [financeability testing] should focus on the benchmark efficient firm represented by the [Commission's financial models, as this ensures the NZCC's decisions are internally

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199 Vector "Submission on IM Review CEPA report on cost of capital" (3 February 2023), p. 5, referring to Oxera "Review of the NZ Commission's WACC setting methodology" 'Submission on IM Review CEPA report on cost of capital' (report prepared for 'Big Six' EDBs, 3 February 2023).

200 NERA "Financeability considerations under the DPP" 'Appendix D -Submission on IM Review CEPA report on cost of capital' (report prepared for Electricity Networks Association, 16 January 2023), p. 1.

201 Ibid, pp. 2-3.

consistent and focuses the financeability conversation on the levers that the [Commission] controls;

should conduct financeability testing during IM reviews under s 52Y and DPP resets, as these are the points in time when we make decisions that may impact financeability; and

focus the financeability test on quantitative metrics used by credit agencies, replicating the rating methodology used by credit rating agencies.

3.287 Oxera for the six EDBs considered the "assessment of financeability is a critical component of ensuring that a price control is in the public interest, given the potentially significant costs to users (and society) if the company experiences financial distress or it lacks the ability and the incentives to make efficient investments."[202] In Oxera's view, "the introduction of a financeability test is timely, as decarbonisation requires higher levels of electrification of the economy. Any delays to this, which might be caused by insufficient funding, could have material adverse impacts on New Zealand's ability to achieve net zero by 2050." Oxera suggested the following considerations for us when deciding how to implement financeability tests:[203]

Deciding whether its assessment should be based on a notional or actual company. We consider that a notional approach is appropriate, but the [Commission] may also want to ensure that any networks whose capital structures depart from the notional company are still financeable, at least during a period of time when the [Commission] considers the actual companies may be adjusting their capital structures to match the notional company. Accordingly, financeability assessment could be based on a notional company basis but informed by market evidence such as the EDBs' actual capital structures.

Deciding on what credit rating to target. The [Commission] currently considers bond yields rated BBB+ for its debt premium assessment. This is consistent with the assumed credit rating for regulated networks in the UK and Australia; the [Commission] may consider this an appropriate benchmark rating.

Deciding which metrics to use to assess the credit rating, and what benchmarks to apply to them. Depending on the comprehensiveness of its financeability assessment, the [Commission] may want to consider a large or small number of financeability metrics. It may then be appropriate for the NZCC to use benchmarks that match those used by the credit rating agencies. It may also be appropriate for the [Commission] to exercise some judgement in aiming for more than a narrow passing of financeability tests, as a narrow pass could indicate that if market conditions change by a small amount, an EDB could face higher debt costs.

202 Oxera "Review of the NZ Commission's WACC setting methodology" 'Submission on IM Review CEPA report on cost of capital' (report prepared for 'Big Six' EDBs, 3 February 2023), p. 53.

203 Ibid, pp. 61-62.

Proposed solution – no financeability test in the IMs

3.288 We do not consider adopting a financeability test in the Part 4 IMs would achieve our IM Review overarching objectives. This is because we do not need a test in the IMs to consider financeability, so it is unnecessary. We can already consider, and indeed have previously considered, financeability where relevant and not inconsistent with promoting the Part 4 purpose. [204,205]

3.289 We first outline our understanding of financeability and then explain our reasoning for not adopting a financeability test in the IMs.

3.290 'Financeability' refers to the ability of regulated suppliers to, under certain assumptions and conditions, raise and repay capital in financial markets readily and on reasonable terms.

3.291 While all suppliers can in principle raise debt and equity, their ability to do so in practice will depend on their specific circumstances.

3.292 We consider that an efficient supplier operating under our benchmark assumptions is very unlikely to face financeability issues, given the way our regulatory accounting is consistent with real NPV=0 over the expected life of the assets. There would need to be a specific change in operating conditions to result in a situation where a supplier would face difficulties maintaining the benchmark leverage and credit rating.

3.293 We note that 'ability' to invest is not the same as 'incentive' to invest. The potential inability to invest can be caused by a range of factors, which may result in the supplier operating in a way that is inconsistent with the benchmark operating assumptions. Examples include poor performance of unregulated business units, or financial management decisions such as excessive dividend payments (over which the supplier has control), or excessive leverage.

3.294 The ability to raise capital depends, among other things, on the availability of cash at points in time. This in turn broadly depends on the time profile of capital recovery (ie, the return of capital, or regulatory depreciation).

3.295 However, as noted above, we do not need to adopt a financeability test in the IMs to be able to consider financeability. We may already consider financeability where doing so is relevant and not inconsistent with promoting s 52A.

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[204] Commerce Commission, "Decision on Aurora Energy's proposal for a customised price-quality path" (31 March 2021).

[205] We may factor in financeability as part of setting alternative rates of price changes for DPPs, CPPs and IPPs, or in any other context if this is relevant to achieving the s 52A purpose.

3.295.1 To provide a practical example of this: in setting Aurora's customised price-quality path (CPP), submissions on our draft decision raised concerns that the amount of revenue deferred through our smoothing approach would lead to a financeability issue.[206] We assessed this in terms of the impact that our decision would have on Aurora's forecast net cashflow compared to Aurora's original CPP application. This approach differed to focusing on the change in revenues because we considered the change in net cashflows was a better indication of Aurora's ability to finance its business.

3.296 We note that a practical challenge in testing a regulated suppliers' ability to raise capital is that financeability relates to the whole firm (eg, credit rating, or ability of the firm to service debt), while we cannot monitor or address financeability issues arising from the supply of unregulated goods and services.[207]

3.297 If we decided that considering financeability would be relevant and not inconsistent with promoting s 52A in a particular context, then we could have regard to the thresholds of minimising "any undue financial hardship to the supplier" or "price shock to consumers", where appropriate.[208]

3.298 In considering financeability, we would expect to assess a range of factors, including:

3.298.1 to the extent relevant, the characteristics of the benchmark (efficient) firm in terms of target credit rating and financeability metrics, and the actual firm;

3.298.2 the likelihood and costs of potential underinvestment (harm to consumers' long-term benefit under s 52A);

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206 Commerce Commission, "Decision on Aurora Energy's proposal for a customised price-quality path" (31 March 2021), at paras G146-G150.

207 As examples of financeability tests, Aurora, pointed us to the duties imposed on Ofgem by section 3A of the Electricity Act 1989 (UK) and section 4AA of the Gas Act 1986 (UK). Section 2 of the Water Industry Act 1991 (UK) imposes a similar duty on Ofwat. When the Infrastructure Pricing and Regulatory Tribunal (IPART) determines prices under its regulatory regime, it tests the ability of the regulated business to finance its ongoing operations using non-statutory financeability tests that IPART has developed, applied, and reviewed in 2018.

208 s 53P(8)(a) of the Commerce Act. We note the principles issued by the AEMC in Australia, that the AER must follow in assessing requests to vary depreciation. See Australian Energy Market Commission "Final Report - Transmission planning and investment - Stage 2" (27 October 2022), p. 11.

3.298.3 the likelihood and cost of bankruptcy, while noting that acquisition of poorly performing suppliers may better promote s 52A (including impact on consumers and the efficiency of prices) than frontloading cashflows; and

3.298.4 the likelihood and magnitude of additional sources of finance.

Chapter 4 Our approach to incentivising efficient expenditure for EDBs and Transpower

Purpose and structure of this chapter

Purpose of this chapter

4.1 This chapter outlines our draft decisions on the IMs affecting the incentives that EDBs and Transpower have to make efficient expenditure decisions under their price-quality paths. This is especially important in the context of increased investment and spend, where efficiency and cost savings in the provision of electricity lines services will help with the affordability of electricity bills (see Chapter 2 for the context in which we are making our decisions).

4.2 In this Chapter we outline our draft decisions, our reasons for them, and the alternative approaches that we have considered in reaching them.

We have assessed whether our approach to expenditure incentives applied in price-quality paths is fit for purpose

4.3 Many of the submissions in response to our May 2022 Process and Issues Paper provided feedback on our approach to expenditure incentives. In response to submitter feedback on incentive mechanisms we have reviewed our current approach to expenditure incentives and how we could evolve our approach as part of the IM Review.

4.4 Our draft decision is that the current expenditure incentives (opex and capex IRIS mechanisms for EDBs, and the opex IRIS and capex incentive schemes for Transpower, applied with a building blocks framework) promote the objectives of the incentive schemes and our IM Review overarching objectives but require targeted improvements. These improvements are discussed later in this chapter.

4.5 We reviewed the effectiveness of expenditure incentives applying in price-quality paths by:

4.5.1 reviewing the objectives for our expenditure incentives, including whether their importance has changed in light of the changing energy landscape; and

4.5.2 assessing our current approach to providing expenditure incentives including the current mechanisms in place, and alternative approaches, in terms of how each approach promotes the incentive scheme objectives and our IM Review overarching objectives.

We sought stakeholder feedback on our approach to expenditure incentives

4.6 To better understand the issues of stakeholders and assess possible solutions, we undertook a series of consultations and engagements on a range of topics related to expenditure incentives.

4.7 In Table 4.1 below we list key documents we shared with stakeholders.

Table 4.1 Key documents related to expenditure incentives

Title	Description	Link
Part 4 Input Methodologies Review 2023 – Process and Issues paper (20 May 2022)	Chapter 5 discusses incentive mechanisms to improve expenditure efficiency for EDBs and Transpower under price-quality regulation.	Link
Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach -Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs' (1 November 2022)	We considered the potential implications of a capex bias and how our expenditure incentives could resolve this issue, including an overview of the current expenditure incentive mechanisms.	Link
Forecasting and incentivising efficient expenditure for EDBs – Infrastructure Regulation Branch Online workshop (7 November 2022)	We sought feedback on the online workshop which discussed the potential for capex bias, the opex and capex IRIS mechanisms and a potential totex approach.	Link
IRIS equivalence staff discussion paper (22 November 2022)	We discuss the incentive strength equivalence of the current opex and capex IRIS mechanisms.	Link
Electricity Distribution Business IRIS Equivalence Model Final Version (22 November 2022)	Model to demonstrate the equivalence of the current opex and capex IRIS mechanisms (read in conjunction with the discussion paper above).	Link
Incentivising efficient expenditure – Questions regarding totex, IRIS and innovation – For use by external stakeholders (22 November 2022)	Questions for stakeholders related to the expenditure incentive mechanisms and the potential capex bias.	Link

Structure of this Chapter

4.8 In this chapter we explain:

4.8.1 how our regulatory regime incentivises expenditure;

4.8.2 our draft decision to keep using the current suite of expenditure incentive schemes for EDBs and Transpower as tools for mitigating capex bias, after considering alternative approaches to mitigating capex bias (including a totex approach);

4.8.3 our draft decision to keep the current suite of expenditure incentive mechanisms for EDBs and Transpower after considering alternative expenditure incentive mechanisms;

4.8.4 our draft decisions for specific changes to EDBs' current expenditure incentive schemes to improve their working and application; and

4.8.5 our draft decisions for specific changes to Transpower's current expenditure incentive schemes to improve their working and application.

Summary of our draft decisions

4.9 The tables below summarise our draft decision and the main policy reason for that decision. The analysis behind the draft decision and reasoning why the decision promotes the overarching objectives of our IM Review framework is detailed in the body of the Chapter.

Table 4.2 Draft decisions on the approach to expenditure incentives

Topic	Draft decision	Reason	Applicable to
Topic 4a – Maintain the current expenditure incentive schemes as tools for mitigating capex bias	Keep the current suite of expenditure incentive schemes for EDBs and Transpower as tools for mitigating capex bias due to financial regulatory incentives. Do not adopt a totex approach.	We consider that the current expenditure incentive mechanisms (with the changes we are proposing in this topic paper) appropriately mitigate capex bias.	EDBs, Transpower
Topic 4b – Maintain the current incentive mechanisms as they best balance considerations of effectiveness and understandability	Continue to apply the opex IRIS and capex incentive mechanisms (do not adopt a different incentive mechanism).	Compared to other approaches assessed, we consider that the current expenditure incentive mechanisms better meet the incentive scheme objectives.	EDBs, Transpower

Table 4.3 Draft decisions applying to current expenditure mechanisms

Topic	Draft decision	Reason	Applicable to
Topic 4c – Adjust IRIS allowances for inflation	Change the approach to set inflation-adjusted IRIS allowances (based on actual CPI) for the purposes of calculating opex and capex incentive amounts.	Removes economy-wide inflation from the calculation of incentive amounts.	EDBs, Transpower
Topic 4d – Maintain our approach to setting incentive rates	Do not provide for setting the opex incentive rate at a price-quality reset.	Maintaining a five-year retention period for the opex IRIS balances uncertainty for suppliers and the outcomes expected in competitive markets.	EDBs, Transpower
Topic 4e – Not to exclude specific expenditure categories from IRIS	Do not provide for the ability to exclude certain expenditure categories from IRIS at a price-quality reset.	Introduces further complexity to the mechanism and does not align with our view on setting incentives at an aggregated level (where over- and underspends are already shared with consumers and there will be upsides and downsides across total expenditure).	EDBs, Transpower
Topic 4f – Use the midpoint discount rate in the opex IRIS calculation	Change our approach to use the midpoint vanilla WACC as the discount rate for estimating the opex incentive rate (rather than using the 67th percentile vanilla WACC).	A discount rate without an explicit uplift is likely to be the best estimate of suppliers' internal discount rate.	EDBs, Transpower
Topic 4g – Maintain our current treatment of operating leases	Make no changes for the treatment of operating leases under the IRIS mechanism.	The treatment of these right-of-use assets was considered in detail previously, and no new evidence has been provided.	EDBs, Transpower
Topic 4h – Make no change to IRIS for undercharging	Make no change to IRIS for suppliers that undercharge their MAR.	Suppliers can continue to voluntarily undercharge their MARs and consider the IRIS implications.	EDBs, Transpower
Topic 4i – Remove the Transpower baseline adjustment term	Remove the baseline adjustment term (IBAT) for Transpower's opex incentive calculation.	Transpower's IBAT has led to significant uncertainty and may negatively impact on Transpower's incentives to achieve efficiency and is unnecessary based on Transpower's expected forecasting approach.	Transpower

How the regulatory regime incentivises efficient expenditure

4.10 This section outlines our approach to setting expenditure incentives for suppliers that are subject to price-quality regulation.

4.11 The purpose of our expenditure mechanisms is to incentivise efficiency, substitutability between expenditure types, and prudent investment and expenditure decisions for suppliers, through the sharing of efficiency gains between suppliers and consumers, consistent with promoting the Part 4 purpose.

4.12 Under a generic revenue cap, suppliers are incentivised to reduce costs below the expenditure allowances. However, without explicit expenditure incentive mechanisms, several issues can arise that detriment the long-term interests of consumers. For example, there may be bias towards capex over opex even if the capex lifetime costs are greater. This is why we have the current expenditure incentive mechanisms for EDBs and Transpower.[209]

4.13 Our expenditure incentive mechanisms are a key part of our regulatory regime that incentivise a range of benefits to consumers which helps promote all limbs of the purpose of Part 4 set out in s 52A. The objectives of the expenditure incentive mechanisms include:

4.13.1 providing equal incentive rates for opex and capex spend;

4.13.2 consistent incentive rates to make efficiency savings over time;

4.13.3 tailoring incentive rates and the extent efficiency gains are shared between suppliers and consumers; and

4.13.4 removing incentives under a revenue cap to inflate costs in some key years.

[209] See Attachment B of our expenditure incentive paper for an overview of the current expenditure incentive mechanisms applying to EDBs and the why we have these mechanisms. Commerce Commission "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach - Staff working paper to inform 7 November 2022 workshop ‘Forecasting and incentivising efficient expenditure for EDBs’" (1 November 2022), Attachment B.

4.14 The priority of these objectives of the expenditure incentive mechanisms has changed since the last IM Review.

4.14.1 We made the decision at EDB DPP3 to equalise the capex incentive rate (which is set at a price-quality path reset) with the opex incentive rate (which is a result of the carry-forward period in the IMs).[210] The changes we made at DPP3 were intended to achieve neutral financial incentives between opex and capex (and as such provide significant flexibility on how much opex and capex suppliers could incur, while within their maximum allowable revenue).[211]

4.14.2 An important reason for introducing the IRIS mechanisms was to provide for consistent incentive rates over time, and this is still a significant benefit of the mechanisms. However, we now consider that providing for equal incentives between opex and capex is an increasingly important outcome we want to achieve through the expenditure incentive mechanisms, as this removes barriers to non-traditional solutions that can lead to lower lifetime costs to consumers. This is particularly essential given that the scope for opex/capex trade-offs is expected to substantially increase.

4.15 The expenditure incentive mechanisms are a key component of our regulations for price-quality regulated EDBs and Transpower. This makes it more important that we assess whether the current mechanisms promote the Part 4 purpose better than alternatives.

4.16 We consider that our current mechanisms work well against the objectives of an expenditure incentive mechanism, but there is room for some technical refinements which we discuss later in this chapter.

4.17 In feedback to our Process and Issues Paper, several distributors said that the DPP3 changes had not achieved the objective of neutralising financial incentives between opex and capex within a regulatory period.

210 See below for a further description of how the current incentive mechanisms work.

211 In the DPP3 decision paper we explained that to ensure distributors have a consistent incentive to spend both opex and capex and do not favour capital solutions over operating expenditure solutions, the DPP3 decision equalised the capex IRIS and opex IRIS incentive rates.
Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision" (27 November 2019), para X81.

4.18 We received feedback in response to our engagement with stakeholders after the 7 November 2022 workshop. Most suppliers that responded to our opex-capex equivalence demonstration model generally agreed that IRIS works as intended in providing neutral regulatory financial expenditure incentives within regulatory periods. Some submitters remain of the view that equivalence, does not apply. We respond to some of these submission points further in Topic 4a and Attachment B.

4.19 Wellington Electricity noted that while there is equivalence within a regulatory period but for certain expenditure trade-offs across regulatory periods this may not hold. Our proposed solution to this point is discussed in Chapter 6.

4.20 There is an interaction between the approach to setting expenditure allowances, flexibility mechanisms during a regulatory period (such as reopeners) and the expenditure incentive mechanisms. Taken together, we consider that our overall package of draft decisions work to produce the outcomes for consumers that achieve our IM Review overarching objectives. Based on this, we have made the proposed adjustments to the expenditure incentive mechanisms to provide for these outcomes.

4.21 For an overview of the how the expenditure incentive mechanisms work for EDBs, see our earlier staff working paper (which includes references to previous IRIS decisions).[212]

4.22 For background on Transpower's expenditure incentive mechanisms, see Table 4.4 below.[213]

212 Commerce Commission "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach - Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs'" (1 November 2022), Attachment B.

213 Note that Transpower's opex IRIS is the same as the EDBs DPP IRIS mechanism, except that it has an additional adjustment term (the Transpower baseline adjustment term).

Table 4.4 Relevant links for Transpower incentive mechanisms

Expenditure type	Document	Link
Capex	Transpower capex input methodology review – Decisions and reasons (29 March 2018) Chapter 2: Incentive mechanisms	Link
Opex	Transpower Individual Price-Quality Path from 1 April 2020 – Companion paper to final RCP3 IPP determination and information gathering notices (14 November 2019) Chapter 4: Determining the IRIS differences in penultimate year amount and baseline adjustment term for RCP3	Link
Opex	Input methodologies review final decision – Transpower Incremental Rolling Incentive Scheme (29 June 2017)	Link

Key themes from stakeholder feedback

4.23 Stakeholder feedback has been valuable in understanding key areas of concern related to the expenditure incentive mechanisms. We are proposing to progress some of the stakeholder suggestions in our draft decisions as part of the IM Review. We intend to consider other stakeholder suggestions in our price-quality and information disclosure regulation processes.

4.24 The key themes from stakeholders during the process up to our draft decisions included:

4.24.1 a total expenditure (totex) approach is a possible way to address capex bias due to financial regulatory incentives and to increase flexibility between opex and capex;

4.24.2 the current scope for opex/capex trade-offs and any capex bias due to regulatory financial consideration is likely limited. However, the scope for efficient opex/capex trade-offs across regulatory periods is expected to increase;

4.24.3 suggestions to make the expenditure incentive mechanisms easier to understand;

4.24.4 ex-ante allowances are not fit for purpose when uncertainty is increasing and when some types of expenditure are outside of suppliers' reasonable control;

4.24.5 our expenditure incentive mechanisms do not support efficient opex/capex trade-offs across regulatory periods;

4.24.6 some stakeholders are concerned about the impact of IRIS incentive amounts on supplier cashflows; and

4.24.7 various other technical refinements to the current expenditure incentive mechanisms.

Topic 4a – Maintain the current expenditure incentive schemes as tools for mitigating capex bias

4.25 Investment in electricity lines services is expected to significantly increase to enable the electrification and decarbonisation of New Zealand. Electricity distributors expect to increasingly rely on non-network alternatives and alternative solutions (often involving opex). While the current scope for opex/capex substitution is limited in practice, it is expected to significantly increase over the next decade.

4.26 In the context of rising investment and an increasing scope for efficient substitution between opex and capex, we want to ensure that financial regulatory incentives do not distort investment decisions.

Draft decision

4.27 Our draft decision is to keep the current suite of expenditure incentive schemes for EDBs and Transpower as tools for mitigating capex bias due to financial regulatory incentives.

Problem definition

4.28 Several submissions in response to our May 2022 Process and Issues Paper suggested we address capex bias (which we discuss in this section) and simplify the regulatory approach to expenditure incentive mechanisms (which we discuss in the next section in Topic 4b).[214] We shared our emerging views on the potential for a capex bias and potential solutions in the 7 November 2022 expenditure incentives workshop and sought feedback on those views.

Expenditure type neutral financial incentives

4.29 When addressing a ‘pole and wire’ investment need, electricity distributors generally choose from a set of ‘pole and wire’ options – for example, the modern equivalent of an end-of life asset. Economic regulators generally require electricity distributors to consider non-network alternatives such as purchasing demand response rather than augmenting network capacity.

[214] For EDBs, we have opex and capex incremental rolling incentive schemes (IRIS). For Transpower, we have an opex IRIS and a capex incentive scheme. For gas, we do not have explicit expenditure mechanisms (ie, the natural financial incentives under a revenue cap apply).

4.30 Given the important role electricity lines services have in supporting decarbonisation through electrification, the sector has, for some time, been considering how to evolve from a traditional (and largely passive) distribution network to a more complex network that meets diverse needs. Technological progress and innovation are changing the options available to distributors to meet investment needs.

4.31 If alternatives to traditional 'pole and wire' solutions can deliver services at a reduced whole-of-life-cost, while also providing a quality of service that reflects consumers demands, then it would be in the long-term interest of consumers if suppliers adopt them.

Capex bias due to financial regulatory incentives

4.32 In the box below we set out how we define capex bias.

Figure 4.1 What we mean by capex bias

We define 'capex bias' as arising where the regulatory approach to setting price-quality paths financially incentivises investment in assets (capex) over alternatives, such as demand response (opex), where those alternatives are more efficient.

We do not use the term 'capex bias' to refer to situations where favouring a traditional network solution over a non-network alternative results in greater net benefits to consumers. Efficient solutions are those that minimise the whole of life-costs while delivering the quality that customers demand, in line with s 52A(1)(a), (b), and (d)).

4.33 There are many possible sources that may result in businesses (inefficiently) preferring capex over opex aside from any financial incentives created by the regulatory regime, such as organisational culture.[215] As regulated businesses face limited or no competitive constraints, there is greater scope for inefficiency. However, our aim is for the regulatory regime to provide neutral financial incentives and enable efficient opex/capex substitution, helping to mitigate capex bias.

Why we are considering this issue now

4.34 We sought further information on the current and future scope for opex/capex substitution after the 7 November 2022 expenditure workshop. Stakeholders generally indicated that there is currently limited scope for opex/capex substitutions but that they expect opportunities to grow over time.

215 Some of these sources are discussed in Commerce Commission "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach - Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs'" (1 November 2022)

4.35 Powerco submitted that:[216]

> We've so far committed to around [commercially sensitive] opex per year, offsetting around $4m of capex.
>
> It is early days for estimating the long-term balance. Differentiating between a permanent vs temporary role of an opex alternative is key too. One way to approximate it is to assume around 10% of peak demand can be met using opex solutions. For Powerco that would translate to an opex figure of around $10 - $20m per year (based on 1GW peak demand) and offset around $400m of capex. For comparison, this opex is equivalent to 10%-20% of annual opex.

4.36 Wellington Electricity submitted that its early modelling indicates that:[217]

> flexibility could save $200-300m from deferring capex expenditure. The exact amount will depend on the customer price point for participating in flexibility services and participation rates.

4.37 In the context of increasing investment and scope for efficient substitution between opex and capex, there is the potential for significant and growing harm due to capex bias. This could come from the current building blocks approach resulting in businesses preferring capex solutions when opex solutions would be more efficient due to financial regulatory incentives.[218]

Capex bias is most relevant for non-exempt electricity distributors

4.38 We consider that issue of capex bias is most relevant for non-exempt electricity distributors, ie, those subject to both PQ and ID regulation under Part 4. In their most recent asset management plans, many non-exempt distributors have signalled significant increases in investments over the next (10-year) planning period to enable the electrification and decarbonisation of the economy, including by investing ahead of demand rather than just-in-time.

4.39 Emerging, non-traditional solutions (involving opex) may play a more significant role in reducing the cost of electrification and decarbonisation of electricity distribution services than for electricity transmission or gas pipeline services.

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216 PowerCo "Submission on Expenditure incentives EDB workshop" (6 December 2022).

217 Wellington Electricity "Submission on Expenditure incentives EDB workshop" (6 December 2022).

218 The regulatory approach to setting price-quality paths for EDBs includes the use of building blocks-based regulation with separate allowances for opex and capex, expenditure incentive schemes (eg, opex and capex IRIS for EDBs), and the provision of a WACC uplift.

4.40 The scope for detailed regulatory scrutiny (ex-ante or ex-post) is smaller under a DPP. Due to significant information asymmetries and limitations of the tools we use to keep costs low, DPPs require simplifying assumptions that are not necessarily well suited to detecting capex bias.[219]

4.41 While electrification and decarbonisation are also important for Transpower, the additional scrutiny under an IPP is better suited to detecting capex bias. Stakeholders' (including Transpower's) views on capex bias are discussed from paragraph 4.50.

4.42 In the 2016 IM Review, we decided not to implement an IRIS for opex or capex for GTBs or GDBs under a DPP, and we removed the existing opex IRIS applying to CPPs for GPBs. At that time, we considered that the benefits from implementing a capex and opex IRIS for gas pipeline services were unlikely to outweigh the costs.[220]

Proposed solution

4.43 Our draft decision is to keep the current suite of expenditure incentive schemes for EDBs and Transpower as tools for mitigating capex bias due to financial regulatory incentives.

4.44 From a regulatory approach viewpoint, this means maximum allowable revenues for the DPP/CPP will continue to reflect a building block approach with separate allowances for opex and capex, complemented by our current expenditure incentive schemes for opex and capex.

4.45 From suppliers' viewpoints, it means they can continue to make expenditure decisions as they see fit, subject to complying with the price-quality path. We use expenditure allowances to set regulatory revenue, and these expenditure allowances are fungible.

4.46 However, we understand some suppliers may treat the opex and capex allowances as key inputs to their budgeting decisions. In Attachment B, we explain how suppliers treating opex and capex allowances as budgets may prevent our expenditure incentive mechanisms from working as effectively as they otherwise would.

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[219] As we noted in our staff working paper, while capex bias has been the subject of many studies, to our knowledge it has not been possible to obtain good empirical evidence on capex bias. Commerce Commission "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach - Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs'" (1 November 2022), para 12.

[220] Commerce Commission "Input methodologies review decisions, Consolidated Reasons paper" (20 December 2016), p. 15.

4.47 Our draft decision reflects our view that our current tools for mitigating capex bias due to regulatory financial incentives — our current expenditure incentive schemes — are effective and better promote the Part 4 purpose than the alternative solutions we have considered. We provide further information on our expenditure incentive mechanisms, including their effectiveness in ensuring opex/capex equivalence within regulatory periods at paragraphs 4.3 to 4.22.

4.48 The followings decisions are related to the Topic 4a draft decision:

4.48.1 Topic 3b – implications of IRIS for cashflow timing;

4.48.2 Topics 4b to 4i in this chapter;

4.48.3 Topic 6b – Encouraging innovation and non-traditional solutions; and

4.48.4 the WACC percentile draft decisions, discussed in Chapter 6 of the Cost of Capital topic paper.[221]

4.49 Submitters have indicated that the scope for opex capex trade-offs is expected to increase. On this basis, the potential inefficiency due to capex bias (if any) may increase. This may be an area where more targeted assessments of capitalisation practices and opex/capex trade-offs (as part of our summary and analysis of information disclosures under s 53B(2)(b)) may help inform whether the regime is providing expenditure-neutral incentives.[222]

Stakeholder views: capex bias under current expenditure incentive schemes

4.50 Several submissions in response to our May 2022 Process and Issues Paper suggested a totex approach as a possible way to address capex bias due to financial regulatory incentives. They also considered that totex would increase submitters' flexibility to substitute between capex and opex under a revenue allowance.

4.51 For example, the ENA submitted:[223]

> While the current (highly complex) IRIS, in theory, achieves parity of incentives between opex and capex, ENA believes there is value in the Commission examining the comparative benefits of a totex approach.

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221 Commerce Commission "Part 4 Input methodologies Review 2023 - Draft decision - Cost of capital topic paper" (14 June 2023).

222 We note that analysis of capitalisation is a focus of analysis for the AER. Australian Energy Regulator "How the AER will assess the impact of capitalisation differences on our benchmarking - Draft Guidance note" (October 2022).

223 Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 10.

4.52 Orion submitted that it:[224]

> believes there is a bias toward Capex over Opex. This is not because EDBs do not want to implement Opex solutions. However, commissioned asset additions to the RAB drives the return of and on capital which is as [building blocks allowable revenue] and ultimately the [maximum allowable revenue]. The IRIS impacts of Opex spending is also more sizeable whether in the favour of the customer or the EDB. The decarbonisation transition toward net zero will be better served by EDBs having incentives to invest in Opex solutions e.g. non-network alternatives, digitisation delivered through the cloud, customer-oriented flexibility services. The effect of the IRIS may also be to drive up debt funding for EDBs to meet customer connection pace and extent of decarbonisation. […] We strongly believe the time has come for a Totex approach.

4.53 The Boston Consulting Group report recommended that: [225]

> [the] CAPEX bias is continued to be removed. We recommend adopting a TOTEX approach as employed by OFGEM in the UK. Until a TOTEX approach is implemented, we recommend adjusting the base-step-trend OPEX spend assessment to include adequate forward-looking considerations, accounting for factors like increased cyber security costs and non-network solutions.

4.54 In our November/December 2022 consultation we shared our capex bias problem definition. Submitters generally agreed with our problem definition. However, Vector submitted:[226]

> We would not characterise the key issue as 'capex bias' but the need for greater flexibility between opex and capex allowances. Investment plans can change within a DPP period so greater flexibility is necessary to ensure EDBs can implement the most efficient solutions with the most up to date information.

4.55 We also sought to better understand whether capex bias arises due to shortcomings with our current expenditure incentive schemes.

4.56 In response to our engagement, Orion, Powerco, and Wellington Electricity and Nera on behalf of the big 6 EDBs submitted that the opex and capex IRIS provide for equivalence and hence opex/capex substitutability within regulatory periods.[227]

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224 Orion "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 74.

225 Boston Consulting Group "The Future is Electric – A Decarbonisation Roadmap for New Zealand's Electricity Sector" (October 2022), p. 188.
We note that expenditure allowance setting is a matter for price-quality regulation rather than input methodologies. However, while we consider it is appropriate to consider the merit of allowing specific step changes at the next DPP reset, we disagree that a change in the *level* of ex-ante expenditure allowances can be expected to effectively mitigate capex bias due to regulatory financial incentives. The marginal incentive to capitalise costs likely remains unchanged following an uplift in fungible expenditure allowances.

226 Vector "Submission on Expenditure incentives EDB workshop - Attachment A" (6 December 2022), para 7.

227 Powerco "Submission on Expenditure incentives EDB workshop" (6 December 2022); Orion "Submission on Expenditure incentives EDB workshop" (6 December 2022); Wellington Electricity "Submission on

4.57 Vector, Wellington Electricity and Nera on behalf of the big 6 EDBs also raised the lack of equivalence in certain opex/capex substitution across regulatory periods as an issue. We discuss this issue in Chapter 6 (Topic 6b).

Stakeholder views: introduce totex approach to address capex bias under current expenditure incentive schemes

4.58 We received limited support for the option to use a totex approach as a tool to mitigate capex bias. We discuss this alternative solution further below.

4.59 Horizon Networks submitted that:[228]

> Horizon Networks will not support any solution that moves away from following GAAP for regulatory reporting purposes.
>
> [..]
>
> Horizon Networks considers it critical that any TOTEX solution does not require EDBs to alter their actual accounting practices or inputs into the RAB or non-IRIS regulatory disclosures.
>
> Horizon Networks strongly opposes any move away from GAAP. Moving away from GAAP would result in inefficient and poor business decisions. Our business and investment decisions rely on clear, accurate accounts in order to measure and understand the impact of the actions we are considering. Such a change would also change comparability with prior periods already disclosed under existing Information Disclosure regulations.

4.60 Transpower submitted in response to our process issues paper, and reiterated this view in its submission in response to our 7 November 2022 workshop:[229]

> We consider that, as demonstrated in Great Britain, that a totex incentive can simplify the overall incentive regime, and ensure incentives are equalised across capex and opex. However, for Transpower there is a material cost of shifting away from our GAAP-based RAB. A wholesale shift from the current arrangements should be carefully considered and not rushed into.

4.61 Vector and Horizon in response to our November/December 2022 consultation submitted that capex and opex are not necessarily substitutable regardless of the equalized incentive rates.[230] Vector submitted:

> We consider capex and opex are not substitutable.

Expenditure incentives EDB workshop" (6 December 2022); NERA Economic Consulting "Innovation under the DPP - potential barriers and solutions" (report prepared for 'Big six' EDBs, 20 December 2022)

228 Horizon Energy Group "Submission on Expenditure incentives EDB workshop" (8 December 2022)

229 Transpower NZ Ltd "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022)

230 Horizon Energy Group "Submission on Expenditure incentives EDB workshop" (8 December 2022), p. 5; Vector "Submission on Expenditure incentives EDB workshop" (6 December 2022), para 13.

> Regardless of the equalized incentive rates, an EDBs actual spend on opex and capex in a particular year will have an impact. If an EDB is close to overspending its opex allowance and has more room in its capex allowance it will be incentivized to choose a capex solution to avoid an IRIS penalty.

4.62 We discuss these submissions further in Attachment B.

Alternative solution considered: totex approach

4.63 In response to our Process and Issues Paper, some submitters suggested investigating the merits of a totex approach. A key problem a totex approach is intended to address, as implemented by Ofgem (in regulating the UK energy sector) and by Ofwat (in regulating the England and Wales water sector), is capex bias.

What we mean by 'totex approach'

4.64 As discussed in our staff working paper, when we say 'totex approach', we mean the approach to setting revenue allowances adopted in the UK by Ofgem and Ofwat. The key feature of this approach is the absence of a distinction between opex and capex in setting ex-ante regulatory revenue allowances and when recognising actual costs: revenue allowances and incurred costs are based on totex.

4.65 A fixed share of totex is 'capitalised', and the remainder is expensed. The regulator sets the fixed share upfront for the duration of a regulatory period. We note that while other regulators have adopted totex for aspects of their regulatory regime (eg, benchmarking), to our knowledge, only Ofgem and Ofwat have adopted a fixed opex-capex-share approach.[231]

4.66 The use of a fixed opex-capex-share removes a potential distortion in behaviour that may arise due to direct financial incentives inherent in the regulatory approach.[232] Whichever solutions the business adopts, and however much their costs may differ from the underlying (implicit) opex and capex allowances, all expenditure gets split according to the fixed opex-capex-share.

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231 For a summary of European regulators' approaches, refer to CEER "Report on Regulatory Frameworks for European Energy Networks 2021" (31 January 2022). The Italian Regulatory Authority for Energy, Networks and Environment (ARERA) is considering the adoption of a UK style totex approach. Oxera "Methodology review for a regulatory framework based on a total expenditure approach ('ROSS-base')" (Report prepared for ARERA, December 2021).

232 Carlotta von Bebenburg & Gert Brunekreeft & Anton Burger. "How to deal with a CAPEX-bias: fixed OPEX-CAPEX-share (FOCS)," (2022), Bremen Energy Working Papers 0039, Bremen Energy Research.

4.67 A totex approach would not eliminate all sources of capex bias. Even if adopted, there may still be obstacles to businesses increasing their efficient use of non-network/flexibility solutions as alternatives to network investments. For example, a totex approach does not address the potentially greater performance uncertainty of procuring from a third party, which may lead a business to prefer capex to opex solutions (as noted in paragraph 13.3 of the staff working paper).[233] We note that IRIS similarly does not address this issue.

4.68 Implementing a totex approach would require significant changes to several of the IMs and consequential changes under PQ and ID regulation. For further information on the totex approach, refer to chapters 3 and 5 of the staff working paper.[234]

Experience with totex approach in other jurisdictions

4.69 We also considered experience in other jurisdictions and have also considered the wider context for those regulatory choices.

4.70 Our regime is unique in its use of default/customised-price-quality regulation. The most comparable approach to our regulation of EDBs is AER's regime. The AER also provides for separate expenditure incentive schemes. The AER and the AEMC considered adopting a totex approach in 2017/2018.[235] Since then, the AER has chosen to evolve its existing opex/capex- based building block regimes rather than pursue a totex approach.[236]

4.71 Ofgem and Ofwat chose to implement a totex approach as a means of addressing capex bias in the investment of large, privately owned utilities that are likely to be highly focused on profit maximisation. Ofgem and Ofwat made these changes alongside a range of other changes to encourage businesses to innovate and focus on solutions rather than regulatory finance implications flowing from accounting categorisations of expenditure. For example, Ofgem's decision to adopt a totex approach for Ofgem's network price controls 2013-2023 (RIIO-1) may have been why electricity distributors became financially indifferent between capex and opex solutions.

233 Commerce Commission "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach - Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs'" (1 November 2022).

234 Commerce Commission "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach - Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs'" (1 November 2022).

235 We understand that part of the AER's decision for continuing with an opex/capex-based approach were the constraints under their statutory framework.

236 For details on the AER's most recent decision on its incentive schemes refer to: Australian Energy Regulator "Review of incentives schemes for networks - Final decision" (April 2023).

4.72 However, the increase in innovation in the UK energy sector over the last 10 years is likely attributable to a combination of moving to a totex approach, innovation incentives and other factors; not just a single change such as the move to a totex approach.

4.73 Ofgem (and Ofwat) moved from a situation of suspected capex bias — a regime that did not have any equivalent of our current opex and capex IRIS with equal incentive rates — to a totex approach.[237] It is not possible to determine the change that would have occurred had there already been expenditure incentive schemes in place similar to ours.

4.74 Other relevant context that impacts the relevance of Ofgem's and Ofwat's experience to Part 4 includes:

4.74.1 Ofgem's approach to setting expenditure allowance placed significant reliance on comparative benchmarking of opex to set expenditure allowances. In practice, this asymmetry in regulatory expenditure scrutiny between opex and capex meant that businesses tended to favour capex to opex solutions and sought to reclassify operating to capital costs in their regulatory accounts, to appear relatively more cost efficient in benchmarking assessments.[238]

4.74.2 Ofgem's regulatory asset value (RAV) does not reflect a detailed underlying financial asset register consistent with GAAP (unlike under Part 4). The use of an aggregate approach to RAV meant that a change in regulatory approach was relatively straightforward to implement.

[237] In the regulatory period prior to adopting a totex approach (DPCR5) Ofgem had modified its approach to capitalisation, with all companies having a fixed percentage of their total network costs capitalised into the asset base and the rest being expensed in year. This was intended to equalise the incentives on capex and opex and avoid distorting decision making.
Ofgem, "Handbook for implementing the RIIO model" (4 October 2010), para 12.20.

[238] Frontier Economics, "Total expenditure frameworks, A report prepared for the Australian Energy Market Commission" (December 2017), pp. 29-30.

4.75 In its recent decision, the Commission for Regulation of Utilities (CRU), the Irish energy regulator, decided to not adopt a totex approach for price-quality regulation applicable to two network companies for the period 2021 -2025.[239] CRU explained its decision as follows:[240]

> On the basis of regulatory certainty and maintaining regulatory precedent, the CRU does not consider it appropriate to move fundamentally from separate allowances for capex and opex. For example, the CRU does not consider it appropriate to move to a totex approach where there is one allowance that does not distinguish between capex and opex. This may come more relevant in future years. For now, the CRU may examine whether some features of a totex mechanism may be appropriate for PC5 as it did in its recent PR5 review.

4.76 We discuss the 'flexibility mechanism' the CRU adopted as another alternative solution considered at 4.89.

Longer term considerations

4.77 While our draft decision does not to provide for a totex approach, we consider that a change in mindset that has been attributed in UK to shift to a totex approach is also desirable for New Zealand infrastructure sectors:[241]

> Rather than a binary approach – totex, or not totex – it seems that the industry has moved on to a point where the question of totex has been absorbed in the much bigger issue of whole systems planning. That is to say, it's no longer just about whether to build a new asset or come up with another solution; rather, it's a question of looking holistically at the infrastructure system, cross-vector, and determining the best solution.

4.78 Our view is that this shift in mindset (and behavioural change) can be achieved in more than one way, including through application of our current expenditure incentive tools and appropriate scrutiny under price-quality and information disclosure regulation.

Applying our Framework to totex as means of addressing capex bias

4.79 The key question for this IM Review is: would moving to a totex approach better achieve our Framework's overarching objectives than the status quo in terms of addressing capex bias?

4.80 We apply our Framework to this question as follows.

239 Commission for Regulation of Utilities,"PR5 Regulatory Framework, Incentives and Reporting" (22 July 2020), p. 35.

240 Commission for Regulation of Utilities "Price Control 5 Strategy" (30 June 2021), p. 39.

241 Ellen Bennet "Has totex done it job?" (25 June 2019) Utility Week <www.utilityweek.co.uk>.

Promoting the Part 4 purpose in s 52A more effectively

4.81 A totex approach is theoretically appealing because the use of a fixed opex-capex-share (ex-ante and ex-post) neutralises a potential distortion in behaviour due to regulatory financial incentives. Once this fixed share is set, no matter what expenditure suppliers actually incur, only that fixed rate of totex may enter the RAB.

4.82 IRIS aims to achieves a similar outcome in neutralising capex bias that may otherwise arise due to regulatory financial incentives. However, if a supplier prefers capex (for non-regulatory reasons), then the supplier may implement capex solutions where possible (including where opex is more efficient than capex). In contrast, a totex approach likely removes such incentives (under a totex approach a supplier does not benefit from changing its expenditure mix: irrespective of the actual spend, only a fixed proportion enters the RAB).

4.83 We do not consider that adopting a totex approach at this time would likely better promote the Part 4 purpose than further refining our current approach to setting price paths. In particular:

4.83.1 the status quo IRIS operates as intended in addressing capex bias due to equalising financial regulatory incentives;

4.83.2 based on evidence from other jurisdictions (discussed above), and tailoring insights to our context, we do not consider there is strong evidence to suggest that a totex approach would be superior under our Framework in addressing capex bias; and

4.83.3 we do not have strong evidence of capex bias in New Zealand, although our limited assessment is based on historical data and does not consider the expected increase in scope of opex/capex substitution.[242]

4.84 For completeness, we note that neither our current expenditure incentive schemes nor a totex approach address the issue of opex/capex trade-offs across regulatory periods discussed in Chapter 6 (Topic 6b).

[242] Commerce Commission "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach - Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs'" (1 November 2022), para 16.

Promoting the IM purpose in s 52R more effectively (without detrimentally affecting the promotion of the s 52A purpose)

4.85 A significant change to IMs would be required to enable a totex approach. In the short term, uncertainty would increase compared to the status quo (noting that we do not consider this short-term increase in uncertainty is major factor in our draft decision: giving significant much weight to this matter over other overarching objectives may result in status-quo bias).

4.86 Longer term, the likely simpler approach to incentive mechanisms under a totex approach may increase certainty compared with the status quo but may require trade-offs with other objectives.[243] The main aspects of a totex approach (ie, the building blocks regulation, setting required parameters) have the potential to provide a similar level of certainty as the current IMs, although the chance of unexpected outcomes when changing to the new approach would be higher than in the current, well understood approach.

Significantly reducing compliance costs, other regulatory costs, or complexity (without detrimentally affecting the promotion of the s 52A purpose)

4.87 We do not have sufficient evidence that, compared to the current approach, a totex approach would better achieve our IM Review overarching objectives relating to ss 52A and 52R.

4.88 A totex approach would require new regulatory accounting rules and processes, in addition to the current rules and process, and would require significant investment by us, EDBs, and audit professionals.[244] Applying our third IM Review overarching objective of reducing compliance costs, other regulatory costs, or complexity; we consider adopting a totex approach would be significantly more costly (both from a financial cost and opportunity cost perspective) than retaining IRIS.

[243] We discussed Ofgem's totex incentive mechanism in appendix C of Commerce Commission “Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach -Staff working paper to inform 7 November 2022 workshop ‘Forecasting and incentivising efficient expenditure for EDBs’” (1 November 2022).

[244] Our current rules and processes generally reflect Generally Accepted Accounting Principles (GAAP). Refer to s 5 of the staff working paper for an overview of some of the implementation matters for ID regulation, price-quality regulation and input methodologies. Commerce Commission “IM review 2023: Incremental rolling incentive schemes equivalence staff discussion paper” (22 November 2022).

Alternative solution considered: 'flexibility mechanism'

4.89 Instead of adopting a totex approach as discussed at 4.64 above, the CRU adopted the 'flexibility mechanism' which allows a business to reallocate allowances between opex and capex (bi-directional).[245] This approach involves businesses proposing changes to their allowances, with ex-post scrutiny. CRU regulates two businesses (EirGrid and ESB Networks) and sets the equivalent of IPPs for these businesses.

4.90 The CRU's flexibility mechanism is mutually exclusive with the Part 4 approach that relies on expenditure incentive mechanisms. The CRU's approach is based on the regulator setting binding maximum allowances for opex and capex. The approach relies on the concept of 'regulatory budgets' for opex and capex, where the regulator applies scrutiny and therefore has a good understanding of suppliers' opex and capex plans for a regulatory period. The flexibility mechanism is the tool for taking certain items from one budget (eg, the 'capex budget') and instead 'moving' an item to another budget (eg, the 'opex budget').

4.91 In contrast, the DPPs for EDBs set fungible opex and capex allowances. When setting DPP regulatory revenue allowances, we do not scrutinise detailed expenditure plans, set budgets for opex and capex, or set expectations for the detailed outputs (eg, projects) a supplier is expected to deliver. Under a DPP, suppliers can use their expenditure allowances as they see fit, subject to complying with price-path requirements. In addition, the opex and capex IRIS provide for within-regulatory period substitutability between opex and capex.[246]

4.92 Setting aside the question of the suitability of a mechanism like the CRU's flexibility mechanism for a relatively low-cost DPP, applying such a mechanism in parallel with an opex and capex IRIS would likely create unpredictable expenditure incentives.

4.93 We considered whether the flexibility mechanism and associated an approach would be workable in the Part 4 DPP/CPP context. However, a high scrutiny 'propose-respond' approach such as the flexibility mechanism would not be consistent with the purpose of DPP/CPP regulation under s 53K.

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[245] Commission for Regulation of Utilities "Price Control 5 Strategy Information Paper" (30 June 2021), p. 39.

[246] We discuss our solution to improve incentives for cross-regulatory period expenditure trade-offs in Chapter 6.

Topic 4b – Maintain the current incentive mechanisms as they best balance considerations of effectiveness and understandability

Draft decision

4.94 Our draft decision is to keep the current approach to expenditure incentive mechanisms for EDBs (opex and capex IRIS) and Transpower (opex IRIS, base capex incentive scheme and major capex incentive scheme). We have considered alternative approaches that would simplify the approach to expenditure incentives but consider that the current approach better achieves our IM Review overarching objectives.

4.95 Our draft decision above should be taken together with the proposed IM changes discussed below to the existing expenditure incentive mechanisms to improve the effectiveness and certainty of the mechanisms, in line with the second and third IM Review overarching objectives.

Problem definition

4.96 The opex and capex IRIS schemes are by nature relatively sophisticated to address a range of potential issues and perverse incentives on suppliers. One of the key criticisms of the current expenditure incentive mechanisms is that they are complicated to understand and apply.

4.97 From discussions with EDBs, we consider that the understanding (and confidence IRIS works as intended) matters most at:

4.97.1 A strategic level: relevant decision makers at the business need to have confidence the approach works and communicate this to relevant people (eg, for EDBs subject to a DPP, they need to be confident that the year 2 IRIS calculations will provide the appropriate IRIS wash up amount for the previous regulatory period).

4.97.2 The investment decision stage: the person tasked with assessing network planning and preparing options analysis and recommendations, and the decision maker that chooses a preferred option, need to know how to take into account regulatory financial incentives in the investment appraisal.

4.98 In order to respond most effectively to the financial incentives that we provide, suppliers need to understand the incentive mechanisms. A lack of understanding could limit the effectiveness of the mechanisms in promoting the overarching objectives of the IM Review.

4.99 This section therefore assesses whether there are alternative approaches that could more simply achieve the objectives of the incentive schemes (outlined above in paragraph 4.13) and achieve our IM Review overarching objectives better than the current mechanisms. After making that assessment, we then discuss specific changes related to the current expenditure incentive mechanisms for price-quality regulated EDBs and Transpower.

4.100 We note that in our 'Staff working paper to inform 7 November 2022 workshop' we mentioned the idea of calculating incentives at a totex level (based on the separate opex and capex allowances) and assessing against actual totex to calculate the incentive amounts.[247]

Proposed solution

Stakeholder views

4.101 Some suppliers have called for the IRIS mechanism to be simplified to better allow suppliers to understand the impacts of their actions and respond to incentives more effectively. For example, Aurora states:[248]

> Aurora considers that the IRIS mechanism needs to be overhauled so that it is simpler to understand, and is able to inform network decision-making.

4.102 There have been some suggestions raised to simplify the incentive schemes, but no proposed changes to the high-level working of the mechanisms. Suggestions have mostly focused on ancillary tools within a price-quality path or alternative treatment for some types of expenditure to avoid going through the incentive mechanisms. For example, Wellington Electricity states:[249]

> We do not know of a better alternative to the IRIS. The focus should be on simplifying the current mechanism and using reopeners and pass-through costs to capture unexpected expenditure requirements (assuming the IRIS baseline is also adjusted to capture new expenditure).

247 Commerce Commission "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach - Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs'" (1 November 2022), Attachment C.

248 Aurora Energy "Aurora Energy – Submission on Expenditure incentives EDB workshop" (6 December 2022), para 15.

249 Wellington Electricity "Wellington Electricity – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 10.

4.103 However, Vector considers that the complexity of the current mechanisms are warranted to achieve the desired outcomes for consumers:[250]

> We accept that a level of complexity is likely inevitable for the mechanism to achieve desired outcomes (and improving the IRIS to e.g. allow better substitution between opex and capex may add further complexity). However, we support the Commission and stakeholders investigating ways to simplify the IRIS while still achieving desired outcomes. We don't consider simplicity should be prioritized over delivering better outcomes for consumers and stakeholders.

4.104 Powerco and Orion submitted that we should investigate the use of a totex-based incentive mechanism that could simplify the incentive scheme for stakeholders.

4.105 Orion states:[251]

> The IRIS mechanism serves its purpose in sharing benefits with consumers.
>
> Setting the DPP4 Opex and Capex allowances at a level which will ensure EDBs can maintain and replace assets is in the long-term interest of consumers.
>
> We therefore do not necessarily recommend removing the IRIS mechanism entirely. However, we recommend that targeting a totex "lite" approach by evaluating opex and capex together for IRIS would assist in simplifying the IRIS incentive for regulated businesses.

4.106 Powerco also supports considering a totex incentive scheme similar to Ofgem's. It also considers that the issues raised in our staff working paper are manageable:[252]

> The problems with the TIM appear to be manageable. As noted in the staff working paper, applying an incentive rate that increases over time can address the time-inconsistent natural incentive problem. While using multiple years as the 'base year' or changing how opex allowances are determined can remove the incentive to shift opex to the base year.
>
> A significant advantage of the TIM, relative to IRIS, is that it is simple to understand and apply, so EDBs are more likely to respond to the incentives.

Our view

4.107 We consider there have been no new 'simple' incentive mechanisms proposed in submissions or used by overseas regulators (that we are aware of) that would achieve our IM Review overarching objectives better than the current IRIS mechanisms.

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250 Vector "Vector – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 6.

251 Orion "Orion – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 10.

252 Powerco "Powerco – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 8.

4.108 The actual benefit of simplifying the incentive mechanism is unknown, including whether simplifying the mechanism encourages behaviour that achieves more efficiency savings. Simplifying the mechanism in a way that had the practical effect of undermining incentives and the achievement of the Part 4 purpose, for example, would be counterproductive.

4.109 Simplicity is not an objective of an expenditure incentive scheme. It does not necessarily have a benefit for consumers and may result in harm to consumers through timing of expenditure that is not efficient and substitution between expenditure types that may not occur (ie, choosing a capex solution that has a greater cost over the long term).

4.110 Effectively, the choice of approach comes down to whether we want a simplified mechanism that does not achieve the objectives of our current incentive schemes or retain the current mechanisms with some improvements (described in later sections). We are proposing to retain the mechanisms that promote the objectives of the incentive scheme, and better achieves our IM Review overarching objectives.

4.111 We acknowledge that IRIS is complicated and, as discussed at paragraph 3.117, certain detailed aspects can be difficult to understand intuitively. We intend to continue to engage with suppliers on clarifying the role of our incentive schemes and how they work, and better understand whether they achieve their objectives.

4.112 Maintaining the existing approach means we can build on suppliers' understanding of the regulatory regime developed over the last 10 years, and we understand that several EDBs have invested in assurance that the capex and opex IRIS work as intended and concluded that it generally does. We recognise that continued engagement between us and suppliers will be required to ensure that the schemes work as intended to the benefit of consumers (and suppliers).

Alternative approaches considered – Simplified incentive scheme

4.113 There have been some suggestions raised to simplify the incentive schemes, but no specific proposed changes to the high-level working of the mechanisms. As noted in the Wellington Electricity submission in paragraph 4.102 above, submitters did not provide an alternative to the current IRIS mechanisms but suggested the focus should be on reopeners and recoverable costs to capture expenditure uncertainty.

4.114 We looked at international regulatory precedent for applying expenditure incentives to see if there are other simple approaches that are being used and could better achieve our IM Review overarching objectives.[253] Some examples of expenditure incentives used by international regulators include:

4.114.1 The AER applies expenditure incentive schemes that are very similar to the opex and capex IRIS (Efficiency Benefit Sharing Scheme (EBSS) for opex and Capex Expenditure Sharing Scheme (CESS) for capex).[254] In a current review of the expenditure incentive schemes, the AER considers that the EBSS remains fit for purpose and proposes some adjustments to the incentive rates applying for the CESS (but retains the same approach for the CESS).[255]

4.114.2 The Economic Regulation Authority (ERA) of Western Australia applies a Gain Sharing Mechanism for opex, similar to the opex IRIS (savings are retained for five years regardless of the year the savings are made), while capex is not subject to an explicit incentive mechanism.[256, 257]

4.115 The treatment of opex incentives across the Australian regulators are consistent with our current approach (ie, carrying forward incentive amounts to ensure a consistent incentive rate). Ofgem's incentive mechanism for totex is simple and transparent but it does not seek to achieve the same objectives as IRIS and relies on the overall totex regime to resolve the substitutability between opex and capex spend.

4.116 The ability of other regulators to use cost efficiency benchmarking arguably allows for less emphasis on expenditure incentives to reveal efficient spending. However, this is not an option for us when resetting DPPs, so we rely on the opex IRIS (one of the objectives of the opex IRIS mechanism is to remove the incentives to inflate costs in the base year).

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253 Noting that there will be differences in statutory purpose, regulatory tools and expenditure forecasting approach that mean different regimes will benefit from different types of expenditure incentive mechanisms to promote consumer interests.

254 For an overview of the AER's current expenditure incentives, see the guidelines on its website.

255 AER "Review of incentives schemes for networks - Draft Decision" (December 2022), p. 5-7.

256 ERA "Framework and approach for Western Power's fifth access arrangement review - Final decision" (9 August 2021), s 7 and 8.

257 The ERA has an Investment Adjustment Mechanism for capex that adjusts target revenue in the next access arrangement period that corrects for any economic loss or gain due to differences between forecast and actual capital expenditure, taking into account inflation and the time value of money, for specific categories of capital expenditure. For more information, see ERA "Framework and approach for Western Power's fifth access arrangement review - Final decision" (9 August 2021), s 7.

4.117 We are not aware of another expenditure incentive mechanism that would be simpler to understand and apply but still provide the same benefits as the IRIS mechanisms, while better promoting the Part 4 purpose.

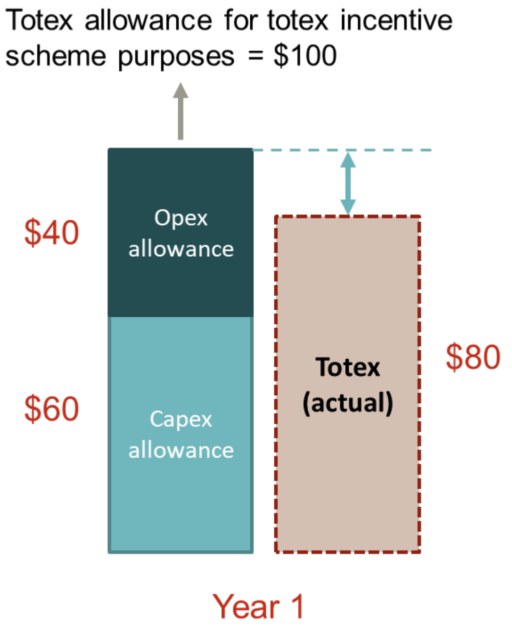
Alternative approaches considered – Totex incentive scheme (for incentive purposes only)

4.118 In our staff working paper we mentioned the idea of applying incentives at a totex level (based on the separate opex and capex allowances) and assessing against actual totex to calculate the incentive amounts (without implementing the Ofgem's full totex approach to setting expenditure allowance).[258] Below we refer to this approach as a 'totex incentive scheme'.

4.119 So, what do we mean by a totex incentive scheme? There is no single approach to setting up a totex incentive scheme and there are multiple ways to apply such a scheme. For example, we could apply the incentive calculation at a totex level year by year or over the total five-year period (similar to the current capex IRIS).

4.120 Figure 4.2 below provides an example of how a totex incentive scheme could apply (in this case on a year-by-year assessment).

Figure 4.2 Example of a totex incentive scheme



Under a totex incentive scheme:

- The outturn proportion of opex and capex do not matter for incentives, only total expenditure
- There are no carry forward amounts or adjustment terms, the mechanism simply looks at the allowance and outturn expenditure in a given year, applies the incentive rate to the difference to calculate the annual incentive amount

Assumptions in this example:

- Assume incentive rate of 50%

Incentive payment calculation example:

$= (allowance_{totex} - actual_{totex}) * incentive\ rate$

$= (\$100 - \$80) * 50\%$

= $10 retained by supplier

[258] In the staff working paper our analysis focused on a totex approach, Ofgem's totex incentive mechanism (the 'TIM') and how it compares to the current expenditure incentive schemes. Commerce Commission "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach - Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs'" (1 November 2022), Attachment C.

4.121 The main advantage of a totex incentive scheme is the simplicity of application. However, in meeting the objectives of an incentive scheme outlined in 4.13, the benefits of a totex incentive scheme are significantly reduced compared with applying an opex and capex IRIS:

4.121.1 incentives between opex and capex are not equalised;

4.121.2 there are not consistent incentive rates over time;[259] and

4.121.3 there are incentives to inflate expenditure in the base year.[260, 261]

4.122 Overall, a totex incentive scheme is unlikely to be able to meet the objectives of expenditure incentive mechanisms, noted above, like IRIS does. IRIS meets the objectives of an incentive scheme and compared to totex incentive schemes, would better achieve our IM Review overarching objectives by promoting all limbs of the Part 4 purpose for the long-term benefit of consumers.

4.123 Below we discuss how each of the following objectives of the expenditure mechanisms are not met by a totex incentive scheme.

Equal incentive rates between opex and capex

4.124 Without a totex approach for setting expenditure allowances (considered in topic 4a above), the benefits of applying incentives at a totex level are reduced. Under a totex approach, the incentives to prefer one type of expenditure over another would be neutralised (which is one of the objectives of an incentive scheme noted above).

4.125 However, this is not the case with just a totex incentive scheme where opex and capex are combined for the purposes of the incentive scheme. Frontier Economics notes in its discussion paper for Energy Networks Australia that without a move to a totex approach the same biases for preferring one type of expenditure would still be present by only applying incentives at a total expenditure level.[262]

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259 A simple incentive amount applying every year (no carry forwards) would result in suppliers being exposed to the 'natural incentive' for opex and capex.

260 This issue depends on how expenditure allowances are set. Assuming a base-step-trend approach to setting opex allowances is used without comparative benchmarking, under a totex incentive scheme suppliers may have greater incentives to shift opex into the base year to receive a greater allowance in the following period.

261 Many regulators, including Ofgem and the AER undertake efficiency benchmarking when setting the base year for expenditure allowances. Under s 53P(10) of the Act, we are not able to do so for a DPP, so the base year will be an issue when setting allowances.

262 Frontier Economics "Why Totex? Discussion paper" (24 July 2018), s 2.2.1.

4.126 A totex incentive scheme does not equalise incentives for opex and capex, which is one of the key outcomes of the current IRIS. We consider providing neutral incentive is important given the scope for opex solutions is expected to increase and we want suppliers to focus on efficient solutions.

Consistent incentive rate during a regulatory period

4.127 A totex incentive scheme can provide a consistent incentive rate for temporary (one-off) opex savings (excluding the base year used for applying the base-step-trend forecasting approach), but for other savings will not provide a consistent incentive rate.

4.128 This is because the incentive rate for permanent opex savings, capex savings and temporary savings in the base year will vary over the regulatory period. Assuming a 50 percent totex incentive rate, suppliers would retain 50 percent of the difference between the combined opex and capex allowance and total actual spend until the end of the period. That is, the incentive rate under a totex incentive scheme would effectively be 50 percent of the natural incentive rate.[263]

4.129 Therefore, the current opex and capex IRIS better meet the objective of providing consistent incentive rates over a regulatory period, which is tied to equalising capex and opex incentives and incentives to spend in specific years.[264]

Incentives to inflate expenditure in certain years

4.130 Under a totex incentive scheme suppliers would have the incentive to inflate costs in certain years to benefit in subsequent regulatory periods. That is without IRIS the use of a base-step-and-trend (BST) approach to expenditure forecasting would be problematic.

4.131 IRIS and the BST forecasting approach with a single base year are intrinsically linked. This is how we have forecast opex for setting DPP price-paths in the current and previous regulatory periods. While alternative approaches exist for forecasting opex in the context of a DPP (eg, multi-year average costs), the advantages and disadvantages in the context EDB DPP4 would need to be further assessed.

4.132 The benefit of the current IRIS mechanism is that it resolves this issue by providing a consistent incentive rate regardless of the year in which the saving is made.

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263 The incentive rates would vary depending on how we specified the totex incentive scheme but we would not be able to achieve consistent incentive rates without a rolling mechanism or totex approach for setting expenditure allowances.

264 A constant incentive rate is also consistent with how we set quality incentive schemes. This ensures consistency between expenditure and quality incentives for suppliers during a regulatory period. Differing incentive strengths between expenditure and quality incentives could result in perverse outcomes in the quality of service provided.

Specific changes to EDB expenditure incentive schemes

4.133 There have been issues raised with the current expenditure incentive mechanisms, including whether some types of expenditure should be exempt from IRIS, and technical points around the working of IRIS. We consider that our proposed changes improve the expenditure incentives on regulated suppliers and will continue to provide incentives that better achieves the overarching objectives of the IM Review.

4.134 We have summarised our draft decisions on the specific changes to the EDB expenditure incentive mechanisms in Table 4.3 above. We explain the reasoning for our draft decisions in more detail later in this section.

Topic 4c – Adjust IRIS allowances for inflation

Draft decision

4.135 Our draft decision is to calculate the opex and capex incentive amounts based on IRIS allowances (adjusted for actual CPI) compared with actual expenditure.

4.136 This would mean our updated approach would be as follows:

4.136.1 set nominal opex and capex allowances based on specific cost inflators at a DPP reset (for example, producer price index (PPI) and labour cost index (LCI) for opex, capital goods pricing index (CGPI) for capex);

4.136.2 deflate IRIS allowances using forecast CPI to calculate the allowances in real terms; and

4.136.3 wash up for actual CPI ex-post to calculate the allowance to compare with actual spend.

Problem definition for this issue

4.137 IRIS allowances are currently set in nominal terms. This means that suppliers are exposed to economy-wide inflation for calculating incentive amounts. Although there is an inflation revenue wash-up as part of the overall revenue path, the fact that IRIS opex amounts are carried forward for five years means that in the subsequent period suppliers will bear any amounts due to inflation (all else equal) as carry-forward amounts. This will result in an over-compensation or over-penalisation of incentive amounts due to inflation.

4.138 This is likely to be a more significant issue for opex compared with capex (as opex savings and overspends are carried forward) and the revenue inflation adjustment washes up inflation assuming that all costs are impacted by economy-wide inflation (proxied by CPI).

4.139 If outturn inflation differs from forecast inflation at the reset:

4.139.1 Revenue throughout the regulatory period is washed-up for unexpected CPI inflation. We do this to maintain the purchasing power of suppliers' allowed revenue.

4.139.2 However, the current IRIS mechanism assumes all components of operating costs are controllable and, while revenue throughout the current regulatory period is adjusted via the wash-up mechanism, a part of the revenue adjustment that relates to operating costs is reversed in the next regulatory period. This happens because the revenue allowance for the next regulatory period is set using operating costs that incorporate the positive or negative incentive adjustments from IRIS that are carried forward.

4.140 Specifically, the IRIS mechanism operates in the following way.

4.140.1 The IRIS allowance is fixed for a regulatory period in nominal terms (although there are reopeners during the period).

4.140.2 If costs vary from the allowance, the IRIS mechanism results in either a positive or negative incentive adjustment.

4.140.2.1 If costs are lower than the allowance, the difference is a positive incentive adjustment (carried for a total of six years) which increases the operating cost building block (and therefore MAR) for the next regulatory period.

4.140.2.2 If costs are higher than the allowance, the difference is a negative incentive adjustment carried for a total of six years) which reduces the operating cost building block (and therefore MAR) for the next regulatory period.

4.141 In the situation where inflation has caused operating costs to be higher than expected, the supplier will not achieve the real rate of return set in the WACC.

4.141.1 nominal revenue in the current regulatory period will be higher due to the revenue-washup mechanism (it will be constant in real terms);

4.141.2 nominal operating costs will be higher due to economy-wide inflationary pressures (they will be constant in real terms);

4.141.3 nominal revenue in the next regulatory period will be lower due to the carry-forward negative incentive adjustment associated with the IRIS mechanism; and

4.141.4 overall, net revenue in (real) present value terms will be lower than expected at the reset.

4.142 The opposite occurs in the situation where inflation has caused operating costs to be lower than expected.

4.143 Particularly in the current high inflation environment, it is important to consider who is best placed to bear inflation risk, including in relation to IRIS amounts.

Proposed solution

4.144 Our draft decision is to calculate the opex and capex incentive amounts based on IRIS allowances (adjusted for actual CPI) compared with actual expenditure. This will remove the impact of economy-wide inflation on incentive amounts for opex and capex.

Stakeholder views

4.145 The ENA notes the impact of high inflation on IRIS carry-forward amounts:[265]

> The global inflationary environment is driven by factors external to EDBs and New Zealand more broadly. While beyond EDBs' control, this general cost inflation has resulted in EDBs effectively being punished by the current IRIS scheme, as non-controllable cost increases are deemed to be an inefficiency that EDBs must carry forward.

4.146 Additionally, the ENA suggests that the IRIS mechanism should be changed to reflect that inflation is outside of EDB's control:[266]

> IRIS should apply only to those costs that can be controlled by EDBs. This is implicitly recognised by the existing cost pass-throughs for some opex costs, including transmission charges, rates, and insurance. No such mechanism exists for capex. The post-pandemic input cost spike demonstrates that the IRIS punishes EDBs for factors beyond their influence.

4.147 Horizon also submitted on the impacts of inflation on IRIS:[267]

> Most recent inflation figures have annual inflation sitting at 6.9%, materially higher than the current default price path (DPP3) forecast inflation. This impacts Horizon Network's ability to operate and maintain the network because actual OPEX costs outstrip the OPEX allocated under the DPP leading to IRIS penalties in future.

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265 Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 9.

266 Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 10.

267 Horizon Networks "Horizon Network – Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 21.

Our view

4.148 We have considered whether the IRIS allowance should be washed-up for the difference between expected and actual inflation. The positive or negative incentive adjustment would then be calculated by comparing actual operating costs to the IRIS allowance corrected for actual inflation. This is the approach that we currently apply to Transpower's base capital expenditure adjustment.

4.149 We note the Australian Economic Regulator and Economic Regulation Authority have IRIS-type allowances that are set in real dollars.[268,269] An option is therefore to calculate the IRIS allowance in nominal terms, as we do now, but convert it to real dollars using the CPI inflation forecast. The IRIS allowance would be set in real terms (rather than nominal), and the calculation of positive or negative incentive adjustments would be calculated based on inflation-adjusted allowances (where nominal operating costs are converted to real operating costs using actual inflation).

4.150 The advantage of a 'real' IRIS mechanism is that suppliers would no longer be exposed to economy-wide inflation risk that they cannot control. Relatedly, this would improve the 'signal to noise' ratio of the incentive scheme, which can make it clearer what incentives the businesses are facing and the link between spending decisions and outcomes.

4.151 We also note that our current approach to setting the IRIS allowance is consistent with the NPV=0 principle based on the assumption that inflation forecasts are unbiased.[270] However, the unexpectedly high inflation has resulted in large negative incentive adjustments from IRIS. While these may eventually be offset by positive incentive adjustments during periods of unexpectedly low inflation, the IRIS mechanism in its current form can result in volatility in revenues.

4.152 We note that under the current approach, the present value benefits to suppliers from reducing costs below the IRIS allowance is approximately 24 percent of the total benefit over the life of the saving; with the remainder of the benefit flowing to consumers through lower prices. These shares would not change if the IRIS allowances are set in real rather than nominal dollars.

4.153 Overall, we consider that our proposed decision to set the IRIS allowances in real terms will contribute to protecting suppliers from uncontrollable economy-wide inflation risk where they cannot manage this risk.

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268 For an illustration, see the Gain Sharing Mechanism for Western Power's access arrangement, at s 7.4.

269 For an illustration, see the Operating Expenditure Efficiency Carryover Mechanism for Jemena's access arrangement, at s 12.

270 For more information see Martin Lally "Review of further WACC issues" (22 May 2016), s 3.3.

4.154 A complication associated with washing-up the IRIS allowance for inflation is that it is not possible to clearly distinguish between the costs suppliers can control and the costs they cannot control. We currently calculate the ex-ante nominal opex IRIS allowance for PQ-regulated EDBs by taking the real IRIS allowance and inflating it by a combination of the PPI and LCI. These are proxies for the expected cost pressures that affect operating costs of an EDB, and the values are decided at a PQ reset (and this method is not prescribed in the IMs).

4.155 We can therefore either wash up for the same inflators used to set the nominal price-path (eg, PPI and LCI for opex) or for general inflation (CPI). This is discussed in the 'alternatives considered' section below.

4.156 Our draft decision is to update the opex and capex IRIS allowances based on CPI primarily because this ensures consistency with the revenue inflation wash up (which is based on CPI). This approach keeps everything consistent in real terms based on CPI and ensures that suppliers are not exposed to economy-wide inflation which they cannot control.

Alternative solutions considered

4.157 As noted above, the alternative approach that we considered was still changing to real IRIS allowances, but washing up for specific cost inflators (eg, generally we have used a mixture of PPI and LCI for setting nominal opex allowances and CGPI for capex allowances) rather than CPI. Therefore, instead of washing up for CPI, we could wash up for the specific cost inflators used to set the nominal allowances.

4.158 On the surface this seems appropriate because we would be washing up for how we are setting the nominal forecasts which we consider best reflect opex and capex in the future. However, as noted above, this would be inconsistent with how we treat inflation at the revenue level.

4.159 The revenue wash up assumes that general inflation (CPI) will be reflected in all costs (including opex and capex), which is outside of suppliers' control, so is washed up for.

4.160 We could change the revenue wash up (which currently washes up CPI at a revenue level) to instead wash up for specific cost inflators (eg, LCI or PPI) and the proportion of overall revenue impacted depending on proportion of opex and capex. However, this change would introduce significant complexity and inconsistency with other parts of the regime.

4.161 Also, as previously noted, these cost inflators are proxies for forecast cost changes into the future which may or may not represent actual costs of suppliers. We consider that using these specific cost inflators to forecast a nominal allowance and then using CPI to wash up for economy-wide inflation is the best approach.

Topic 4d – Maintain our approach to setting incentive rates

Draft decision

4.162 Our draft decision is to not change our current approach to the opex incentive rate being determined through the IMs. We discuss our consideration to allow for setting incentive rates as at a PQ reset and instead retain the opex incentive rate being set through the IMs for EDBs and Transpower.

Problem definition for this issue

4.163 Currently, the opex incentive rate (which is a function of the length of retention period, ie, the length of time that over which incentive amounts are held by the business, and the WACC as the discount rate) is determined by the IMs. This means that the opex incentive rate changes based on the external economic environment between regulatory periods, and we do not have control over the strength of this rate at a PQ reset.

4.164 By holding the retention period constant, as the discount rate changes between regulatory periods, so does the incentive strength, and the extent to which efficiency gains (or losses) are shared between suppliers and consumers. This could potentially lead to suppliers anticipating a change in one direction and therefore being inefficiently incentivised or disincentivised to make savings or overspends.

4.165 An option to address this issue could be to shift the length of the IRIS retention period from the IMs (where it is currently defined as five years) to the DPP/ IPP reset decision. This would enable us to tailor incentive rates for opex at a PQ reset, allowing us to control incentive rates based on the objectives at the time. The capex incentive rate is currently already determined at the PQ reset.

4.166 However, this may not provide for consistent incentive rates across regulatory periods (as the WACC and retention period would now change between periods) and would introduce uncertainty to suppliers.

4.167 We noted our intention to investigate moving some of the working of the IRIS mechanism from the IMs to a price-quality path reset in our Process and Issues paper.

Proposed solution

4.168 Our draft decision is not to allow for setting incentive rates as at a DPP reset and instead retain the opex incentive rate being set through the IMs for EDBs.

Stakeholder views

4.169 In response to our Process and Issues paper statement around providing for the incentive mechanism and/or incentive rate in a price-quality determination, Transpower states:[271]

> we are concerned that if incentive rates are uncertain or subject to change between resets it could impact on incentives to innovate and improve efficiency; and encourage a focus on efficiency improvements that can be made within a shorter (within RCP) time-period.

Our view

4.170 We consider that the status quo of retaining a retention period of five years for the opex IRIS mechanism will promote the Part 4 purpose and balance uncertainty to suppliers and changes in the external environment.

4.171 The benefits of retaining the fixed five-year retention period for the opex IRIS are that this:

4.171.1 reflects the natural incentive strength if a supplier were to make a saving or overspend at the beginning of a five-year regulatory period;

4.171.2 can reflect competitive markets in that suppliers will be able to benefit from savings for a period of time and the discount rate will change over time (ie, the effective retention of savings over time would vary with the discount rate); and

4.171.3 is the approach that suppliers have become accustomed to for the working of the mechanism, a change could further complicate understanding.

4.172 In addition, we note that a retention period of five years is consistent with the strength of the incentive that is applied by the AER.

4.173 The current approach will result in different discount rates between regulatory periods. However, this reflects that the financial environment will change over time and the discount rate (and incentive rate) will change with this.

Alternative solutions considered

Setting the opex incentive rate at a PQ reset

4.174 Given the expected uncertainty in forecasts for future DPP resets, increasing flexibility at the reset to set an opex incentive rate that promotes the Part 4 purpose at the time could be explored. The capex incentive rate is already set at a DPP determination, but in DPP3 was set equal to the opex incentive rate.

271 Transpower "Transpower NZ Ltd – Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2021), p. 31.

4.175 This would mean the incentive strength decision would be made at the time of the DPP reset rather than fixed in the IMs. This would enable us to decide at the reset whether we want higher or lower incentive strength (through varying the retention period) relative to the current five years based on prevailing market conditions, recent historical EDB performance, technological changes, etc.

4.176 The downside of this approach would be the uncertainty associated with it. Suppliers will not know in advance what the incentive strength will be (though we could consult on it as part of the DPP process) and there could be greater volatility in incentive strength from one regulatory period to another.

4.177 However, the current IM settings mean that the incentive rate for opex already changes between regulatory periods with changes in the discount rate, while the capex incentive rate is currently set independently at a PQ reset.

4.178 To partially mitigate this uncertainty, we could have an IM criterion for when we change incentive rates between regulatory periods and/or provide for a range of incentive rates.

Fixed opex and capex incentive rates in the IMs

4.179 An alternative approach could be to 'fix' the opex and capex incentive rates over time based on an exogenous number in the IMs. With the current rolling opex mechanism, this would require varying the carry-forward period to ensure that the resulting incentive rate is equal to our fixed value.

4.180 The certainty around the retention of savings over time could promote efficient behaviour (compared with incentive rates that change between regulatory periods) but would limit our flexibility to tailor incentive rates if we consider that incentives are too weak or strong.

4.181 While this would provide consistency in incentive rates between regulatory periods, there would also be practical issues:

4.181.1 if the retention period (to fix the incentive rate) was shorter than the length of the regulatory period, then the natural incentive would be greater than the incentive scheme, resulting in an incentive rate that is not consistent over the full retention period; and

4.181.2 arguably, having different retention periods between overlapping regulatory periods could further complicate an already complicated mechanism (this would be the retention length changing between periods as opposed to the incentive rate changing).

Fixed capex incentive rate with varying opex rate

4.182 A different option would be fixing the capex incentive rate in advance in the IMs while allowing the opex incentive rate to vary over time with the discount rate based on a set retention period. This is currently applied by the AER which keeps its capex incentive rate constant (at 30 percent based on a real WACC of 6 percent) while the discount rate changes over time, leading to differing relative incentives between opex and capex.

4.183 CEPA for the AEMC discusses this issue:[272]

> …the 30% sharing factor estimated for the EBSS is based on a 6% discount rate, used to estimate the share of opex savings in perpetuity. If the discount rate is lower, the sharing factor decreases (approximately 25% with a real discount rate of 5%). Therefore, if considering the benefits to NSPs from longer lived solutions, they retain more of the benefits from the 30% ex ante capex sharing factor compared to a 25% in perpetuity opex sharing factor.
>
> This is an important point as the WACC (discount rate) does change over time, and there is no guarantee that it will be 6% real at each determination.

4.184 We would not recommend that approach as it could lead to differences between the fixed capex incentive rate and variable opex rate (depending on the discount rate). We consider that ensuring equivalence between opex and capex incentive rates is the main benefit of the current expenditure incentive scheme and promotes efficient investment in line with s 52A(1)(a) and (b).

Topic 4e – Not to exclude specific expenditure categories from IRIS

Draft decision

4.185 Our draft decision is to not change our current approach of applying the expenditure incentive mechanisms to all categories of opex and capex allowances. We discuss our consideration to allow for setting expenditure categories being excluded from the incentive schemes to be decided at a PQ reset.

Problem definition for this issue

4.186 An issue raised in submissions is which expenditure categories should be subject to expenditure incentives. There may be an argument for some expenditure categories that are less controllable or uncertain to be excluded from IRIS.

4.187 Based on our view of the uncertainty in forecast expenditure requirements and the appropriate risk allocation between consumers and suppliers at the time of a DPP or CPP reset, we may want certain expenditure types to be subject to different incentives.

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[272] Cambridge Economic Policy Associates (CEPA) "Expenditure incentives faced by Network Service Providers - Final report" (25 May 2018), p. 52.

4.188 Some types of expenditure are already treated this way, via pass-through and recoverable costs (for example, the innovation project allowance). However, these are recovered outside of the smoothed Building Blocks Allowable Revenue (BBAR).[273] Large expenditure categories being treated as recoverable costs can lead to significant price volatility.

4.189 Therefore, we could consider excluding some cost categories from being subject to IRIS but still fall under the overall smoothed BBAR (ie, still recovered through the RAB over time for larger expenditure categories).

Proposed solution

4.190 Our draft decision is to not change our current approach of applying the expenditure incentive mechanisms to all categories of opex and capex allowances.

Stakeholder views

4.191 Orion recommends the following suggestion to exclude certain categories of expenditure from entering IRIS:[274]

> Carve out certain categories of capex so they do not enter the IRIS i.e., customer connections or, apply a variable adjustment for connection capex similar to that applied for Chorus e.g. the difference between the baseline allowance, based on forecast connection volumes, and the actual connection volumes. Chorus's capex allowance increases if actual connections exceed forecast connections and Chorus receives a benefit if it can connect additional users (above the baseline forecast) at a lower cost than the unit cost.

4.192 Wellington Electricity states:[275]

> We agree that different rates would add complexity. We believe there are better solutions to solving issues like faster than expected connection growth:
>
> • Treating connection capex as a pass-through cost
>
> • Using reopeners for unforeseen connections and reinforcement growth.

4.193 Horizon considers that the increased complexity of having different incentive rates for different types of expenditure within IRIS would further cloud the understanding of the mechanism, which is already not well understood.[276]

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273 If the costs are entirely outside the control of the supplier, then we can provide for them to be pass through costs under EDB IM clause 3.1.2(1)(b) & (3), which allows us to set new pass-through costs when we set a DPP or CPP determination.

274 Orion "Orion – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 9.

275 Wellington Electricity "Wellington Electricity – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 9.

276 Horizon Energy "Horizon Energy Group – Submission on Expenditure incentives EDB workshop" (8 December 2022), p. 7.

Our view

4.194 Our general approach to providing incentives for suppliers in our regime is that:

4.194.1 we provide an overall level of opex and capex that a prudent EDB would require; and

4.194.2 suppliers can respond to this by seeking efficiencies to reduce costs (where beneficial to consumers) and reprioritise expenditure (within or between types of expenditure) to achieve the lowest cost of life solutions to promote the long-term interests of consumers.

4.195 We also note that for both opex and capex, savings and overspends are shared with consumers, with consumers bearing the majority of the difference from expenditure allowances. Therefore, even if some categories of expenditure are less controllable, cost differences will be shared with consumers and will be expected to go in both directions.[277]

4.196 The AER notes this in reference to its capex incentive mechanism:[278]

> We acknowledge that the CESS will reward or penalise NSPs for some uncontrollable events. However, on the whole, the risk of uncontrollable events presents both upside and downside risk to NSPs and this risk can already be managed somewhat through pass-through events and contingent projects. We do not think that there is a compelling argument as to why uncontrollable costs should be shared differently to all other costs facing NSPs.
>
> While we accept that some events may be uncontrollable, in most cases, a NSP also still has the ability to control the costs associated with such events. Allowing exclusions would increase the risk that we would dilute a NSP's incentives to improve its efficiency.

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277 We note that excluding some categories of expenditure from IRIS would result in that expenditure being exposed to the natural incentive rate over the period, rather than no incentives (unless the expenditure is made a pass through or recoverable cost). This is discussed further in the alternative solutions that we have considered.

278 AER " Explanatory Statement - Capital Expenditure Incentive Guideline for Electricity Network Service Providers" (November 2013), p. 51.

4.197 Having multiple incentive rates applying to different types of expenditure has been considered before in the EDB DPP3 reset. We noted that this could lead to risks of gaming expenditure categories (allocating other categories of expenditure into 'buckets' where there are lower incentives):[279]

> we consider that introducing different incentive rates for different categories of capex would introduce further complexity to a mechanism that is already complex. We also note that there is a grey area in categorisation of different types of capex, so having different incentive rates could introduce an intra-capex bias. Having a zero-incentive rate for certain categories of capex could lead to inefficiency where costs are controllable and issues of categorisation of capex.

4.198 We currently use different incentive rates for base capex and major capex under the Transpower Capex IM. However, we set separate non-fungible allowances for base capex and major capex projects, ie, there is no scope for shifting costs between base and major capex. Major capex is much more uncertain compared with the generally more routine base capex. Therefore, this is not a comparable situation to EDBs.

4.199 Related to this issue, we have proposed some draft decisions around connection expenditure.

4.199.1 Allow for a connection capex volume wash-up mechanism for EDBs on a CPP. This takes into account that externally driven connection volume is outside of supplier control, but the unit cost of each connection is within their control, and we should provide incentives on these costs (but not expose EDBs to the volume risk).[280] This will update the allowance based on actual number of connections and will therefore be subject to IRIS. This is discussed further in Topic 3c above.

4.199.2 We are also proposing to introduce large connection contracts for EDBs, similar to the New Investment Contracts for Transpower, which take new connections that meet certain criteria outside of the regulatory asset base and revenue. These sit outside of IRIS.

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[279] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), p. 279.

[280] We consider that we do not have sufficient unit cost information currently to apply for a DPP. We are recommending more ID disclosures around this with the intention of considering a DPP mechanism in the future.

4.200 If we were to pursue excluding some expenditure categories from the IRIS mechanisms, ignoring the other reasoning for not proposing, this would result in increased complexity of the regime through:

4.200.1 different expenditure categories being subject to different incentives, which also increases the importance of classification of expenditure; and

4.200.2 the treatment of the expenditure categories exempt from IRIS would likely need to be done through a new type of recoverable cost that still enters the RAB which will increase complexity in implementation and understanding.

4.201 Innovation spending was one category noted in submissions that should be excluded from incentives. This can already be dealt with at a DPP through the innovation project allowance as it is treated as a recoverable cost. Therefore, we consider that we do not need to make changes to the IMs exclude innovation allowances from IRIS.

Alternative approaches considered

4.202 We considered the option of allowing for the exclusion of some expenditure categories from IRIS at a reset (but still being subject to the smoothed BBAR and can be recovered through the RAB to avoid price volatility).[281]

4.203 This would be similar but slightly different to the current recoverable costs mechanism that are already passed through (and recovered straight away not over time). This could provide flexibility for certain expenditure categories where there is significant uncertainty or costs are almost entirely outside of EDBs' control.

4.204 This issue is also related to the connection capex volume wash-up mechanism that we have proposed for a CPP but not for a DPP (see Topic 3c above).

4.205 We consider that excluding certain expenditure categories from IRIS this could provide flexibility for future resets. This could apply to certain expenditure categories where there is significant uncertainty or costs are almost entirely outside of EDBs' reasonable control.

[281] As noted above, this is also why we are also proposing to introduce large connection contracts for EDBs which take new connections that meet certain criteria outside of the regulatory asset base and revenue.

4.206 If categories were excluded from IRIS, we would need to consider how these categories would be treated. Treating these larger cost categories as a recoverable cost through the current mechanism could lead to significant price volatility. We consider that an alternative option could be to allow costs to pass through into the RAB (but not be subject to incentives) such that it is still recovered over time and not cause a price shock.

4.207 Having the flexibility to set different incentive rates would give us the option to apply them at a reset – we are not tied to excluding certain categories. At a reset we would need to decide whether to exclude any categories (eg, based on our view of the uncertainty in forecast expenditure requirements and our views on the appropriate risk allocation between consumers and businesses at the time of the reset).

4.208 However, for the reasons noted above, we consider that keeping the status quo would be promote the Part 4 purpose.

Topic 4f – Use the midpoint discount rate in the opex IRIS calculation

Draft decision

4.209 Our draft decision is to change our approach from using the 67th percentile vanilla WACC as the discount rate to using the midpoint vanilla WACC for discounting opex savings and estimating the opex incentive rate.

Problem definition for this issue

4.210 Currently, we estimate the implied opex retention factor based on the 67th percentile vanilla WACC as the discount rate (ie, the WACC applying for a price-quality path). Based on this retention factor we equalise the capex incentive rate with this rate. There is a technical question around whether this is the correct discount rate for the context.

4.211 The discount rate in the opex IRIS is simply the discount rate for cash-flows that suppliers receive in the future. If we want to equalise incentive rates between opex and capex, to the conceptually correct discount rate is as close as possible to the supplier’s internal discount rate, otherwise there may be differing incentives between opex and capex savings.

Proposed solution

4.212 Our draft decision is to change our approach from using the 67th percentile vanilla WACC as the discount rate to using the midpoint vanilla WACC for discounting opex savings and estimating the opex incentive rate.

Stakeholder views

4.213 As noted in our Process and Issues paper, a personal submission by Pat Duignan on the DPP3 reset recommended that the midpoint level of the WACC (50th percentile) should be used rather than the 67th percentile for the discount rate used in calculating the strength of the relevant IRIS and WACC incentives.[282]

4.214 Mr Duignan suggested that we provide a view on whether a post-tax WACC should be used (rather than the vanilla WACC that we currently use) as the relevant discount rate in the opex IRIS:[283]

> It is possible, depending on the exact way tax is treated in the operation of the Opex IRIS, that the post-tax WACC rather than the vanilla WACC could be the relevant discount rate to use in assessing a distributor's incentives regarding expenditure decisions. I hope that the Commission will provide its view on this issue.

Our view

4.215 To estimate the opex incentive rate, we want to use a discount rate for opex savings that is close to suppliers' internal discount rates. The opex incentive rate (which is a function of the discount rate used) is important because we use it to set the capex incentive rate and equalise rates.

4.216 Our best estimate of the cost of capital at the beginning of a price-quality path is the midpoint WACC. We do not consider that regulated suppliers would use the rate with an uplift because this is what is applied to calculate the return on capital. The WACC uplift was introduced for the purpose of promoting investment (noting that underinvestment has a greater cost to consumers than overinvestment). However, this is not relevant to setting the discount rate on opex savings.

4.217 We propose to continue using the vanilla WACC rather than post-tax WACC because this is consistent with how we set a WACC for DPPs. The calculation of the opex IRIS as a recoverable cost is independent of the calculation of tax cash flows.

Alternative solutions considered

4.218 We have considered whether retaining the current approach (setting the discount rate equal to WACC applied for a price-path) remains appropriate.

4.219 If we were to assume that suppliers use a discount rate that is similar to the WACC that we set at a DPP reset (ie, the 67th percentile), the incentive rate for opex savings would reflect that of suppliers.

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282 Pat Duignan "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

283 Pat Duignan "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

4.220 A benefit of maintaining the current approach would be simplicity and not having multiple WACC values used for different purposes. This can reduce implementation errors of using the incorrect cost of capital. However, we already use several variations of the cost of capital (for example, we bring forward incentive amounts at the cost of debt because we considered that there is no equity risk associated with these cash flows).

Topic 4g – Maintain our current treatment of operating leases

Draft decision

4.221 Our draft decision is that no change to the current mechanism is required to account for the treatment of right of use assets/operating leases.

Problem definition for this issue

4.222 The new accounting standards change that came into effect in 2019 (New Zealand Equivalent to International Financial Reporting Standard 16 Leases (NZ IFRS 16)) meant that operating leases changed from being treated as opex to being treated as capex. For incentive purposes, we decided that it made more sense that cashflows align with opex treatment (as was the case before the introduction of NZ IFRS 16).[284]

Stakeholder views

4.223 In its submission on the Process and Issues paper, Wellington Electricity states: [285]

> The application of IFRS 16 has added complexity to the IRIS calculation and requires the additional ongoing maintenance of assets and costs as though IFRS 16 never happened. The requirement to forecast future lease costs and right-of-use capitalisation when determining the "trend" allowances for IRIS creates additional forecast error.

4.224 Wellington Electricity described this issue as a low review priority but suggested that we review the IFRS 16 adjustment to exclude the added complexity.

Proposed solution

4.225 Our draft decision is that no change to the current mechanism is required to account for the treatment of right of use assets/operating leases.

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[284] For a full discussion of our reasoning for making this change, see Commerce Commission "Treatment of operating leases – Final decisions paper" (13 November 2019).

[285] Wellington Electricity "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 16.

Our view

4.226 We considered this issue in detail during our decisions on the treatment of operating leases. We consider that the benefit of the additional complexity outweighs the volatility and timing mismatch of treating the leases as capex.[286]

4.227 We have not been provided with any evidence that suggests that our updated treatment of leases for incentive purposes is not working, or that presents alternatives that would better achieve the IM Review overarching objectives.

Topic 4h – Make no change to IRIS for undercharging

Draft decision

4.228 Our draft decision is that an IM change to IRIS is not required for suppliers that undercharge their maximum allowable revenue (MAR) and would not otherwise better achieve our Framework's overarching objectives.

Problem definition for this issue

4.229 Undercharging occurs when a supplier does not charge up to its MAR. IRIS generally assumes that suppliers price to their MAR, so if a supplier's undercharging is due to differences in expenditure, there can be IRIS implications.

4.230 We discussed this issue in the setting of the DPP3 reset.[287] We noted that, with the move to a revenue cap, we allowed EDBs to 'bank' some amount of undercharging (up to a certain amount) that could be recovered in the future, and that suppliers should continue to undercharge where it in the best interests of consumers, but consider the IRIS impacts.

Stakeholder views

4.231 TLC submitted that our approach to voluntary undercharging does not incentivise EDBs to do so:[288]

> The IRIS model anticipates that all regulated distributors price to their allowable revenues. However, where a distributor, such as TLC, chooses or cannot price to allowable revenue (for example, for community affordability reasons), the impact of the IRIS mechanism is perverse and compounds, i.e. if a distributor does not price to allowable revenue during the regulatory period, the distributor is not 'rewarded' but still must share the efficiency gains through lower prices in future periods.

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286 For further explanation, see Commerce Commission "Treatment of operating leases - Draft decisions and reasons paper " (28 August 2019), Chapter 7.

287 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), para E114 - E132.

288 The Lines Company "The Lines Company – Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 2.

> …
>
> We encourage the Commission to consider this situation further in this review as commenting that consideration by distributors of IRIS impacts for undercharging does not provide a solution and does not incentivise distributors to do so (voluntarily undercharge).

Proposed solution

Our view

4.232 We encourage EDBs to continue to undercharge where this can benefit consumers and the wider community, but do not consider that an IM change to the current IRIS approach is necessary to enable voluntary undercharging or would otherwise better achieve our Framework's overarching objectives.

4.233 The IRIS schemes share over- and underspends (against the forecast allowances) with consumers over time. For opex cost savings, this results in lower prices being shared with consumers at the end of the retention period (six years), and for capex savings, in the subsequent regulatory period. By voluntarily undercharging, an EDB is choosing to lower prices for consumers sooner than through the IRIS mechanism and receive a lower portion of the overall saving compared with IRIS.

4.234 Undercharging revenue is not necessarily tied to expenditure or the allowances set at a DPP and could be done for any number of reasons. Adjusting IRIS allowances for any undercharging of revenue would require unpicking the differences in the undercharged revenue amount and allocating for the impact on opex and capex allowances. This could potentially allow for gaming opportunities and would add significant complexity to the mechanism.

4.235 The choice of revenue to recover and the expenditure decisions that IRIS applies to are not fundamentally tied. By voluntarily undercharging, suppliers should know that the incentive amounts will not be the same as pricing to their MAR.

4.236 We also note that, under the current IMs, an EDB can bank up to 20 percent of revenue from undercharging to be recovered at a later date (and our draft decision is to allow for flexibility in this at a DPP reset rather than in the IMs).

Specific changes to Transpower expenditure incentive schemes

4.237 The specific changes applying to the EDB expenditure schemes also generally apply to Transpower's expenditure incentives, while there is one specific topic for Transpower that is not relevant for EDBs (removing the Transpower baseline adjustment term).

4.238 We have summarised our draft decisions on the specific changes to the Transpower expenditure incentive mechanisms in Table 4.3 above. We explain the reasoning for our draft decisions in more detail later in this section.

Topic 4i – Removing the Transpower baseline adjustment term

Draft decision

4.239 Our draft decision is to remove the baseline adjustment term for Transpower's opex incentive calculation.

Problem definition for this issue

4.240 Prior to 2017, the Transpower opex IRIS mechanism assumed that any permanent savings made up to and including year four of a regulatory control period (RCP) were included in the IPP opex forecast for the following RCP. Transpower informed us that initial IPP forecasts are developed in year three of the previous RCP, and as such, are unlikely to incorporate year four savings in the forecast.[289]

4.241 This led to the adjustment term defined in the Transpower IRIS IM being modified to cover 'total' savings, rather than temporary savings. This 'total savings' term needed to be estimated as there is no deterministic method to calculate this amount (as there is no direct link between historically incurred opex and opex forecasts under an IPP).[290]

4.242 When this was implemented at Transpower's RCP3 reset, there was significant uncertainty and interpretation issues during the determination of the adjustment term. To be an effective driver for the desired behaviour, an incentive mechanism should provide some level of certainty, and a clear link between behaviour (eg, improve efficiency) and outcomes (eg, a reward for efficiency).

4.243 The baseline adjustment term introduced significant levels of uncertainty to the IRIS mechanism which is proving detrimental to the predictability and effectiveness of the mechanism. This can undermine both the s 52R IMs purpose (in terms of the certainty of Part 4 rules) and the promotion of efficient investment in terms of s 52A(1)(a) and (b).

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289 If year four savings are not incorporated in the IPP forecast, then the IRIS mechanism will over-reward savings (and over-penalise overspends) made in year four based on the IRIS assumptions pre-2017. Absent an adjustment the reward for permanent savings would be almost twice the intended amount.

290 These total savings are estimated in the 'differences-in-penultimate year' term. We determine this term, having regard to interested persons' views. We outlined two possible methods we could use to estimate this term in the Transpower IRIS paper. See Commerce Commission "Input methodologies review final decision - Transpower Incremental Rolling Incentive Scheme" (29 June 2017).

4.244 During Transpower's RCP3 IPP reset process, there was an $110 million difference between Transpower's proposed incentive amount and our draft decision.[291] This represented approximately three percent of total revenues over the period. Our final incentive amount was approximately $33.7 million different from Transpower's updated calculation of the incentive amount. This demonstrates the uncertainty associated with the subjective baseline adjustment term applying to Transpower which, if retained, could have a detrimental impact on incentives to invest and make efficiency savings.

Proposed solution

4.245 We propose removing the Transpower baseline adjustment term and setting Transpower's opex IRIS in the same way we do a for a standard DPP for EDBs.

Stakeholder views

4.246 Transpower notes on the IRIS baseline adjustment term (IBAT):[292]

> The IRIS requires a determination (the IBAT) by the Commission in future RCPs on the baseline adjustment term (via the "differences in penultimate year") – the baseline adjustment term is complex and creates uncertainty for stakeholders.

Our view

4.247 For incentive schemes to be effective, the implications of those incentive schemes must be understood in advance and there should be a clear link between a supplier's behaviour and the outcomes.

4.248 The reason that the baseline adjustment term was required was to 'link' regulatory periods, which the IRIS mechanism requires. The link between periods was not present due to Transpower's forecast that informed the expenditure allowances for RCP1 and RCP2 were bottom-up. This meant that there was no explicit link between regulatory periods.

4.249 The expenditure forecasts that underpinned the expenditure allowances for RCP3 were informed by base-step-trend forecasts prepared by Transpower.[293]

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291 Transpower NZ Ltd "Transpower submission on Draft IBAT decision" (21 August 2019), p. 3.

292 Transpower "Transpower NZ Ltd – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 1.

293 Transpower used also bottom-up approaches to inform its forecasts.

4.250 If Transpower continues to use a BST approach in its RCP4 expenditure proposal this would establish the link between regulatory periods which would allow the use of the opex IRIS approach applied in the EDB DPP.[294] This removes the need for the baseline adjustment term and associated uncertainty surrounding the 'differences-in-penultimate-year' term that is determined by us.

4.251 The current opex IRIS mechanism provides us with substantial discretion to set the baseline adjustment term, which can reduce certainty and incentives to invest and/or find opex efficiencies. Removing the term would allow Transpower to better predict their return from the making opex efficiency savings under the IRIS incentive mechanism.

4.252 We consider that removing the baseline adjustment term, with effect from the RCP4 reset onwards, would:

4.252.1 Better promote the Part 4 purpose by better providing incentives to invest, improve efficiency and provide services at a quality demanded by consumers, in line with s 52A(1)(a) and (b).

4.252.2 Reduce complexity and compliance costs (without harming the promotion of s 52A) associated with estimating the adjustment term and the resulting impacts on revenues/profits, consistent with the third IM Review overarching objective.

4.253 For the reasons outlined above, we consider that removing the baseline adjustment term, would better achieve the IM Review overarching objectives than alternative implementation options.

Alternatives considered

4.254 We considered whether we could keep the IBAT in place for Transpower's incentive calculations but considered that this was not appropriate given:

4.254.1 Transpower is expected to continue using a top-down base-step-and-trend approach for opex, so the need for this adjustment is removed; and

4.254.2 the complexity and uncertainty created by the mechanism could have a negative impact on Transpower's incentives to seek efficiencies.

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294 On the issue of timing of Transpower's expenditure proposal, while Transpower has used Year 3 of the RCP3 as its base year for the RCP4 forecast, we understand that it will update the proposal to be based on Year 4 actuals in time for our final decision. See Table 21, Table 22 here: Transpower "RCP4 Consultation" (September 2022), pp. 81, 84.

Chapter 5 Inflation risk

Purpose and structure of this chapter

5.1 This chapter presents our review of the IMs that relate to the method for forecasting inflation, and to exposure to inflation risk and associated compensation. Inflation and its impacts have become an important issue for consumers and suppliers (see Chapter 2).

5.2 This chapter covers two topics:

5.2.1 Our review of inflation forecasting methods. In implementing our regulatory regime, we need to forecast inflation as an input to determining ex-ante PQ paths. One reason to do this is to provide suppliers with an expectation of financial capital maintenance (FCM) in real terms.[295]

5.2.2 Our review of exposure to inflation risk and associated compensation for Transpower, EDBs and GPBs. Once we have forecast inflation, and since there is a risk that inflation outcomes will almost invariably differ from forecast, we need to decide how that risk should be allocated. Exposure to this risk only exists to the extent that the regime does not fully wash up inflation actuals from forecast. Washing up for inflation actuals that are different from forecast is a mechanism that protects both suppliers and consumers from inflation risk – the revenue that suppliers recover from consumers remains stable in real terms, over time. Any residual inflation forecasting risk exposure drives the need for any corresponding compensation.

Topic 5a – Method for forecasting inflation

5.3 We use inflation forecasts in our regulatory regimes, including for ex-ante indexing the revenue path and forecasting RAB revaluation gains. This section discusses our draft decision on the method for forecasting inflation for the purposes of setting price-quality paths.

Draft decision

5.4 Our draft decision is to maintain the status quo: forecasting the CPI for the regulatory period by using the most recently available Reserve Bank of New Zealand (RBNZ) CPI forecasts at the relevant time. This timing falls into three categories:

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295 The aim is to achieve compatibility between the inflation forecasts we make at the start of the regulatory period and the implicit inflation in the WACC. We need this compatibility to deliver a real return expectation when we treat revaluation gains as income, and use actual inflation to index the RAB. It does not matter for this purpose if actual inflation turns out to be different from forecast inflation.

5.4.1 for forecasting the revaluation rate and for the purposes of calculating forecast inflation for the cost of debt wash-up, this is the RBNZ forecasts available at the time we determine the risk-free rate and debt premium (used in the WACC estimate that applies for a price-quality path);

5.4.2 for indexing the revenue path at the start of the regulatory period, this is the most recently available RBNZ forecasts at the time the revenue path is determined; and

5.4.3 for suppliers subject to a revenue path updating their forecast net allowable revenue each year, this is the RBNZ forecasts available when suppliers set their prices for each year.

5.5 The RBNZ currently forecasts CPI for 13 quarters ahead. For the remaining quarters of the regulatory period, which forecasts are not produced for, we linearly trend to the midpoint of the RBNZ inflation target band (currently two percent) by the end of the forecasting window.

5.6 This section deals principally with the timing of forecasts as they relate to the revaluation rate. The detailed changes about how the revenue path operates during the period are dealt with in Attachment D.

5.7 As we explain below, we consider that compared to alternatives, the status quo will better achieve our IM Review overarching objective of promoting s 52A by aiming to minimise the difference between forecast and actual inflation over the forecast window.

Problem definition

5.8 In setting price-quality paths, it is desirable to use the best CPI forecast. By 'best CPI forecast' we mean a forecast that is as close as possible to:

5.8.1 investors’ expected inflation inherent in the WACC, ie, market’s inflation expectations (where the forecast of CPI is being used to forecast revaluations); or

5.8.2 actual inflation (where the forecast is being used to index or updated the revenue path).

5.9 Using the best CPI forecast is particularly important in the current uncertain and volatile inflationary environment.

5.10 Differences between the forecast CPI and the market’s expected CPI inherent in the nominal WACC result in higher or lower ex-ante real returns for the regulated firms, violating real ex-ante NPV=0, the application of the real expected FCM principle.

5.11 Where there are ex-post CPI wash-ups (including the rolling forward of the RAB using actual CPI), a forecast that is close to outturn minimises the size of these adjustments and, in the intervening time, any associated risk of financial distress for the regulated firms or overpayment by consumers.[296]

5.12 Investors’ expected inflation is unobservable and must be estimated.[297] Our key assumption is that the best estimate of investors’ expected inflation is an inflation forecast methodology that produces the most accurate forecasts; one that minimises the difference between forecast and actual inflation. This assumption is consistent with the position of the Queensland Competition Authority (QCA).[298]

5.13 Therefore, our objective is to identify the option for forecasting inflation that minimises the difference between forecast and actual inflation over the forecast window.

5.14 As per paragraphs 5.15 to 5.17, stakeholders submitted that we should review our approach to CPI forecasting, so it results in more accurate and credible forecasts.

Stakeholder views

5.15 ENA:

> The ENA recognises that forecasting inflation is not easy. It believes there is value in the Commission investigating if its current approach is fit for purpose. Various approaches have been investigated and/or adopted in other jurisdictions. ENA strongly recommends the Commission conduct a review of best practices for inflation forecasting.[299]

5.16 Aurora:

> There has been a sustained period of variation in out-turn inflation compared to forecast, which has resulted in EDBs being significantly undercompensated over a number of regulatory periods…While inflation has recently swung to be above the Commission’s forecasts, it would take a materially sustained period of high inflation before under-compensation was balanced out…Accordingly, Aurora supports the inclusion of inflation forecasting in this topic area, and suggests that the issue should be extended to examine whether there are effective options for washing up inflation variances from forecast.[300]

5.17 Vector:

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296 In topic 5b we discuss proposed changes to improve the wash-ups for inflation, which should reduce suppliers' residual exposure to inflation forecasting risk.

297 See paragraphs 5.45 to 5.50 for why relying on market-derived inflation forecasts is an unreliable measure of investors' expected inflation.

298 Queensland Competition Authority "Inflation forecasting final position paper" (October 2021), p. 27.

299 Electricity Networks Association “Submission on IM Review Process and issues paper and draft Framework paper” (11 July 2022), p. 12.

300 Aurora Energy “Submission on IM Review Process and issues paper and draft Framework paper” (11 July 2022), p. 12.

The current methodology for estimating inflation led the Commission to persistently over-forecast inflation over previous regulatory periods…We recommend the Commission review its methodology to forecast inflation. We consider a market-based methodology would produce a more credible forecast. The current approach undermines the Part 4 purpose by producing a disincentive to investment. Along with years of losses already produced, there is every reason for regulated businesses and their investors to expect continued inflation forecast error given the persistent under-forecast produced by the methodology thereby undermining investment confidence. Furthermore, in the current environment of rising inflation, there is increased risk of the Commission under-forecasting inflation resulting in overpayment by consumers. We consider the long-term benefit of consumers is best promoted by a methodology that produces the most accurate inflation forecast possible.[301]

5.18 Vector submitted a memorandum from Motu, written in 2020 (before the pandemic) that among other things found the following:

The four-leading methods of constructing inflation expectations (model-based, market-implied, professional surveys, and business and household surveys) have all resulted in significantly biased results in the past decade. In New Zealand, the market-implied measures have performed better than the alternatives for forecasting five years-ahead inflation… a switch to using market-based measures of inflation expectations provides the best option.

Unfortunately, since whatever method the Commerce Commission chooses will be in place for five years, it may be that no technique is fit for purpose for determining the regulated network investor's five-year view of inflation.

Given the uncertainty, the Commerce Commission's current approach of reverting back to the Reserve Bank's mid-point over 5 years is not reasonable. Using market-based data would provide a better view of investor expectations for inflation.[302]

5.19 Subsequently, Vector submitted a March 2023 update to the 2020 Motu memorandum, which stated the following:

The four-leading methods of constructing inflation expectations (model-based, market-implied, professional surveys, and business and household surveys) all delivered poor forecasting performances; over-forecasting in the decade before the pandemic and under-forecasting in the post-pandemic period.

Forecasting central banks' resolve seems as complicated as forecasting inflation itself. Now that central banks have broken businesses' belief in price stability, inflation expectations have become unanchored, and the inflation outlook is significantly more uncertain in both directions.

As discussed in my original Memorandum, no forecasting approach that is fixed in place while the economic and social environment is changing will be able to forecast well. Unfortunately, the current approach adopted by the Commerce Commission risks generating significant forecasting errors and is undoubtedly not fit for purpose.[303]

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301 Vector "Submission on the Process and issues paper" (11 July 2022), pp. 21 22.

302 Motu "Memorandum: Performance Inflation Forecasting Problem" – 'Submission on IM Review CEPA report on cost of capital' (prepared for Vector, 9 November 2020), pp. 2, 6, 10.

303 Motu "Memorandum: Update on the Difficulties of Forecasting Inflation"(prepared for Vector, 13 March 2023).

Proposed solution

5.20 We propose to maintain our current approach, which is to use the most recent RBNZ CPI forecast to our estimation of the WACC applying for a price-quality path.

5.21 Our view is that, compared to the other options, the proposed method for forecasting CPI is as likely, if not more, to minimise the difference between forecast and actual inflation over the forecast window. As explained in paragraph 5.12, this is also our best estimate of the market's expectation of inflation embedded in the WACC. This therefore delivers an expectation of real FCM. In doing so, it provides regulated suppliers with incentives to invest, consistent with s 52A(1)(a).

5.22 Where there are ex-post CPI wash-ups, a secondary benefit of an accurate CPI forecast—one which is closer to outturns—is that it minimises the size of these adjustments and, in the intervening time, any associated risk of financial distress for the regulated firms (consistent with s 52A(1)(a)) or overpayment by consumers, which contributes to price stability.[304]

5.23 For clarity our draft decision retains an RBNZ forecast which currently forecasts CPI for 13 quarters ahead. For the remaining quarters of the regulatory period, which forecasts are not produced for, we propose to continue to linearly trend to the midpoint of the RBNZ inflation target band (currently two percent) by the end of the forecasting window.

5.24 We consider that this draft decision best promotes the overarching objectives for the IM Review by promoting the Part 4 purpose in s 52A more effectively than the alternatives.

Alternatives considered

5.25 We considered the following alternatives:

5.25.1 RBNZ forecast for Q1 to Q8, then trend to two percent by Q20;[305]

5.25.2 RBNZ forecast for Q1 to Q4, then trend to two percent by Q20;

5.25.3 glide-path that trends to a 'rules-based anchor point' at end of the forecasting window;

5.25.4 market-derived forecasts;

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[304] In our 2016 IM Review decision on form of control, we considered that price stability is a factor that consumers tend to value see: Commerce Commission "Input methodologies review decisions Topic paper 1: Form of control and RAB indexation for EDBS, GPBs and Transpower" (20 December 2016), para 6.

[305] Q20 for a five-year regulatory period. It would be Q16 for a four-year regulatory period.

5.25.5 survey-derived forecasts; and

5.25.6 model-derived forecasts.

5.26 We now briefly expand on each of the alternatives and explain the reasons why we propose to maintain the status quo.

RBNZ forecast for Q1 to Q8, then trend to two percent by Q20

5.27 This option would use RBNZ CPI forecasts, but only up to Q8. For the remaining quarters, we would linearly trend to the midpoint of the RBNZ inflation target band (currently two percent) by the end of the forecasting window.

5.28 The rationale behind using fewer forecasts—stop using Q9 to Q13 forecasts—would be twofold:

5.28.1 the accuracy of RBNZ's CPI forecasts is highest for Q1 and decreases the further out in time we go.[306] This option places more weight on near-term forecasts, and by implication, weakens the reliance on the feature implicit in RBNZ's methodology where the forecasts revert to the two percent midpoint in year three; and

5.28.2 there is some evidence—mainly international—that inflation may take longer to revert to the target after a period of sustained low or high inflation.[307]

5.29 This option is also consistent with the Australian Economic Regulator's (AER) approach,[308] and largely consistent with the QCA's approach.[309]

5.30 This option would replace RBNZ forecasts for Q9 to Q13 with forecasts resulting from an alternative method (trending Q8 forecast to two percent by end of the forecasting window).

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306 This would be expected from efficient forecasts which use all information available to the forecaster at the time. See Reserve Bank of New Zealand "Evaluating the Reserve Bank's Forecasting Performance" (November 2022), p. 13.

307 Reserve Bank of New Zealand "Evaluating the Reserve Bank's Forecasting Performance" (August 2016), pp. 9-10; Australian Energy Regulator "Final position paper Regulatory treatment of inflation" (December 2020),p. 53; Martin Lally "Review of the AER's inflation forecasting methodology" (8 July 2020), p. 3.

308 Australian Energy Regulator "Final position paper Regulatory treatment of inflation" (December 2020).

309 The difference with the QCA's methodology is that the QCA trends down to a "rules-based anchor point" by the end of the forecasting window, rather than the Reserve Bank of Australia's (RBA) midpoint (2.5 percent).

5.31 However, we consider that maintaining the status quo - using the RBNZ CPI forecasts for Q9 to Q13, which revert to the two percent target by year three - is appropriate based on the New Zealand evidence.

5.31.1 We found 19 episodes between 1990 and 2021 where CPI differed from two percent and looked at how many quarters it took for it to return to two percent. It took around seven quarters on average, with a median of six quarters and a range of two to 22 quarters.

5.31.2 Over the longer run, inflation has averaged two percent. Average inflation between 1992 (when the period of low inflation began) and mid 2021 (before the current inflationary surge) equalled exactly two percent.

5.31.3 The RBNZ's February 2023 Monetary Policy Statement (MPS) projects CPI to return to the two percent target in Q12 ahead, or year three (Q4 2025).[310]

5.31.4 The RBNZ evidence footnoted in paragraph 5.28.2 supports a longer time to revert to target. However, it refers to a document written in 2016, which is when it took 22 quarters for inflation to revert to two percent, the longest in the sample.

5.32 We note that this analysis is backward-looking and there is a risk that past inflation dynamics are not a reliable indicator of future ones. This is especially the case given the current economic context of higher and more volatile inflation.

5.33 However, we would expect that, given its statutory mandate and track record, the RBNZ has a strong incentive and ability to understand and forecast inflation as well – or better – than a mechanistic approach based on linear trending. Further, there is evidence that the RBNZ inflation forecasts for one and two years ahead are as good or better than those of non-RBNZ forecasters (see paragraph 5.59).

RBNZ forecast for Q1 to Q4, then trend to two percent by Q20

5.34 As with the above option, this option would use RBNZ CPI forecasts, but only up to Q4. For the remaining quarters, we would linearly trend to the midpoint of the RBNZ inflation target band (currently two percent) by the end of the five-year forecasting window.

5.35 This option more extensively applies the rationale in paragraph 5.28.1, reflecting that short term inflation forecasts are more accurate.

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310 Reserve Bank of New Zealand "Monetary Policy Statement" (February 2023), p.57.

5.36 This option would replace RBNZ forecasts for Q5 to Q8 with forecasts resulting from an alternative method (trending Q4 forecast to two percent by end of the forecasting window).

5.37 We consider that using only four quarters of RBNZ forecasts (Q1 to Q4) when they produce 13 quarters may unduly favour a mechanistic forecasting approach (linear trending) relative to using authoritative RBNZ forecasts for Q5 to Q8, which have proved to perform well (see paragraph 5.59). It would be a material departure from the status quo, and for the reasons at paragraphs 5.21 and 5.22 above, would not promote s 52A as well as the status quo if it resulted in greater differences between forecast and actual inflation.

Glide-path that trends to a 'rules-based anchor point' at end of the forecasting window

5.38 This option would also use RBNZ CPI forecasts, and then linearly trend (or glide path) from the last forecast to a 'rules-based anchor point' by the end of the forecasting window, rather than the target midpoint.

5.39 Under this approach, as applied by the QCA (with reference to the Reserve Bank of Australia's (RBA) target midpoint of 2.5 percent), if the last forecast is:[311]

5.39.1 less than or equal to two percent, the anchor point could be set at 2.25 percent;

5.39.2 between two percent and three percent, the anchor point could be set at 2.5 percent; and

5.39.3 greater than or equal to three percent, the anchor point could be set at 2.75 percent.

5.40 This approach intends to reflect the possibility that low or high inflation may take longer to revert to the midpoint, and this would be reflected in inflation expectations.

5.41 We note that Frontier Economics considers "the QCA approach is the best available method for determining the regulatory inflation parameter".[312]

5.42 However, we did not consider this option any further because an anchor point different from the RBNZ's midpoint target would not have been necessary over the period of our analysis (up to the February 2023 MPS) because the RBNZ's forecasts have always ended within the target range. Therefore, this approach is not relevant based on the RBNZ's historical forecasting methodology.

311 Queensland Competition Authority "Inflation forecasting final position paper" (October 2021), p. 36.

312 Frontier Economics "Return on capital, inflation and financeability" (11 March 2022), para 167.

5.43 The RBNZ's furthest ahead forecast (ie, Q13 ahead) has not been outside the 1.5 to 2.5 percent range (equivalent to RBA's two to three percent band given their 2.5 percent midpoint). This continues to be the case in the RBNZ's February 2023 MPS, where CPI is projected to return to the two percent target in Q12 ahead, or year three (Q4 2025).

Market-derived forecasts

5.44 This option would use bond yield data and inflation swap data to derive inflation expectations.

5.45 Conceptually, inflation expectations derived from market data should accurately reflect investors' true inflation expectations.

5.46 The QCA's recent review of inflation forecasting has a helpful explanation of the two market-based methods – bond breakeven and inflation swaps:[313]

> The bond break-even method assumes that the difference between nominal and indexed bond yields reflects investors' inflationary expectations. This method derives the expected inflation rate that equalises nominal and indexed bond yields, by applying the Fisher equation to the yields to maturity of nominal and inflation-indexed ('indexed') Treasury bonds with similar maturity dates.[314]
>
> In an inflation swap, counterparties agree to exchange payments that are linked to a predetermined (or fixed) inflation rate and the actual inflation rate. The fixed rate of an inflation swap can be interpreted to reflect market expectations of inflation, given that one party to the swap will be required to make a net cash payment, should the fixed inflation rate vary from the actual inflation rate over the term of the swap.[315] For example, the 10-year inflation swap rate measures market expectations of average inflation over the next 10 years.

5.47 While this approach is conceptually appealing, we have ruled this option out for the following reasons.

313 Queensland Competition Authority "Inflation forecasting final position paper" (October 2021), p. 18.

314 The Fisher equation outlines the relationship between the nominal interest rates, expected inflation and real interest rates.

315 The party paying the fixed rate (eg a pension fund) typically has a long-term indexed liability and may be seeking to mitigate its exposure to unexpected increases in inflation. The party paying the actual inflation rate (eg a utility) typically has revenues linked to changes in inflation and may be seeking to hedge its exposure to variable revenues. One of the counterparties to the inflation swap will generally be a swaps dealer.

5.47.1 We considered it in the last IM Review and in the setting of Fibre IMs and concluded that there were several issues that made it an unreliable method for estimating inflation expectations.[316] Specifically:

5.47.1.1 yields on nominal government bonds can include a premium for bearing inflation risk which can distort the implied inflation forecast; and

5.47.1.2 yields on CPI-indexed government bonds can include a liquidity premium, given the relative scarcity of this type of bonds. This can distort the implied inflation forecast.

5.47.2 The more recent Australian evidence we are aware of has confirmed the above two issues, in addition to many others.[317]

5.48 We note that while the reasons outlined below, used in the last IM Review to discard this option, do not seem to apply as strongly now, our judgement is that the above reasons still justify rejecting this option, on balance.

5.48.1 The shortest dated NZ government inflation-linked bond matures in 2025. In 2016 (last IM Review) we considered that any implied inflation would be an average over the period until the bond matures and would not necessarily correspond to the five-year regulatory period. However, the next price-quality reset for EDBs and Transpower takes effect in 2025, and we now have inflation-linked bonds maturing in 2025, 2030, 2035 and 2040.

5.48.2 In a low-inflation environment, the difficulty in inferring inflation from the yields on different bonds becomes more difficult because the impact of the various premiums can significantly outweigh the actual level of inflation. While we are in a high-inflation environment now, the RBNZ forecasts inflation to revert to two percent in 2025.

[316] Commerce Commission "Input methodologies review decisions Topic paper 1: Form of control and RAB indexation for EDBS, GPBs and Transpower" (20 December 2016), para 294.

[317] Australian Energy Regulator "Draft position paper Regulatory treatment of inflation" (October 2020), pp. 133-135; Martin Lally "Review of the AER's inflation forecasting methodology" (8 July 2020), p. 28.

5.49 During the Fibre IM process, Vector noted that the Treasury has set out a methodology for forecasting the CPI which gives breakeven inflation (calculated using inflation-indexed government bonds) a 50 percent weighting. [318] This methodology is prescribed for the purposes of valuing long-term assets and liabilities on the Crown balance sheet.[319] Short-term timing differences in CPI inflation have little impact on these long-term valuations, so are less of a focus than for our purposes. In contrast, the official inflation forecasts in the Treasury's six monthly economic and fiscal updates (which are legally required to represent their best professional judgement) are produced in a similar way to those of the RBNZ.[320]

5.50 An additional reason for not relying on market-derived forecasts is that liquidity in the market for index-linked bonds depends to a significant degree on the Treasury's bond issuing strategy. If it were to decide to put less weight on index-linked bonds, this would likely lower liquidity in the bond market and reduce the reliability of breakeven inflation calculations. This is something which happened in Canada in 2022.[321]

5.51 We note that, as we understand it, the RBNZ inflation forecast is not a purely model driven, so it does include market data to the extent that the Monetary Policy Committee and forecast team consider it relevant.[322]

5.52 We now respond to Vector/Motu's points, which they use to support a change to a market-based method. For the reasons below, we are not persuaded by these submissions.

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318 Vector Communications "Submission to the Commerce Commission Fibre Input Methodologies Project" (28 January 2020), para 54.

319 The Treasury "CPI inflation assumption review for 30 June 2021" (5 July 2021).

320 Section 26W(3)(a) of the Public Finance Act 1989.

321 John Cochrane and Jon Hartley "The government ditched inflation-protected bonds - companies should start issuing their own" (1 February 2023) The Globe and Mail <www.theglobeandmail.com> (Viewed on 5 May 2023).

322 Reserve Bank of New Zealand Te Putea Matua (2020) "Monetary Policy Handbook", version 2, 1 September, p. 53.

5.53 In its 2020 memo, Motu stated that the market-implied method performed better than the alternatives.[323] Looking at the evidence presented in that memo (figures 2 and 3), we note the following:

5.53.1 We agree that by 'eyeballing' the figure (which is all we can do with the information presented), between 2011 and 2015, the breakeven inflation estimate (blue line in figure 3) was closer to actual inflation than professional forecasters' expectations (blue line in figure 2). However, it is not clear from the memo how the professional forecasters' expectations were calculated. Importantly, we do not know whether – or the extent to which – the RBNZ forecasts are included, which is what our status quo method uses.

5.53.2 From looking at these figures, it is not clear to us by which method performed better in the period 2016 to 2020. We understand that the RBNZ introduced a new forecasting model in the second half of 2013. To the extent that RBNZ forecasts are behind figure 2, then the performance of these forecasts improved in 2016-2020 relative to 2011-2015 (noting the upward bias).

5.54 In its 2023 memo, Motu submitted that all forecasting methods delivered poor performance.[324] It no longer supported the market-derived method, and it provided no new or updated evidence on their relative performance. We consider that, given the magnitude of socioeconomic developments after 2020, we would at least require clear evidence that the market-derived method performed (and is expected to continue to perform) better than the status quo in promoting our IM Review overarching objectives.

5.55 Finally, Motu also submitted that "inflation expectations have become unanchored". This point is important because our status quo method reverts to the target midpoint of two percent in year three. So, to the extent that longer term inflation expectations are materially different from two percent, and this results in inflation outcomes that are also materially different from two percent, then this would be a weakness of the current method. Here is the latest data on inflation expectations from RBNZ:[325]

> The mean one-year-ahead inflation expectation decreased from 5.11% to 4.28%, 83 basis points lower than the last quarter. This was the largest drop recorded since June 2020.

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323 Motu "Memorandum: Performance Inflation Forecasting Problem" – 'Submission on IM Review CEPA report on cost of capital' (prepared for Vector, 9 November 2020), pp. 2, 6, 10.

324 Motu "Memorandum: Update on the Difficulties of Forecasting Inflation"(prepared for Vector, 13 March 2023).

325 Reserve Bank of New Zealand "Survey of expectations (Business) - April 2023" (12 May 2023), p. 1.

> The mean two-year-ahead inflation expectation decreased by 51 basis points to 2.79% from 3.30% in the previous quarter, falling back into the target inflation band of 1-3% for the first time since December 2021. The spread of the responses narrowed compared to the previous quarter, with a lower quartile of 2.00% and an upper quartile of 3.00%.
>
> The mean five-year-ahead inflation expectation was 2.35%, down slightly from 2.36% in December 2022. The mean ten-year ahead inflation expectation increased by 9 basis points to 2.28% from 2.19% in the previous quarter.

5.56 Looking at this evidence, we agree that one and two-year ahead inflation expectations are above the two percent target (although the two-year ahead one has returned to within the target band of one percent to three percent), but five and 10-year-ahead ones are closer to two percent rather than three percent. Our reading of the data is that, rather than a "broken businesses' belief in price stability"[326] and inflation expectations becoming fully unanchored, businesses expect inflation to take between two to five years to return to target, which is consistent with the RBNZ's forecasts (where CPI returns to target in Q4 2025).

5.57 To conclude, it is possible that over any given period, one or other method will, ex post, have more accurately predicted past inflation. However, we have seen no evidence that, ex ante, any of the other methods are expected to outperform our preferred approach in achieving the IM Review overarching objectives, particularly because it incorporates insights that the other methods provide.

Survey-derived forecasts

5.58 This option would use the results of survey(s) of inflation expectations of different economic actors. The main groups include business leaders (ie, price setters) and households.[327] We also include within this option professional forecasters (eg, banks).

5.59 There is evidence that RBNZ forecasts for one and two years ahead are as good or better than those of non-RBNZ forecasters: [328, 329]

> Besides the May 2020 MPS – where the Reserve Bank underestimated inflation relative to the private banks' forecasts – the Reserve Bank's inflation forecasts appear to have been roughly in line with private banks'.

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326 Motu "Memorandum: Update on the Difficulties of Forecasting Inflation"(prepared for Vector, 13 March 2023), p. 3.

327 See for example the RBNZ's survey of expectations here: RBNZ "Survey of expectations"; or its survey of household inflation expectations here: RBNZ "Survey of household inflation expectations"

328 Reserve Bank of New Zealand "Evaluating the Reserve Bank's Forecasting Performance" (November 2022), p. 21.

329 Reserve Bank of New Zealand "Evaluating the Reserve Bank's Forecasting Performance" (June 2016), p. 10.

> …the Reserve Bank returned the best forecast performance over the period with regard to inflation. On the one-year ahead method, the RMSE for the Reserve Bank was 0.91 while the next best forecaster recorded a score of 1.07. The Reserve Bank also performed relatively well on the two-year ahead measure. All forecasters over-estimated the amount of inflation in the economy, but the bias for the Reserve Bank was slightly lower than other forecasters.

5.60 Furthermore, we understand that RBNZ uses survey information to inform its model-based inflation forecasts.[330]

5.61 Beyond the RBNZ's forecasting horizon (currently 13 quarters ahead), survey-derived inflation expectations remain anchored around the two percent midpoint.[331] Therefore, there is likely to be little difference between the status quo and using this survey data.

Model-derived forecasts

5.62 This option would involve us building and maintaining an economic model to forecast inflation. We did not consider it further because the RBNZ and professional forecasters already use economic models to produce their forecasts. Replicating this by producing our own model would not be justified, in our view, mainly because the unlikely benefits (better forecasts compared to those under the status quo, or other professional forecasters) are unlikely to outweigh the certain costs (building and maintaining a complex model of the New Zealand economy).[332]

Topic 5b – Inflation risk allocation and compensation

5.63 The unexpected increase in inflation since the last IM Review has highlighted issues with the way our regulatory regime assigns inflation risk between suppliers and consumers. The current assignment of inflation risk benefits neither suppliers nor consumers as it makes revenue unnecessarily uncertain, can result in windfall gains and losses, and may affect incentives to invest.

5.64 We summarise our draft decisions below, then set out our analysis of the problem definition and potential solutions.

5.65 Note that when we discuss 'inflation' throughout this Chapter we are referring to economy-wide CPI inflation.

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330 Gunes Kamber, Chris Mcdonald, Nick Sander and Konstantinos Theodoridis "A structural model for policy analysis and forecasting: NZSIM" (November 2015). s 5.

331 For business see: Reserve Bank of New Zealand "In Retrospect: Monetary Policy in New Zealand 2017-22" (10 November 2022), p. 98; for households see: RBNZ "Household inflation expectations"

332 For a description of RBNZ's current model see: Gunes Kamber, Chris Mcdonald, Nick Sander and Konstantinos Theodoridis "A structural model for policy analysis and forecasting: NZSIM" (November 2015).

Draft decisions

5.66 We have decided to amend the EDB IMs and GTB IMs to:

5.66.1 wash-up allowable revenue for the first year of a regulatory period when inflation differs from expected inflation; and

5.66.2 exclude from the annual revenue wash-up the difference between:

5.66.2.1 the return on debt for the year (including forecast inflation); and

5.66.2.2 the return on debt for the year updated for actual inflation.

Problem definition

5.67 At a price-quality path reset, we apply our key economic principle of ex-ante real FCM in relation to the RAB, to give suppliers the opportunity to earn a normal return on their efficient investments, and more generally the economic principle of ex-ante real NPV=0 in relation to net revenue, consistent with s 52A(1)(a) and (d).[333]

5.68 Following a price-quality path reset, as inflation differs from our forecast, there will be unexpected consequences for revenue and costs. Unexpected inflation may result in some periods where there are windfall gains for suppliers and other periods where there are windfall losses, compared to what was expected at the reset. This is consistent with ex-ante real NPV = 0 if we expect the periods of windfall gains to offset the periods of windfall losses.

5.69 The annual revenue wash-up process, however, can be designed to account for unexpected inflation in a way that reduces the likelihood of there being periods of windfall gains and losses. We have reviewed the annual revenue wash-up process and consider there are four issues in that respect:

5.69.1 the first is that we do not wash-up EDB and GPB revenue for inflation in a way that is consistent with the assumption underlying the hybrid cost of debt approach. This underlying assumption is that suppliers can hedge the risk-free rate component of the cost of debt for a regulatory period; that is, our benchmark firm fixes its debt servicing costs in nominal terms which is consistent with how we set the WACC for a regulatory period. However, the annual wash-up assumes our benchmark firm incurs annual debt servicing costs that vary with inflation;

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333 The High Court has approved of our application of the FCM and NPV=0 principles and their relationship with the s 52A purpose (see *Wellington International Airport Ltd v Commerce Commission* [2013] NZHC 3289, at [256]).

5.69.2 the second is that we do not wash-up EDB and GTB revenue for inflation in the first year of a regulatory period;

5.69.3 the third is that we do not wash-up Transpower's revenue, nor adjust its RAB, for actual inflation; and

5.69.4 the fourth is that the IRIS mechanism penalises suppliers for costs that are uncontrollable due to inflation.

Stakeholder views

5.70 We raised the issues related to inflation in Chapter 5 of the Process and Issues Paper.[334]

5.71 We have grouped the issues raised in submissions in response to our consultation into the two categories.

5.72 The first issue was that inflation was creating a problem for EDBs and GPBs because they were not being compensated for the higher interest payments (above what we allow for in the cost of debt) associated with higher inflation.

5.72.1 Frontier's report for Transpower explains that the cashflow allowance to EDBs and GPBs can, under certain circumstances, be insufficient to pay the full amount of interest each year.[335]

5.73 Suppliers have submitted that there is a debt compensation issue associated with the current treatment of EDBs and GPBs (ie, inflation indexation of the RAB). After reviewing this matter, we have concluded that the debt compensation issue only arises when inflation is less than expected.

5.74 As we explain later in this section, we consider the current annual revenue wash-up needs to be changed because it creates excessive variation in net cash flows (windfall gains and losses) and is inconsistent with the assumption that suppliers can hedge the risk-free rate component of the cost of debt for the regulatory period. Our proposed change would also mitigate the debt compensation issue.[336]

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334 Commerce Commission "Part 4 Input Methodologies Review 2023 Process and issues paper" (20 May 2022), para 5.184-5.225.

335 Transpower NZ Ltd "Submission on IM Review Process and issues paper and draft Framework paper" (RAB indexation –11 July 2022), pp. 8-9.

336 While both approaches adequately compensate debt costs, the indexed RAB approach backloads cashflows relative to the unindexed RAB approach. So, a firm in identical financial circumstances will have more cashflow to cover debt costs in the short term under the unindexed approach relative to the indexed one.

5.75 The debt compensation issue has been used as an argument for switching the EDBs and GPBs onto the Transpower method (ie, no inflation indexation of the RAB). It has also been used as an argument to change the form of indexation so that it is only the equity portion that is indexed for inflation.[337] However, we consider that our proposed change to the annual revenue wash-up deals with the debt compensation issue and better achieves our IM Review overarching objectives.

5.76 In our view, the proposal to not index the debt portion of the RAB would not address the exposure suppliers face when their revenue is adjusted for inflation each year in a way that is inconsistent with their (fixed) cost of debt.[338] Not indexing the debt portion of the RAB would also change the depreciation profile so that revenue would be brought forward compared to indexing the full RAB, although revenue would not be brought forward by as much as if the RAB was not indexed.

5.77 The second issue raised in submissions was that inflation had highlighted a difference in the regulatory treatment of the RABs, and consequently cashflows, of Transpower versus the EDBs and GPBs and that this may not be appropriate (the EDBs and GPBs have their RABs indexed whereas Transpower does not).

5.78 We have summarised points raised by submitters and discussed and made draft decisions on them in topic 3a (from paragraph 3.12) rather than in this section.

Proposed solution

5.79 Our process of responding to the issues regarding inflation has involved:

5.79.1 considering our previous decisions and reasoning;

5.79.2 developing a demonstration model to show how NPV=0 is achieved under the different regulatory accounting methods considered in this section; and

5.79.3 assessing our proposed solutions against our IM Review decision-making framework.

5.80 We have published the demonstration model on our website.

337 Unison – "Submission on IM Review Process and Issues paper and draft Framework paper" (11 July 2022), para 3b.

338 Our proposed change to the annual revenue wash-up would be required irrespective of the form of indexation applied to suppliers (e.g. full indexation, hybrid indexation or no indexation).

Finding 1. The annual revenue wash-up for PQ-regulated suppliers can create windfall gains/losses (debt compensation issue)

5.81 Our first finding is that the annual revenue wash-up for inflation can cause PQ-regulated suppliers (other than GDBs) to earn excess revenue when inflation is higher than expected and have a revenue shortfall when inflation is lower than expected.

5.82 We highlighted the issue of debt compensation in our Process and issues paper.[339]

5.83 As we assume debt costs are fixed in nominal terms (which is also our assumption underlying the hybrid cost of debt – ie, that suppliers can hedge the risk-free component of their cost of debt) there is a risk to suppliers when inflation is lower than predicted at the reset. In that situation the annual revenue wash-up could create a cash flow concern.[340]

5.84 There is no cashflow concern (but there is over-compensation) when inflation is higher than predicted, because in that situation the annual revenue wash-up creates excess revenue. This is because debt costs are fixed in nominal terms but the annual revenue wash-up in effect assumes debt costs are variable.

5.85 Frontier for Vector calculated that the over-forecasting of inflation in the past has resulted in energy suppliers in total being undercompensated by $250 million between 2013-14 and 2019-20, with Vector undercompensated the most by over $80 million.

5.86 However, during the current regulatory period, inflation has been higher than expected and this will result in overcompensation for EDBs and GPBs.[341]

5.87 We have calculated the net effect for Vector over the period 2015-16 to 2021-22 is -$3 million. Based on the latest Reserve Bank forecasts, the net benefit to Vector over the period 2015-16 to 2024-25 is $166 million.

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339 Commerce Commission "Part 4 Input Methodologies Review 2023 Process and issues paper" (20 May 2022), para 5.195.

340 This bankruptcy risk was noted by Dr Lally at Martin Lally "Review of Further WACC Issues" (note prepared for New Zealand Commerce Commission, 22 May 2016), p. 5.

341 However, the current IRIS mechanism results in a financial penalty when inflation is higher than expected and a reward when inflation is lower than expected (see section 4c for our proposal to change the IRIS mechanism from nominal to real).

5.88 Our view is that these revenue windfall gains and losses are due to the inconsistency between the assumption in the annual revenue wash-up, which is that nominal debt costs are variable, and the assumption in the WACC, which assumes nominal debt costs are fixed. In particular, we note the submission by Frontier Economics which proposes we change the IMs to address this inconsistency.[342]

5.89 We also note Competition Economist Group's (CEG) report to Vector, which indicates suppliers cannot do anything about this mismatch between the assumption in the WACC and the assumption in the annual revenue wash-up:

> …there is simply no method available to EDBs to hedge their debt portfolios to the real return on debt set in the IMs.[343]

5.90 In addition to CEG's point that suppliers cannot hedge their portfolios to the real return, there are two other reasons why we consider this issue needs to be corrected (for application after the next reset). The first is because it can cause windfall gains and losses. The second is that it is possible over time that the under and over-compensation may not balance out. There may be a greater potential for inflation to be significantly above forecast than below forecast, although we note the recent historical record of inflation being slightly below forecast for an extended period. If this persisted for long enough it could result in under-compensation dominating.

5.91 We are proposing to amend the IMs for EDBs and the GTB to provide an adjustment to the annual revenue wash-up to account for debt servicing costs being fixed in nominal terms. No IM change is needed to provide for this in the case of Transpower and GDBs, as their IMs already permit us to do so at the IPP and DPP reset, respectively,[344] if we decide at that point that it would promote the Part 4 purpose.

5.92 When inflation is higher than expected, the annual revenue wash-up would not increase revenue for the entire amount of inflation, but rather, a lesser amount to exclude the effect inflation has on the cost of debt.

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[342] Frontier Economics "Regulatory inflation and return on debt allowances" (note prepared for New Zealand Commerce Commission, 17 May 2021), pp. 5-6.

[343] CEG "CPI indexed debt a panacea for EDB's" – 'Submission on IM Review CEPA report on cost of capital' (report prepared for Vector, 3 February 2023), para 18.

[344] The Transpower IMs would allow us to provide for this in the IPP as an EV account entry for the purpose of the forecast EV adjustment. The GDB IMs would allow us to provide for this in setting the DPP price path by requiring us to specify 'allowable notional revenue' as a function of starting price (for the first year of the regulatory period) and as a function of CPI (for each subsequent year).

5.93 Conversely, when inflation is lower than expected, the annual revenue wash-up would not decrease revenue for the entire amount of inflation.

5.94 The proposed change protects suppliers from a potential revenue shortfall (overpayment) in situations where revenue would otherwise have been decreased (increased) by the full amount of inflation, consistent with NPV=0.

Finding 2: We do not wash-up revenue for EDBs or the GTB when inflation differs from expected inflation in the first year of a regulatory period

5.95 When we adjust EDB and GTB revenue for outturn inflation, we do so for each year of a regulatory period except the first. This issue is the same as noted from Chorus' submission, where the first year of the regulatory period for Chorus's fibre price-quality path happened to coincide with a year of unexpectedly high inflation.[345] This has not been an issue for GDBs because we have set their allowable notional revenue for the first year using lagged actual inflation.[346] As with finding 1, no IM change is needed to provide for this in the case of Transpower as the IMs allow us to do so at the reset, if we decide at that point that it would promote the Part 4 purpose.

5.96 The absence of a first-year wash-up is not necessarily a concern if our inflation forecasts are consistent with ex-ante real NPV = 0. That is, there will be times when we over-predict and times when we under-predict inflation, which is consistent with ex-ante real NPV=0.

5.97 However, this has highlighted that a supplier faces the risk that our inflation forecasts result in years when inflation is much higher than expected.

5.98 EDBs and the GTB have not been affected as significantly as Chorus because the actual CPI in the first year of their DPP3 regulatory periods was lower than forecast (actual of 1.46 percent vs. forecast of 1.75 percent).

5.99 We are proposing to have the EDBs and the GTB revenue wash-up for inflation account for any variation between predicted and outturn inflation for the first year of a regulatory period. If inflation spikes again in the first year of a regulatory period, EDBs and the GTB would have their revenue adjusted.

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345 As discussed in Incentia Economic Consulting "Options to address the gap in CPI inflation correction" (report prepared for Chorus, 11 July 2022).

346 Clause 3.1.1(2)(a) and Schedule 4 of the *Gas Distribution Services Default Price-Quality Path Determination 2022* [2022] NZCC 19.

5.100 We note that Incenta Economic Consulting's (Incenta) report for Chorus suggested another option for correcting the absence of the wash-up in the first year of a regulatory period.[347] This option is to dispense with the annual revenue wash-up for inflation and instead recalculate revenue at the end of the regulatory period after actual inflation becomes available (the calculation would use the corrected nominal WACC). However, we agree with Incenta that this would impose additional administrative cost. It would also not have the benefit that the annual wash-up provides of having revenue adjusted on an annual basis.

Finding 3: Transpower is exposed to inflation risk

5.101 Our third finding is that inflation has highlighted an inconsistency in the regulatory treatment of Transpower versus the EDBs in terms of inflation risk exposure at a RAB level and at a revenue level.

5.102 At the revenue level, we outline at paragraph 5.109 the adjustment that would be needed to address this inconsistency.

5.103 At the RAB level, the inconsistency would no longer be an issue if, in our final decision, we decided to adopt our draft decision in topic 3a (to index Transpower's RAB). We explain here what would need to change if, after taking account of submissions, we decided it would better achieve our IM Review overarching objectives to adopt:

5.103.1 Alternative A (more favoured): as outlined at paragraph 3.66.1, under this alternative, we would delay RAB indexation to start from RCP5 onwards and implement for RCP4 a RAB inflation wash-up.

5.103.2 Alternative B (less favoured): as outlined at paragraph 3.66.2, under this alternative, we would retain the status quo (not indexing Transpower's RAB) and implement for RCP4 the RAB inflation wash-up.[348]

5.104 We noted in the Process and Issues Paper that we do not wash-up Transpower's RAB for inflation. We also do not provide an annual revenue wash-up.

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347 Incenta Economic Consulting "Options to address the gap in CPI inflation correction" (report prepared for Chorus, 11 July 2022), s 4.3.

348 For either alternative, proceeding with the RAB inflation wash-up would not require a change to the Transpower IMs, but would rather be something we would consult on and decide as part of the IPP reset for RCP4, if we considered in that context that doing so would better promote s 52A.

5.105 The RAB wash-up issue was also identified during the 2016 IM Review, when we proposed the following:

> To create an annual capital charge adjustment through the MAR wash-up. The adjustment would be equal to the difference between the actual and forecast inflation rate, multiplied by the opening RAB. [349]

5.106 Transpower submitted in 2016 that it did not support the adjustment we proposed then:

> However, we agree with the Commission's suggestion that "the net benefits of the proposed change may be relatively small, since inflation forecast errors are likely to be uncorrelated and inflation has low variability in New Zealand"[350]

5.107 Inflation has since turned out to be more variable than expected. There are now significant consequences for Transpower for not washing-up inflation.

5.108 Transpower has not submitted on this matter to date as part of this IM Review.[351]

5.109 The adjustments that would be needed are a wash-up for Transpower's RAB for actual inflation and to introduce an annual revenue wash-up. No IM change would be needed to provide for either of these as the Transpower IMs already permit us to do so at the IPP reset, [352] if we decide at that point that it would promote the Part 4 purpose.

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349 Commerce Commission "Input methodologies review decisions Topic paper 1: Form of control and RAB indexation for EDBS, GPBs and Transpower" (20 December 2016), para 320-321.

350 Commerce Commission "Input methodologies review decisions Topic paper 1: Form of control and RAB indexation for EDBS, GPBs and Transpower" (20 December 2016), para 322.

351 Transpower's submission on our Process and issues paper focussed on the consequences to Transpower if it were switched to indexation. We discuss this in relation to our draft decisions on topic 3a. Transpower NZ Ltd "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), pp. 26-27.

352 The Transpower IMs would allow us to provide for each adjustment in the IPP as an EV account entry for the purpose of the forecast EV adjustment, if we decide at that point that it would promote the Part 4 purpose. The RAB inflation wash-up would not be a revaluation.

5.110 We have demonstrated in our modelling, which we have published on our website, that introducing an annual revenue wash-up for inflation would be insufficient to compensate Transpower for inflation risk if Transpower's RAB remained unindexed. A wash-up for Transpower's RAB for actual inflation at the start of each regulatory period would also be required. This adjustment would result in the taxation building block varying by an amount that is consistent with the effect inflation has on revenue and costs.[353] This would not be required for EDBs and GPBs (or Transpower under our topic 3a draft decision to index its RAB) because their RABs are indexed to inflation.

5.111 The current lack of such a wash-up for the RAB for Transpower exposes it and consumers to inflation risk. Over RCP3, because actual inflation has been higher than forecast, we estimate this effect is likely to be approximately negative $680 million. By contrast, in RCP2, inflation was lower than forecast, so the estimated effect was approximately positive $160 million.[354]

5.112 As we note in topic 3a, while the three options (our draft decision to index Transpower's RAB with effect at the RCP4 reset, Alternative A, and Alternative B) equally protect both Transpower and consumers from inflation forecast risk (consistent with s 52A(1)(a)), for the reasons we discuss in topic 3a, our draft decision is more likely to better promote s 52A(1)(b) in supporting a more efficient price profile, followed by Alternative A and then Alternative B.

Finding 4: The IRIS mechanism penalises suppliers for costs that are uncontrollable due to economy-wide inflation

5.113 Our fourth finding is that the current opex IRIS mechanism for Transpower and EDBs, and current capex IRIS for EDBs, penalises suppliers for costs incurred that are uncontrollable due to inflation.[355] We have addressed this issue in Section 4c (4.1374.135 onwards) for EDBs and Transpower.

Implementation

5.114 This section outlines the proposed IM changes that we consider are required to implement the findings above (except for finding 4, which is discussed in chapter 4 section 4c).[356]

353 If there was no taxation, there would be no need for this RAB adjustment. Also, if outturn inflation is equal to expected inflation, there would be no need for this RAB adjustment.

354 Note that these amounts are estimates based on high level calculations and not on Transpower's actual models, as these are not produced by us.

355 Transpower's capex incentive mechanisms already take actual CPI into account in the incentive calculations.

356 Some aspects of our findings do not need IM changes to implement. For example, if we decide at the IPP reset that it would promote s 52A to implement a wash-up for inflation to Transpower's revenue (finding

5.115 The EDB IMs and GTB IMs currently have an annual wash-up to revenue for the difference between actual and forecast inflation. We are proposing two changes for findings 1 and 2, including new defined terms where appropriate:

5.115.1 adjust revenue for the first year of a regulatory period by the difference between forecast CPI and actual CPI; and

5.115.2 subtract from annual revenue the revenue debt adjustment.

2a) and to implement a wash-up to Transpower's revenue to account for debt servicing costs being fixed in nominal terms (finding 3), we could do so under the current IMs.

Chapter 6 Innovation incentives for EDBs and Transpower

Purpose and structure of this chapter

6.1 Under s 52A(1)(a) of the Act, one of the four outcomes of a workably competitive market that we must promote under Part 4 is that regulated suppliers have incentives to invest and innovate, including in replacement, upgraded, and new assets.[357]

6.2 This chapter focuses on specific tools for promoting innovation under our regulatory regime, including the scope for regulatory sandboxes, the innovation project allowance (IPA) provided for under the EDB IMs, and how we incentivise expenditure across regulatory periods for both EDBs and Transpower. This is especially important in the context of electrification and decarbonisation, where non-traditional solutions may reduce the costs associated with the transition towards carbon zero.

6.3 While our Report on the Review sets out our draft decisions on all IM policy decisions (including mechanisms that promote innovation) for all regulated sectors, this chapter focuses on EDBs and Transpower because:

6.3.1 most submissions we have received on innovation focused on tools and aspects of innovation related to price-quality regulated EDBs;

6.3.2 submissions from GPBs regarding innovation focussed on preparing for the shift away from natural gas distribution towards renewable gases (when we reset the gas DPP, we provided opex funds for these investigations and consider that this continues to be appropriate);[358, 359] and

6.3.3 Airports are subjected to ID regulation only and we are not aware of any constraints the IMs place on their ability to innovate. Some airport related submissions emphasised the need to support New Zealand's decarbonisation goals by enabling innovative approaches across all the sectors we regulate under Part 4.[360]

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357 Note that we may not treat income generated from innovative solutions sold by one supplier to another as regulated income.

358 First Gas Limited "Submission on IM Review Process and issues paper and draft Framework paper" (13 July 2022), pp. 3, 32.

359 Commerce Commission "Default price-quality path for gas pipeline businesses from 1 October 2022 – Final Reasons Paper" (31 May 2022), para X13.5 and X31.2.1.

360 For example Air New Zealand "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 3.

6.4 Our main Part 4 tools for achieving this can be split into tools that only apply to price-quality regulated EDBs and Transpower, and tools that apply to all EDBs and Transpower.

6.4.1 For all EDBs and Transpower, we set information disclosure requirements. We have recently introduced new reporting requirements on EDBs' innovation practices in their asset management plans.[361]

6.4.2 For price-quality regulated EDBs and Transpower, we also set a price-quality path (which includes quality standards) and have incentive mechanisms. Together, this encourages suppliers to innovate to achieve and retain cost savings (eg, IRIS), to improve quality relative to forecasts (eg, quality incentive scheme), and to make the right investment at the right time.

6.5 The chapter discusses:

6.5.1 how the Part 4 regulatory regime promotes innovation for EDBs;

6.5.2 Topic 6a: regulatory sandboxes under Part 4 for EDBs; and

6.5.3 Topic 6b: innovation schemes under price-quality regulation.

How the Part 4 regulatory regime promotes innovation for EDBs

6.6 The regime currently promotes innovation for EDBs in these ways:

6.6.1 we require information disclosure of EDBs asset management plans which includes reporting requirements on each EDBs innovation practices;

6.6.2 our summary and analysis of disclosed information related to innovation highlights developments in innovation and good practice by regulated suppliers;

6.6.3 we set default price-path revenue allowances that can be spent in the manner a supplier sees fit. This approach provides significant flexibility to suppliers to choose the work they undertake (including in respect of innovation). If that approach does not suit the particular circumstances of a supplier, it can apply for a customised price-path;

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361 Commerce Commission "Targeted Information Disclosure Review – Electricity Distribution Businesses – Final decision paper – Tranche 1" (25 November 2022), p. 28, introduced new reporting requirements on EDBs' innovation practices into the asset management plan required under the EDB ID determination. At paragraph 1.22 of our Tranche 1 final decision, we also noted that innovation is touched on in our Tranche 1 decisions but will continue to be a focus for us beyond this review, and has implications wider than ID. For certain issues touched on in Tranche 1, we have signalled in the decision paper that we intend to follow up in Tranche 2 or in a future project.

6.6.4 the benefits of innovations that lead to cost savings within the regulatory period with suppliers are shared via expenditure incentive schemes such as IRIS;

6.6.5 we provide expenditure incentive schemes that make EDBs indifferent between opex and capex solutions from a regulatory financial perspective, removing potential financial barriers to non-network solutions;

6.6.6 the quality standards incentive scheme provides incentives for innovation that improves the quality of service supplied to consumers relative to the ex-ante forecast; and

6.6.7 the provision for the IPA is intended to improve incentives to innovate and encourage distributors to try new ways of doing business.[362]

6.7 The IMs and Part 4 regulation are part of wider regulatory system concerned with encouraging innovation and investment. There are also several external organisations who provide innovation funding and support.[363]

6a: Regulatory sandboxes for EDBs

6.8 Some suppliers felt that our existing innovation tools were not sufficient to promote innovation and that the addition of a regulatory sandbox would better promote the Part 4 purpose.

6.9 Formal regulatory sandboxes have been implemented overseas, and an informal one by the Electricity Authority, to increase the flexibility of regulatory regimes to better enable innovation.[364] Sandboxes aim to reduce the financial risk and/or compliance risk of innovative activities. Sandboxes may provide for upfront flexibility built into the rules, ad-hoc rule exemptions, or guidance on how the rules apply.

6.10 Tools used by these schemes can be broadly broken down into three categories:

6.10.1 formalised regulatory guidance, where the regulator works with suppliers to navigate regulatory rules, giving suppliers confidence that they will avoid penalties incurred for breaching regulatory rules;

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362 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), para 6.53.

363 For example see the GIDI fund and Callaghan Innovation.

364 For examples of regulatory sandboxes run by overseas regulators see Ofgem "What is a regulatory sandbox?" (7 September 2018); Ontario Energy Board "Innovation Sandbox" (2022)

6.10.2 regulatory rules exemptions, where suppliers are granted short term, limited scope exemptions to regulatory rules that may be standing in the way of an innovative project; and

6.10.3 regulatory rules changes, where suppliers and the regulator work together to draft a change to a specific regulatory rule which is then trialled on a limited time basis by the supplier.

Draft decision

6.11 We consider the IMs generally enable the desired outcomes of regulatory sandboxes and do not propose to change them for this purpose. Our view is that the current rules afford a large degree of flexibility for suppliers to innovate, and, we have not been presented with evidence of specific examples where innovation has not occurred that a regulatory sandbox would have enabled.

Problem definition

6.12 The outcomes of innovation are risky. Innovation may be unsuccessful or not provide the expected benefits. In a workably competitive market, the benefits of successful innovation are sufficiently captured by the innovating business to encourage businesses to innovate. In the long run, the gains from innovation are shared with consumers including through lower prices.

6.13 In a regulated environment, regulatory rules could be a barrier to innovation. Specifically, efficient innovations may be deterred if the expected benefits/returns allowed under the regime do not sufficiently offset the risks of failure. For example, periodic price resets can limit a regulated supplier’s ability to profit from successful innovation.

6.14 Price-quality regulated suppliers are subject to incentives that reward or penalise them for over- or under- performing compared to their ex-ante price and quality forecasts which interact with incentives to innovate. While the expenditure incentive schemes cap the upside risk for suppliers by limiting their ability to benefit from underspending their allowances, the schemes symmetrically limit the downside risk of overspending as suppliers only bear 23 percent of any overspend incurred with consumers bearing the rest.

6.15 However, price-quality regulated suppliers may not benefit from innovations that would increase revenue, except in the case where they price below the revenue cap prior to the innovation.

6.16 The electricity sector is in a period of change as the sector adapts to New Zealand's decarbonisation goals. Innovation will play an important role in this transition. The innovative approaches may involve small scale trials or proof of concept tests that run the risk of breaching regulatory rules. Increasing the ability for the regime to be responsive and provide flexibility surrounding regulatory rules may better promote the Part 4 purpose.

Proposed solution

6.17 As noted above, our draft decision is to make no changes to the IMs to enable a regulatory sandbox. The reasons for our draft decision are:

6.17.1 we consider we have sufficient flexibility between the tools of setting the price path, IRIS and the innovation project allowance to provide EDBs with financial incentives to innovate;

6.17.2 we already have broad scope to set flexibility regarding quality standards at the DPP reset (there are no input methodologies for quality standards); and

6.17.3 in our consultation and engagement with stakeholders, we sought examples of projects that would be possible in a regulatory sandbox, but due to our regulatory rules, are not currently viable. To date suppliers have not provided us with examples of any such projects.

6.18 To assess whether there was a need to implement a regulatory sandbox scheme we evaluated the existing Part 4 regime's ability to:

6.18.1 provide flexibility to innovate to suppliers regarding expenditure; and

6.18.2 provide flexibility to innovate to suppliers regarding quality.

Existing settings provide flexibility regarding expenditure

6.19 In setting the price path we set fungible expenditure allowances that suppliers can spend as they see fit. The IMs do not govern how we set capex and opex envelopes. Instead, in setting a price path we are guided by the Part 4 purpose, including incentives to innovate and invest.

6.20 IRIS provides expenditure-type neutral financial incentives within regulatory periods.[365,366] It provides innovation incentives in the following ways:

6.20.1 it shares with suppliers savings made by innovative approaches that lead to reduced costs within the regulatory period;

6.20.2 it equalises the incentive strength for capex and opex (within the regulatory period), so an innovative solution that saves on capex but requires additional opex (and vice versa) is desirable; and

6.20.3 it helps ensure the solution is viable from a purely financial perspective and removes potential investment timing distortions (without IRIS businesses may consider timing their investment to maximise the financial benefit).

6.21 The IPA was provided to ensure that suppliers receive some benefit from projects that would otherwise not be captured by the regime, for example if they occur only in future DPP periods.[367] While there are potential issues with the current IPA mechanism, our proposed amendments at 6.40 aim to improve the ability for us to provide better financial incentives to innovate, in line with s 52A(1)(a).[368]

Existing settings provide flexibility with quality standards

6.22 Quality standards are prescribed at a price-quality path reset, rather than in the IMs. Under s 53M(3), we have broad scope and flexibility to decide how to set and apply these standards in resetting the price-quality path, including excluding certain types of outages from the application of the relevant quality standards.[369] However, once set, the price-quality path cannot be reopened except under specific circumstances,[370] so any exclusions or carve outs need to be prescribed ex-ante, at the reset.

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365 For more details on the working of IRIS see Attachment B.

366 An issue arises when opex spend in the current regulatory period results in a capex savings in a future regulatory period. This issue and our proposed solution are discussed in 6b.

367 Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper” (27 November 2019), para 6.53.

368 For more detailed discussion on the changes to the IPA see topic 6b.

369 For example, we have set DPP/ CPP normalisation measures ex-ante so that:

(a) the extreme event quality standard excludes any unplanned interruption that is the result of major external factors; and

(b) the SAIDI/ SAIFI boundary value we set under para (1) of Schedule 3.2 of the DPP normalises an unplanned major event by replacing any half-hour within an identified major event that is greater than 1/48th of the boundary value with 1/48th of the boundary value.

370 s 52T(1)(c)(ii) and s 53ZB of the Act. There are legal constraints that limit our ability to provide ad-hoc exemptions to either price or quality, these are discussed in para 6.27.

6.23 It is outside the scope of the IM Review to determine how we will set quality standards at the next price-quality path reset. However, at that reset, we could consider excluding outages arising from innovative projects or initiatives from the scope of quality standards.[371] De-risking the quality path may encourage consideration of a wider set of solutions that might otherwise increase the risk of a breach of quality standards. Increasing the scope for a wider set of solutions could promote s 54Q by relying more on demand side management. This may involve consumers shifting their consumption of electricity conveyed by line to different times and/or using non-electricity line supplied electricity.

6.24 For substantial innovations that are likely to have a significant price or quality impact on consumers, a CPP may be a more appropriate tool, reflecting the greater scope to set a CPP price path and quality standards that better meet an individual supplier's circumstances.[372]

Alternatives considered

6.25 We have reviewed formal regulatory sandbox schemes in other jurisdictions and concluded that the benefits of these schemes are best provided for under the current IMs.

6.26 There are some tools commonly seen in regulatory sandboxes that are more difficult to provide for under Part 4 regulation. These are:

6.26.1 temporary rule exemptions such as 'IM/ price-quality exemption mechanisms'; and

6.26.2 temporary rule changes such as 'trial IMs/ price-quality provisions'.

6.27 While we can amend IMs and price-quality paths, our scope for providing for 'IM/ price-quality exemption mechanisms' or 'trial IMs/ price-quality provisions' during a regulatory period, unless explicitly provided for in advance, is limited because:

6.27.1 under s 53ZB(1) of the Act, if we amend an IM during a regulatory period, that amendment will not apply to the price-quality path until the next regulatory period;

6.27.2 once we have set the price-quality path for a regulatory period, under ss 52T(1)(c)(ii) and 53ZB(1) of the Act, we may only reconsider (and amend) the price path or quality standards during the regulatory period in circumstances specified in the IMs (ie, reopeners); and

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371 In the DPP context, such a decision would need to promote the Part 4 purpose, taking account of the s 53K purpose of DPP/CPP regulation where relevant.

372 s 53K of the Act.

6.27.3 at the IM level, we cannot make new IMs beyond those we have made under s 52T(1)[373] and we do not have the same scope to grant IM exemptions that we do in respect of ID requirements under the ID determination, as permitted under s 53C(3)(d).

6.28 This means that, while we have substantial scope to provide flexibility and to lower risk when setting the price-quality path,[374] and we can reconsider and reopen the price-quality path via an IM reopener, we have less scope under Part 4 to give ad-hoc exemptions or make trial rules during the regulatory period.

6.29 With respect to the issue of regulatory guidance, we already provide regulatory guidance on an ad-hoc basis – both informally when requested and in published written form.[375] A regulatory sandbox scheme could formalise and centralise such guidance. Enacting a formal guidance scheme could occur without an IM change, should we consider it would better promote the Part 4 purpose.

6.30 Understanding if there are specific regulatory rules that are standing in the way of innovation is important for the regime. We welcome further submissions on this subject.

Stakeholder views on sandboxing

6.31 Following our Process and Issues paper, we received multiple submissions highlighting regulatory sandboxes as a potential tool for improving incentives to innovate by providing flexibility. These submissions have been considered in reaching our draft decision.

6.32 Vector identified sandboxes as a tool used by overseas regulators submitting:[376]

> Energy regulators in Europe, the UK, Canada and Singapore have also introduced regulatory sandboxes to accelerate innovation and highlight changes needed in the regulatory framework as the energy sector transforms.

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373 Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022), para 2.65-2.74.

374 Noting that, in line with s 53K, our scope to provide flexibility and lower risk to better meet the particular circumstances of a supplier is greater under a CPP than it is under the DPP.

375 For example, see our Guidance on the s 54C definition of 'electricity lines services' under Part 4 of the Commerce Act, published with our response to Orion New Zealand Limited on their innovation allowance application in June 2021.

376 Vector "Submission on the Process and issues paper" (11 July 2022), para 45.

6.33 Orion submitted that we should investigate regulatory sandboxes:[377]

> Regulators are aware of these challenges and should provide regulatory mechanisms to enable this investment, in a timely manner in collaboration with sector entities. More flexible mechanisms such as regulatory sandboxes and access to in-period contingent allowances / wash-up adjustments are required. Orion attended a presentation on regulatory sandboxes presented by Stratagen in the U.S. The regulators took a forward-looking collaborative view on innovation and the use of Regulatory Sandboxes to accelerate innovation for an Evolving Electric Grid.

6.34 The ENA submitted supporting investigation into sandboxing stating:[378]

> Introducing regulatory sandboxes is one way the IMs can encourage innovation, and these should be considered by the Commission.

6.35 Following the "Forecasting and incentivising efficient expenditure for EDBs" workshop held on 7 November 2022 we sought submissions regarding which tools of a regulatory sandbox were important to suppliers. [379]

6.36 While we received submissions supportive of sandboxes that include the listed tools, we received no specific proposals regarding how they should be applied or what IM changes would be needed to support them.

6.37 On sandboxing tools Horizon submitted:[380]

> Agree with the concepts shown in staff presentation, slide 58 where Commission can provide advice and help without breaching regulatory rules, provide waivers from specific regulatory rules for a set period and provide a framework to test changes to the existing regulatory rules.

6.38 Also on sandboxing, Orion submitted:[381]

> Key ingredients we consider important for an effective regulatory sandbox are:
>
> • Application process to access funding
>
> • Fast turnaround on the rule making process e.g., less than 8 weeks duration with one round of consultation.
>
> • Clear demarcation between sandboxes and the use of the innovation allowance e.g., sand box could be more appropriate for larger or more complex projects
>
> • Funding should be up front

377 Orion "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 35.

378 Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 11.

379 Commerce Commission "IM Review 2023: Forecasting and incentivising efficient expenditure for EDBs - 'Full slide deck'" (7 November 2022).

380 Horizon Energy Group "Submission on Expenditure incentives EDB workshop" (8 December 2022).

381 Orion "Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 15.

• Upfront funding allows investment that may not have occurred otherwise.

• The ability for cross sector players to work together on an innovation will be important for supporting energy system outcomes

6b: Encouraging innovation and non-traditional solutions

6.39 We added the IPA at the EDB DPP3 reset in 2019 to encourage businesses to try new ways of doing business.[382] There has been limited interest in applying for the IPA, as implemented in DPP3, so far. Suppliers have asked us to improve the IPA so that it better incentivises innovation.[383]

Draft decision

6.40 Our draft decision is to amend and expand the IPA into the 'innovation and non-traditional solutions allowance' to enable more scope and flexibility to set a wider range of schemes to provide better incentives for innovation and non-traditional solutions, at DPP resets or when setting a CPP.

Problem definition

6.41 There are many facets to the 'innovation problem' (whereby less innovation-related activity may occur than the optimal amount for consumer outcomes in the longer term). This is reflected in the broad ranging submissions we received in relation to innovation.[384] Regulatory support for innovation or, more generally, non-traditional solutions that will support the transition to a lower carbon economy may take different forms.

6.42 For EDBs, the current IMs have mostly an enabling role in encouraging innovation, with implementation left to price paths.[385] The IPA provides for a mechanism under the DPP that helps incentivise innovation that provide benefits that are not captured by other incentive schemes within the regime.[386] The IPA, as implemented in DPP3, does this by allowing EDBs to recover a portion of the costs incurred in innovative projects (as a recoverable cost) subject to Commission approval.

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382 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), para 6.53.

383 See for example Vector "Cross-submission on IM Review Process and issues paper, and draft framework paper" (3 August 2022), para 32-37.

384 For example NERA Economic Consulting "Innovation under the DPP - potential barriers and solutions" (report prepared for 'Big six' EDBs, 20 December 2022).

385 We discuss the current role of Part 4 in promoting innovation at paragraph 6.6.

386 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), para 6.52.

6.43 Suppliers have shown limited interest in applying for the IPA as implemented in DPP3. To date, we have only had two formal applications to drawdown on the IPA. We have also had informal discussions with potential DPP3 IPA applicants.

6.44 The workings of the IPA featured in submissions from multiple suppliers. Several of the issues that suppliers raised with the IPA, such as the quantum of funds available and the ex-post nature, are related to how the IPA is implemented under the DPP.[387]

6.45 The DPP-related issues could be addressed in how we specify the IPA draw down at the next DPP reset, without changing the IMs. The IMs' current definition of 'innovation project allowance' does not prevent us from changing the amount available for draw down in the DPP and does not specify that the IPA must be an ex-post scheme. The current IMs provide some flexibility and scope to set the IPA mechanism in a way that better promotes the Part 4 purpose in the context of the DPP reset.

6.46 We also considered a specific problem related to innovation and non-traditional solutions: how to improve incentives for opex/capex trade-offs across regulatory periods. This may involve procuring services from flexibility service providers (opex) to efficiently defer investments to increase network capacity planned for future regulatory periods (capex). Several EDBs expect to increasingly use such solutions and several submissions raised that the current regulatory settings may discourage such efficient deferrals.

6.47 Considering the limited uptake of the IPA to date, and the volume of innovation/non-traditional solution related submissions (including complaints on the operation of the IPA), we have assessed whether the IM provisions for the IPA are fit for purpose and, if change is required, what changes would best IM Review overarching objectives.

Proposed solution

6.48 Our draft decision is to amend and expand the IPA to the 'innovation and non-traditional solutions allowance' mechanism to enable more scope and flexibility to set a wider range of schemes to provide better incentives for innovation and non-traditional solutions, at DPP resets or when setting a CPP.

6.49 Along with changing the IPA to become the 'innovation and non-traditional solutions allowance', we also propose to remove the associated definition of 'innovation project'. We describe the allowance in the box below.

387 Vector "Submission on the Process and issues paper" (11 July 2022), para 45; Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 9.

Figure 6.1 Proposed 'innovation and non-traditional solutions allowance'

Under the proposed ‘innovation and non-traditional solutions allowance', at the DPP reset or in setting a CPP:

- we would set the amount or amounts EDBs may recover with our approval
- we would specify the conditions under which EDBs may recover the amounts, which could include the delivery of a project, the achievement of particular outcomes, and penalties and rewards
- The allowance applies to DPPs and CPPs.

Consistent with s 53K, we would expect that:

- under a DPP, the allowance would be implemented so that it is available and relevant to all suppliers on the same types of conditions (ie, similar to the current innovation project allowance)
- under a CPP, the allowance could be implemented with supplier-specific conditions.

We provide examples of schemes that could be implemented under the allowance in a DPP and CPP in Attachment C.

6.50 The differences between the status quo (ie, the 'innovation project allowance' and the 'innovation project' definitions) and the proposed 'innovation and non-traditional solutions allowance' are:[388]

6.50.1 The IPA does not allow us to set schemes that contain rewards or penalty elements (it just provided a simple allowance for drawdown).

6.50.2 The 'innovation project' definition may limit the implementation of schemes that encourage innovative or non-traditional solutions but are outside the definition's scope (even if encouraging those solutions better promotes the long-term interest of consumers).

[388] Both the status quo and the proposal are implemented to apply under price-quality regulation by means of a recoverable cost.

6.51 The changes we are proposing provide a wider scope at the DPP reset or in setting a CPP to implement schemes that we consider better promote the Part 4 purpose. The proposed changes allow us to:

6.51.1 Provide for penalty/reward elements to better incentivise specific outcomes, such as the efficient capex deferral using non-network solutions to lower prices paid by consumers. Providing for this in the IMs will promote certainty as to the Part 4 rules – ie, the IM purpose in s 52R – more effectively.

6.51.2 Provide for schemes that encourage (or do not discourage) solutions that are not strictly speaking innovative but traditionally not have been used or widely used by a specific supplier or, more generally, suppliers in New Zealand. For example, the proposed changes provide scope for implementing a solution to the problem relating to opex/capex trade-offs across regulatory periods, discussed at paragraph 6.46 when setting a price-path.

6.51.3 Set more than one scheme to address different issues. For example, we could set a general innovation funding scheme, as well as a scheme that improves incentives for opex/capex trade-offs across regulatory periods (noting that we would have to have regard to the s 53K purpose of DPP/CPP regulation, which we expect would limit the number of schemes that could operate concurrently in the DPP context).

6.51.4 Make it explicit that the 'innovation and non-traditional solutions allowance' applies to CPPs. This improves certainty (noting that a CPP provides more scope for engaging with supplier specific issues, including in relation to innovation).

6.52 NERA on behalf of the 'Big 6' EDBs submitted that the current definition of 'innovation project' found in the IMs is imprecise, which has caused confusion about whether a project will be considered eligible.[389]

6.53 We agree with submitters that the existing 'innovation project' definition in the IMs is imprecise. We consider that removing the definition from the IMs altogether and specifying all the criteria in a DPP or CPP determination is preferable to increasing prescription in the IMs. We detail our consideration of more specificity of the innovation project definition below.

389 NERA Economic Consulting "Innovation under the DPP - potential barriers and solutions" (report prepared for 'Big six' EDBs, 20 December 2022), p. 15.

6.54 Removing the 'innovation project' definition from the IMs and leaving the allowance criteria to a DPP or CPP reset would improve the responsiveness of DPPs and CPPs (for example, to new information available at the time of setting a price-quality path).

6.55 These changes would also provide the scope to calibrate incentive schemes at a DPP or CPP reset in a way that better promotes the Part 4 purpose. Depending on the scheme or schemes we choose to implement when setting a price-path, the allowance may promote s 54Q. For example, a solution that improves incentives for opex/capex trade-offs across regulatory periods (discussed at paragraph 6.46 and in Attachment C) may encourage suppliers to increase their use of demand side management (including by using non-traditional solutions).

6.56 We consider the above changes are the best balance between promoting incentives to innovate and invest under s 52A(1)(a), and the s 52R IM purpose of promoting certainty to suppliers as to our rules and processes.

Alternative solution: shift prescription out of the DPP into the IMs

6.57 As raised by Nera, the 'innovation project' definition in the IMs may be considered imprecise and has caused some confusion. We considered changing the definition of ‘innovation project’ to better emphasise the characteristics of innovative projects. For example, innovative projects tend to be relatively risky, and in workably competitive markets potentially produce relatively higher returns or relatively high losses.

6.58 Providing for more specificity on what an innovation project is would improve certainty. However, it could also limit responsiveness of price-quality regulation at a time when the pace of change in the sector is faster than previously. We recognise that suppliers may require more information on what solutions may qualify under the proposed broader definition or the current IPA definition (as implemented in a DPP or CPP). We consider that guidance is likely more effective at clarifying implementation matters than increasing the specificity of the criteria for an 'innovation project' in the IMs.

Alternative solution: provide also for other solutions in the EDB IMs

6.59 As discussed at paragraph 6.46 we received several submissions in relation to an innovation or non-traditional solutions related problem.

6.60 This issue was identified in submissions by Wellington Electricity, Transpower and NERA on behalf of the big six EDBs.

6.61 NERA's report for the big six EDBs states that:[390]

> 35. The short regulatory period is a final regulatory parameter that may result in a material barrier to innovation. New Zealand's current regime is a regulatory period of five years, which means that an EDB is only compensated for generating efficient savings within a five-year period. Accordingly, any efficient action that generates a saving between regulatory periods is not compensated. To be clear, the problem is not the length of the regulatory period in absolute terms per se, but rather the potential mismatch between the regulatory period and the time horizon that innovation delivers benefits. This barrier is important because innovation is increasingly taking the form of non-wire solutions that by their nature are designed to optimise the use of the network, and so defer investment.
>
> 36.To explain this point further, suppose an EDB is considering whether to innovate by procuring a flexibility service, which would allow the EDB to efficiently defer capex (i.e., reduce the cost of providing electricity). Now consider the following two possible scenarios depending on when the capex in question would be deferred:
>
> 36a Defer capex within regulatory period: The EDB finds this investment attractive as it makes a saving from deferring capex that is rewarded under the IRIS; and
>
> 36.b Defer capex that will occur in the following regulatory period: this change in timing means that the EDB no longer finds this (otherwise equivalent) investment attractive. In response, the EDB may inefficiently choose to avoid a more efficient opex solution, such as flexibility solutions. This outcome arises because the flexibility service costs opex today, which would lead to an IRIS penalty. Then in the following regulatory period, the capex saving made possible by the flex services enters the capex forecast, so that the EDB does not benefit from the reduction in capex.

6.62 Wellington Electricity submitted that the issue is expected to bias traditional capex wire solutions over non-wire solutions funded by opex.[391] Limiting IRIS opex/capex substitution to a single regulatory period causes bias by not allowing offsetting opex/capex expenditure substitution across regulatory periods.[392]

> … the IRIS does not allow a network to be rewarded for capex cost savings that may occur in future regulatory periods. While the IRIS is designed to make investment decisions agnostic about whether expenditure was made using opex or capex, the offsetting incentives and penalties only apply within the same regulatory period.

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390 NERA Economic Consulting "Innovation under the DPP - potential barriers and solutions" (report prepared for 'Big six' EDBs, 20 December 2022), p.17.
We note that NERA's submission characterises the issue as an innovation issue, whereby a business has no incentive to innovate if expenditure occurs in the current period, but the benefits only arise in the following regulatory period. We do not consider that this issue is just a barrier to innovative solutions. EDBs may already have tools for demand management at their disposal (eg, ripple control), but choose not to use them to their full potential due to financial disincentives (potentially combined with other barriers such as co-ordination problems).

391 Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 14.

392 Ibid.

> For example, an EDB purchases flexibility services using operating expenditure (a cost that the current allowance calculation does not provide), which delays the need to make a capital investment for five years. The capital investment was planned in the next regulatory period – flexibility services will be purchased well before an investment is needed to provide EDBs time to plan and build the new capacity before its needed.
>
> The IRIS will penalise the EDB for overspending their opex allowance but will not be rewarded for delaying capex expenditure because the capex forecast for future regulatory periods will include the expected impact of the flexibility service (the expenditure forecasts provided in asset management plans must be based on management's best forecast of future demand, capacity and investment requirements).

6.63 Transpower submitted that there is a broader issue in relation to opex/capex trade-offs:

> One of the issues we have experienced is the impact of differential incentive rates between capex and opex. For example, recent International Financial Reporting Standards (IFRS) require software as a service (SaaS) to be treated as operating costs. Previously we had capitalised SaaS. While in theory the opex and capex incentives are equalised from the consumer perceptive for Transpower, in practice, they are not. The capex incentive relies on an explicit percentage of the under/ over-spend to be retained, while the opex incentive relies on an in-perpetuity assumption.
>
> This applies to all areas of opex and capex trade-offs, for example, where we identify transmission alternatives and undertake a more efficient opex solution, we are worse off, financially, than if we proceeded with a capex solution.

6.64 Our proposal is to provide for flexibility in the IMs to provide a solution to the problem raised above by broadening the definition of the IPA to become the innovation and non-traditional solutions allowance. Implementation of any specific solutions is left to the price-path determination.

6.65 Given submissions' focus on this specific problem we considered this problem in some detail and considered alternative solutions (which could complement the proposed change proposed in topic 6b). We consider that our proposal better achieves our Framework's overarching objectives in relation to innovation and non-traditional solutions.

6.66 For further information refer to Attachment C, where we provide tentative examples of schemes that, if we proceeded with our draft decision and decided it appropriate in the context, we could implement under DPPs and CPPs.

We are not proposing any changes to the Transpower IMs

6.67 The potential financial disincentives to make certain opex/capex trade-offs may also be relevant for transmission services. As noted in 6.63, Transpower submitted it may be financially worse off when substituting opex for capex, for example when adopting transmission alternatives (involving opex).

6.68 Transpower's explanation of the problem differs from submissions on the problem raised by EDBs, further discussed in Attachment C. However, in our view the underlying problem definitions are the same, only Transpower expands the scope also to other areas with potential trade-offs.

6.69 We are not proposing any changes to the Transpower IMs to provide explicit tools in the IMs to encourage innovative or non-traditional solutions. We consider Transpower's IPP provides for flexibility when setting expenditure allowances, including in relation to innovation and non-traditional solutions.[393]

[393] For example, while at RCP2 the Commission provided an explicit ex-ante allowance for innovation related activities, at RCP3 it provided an implicit allowance (included in the base opex allowance that was based on a base-step-trend approach).

Attachment A Supporting information on Topic 3b (IRIS cash flow timing)

A1 In this attachment we provide further analysis that supports the problem definition of 'Topic 3b - Implications of IRIS for cashflow timing' discussed in Chapter 3.

A2 We consider that the understanding of cashflow timing implications of our regulatory tools are important for suppliers subject to price-quality regulation under Part 4. As we discuss in Topic 3b, the cashflow timing implications of IRIS are predictable (and manageable) but the details can be non-intuitive.

Transparency and understanding of IRIS cashflow timing implications

A3 Understanding the implications of incentive regulation for businesses finances is important, for example so that:[394]

A3.1 management can decide how to efficiently finance operations and manage cashflows;

A3.2 regulators understand the implications of their tools for regulated suppliers; and

A3.3 investors can understand a business' cash flows (eg, free cashflow) for investment decisions.

A4 Below we describe the differences in cashflow timing that may arise due to EDB opex and capex IRIS.

IRIS implications for cashflow timing

A5 The opex and capex IRIS has the following components that influence incentive cashflow timing:

A5.1 the difference between actual costs and the allowance during the regulatory period (under- or overspends) for both opex and capex; and

A5.2 the incentive amounts carried into the following regulatory period:

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[394] For example, the International Accounting Standards Board (IASB), which owns the International Financial Reporting Standards (IFRS), sought to understand whether to specify the components of total allowed compensation for rate-regulated activities. An IASB staff paper recommended to the IASB that: "The final Standard does not specify the components of total allowed compensation but rather focuses on helping entities identify differences in timing. The application guidance will focus on the most common differences in timing that may arise from different types of regulatory schemes." The focus on differences in timing recognises that a range of possible regulatory schemes with varying timing implications are possible and accounting rules need to be able to deal with these.

A5.2.1 the opex carry-forward amounts are cumulative and carry into the subsequent regulatory period; and

A5.2.2 the capex IRIS cashflow implications for the next regulatory period include the capex wash-up and retention adjustment.

Difference between actual costs and the allowance (over- and underspends)

A6 This timing difference is a necessary by-product of any form of incentive regulation (ie, whether we have an IRIS or not). The key characteristics are:

A6.1 timing differences are near term and predictable (based on observed spend) and generally considered under suppliers' control: ie, the IRIS cashflow implications can be managed by EDBs;

A6.2 the regulatory regime has mechanisms for events that are not predictable and less controllable (re-openers and CPPs), and IRIS takes these into account; and

A6.3 some types of costs are passed through directly to consumers (pass through costs, recoverable costs), including the incentive carry-forward amounts.

Carry-forward incentive amounts

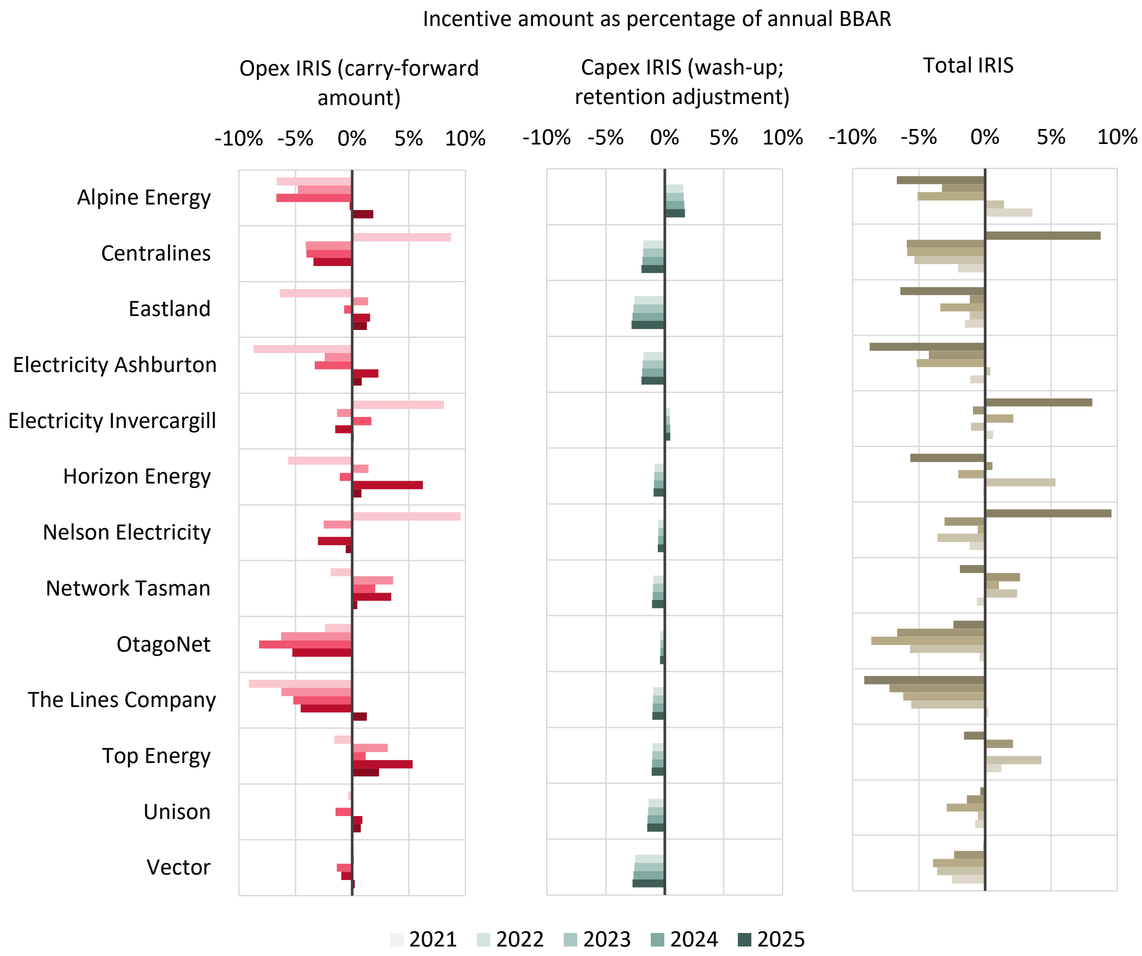
A7 The function of the incentive carry-forward amounts is to promote efficient expenditure (the right investment at the right time, in line with s 52A(1)(a) and (b)), including by making the investment incentives time of investment invariant and equalising regulatory financial incentives between opex and capex. Without the carry-forward amounts (ie, with natural incentives alone), businesses' decisions may be distorted.

A8 For the opex IRIS, suppliers can accurately predict the quantum of the carry-forward amounts (five years in advance) from expenditure decisions made now. That is, if a supplier is considering the incentive impacts of over- or underspending its opex allowance, it can predict what the outcomes will be in the subsequent regulatory period. Given the inherent predictability, any cashflow implications can be understood and, if required, actively managed by businesses.[395]

A9 To illustrate the cashflow characteristics of IRIS under the DPP, the figure below shows incentive amounts carried forward into the following regulatory period relative to the annual allowable revenue.

[395] The capex IRIS, is based on total capex spend over the period but is not rolling like the opex IRIS so is more intuitive to understand the cashflow timing implications.

Figure A1 IRIS incentive amounts as a proportion of annual BBAR[396]



Note: Figure excludes Aurora and businesses on a CPP at the time (Orion, Powerco and Wellington Electricity). The underlying data reflects actuals for 2016 to 2020.

A10 The capex IRIS carry-forward implications are similar each year (due to how the capex IRIS works, where there is an incentive component (the retention adjustment) and a wash-up component (capex wash-up)) and for DPP3 were smaller compared to opex.[397]

A11 The opex IRIS implications (carry-forward amounts) are more variable than the capex IRIS timing implications. Each carry forward amount depends on the difference between actual and allowance 5 years prior, building cumulatively over the regulatory period.

396 Aurora Energy has not been included in this analysis as it is on a CPP and subject to different incentives under the CPP.

397 The capex wash-up ensures that suppliers' actual capex spend enters the RAB. The capex wash-up and retention adjustment offset each other which results in lower overall capex amounts carried forward into the subsequent regulatory period.

Illustration of opex and capex IRIS cashflow timing differences

A12 There are differences between opex and capex IRIS timing: Opex and capex incentive amounts carried forward into the subsequent regulatory period differ somewhat in their timing (due to the inherent characteristics of opex and capex). We explain this characteristic and the potential implications in more detail below.

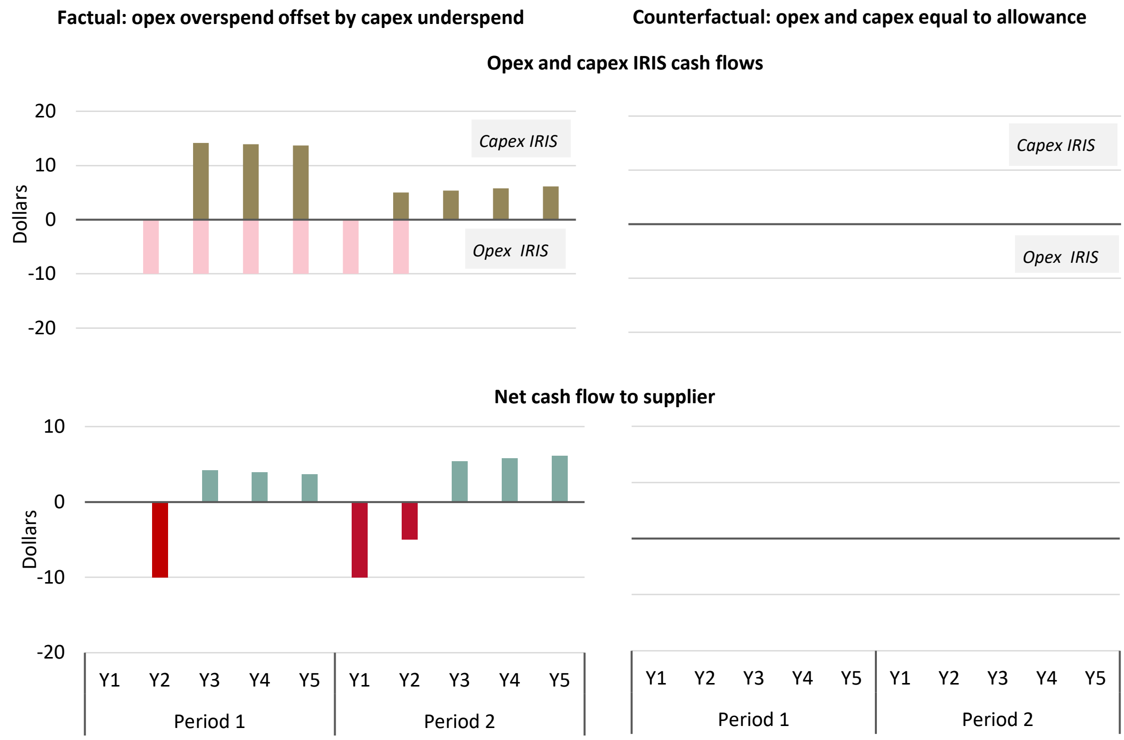
A13 To illustrate opex and capex IRIS cashflow timing differences, we have modelled two NPV equivalent cashflows.

A13.1 In the counterfactual, the supplier's opex and capex is equal to the allowance in the current period (RCP1). This means there are no cashflow timing implications in the current or subsequent due to the working of opex and capex IRIS.

A13.2 In the factual, the supplier substitutes capex in Year 2 (approximate $150 NPV) with opex ($10 a year in perpetuity, approximate $150 NPV). This means the supplier underspends its capex allowance by approximately $150 in Year 2 and overspends the opex allowance by $10 (ie, a permanent opex overspend). Although the amounts retained by the supplier offset over the life of the savings (ie, have the same retention factor), there are IRIS cash flow timing implications.

A14 Figure A2 below compares the cashflow implications under the factual and the counterfactual. The top row shows the opex and capex IRIS cashflows, and the bottom row shows the net cashflow to suppliers.

Figure A2 Incentive mechanism cashflow implications of capex substituted to opex in year 2 of a regulatory period[398]



A15 Figure A2 illustrates that IRIS introduces cashflow timing implications, and that the timing implications differ between opex and capex. Suppliers can minimise cashflow implications if they spend the same amount as the allowance (ie, the counterfactual).

A16 The bottom left panel shows the net cashflow timing from substituting capex for an ongoing opex solution:

A16.1 the opex implications of the year two substitution in the current period (ie, the financial penalty) finishes by year 2 of the following period. The (net) opex IRIS implications are shown in red; and

A16.2 the capex implications (ie, the financial benefit) do not finish until year five of the following regulatory period. The (net) capex IRIS implications are shown in green.

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[398] Opex overspend and capex underspend are NPV equivalent, and both occur in year 2 of a regulatory period, based on a discount rate of 7 percent and incentive rate of 33.4 percent (as a result of the 7 percent WACC). Total opex overspend of $154 over the life of savings (permanent overspend of $10 per year) with an equivalent capex saving in year 2.

A17 Whether these amounts are likely to influence a business (due to cashflow timing) to prefer spending capex instead of increasing opex depends on factors such as:

A17.1 the total value of substitutions like those in the example (in general, likely modest relative to the size of costs overall);

A17.2 whether the substitutions can be made within allowances or not;

A17.3 the suppliers' cash flow management effectiveness; and

A17.4 whether a specific supplier has financial headroom for managing these cash flows.

Attachment B Supporting information for Topic 4a (opex and capex substitutability)

B1 In this Attachment we provide further analysis that:

B1.1 supports the problem definition of topic 4a 'Maintain the current expenditure incentive schemes as tools to mitigate capex bias'; and

B1.2 provides further detail on how the IRIS mechanisms achieve our objectives.

Capex and opex equivalence

B2 As discussed at paragraph 4.13, equivalence of incentive rates is a key objective of the expenditure incentive mechanisms and is related to why we have made some of our draft decisions. In this section we respond to some of the supplier views raised in submissions here.

B3 In support of our November/December 2022 consultation on expenditure incentives we published a staff discussion paper and model on the equivalence between the opex and capex IRIS.[399] In stakeholder feedback EDBs generally considered that the equivalence within a regulatory period holds, but some suppliers did not consider this was true.

Stakeholder views

B4 Wellington Electricity agrees that there is equivalence during a regulatory period but not across periods under some circumstances. Under current regulatory settings distributors may be financially penalised when they make opex/capex trade-offs between regulatory periods. Our proposed solution to this issue is discussed in Chapter 6.

B5 Horizon Energy did not consider that there was broadly financial equivalence between opex and capex stating:[400]

> The example provided by the Commission is based on a static view with only one variable changed and all other factors considered equal. In reality, the IRIS and DPP resetting models are dynamic and depend upon numerous variables being considered.
>
> However, other considerations such as cash flows, full cost recoveries and the valuation of the Network can create inequality between the total cost impact of OPEX compared to the total cost impact of a CAPEX investment alternative.

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399 See: Commerce Commission “IM Review 2023: Incremental rolling incentive schemes equivalence staff discussion paper” (22 November 2022) and Commerce Commission “IM Review 2023: Incremental rolling incentive schemes equivalence model” (22 November 2022).

400 Horizon Energy Group “Submission on Expenditure incentives EDB workshop” (8 December 2022), p. 5.

B6 Vector submits that incentive rates are equalised but that the allowances are not substitutable:[401]

> We consider capex and opex are not substitutable.
>
> Regardless of the equalized incentive rates, an EDBs actual spend on opex and capex in a particular year will have an impact. If an EDB is close to overspending its opex allowance and has more room in its capex allowance it will be incentivized to choose a capex solution to avoid an IRIS penalty.

Our view

B7 We consider that, all else equal, the opex and capex IRIS provide broadly consistent financial incentive rates and trading off one type of expenditure for another will result in a NPV equivalent outcome over time.[402]

B8 Setting equivalent IRIS incentive rates is not a silver bullet to changing behaviour, but simply ensures that suppliers are not disadvantaged (in NPV terms) from choosing one type of expenditure over another if it is efficient to do so. Only EDBs are able to respond and change behaviour to benefit consumers. This is explained further in the next section of this Attachment.

B9 In response to Horizon's submission points above, we agree that there are many factors (regulatory and non-regulatory) that inform investment decisions. We acknowledge the wider context but consider that only the relative financial incentives between expenditure types for regulatory reasons should inform our decisions. Below our short responses to Horizon's other considerations:

B9.1 **Cash flows**: while we note that there can be cash flow implications of substituting one type of expenditure for another, we consider that in NPV terms these are equivalent.[403] We discuss IRIS cashflow timing implication in Chapter 3 (Topic 3b) and Attachment A.

B9.2 **Full cost recoveries**: these would only not occur if a supplier overspends their allowances (taking into account any expenditure trade-offs with IRIS implications). Any overspend would be shared with consumers over time, which would happen with or without an IRIS under a revenue path. As we discuss further below, IRIS may be perceived to not work if a supplier treats opex and capex allowances as budgets (which they are not intended to be).

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401 Vector "Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 6.

402 Commerce Commission "IM Review 2023: Incremental rolling incentive schemes equivalence model" (22 November 2022)

403 We discuss cash flows from IRIS in Chapter 3 (Topic [3c]) above.

B9.3 **Valuation of the network**: consumers do not consider the valuation of the network in the utility they gain from the regulated service. However, suppliers may value a larger RAB, which may result in a preference for capex (or 'capex bias due to non-regulatory financial reasons'). While addressing capex bias for financial regulatory reasons (as defined in topic 4a) is within our control, a supplier's preference for a larger RAB is not.

B10 In response to Vector's comments at B6 above, this may reflect a misunderstanding of the expenditure incentive mechanism's objective rather than an issue with its operation.

B11 The marginal incentive rate for a dollar of additional spend of capex and opex is equal over the life of a saving. Therefore, the marginal incentive rate (and hence the financial incentive) is the same independent of a supplier's actual spend relative to its expenditure allowances.

B12 Building on Vector's example at B6, assume:

B12.1 a supplier has a choice between an opex solution and a capex solution that are otherwise financially identical;

B12.2 the supplier has a large headroom in its capex allowance; and

B12.3 the supplier would exceed the opex allowance if it implemented an opex solution.

B13 Turning now to the IRIS financial implications of choosing either the opex or capex solution, the following two decisions are financially equivalent in NPV terms for the supplier:

B13.1 spending capex (which reduces the underspend that would otherwise occur and hence requires forgoing the positive incentive adjustment associated with the larger capex underspend) and avoid a negative opex IRIS adjustment; and

B13.2 spending opex above its allowance (and getting a negative opex IRIS adjustment) and maintaining the underspend on capex (with a greater positive capex IRIS adjustment than if the capex solution was chosen).

B14 As such, the opex and capex IRIS ensure that the supplier can expect to be financially neutral between adopting an opex or a capex solution (all other things equal). The combined positive and negative incentive adjustments will offset over time. The example assumes there is headroom in the capex allowance, but IRIS would also ensure financial neutrality if there were headroom in the opex allowance.

B15 We recognise that, even with equalised incentive rates, not all EDBs respond to marginal incentives and there may be other reasons why a supplier may prefer one type of expenditure over another. For example, rather than considering marginal incentives for expenditure, suppliers may have absolute target rates of returns and 'budgets' for each type of expenditure.

B16 If a supplier views its DPP expenditure allowances as budgets, and for organisational reasons this results in expenditure 'silos', in practice, substitutability between opex and capex may be limited. Viewing allowances as budgets may lead to an undue focus on target rates of return (and variations on profits relative to target returns), and insufficient focus on optimal spend.

Attachment C Supporting information for topic 6b

C1 In this attachment we:

C1.1 discuss a specific sub-set of the problem definition for topic 6b (incentives for adopting innovative and non-traditional solutions), which may disincentivise opex/capex trade-offs across regulatory periods;

C1.2 consider solutions we considered that may improve incentives for opex/capex trade-offs across regulatory periods (other than the proposed change we discuss in topic 6b);

C1.3 expand on our decision to make no changes to Transpower's IMs in relation to opex/capex trade-offs across regulatory periods; and

C1.4 provide examples of schemes that, if we proceeded with our draft decision and decided it appropriate in the context, we could implement under EDBs DPPs or CPPs.[404]

Problem definition: expenditure incentives across regulatory periods

C2 A periodic reset of the revenue allowance is a normal (and necessary) feature of incentive regulation. However, the need to periodically reset prices may reduce incentives to invest in the efficient solution in certain circumstances.

C3 Incentive regulation works by decoupling the firm's revenue and actual costs.

C3.1 By providing scope for financially benefiting from incurring costs below the allowance, a supplier faces incentives to reduce its costs.

C3.2 By not providing for (full) revenue recovery of costs in excess of the allowance, a supplier faces incentives to not exceed its allowance.

C4 The connection between actual costs and revenues is re-established at regular intervals in price-path resets. Resets (combined with the expenditure incentive mechanism) share the benefits of efficiency gains in the previous period between consumers and suppliers (including through lower prices), and set revenue allowances (based on more up-to-date information) for the next regulatory period.

[404] The examples do not constrain our decision making at the upcoming DPP reset or in setting a CPP.

C5 The need to periodically reset price-paths may affect certain investment choices:

C5.1 where a supplier has the choice between a capex solution or an alternative opex solution; and

C5.2 the benefits of the opex solution arise in future periods (in the form of capex deferrals).

C6 A supplier may face financial incentives to adopt the capex solution, even though its whole-of-life costs are expected to be higher than the alternative. Without a formal mechanism, a regulated supplier may be financially disincentivised to make efficient opex/capex trade-offs across regulatory periods.

C7 For example, an EDB identifies an opportunity to reduce whole-of-life-costs by deferring the need for augmentation capex by five years from the next period to the one following. To enable this deferral, the EDB intends to use flexibility services (requiring ongoing opex) to manage demand until the need for capex can no longer be efficiently deferred.

C8 The EDB may be financially incentivised to prefer a traditional capex solution to the efficient capex deferral solution if:

C8.1 the EDB expects to recover less than the cost incurred in the efficient capex deferral. This is the expected outcome if the additional opex results in actual opex exceeding the opex allowance for the current regulatory period, so that the EDB has to bear a share of the overspend.[405]

C8.2 The capex forecast allowance setting for the next regulatory period, reflects the value of deferred investment (rather than the capex without deferral).

C9 In these circumstances:

C9.1 consumers can expect to receive the full benefit from the deferral but incur only part of opex to defer capex; and

C9.2 suppliers can expect to recover less than cost (due to the IRIS adjustment) and receive no financial benefit from the deferral.

[405] The opex IRIS ensures that most of the overspend incurred is shared with consumers (about three quarters of costs of any overspend) and the EDB would incur one quarter of the costs.
Note that these marginal incentives to substitutes arise in general with any incremental spend decision, not just when a suppliers consider incremental spends above their allowance. The cost to suppliers (of any incremental spend decision) is the change in IRIS amount (gain or loss) due to making the substitution.

C10 In addition, the risk associated with the alternative opex solution may be higher than the network solution (eg, effectiveness and cost of deferring the capex may be more uncertain). This may mean that, even if the price path allowance were sufficient to fund the flexibility services (ie, without incurring IRIS penalties), the higher risk may discourage suppliers from considering opportunities for non-network solutions to defer capex.

C11 To the extent there is uncertainty about the timing of investments, it also means that these opportunities cannot necessarily be appropriately factored in (by suppliers in their forecasts that inform resets, or by us when setting ex-ante allowances).

C12 We set out key submissions on this problem in section 6b at paragraphs 6.60 to 6.63.

C13 To provide an indication of the significance of the issue we sought submissions following the "Forecasting and incentivising efficient expenditure for EDBs" workshop held on 7 November 2022.[406] EDBs indicated that the current scope for deferral is limited but they expect opportunities to grow significantly over time.[407] With opportunities for non-network solutions generally expected to increase, the loss for consumers from EDBs not adopting these solutions as quickly as practicable (ie without disincentives to make efficient opex/capex trade-offs) is expected to increase over time.[408]

C14 In a case study, Wellington Electricity quantified the scope for capex deferral on its network at $317 million over 35 years. This value would be passed to customers either by lower distribution prices or as a payment for purchasing flexibility services.[409]

406 Commerce Commission "IM Review 2023: Forecasting and incentivising efficient expenditure for EDBs - 'Full slide deck'" (7 November 2022).

407 Powerco "Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 5.

408 The overall benefit to be shared between consumers and producers is the NPV of deferred capex minus opex incurred to defer the capex. In practice, the NPV could be positive or negative. A net cost for a specific project in the short term may be worthwhile in the long term if it helps with learning, establishing a market for flexibility services etc.

409 Wellington's case study quantifies the scope for capex deferral at $317 million (likely in absolute dollar terms). The case study assumes flexibility services will be available. It does not assess whether the deferral would be cost effective (The case study does not assess whether the expected opex to enable the deferral is less than the NPV of the capex deferral). Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 33.

C15 Powerco submitted that:[410]

> It is early days for estimating the long-term balance. Differentiating between a permanent vs temporary role of an opex alternative is key too. One way to approximate it is to assume around 10% of peak demand can be met using opex solutions. For Powerco that would translate to an opex figure of around $10 - $20m per year (based on 1GW peak demand) and offset around $400m of capex. For comparison, this opex is equivalent to 10%-20% of annual opex.

C16 We consider that the benefits from addressing the issue may be significant (depending on the portion of costs involving opex/capex trade-offs across regulatory periods).

C17 If the problem is not (or not just) a funding problem, but also a more general problem with insufficient adoption of non-traditional and innovative solutions (including due to risk and uncertainty), not addressing the problem may have wider implications for the electricity sector. For example, if EDBs are overly conservative in adopting flexibility services to enable capex deferrals, and instead continue to implement traditional capex solutions (due to Part 4 regulatory settings), the emerging market for flexibility services may develop more slowly than it otherwise would.

Alternative implementation solutions considered

C18 As discussed at para 6.48, our proposal is to broaden the innovation project allowance to include non-traditional solutions. Below we discuss alternative solutions we considered.

Longer regulatory period

C19 Longer regulatory periods could be a partial solution for the cross-regulatory period issue. Under a longer regulatory period, the additional costs (opex) and savings (capex) would more likely both be considered when calculating performance against the allowances.[411] However, eventually, the investment planning horizon would clash with the fixed horizon of the regulatory period and other issues would arise.

410 Powerco "Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 3.

411 Many incentive regulatory regimes have settled on a "sweet spot" for the regulatory period of about five years. After an eight-year regulatory period for RIIO1, Ofgem moved back to five-year period for RIIO2.

C20 The length of a regulatory period is set under Part 4 of the Act, and can be either four or five years (s 53M(4) and (5)).[412] As such we do not have the ability to extend duration of the regulatory period beyond its current length.

C21 Even if we could extend the regulatory period, allowing revenue to depart from actual expenditure for an extended period during periods of high uncertainty with expected large increases in investment would be unlikely to promote the overarching objectives of the IM Review. Given the possibility of providing an amount that differs materially from the expenditure requirement, a longer regulatory period could weaken the limit on businesses' ability to extract excessive profits (s 52A(1)(d)) or, reduce incentives to innovate and invest (s 52A(1)(a)).

Change IRIS

C22 Another option to address the discontinuity created by a fixed regulatory period is to change the IRIS to account for estimates of avoided capex across regulatory periods. NERA on behalf of the 'Big 6' EDBs submitted that:[413]

> A possible solution would therefore be to design an incentive mechanism that rewards efficiencies that happen between periods. This would require estimating the future capex (or opex) savings that have resulted from an innovation and passing a proportion of these savings back to the EDBs. For example, a flex trial might lead to flex services, which reduce or defer future capex. If it is possible to estimate the present value of these capex savings in future periods, then in concept the firm can be rewarded for this avoided future capex through the IRIS. While conceptually this approach works, we imagine it would face practical challenges.

C23 Vector also suggested further investigating IRIS as a solution to encourage savings beyond the current regulatory period:[414]

> We consider the Commission and stakeholders should still investigate how IRIS could be amended to reflect (and therefore better incentivise) savings beyond the carry-forward period. The impact of this issue may become greater overtime given opportunities presented by, for example, digitalisation to create significant future cost savings. It is critical that incentive mechanisms do not inadvertently discourage this kind of expenditure.

C24 We consider the practical challenges of estimating future savings required to implement an IRIS solution would be considerable and as such do not consider this as a practical option.

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412 To align with the GDB DPP, we are proposing changes to the EDB and Transpower IMs that allow us to also determine a WACC for a four-year regulatory period. For more information see Chapter 6 in Commerce Commission “Part 4 Input methodologies Review 2023 - Draft decision - Cost of capital topic paper" (14 June 2023).

413 NERA Economic Consulting "Innovation under the DPP - potential barriers and solutions" (report prepared for 'Big six' EDBs, 20 December 2022), p. 22.

414 Vector “Submission on Expenditure incentives EDB workshop” (6 December 2022), para 15.

Transpower

C25 We are not proposing any changes to the Transpower IMs in relation to opex/capex trade-offs across regulatory periods. Electricity distributors' submissions generally focussed on disincentives to making efficient opex/capex trade-offs using demand management (such as flexibility services) to defer capex in future periods.

C26 As discussed in chapter 6, the potential financial disincentives to make certain opex/capex trade-offs may also be relevant for transmission services. As noted in 6.63, Transpower submitted it may be financially worse off when substituting opex for capex, for example when adopting transmission alternatives (involving opex).[415]

C27 Transpower's explanation of the problem differs from submissions on the problem raised by EDBs, further discussed above. However, in our view the underlying problem definitions are the same, only Transpower expands the scope also to other areas with potential trade-offs.

C28 We are not proposing any changes to Transpower's IMs to provide explicit tools in the IMs to encourage innovative or non-traditional solutions. We consider Transpower's the Part 4 regulatory regime already provides for flexibility to provide desirable longer term planning incentives, including in relation to innovation and non-traditional solutions.[416]

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415 On Transpower's specific example of SaaS, we note that we have considered the transitional implications of the IFRS clarification regarding the appropriate treatment of SaaS as an operating cost in the context of Chorus PQ path and in the Powerco CPP to DPP transition (reference below).
To the extent businesses previously classified SaaS costs as capex, the IFRS clarification has involved an opex for capex substitution: many costs formerly treated as capex are now treated as opex. There is no benefit to consumers from the change. Businesses' opex requirement increases and the capex requirement correspondingly decreases (all other things equal).
The IFRS clarification relating to SaaS does not require an IM change. The transition to the new accounting treatment has already occurred as the change was effective from 2021. If the financial impact of the change had been material enough (one percent of MAR), it could have been addressed under the change event reopener.
Commerce Commission "Powerco Limited's transition to the 2020-2025 default price-quality path – Draft Reasons Paper" (18 August 2022), p. 39.

416 For example, while at RCP2 the Commission provided an explicit ex-ante allowance for innovation related activities, at RCP3 it provided an implicit allowance (included in the base opex allowance that was based on a base-step-trend approach).

C29 If there were disincentives, eg in relation to transmission alternatives, a potential solution might be the AER's demand management incentive scheme (which we discuss at C38 as an example of a solution relevant to EDB CPPs). We note that the AEMC considered in 2019 whether to introduce a DMIS scheme similar to that for EDBs in the AER's regime.[417] The AEMC concluded that:

> The Commission is not satisfied that the benefits of applying the DMIS to transmission networks would outweigh the additional costs to consumers. This decision is supported by all stakeholder submissions to the draft determination, except for Energy Networks Australia
>
> If the DMIS is implemented, transmission businesses would receive more revenue for undertaking non-network options that they would already have been required to adopt under the regulatory investment test for transmission (RIT-T). Although it is accepted that networks may face upfront, transitional costs to develop their ability to utilise non-network options, we consider these mostly one-off costs can already be recognised and funded under the current regulatory framework.

C30 We also considered the following solutions for Transpower but decided not to adopt them:

C30.1 **Changes to expenditure incentive schemes**. Our reason for not proposing any changes to Transpower's expenditure incentive schemes is the same as for EDBs discussed at paragraph C24: we consider the practical challenges to estimate future savings to implement an IRIS solution would be considerable and as such do not consider this as a practical option.

C30.2 **Commission of Regulated Utilities' (CRU) flexibility mechanism**: Our view is that the CRU's 'flexibility mechanism' would be inconsistent with fungible expenditure allowances and would likely create unpredictable expenditure incentives also applies to Transpower (refer to paragraph 4.92).

C31 We note that the Electricity Authority also has an interest that Transpower and EDBs have neutral investment incentives, including when choosing between network and non-network solutions.

[417] AEMC "Rule Determination, National Electricity Amendment (Demand management incentive scheme and innovation allowance for TNSPs) Rule 2019" (5 December 2019).

DPP example

Use-it-or-lose-it allowance

C32 A mechanism that would be consistent with the relatively low-cost nature of a DPP could be an in-period adjustment mechanism that provides EDBs additional opex allowances for demand management solutions that efficiently defer capex expected to be required beyond the current regulatory period to an even later date.[418]

C32.1 The purpose of such a DPP mechanism would be to address the potential financial disincentives for efficient opex-capex trade off across regulatory periods.

C32.2 The implementation could be in the form of a 'use it-or-lose-it' allowance, with thresholds and certification criteria set at a DPP reset.

C33 This mechanism would seek to offset the funding sufficiency problem discussed at paragraph C8 by providing an additional opex allowance to offset any IRIS penalties for *exceeding* the allowance in order to efficiently defer capex.[419]

We do not consider ex-ante allowances would better promote the Part 4 purpose

C34 A DPP is intended to be a relatively low-cost way of setting price-quality paths for regulated suppliers.[420] Given this, we considered whether an ex-ante allowance for opex to better enable opex/capex trade-offs related to longer-term demand management would be preferable to an in-period adjustment.

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[418] In the absence of a change, this disincentive arises because the EDB may otherwise be financially penalised for exceeding its forecast opex without retaining any of the benefit from a capex deferral.

[419] The opex IRIS ensures that most of the overspend incurred is shared with consumers (about three quarters of costs of any overspend) and the EDB would incur one quarter of the costs.
Note that these marginal incentives to substitutes arise in general with any incremental spend decision, not just when a suppliers consider incremental spends above their allowance. The cost to suppliers (of any incremental spend decision) is the change in IRIS amount (gain or loss) due to making the substitution. However, expenditure allowances are fungible and we consider that within-allowance trade-offs would not be easily identifiable or verifiable under price-quality regulation.

[420] Section 53K of the Act. See also Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper” (27 November 2019), para 3.14.1.

C35 Ex-ante allowances (eg, step-changes in DPP base step trends) may be a viable option if:

C35.1 the scope and timing of capex deferrals could be robustly forecast;

C35.2 the opex required to enable the deferral could be robustly forecast; and

C35.3 assessing forecasts could be done in a relatively low-cost way.

C36 As noted at paragraph C17,the uncertainty and risk of these alternative solutions (including regarding timing and cost) with these solutions may be part the problem. Robust forecast may not be possible given the heightened uncertainty in the current environment. For example, while Wellington Electricity provided estimates of the potential capex deferral, it did not include estimates of the cost of flexibility services to enable this deferral.[421]

C37 Ex-ante allowances may be insufficient or result in windfall gains. Therefore, we consider an in-period adjustment that provided for additional allowances which are only drawn upon if required (and provide for actual cost incurred), would likely better promote the Part 4 purpose. If the factors that rule out ex-ante allowances as a preferred option change sufficiently, we could consider adopting ex-ante allowances at a PQ reset.

CPP example

C38 The proposed 'innovation and non-traditional solutions' allowance would also allow for schemes such as the demand management incentive scheme introduced by the AER.[422] Under such a scheme if a project implemented successfully reduces the gap between average and peak demand, a supplier is rewarded with the cost of the project and a cost multiplier, to compensate them for uncertainty surrounding the project.

C39 We consider that incentives schemes such as the AER's – which not only focuses on inputs, but also rewards the success of schemes in achieving targeted outcomes – could better promote s 52A than a scheme that exclusively focuses on inputs. This would be because an AER-like incentive scheme would better incentivise efficient expenditure, in line with s 52A(1)(a) and (b).

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421 Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 35.

422 Australian Energy Regulator "Final decision: Demand management incentive scheme and innovation allowance" (13 December 2017).

C40 Such a scheme would only be appropriate under a CPP where there is more scope to provide more detailed scrutiny to projects than a DPP. For the same reasons as DPPs, discussed above in para C37, we do not consider ex-ante allowances would be appropriate.[423]

[423] Section 53K of the Act. See also Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), para 3.14.1.

Attachment D Effectiveness improvements to revenue path wash-up mechanism

Purpose of this attachment

D1 This attachment sets out and explains proposed changes to the revenue cap and wash-up mechanisms for EDBs and GTBs.

D2 We have proposed these changes to:

D2.1 give effect to substantive draft decisions respect of inflation risk and connection capex for CPPs;

D2.2 better manage revenue and price volatility;

D2.3 mitigate potential issues with cashflow timing and financeability; and

D2.4 reduce the complexity of the overall wash-up mechanism.

Structure of this attachment

D3 The first three sections of this attachment deal with the packages of changes we are proposing. These are:

D3.1 improvements to the revenue path to better manage volatility during the regulatory periods;

D3.2 modifications to the wash-up mechanism to implement other policy decisions, and to reduce compliance cost and complexity; and

D3.3 changes to the wash-up treatment for CPI.

D4 The final section gives a more detailed account of how we foresee compliance with these provisions working.

Context for these decisions

D5 The primary purpose of wash-up mechanisms is to deliver outcomes that are consistent with our risk-allocation principles. They do this by washing up for the present-value revenue outcomes of a given forecast versus actual difference.

D6 Secondarily, wash-up mechanisms can help manage revenue and price volatility. This covers both volatility caused by the washing-up process itself and other sources of change in allowable revenue.

D7 In a context of greater uncertainty about the future of energy networks and higher and less predictable inflation, it is even more important that the wash-up mechanism works well. Less certain forecasts (of demand or inflation) mean potentially greater differences between forecast and actual inputs, and a more material impact on prices and/or revenues.

D8 While the decision to have or not have a given wash-up has present-value implications, the decision of how to implement them should be present-value neutral: it alters the profile of revenue recovery, but not the total amount. Nevertheless, certainty and volatility impacts have a material effect on supplier performance and customer outcomes.

D9 The wider suite of current EDB/GTB revenue path, wash-ups, and related mechanisms have been incrementally added to over time. While the fundamental concept of ex-ante compliance with an ex-post wash-up is still sound:

D9.1 interactions of multiple distinct mechanisms risk both unnecessary revenue volatility and overdetermination (a position where compliance with all aspects is impossible); and

D9.2 the drafting of the mechanisms between the IMs and PQ determinations are more complex than we consider necessary.

Improvement to the revenue path to manage volatility

D10 We have proposed to:

D10.1 replace the “limit on the increase in forecast revenue from prices” with a “revenue smoothing limit”;

D10.2 apply this secondary limit to revenue including recovery of recoverable costs, but excluding recovery of pass-through costs; and

D10.3 reclassify transmission recoverable costs as pass-through costs (for EDBs only).

D11 We have also proposed retaining the "voluntary undercharging" lower limit on the revenue path and removing the provision for a "limit on increase in revenue as a function of demand".

Problem definition

D12 The current revenue path effectively has two controls on revenue: the ‘primary’ revenue path – “forecast allowable revenue” – and a present value-neutral ‘secondary’ control expressed in terms of a percentage change in the increase in “forecast revenue from prices”. The problems the Commission and stakeholders have identified are with this secondary control.

D13 The intent of the secondary revenue control is to manage all-cause volatility in gross allowable revenue and to protect customers from mid-period price-shocks. The current mechanism is effective in doing this, but it has two problems:

D13.1 the requirement in the IMs for it to be a “percentage” change is unduly restrictive, preventing us from setting DPPs or CPPs that respond to circumstances at the time; and

D13.2 expressing it in “forecast revenue from price” terms creates a ratchet effect, where a decision to temporarily undercharge lowers the secondary limit for the duration of the period.

Submissions on problem definition

D14 Multiple EDBs have taken issue with the secondary revenue control:

D14.1 it is expressed in nominal terms, requiring EDBs to temporarily bear additional costs from rising inflation without passing them on; [424] and

D14.2 because it applies to all revenue, it requires EDBs to absorb increases in transmission costs.[425]

D15 They have also objected to the limit being set as low as it is (10 percent).[426]

Draft decisions

Secondary revenue limit

D16 We propose reframing the secondary revenue control as a “revenue smoothing limit” that applies only to ‘below the line’ revenue – the supplier’s own revenue and recovery of recoverable costs– but not to ‘above the line’ revenue or pass-through costs.

D17 If revenue net of pass-through costs would otherwise exceed the revenue smoothing limit, suppliers will be required to lower prices to avoid exceeding it. The resulting under-recovery would accrue to the wash-up account as outlined in the next section.

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424 Aurora Energy “Submission on IM Review Process and issues paper and draft Framework paper” (11 July 2022), para 47; Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 17.

425 Electricity Networks Association “Submission on IM Review Process and issues paper and draft Framework paper” (11 July 2022), p. 11; Vector “Submission on the Process and issues paper” (11 July 2022), para 53.

426 Vector “Submission on the Process and issues paper” (11 July 2022), para 55. Note that this is a matter specified in PQ determination, so we propose no IM change.

D18 Put another way, the maximum a supplier could charge in any year is the lesser of:

D18.1 the sum of forecast net allowable revenue, recoverable costs, and pass-through costs; or

D18.2 the sum of the revenue smoothing limit and pass-through costs.

D19 While the revenue smoothing limit will be provided for in the IMs, the details of how it is specified (dollar vs percentage terms, real or nominal etc.) would be left to the PQ determination. Compliance with these limits is illustrated in Figures D2 and D3 at the end of this attachment.

D20 For EDBs, also we propose recategorizing transmission-related recoverable costs as pass-through costs, to ensure they not captured by the smoothing limit and can be passed through directly and in a timely fashion.

Other revenue controls

D21 We propose retaining the “voluntary under-charging limit”, to avoid the build-up of significant wash-up balances via undercharging. We propose removing the limit on increase in revenue as a function of demand, as we do not consider it practicable to actually apply the mechanism, and because the revenue smoothing limit may make it unnecessary.

How this decision will promote the overarching objectives

Better promoting the s 52A purpose

D22 The purpose of pass-through costs is to ensure risks are allocated properly, and that costs over which suppliers have no control are passed through. Doing so promotes incentives to invest and improve efficiency. While the current settings ensure this happens on a present-value basis, they do not necessarily do so in a timely way. EDBs may be forced to limit their own revenue recovery to manage volatility in transmission charges. We agree with supplier submissions that the appropriate place to manage transmission volatility is either via the TPM or in Transpower’s IPP setting.

Promoting regulatory certainty

D23 This decision will continue to promote regulatory certainty to a similar extent to the current IMs. The fundamentals of how compliance is with the revenue path is assessed will be outlined in the IMs (so suppliers and customers will have certainty from regulatory period to regulatory period) but with some flexibility in how values are specified left to the PQ determinations.

Reducing compliance cost and complexity

D24 While there may be some transitional costs for the Commission and suppliers, we do not believe these will be substantial: the core of the compliance process remains unchanged. In any event, we consider the benefits in terms of promoting s 52A outcomes justify any transitional cost.

D25 Additionally, the removal of the function of demand limit will reduce the overall complexity of the IMs.

Price stability

D26 Finally, while there is no explicit statutory requirement to consider price volatility outside the s 53M(8) discretion to determine alternative rates of change when resetting prices, as we noted when moving to a revenue cap in the 2016 IM Review, price stability is generally valued by consumers. To the extent that we can achieve the framework objectives without creating volatility, we consider it worthwhile to do so.

Improvements to the wash-up mechanism

Problem definition

D27 The current revenue path wash-up mechanism for EDBs and GTBs (as illustrated in Figure D1 below):

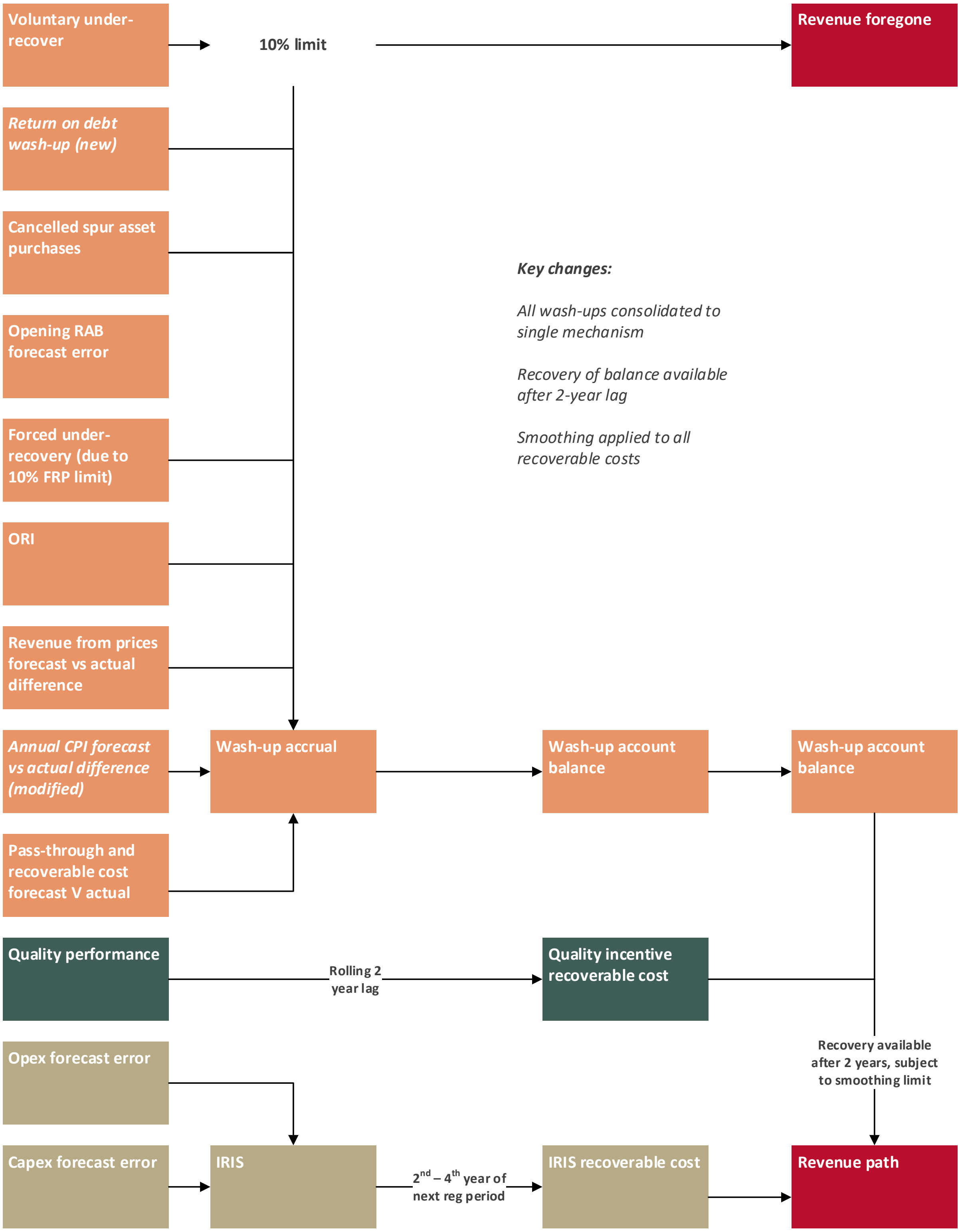
D27.1 calculates a number of different wash-up components separately;

D27.2 requires drawdown over varying timeframes, but for the main wash-up on a two-year lag; and

D27.3 allows no Commission discretion (and only limited supplier discretion) over the rate of drawdown.

D28 While the current mechanism is workable, these design decisions risk creating significant and unnecessary revenue volatility for suppliers and price volatility for consumers. Proposals for additional wash-ups would exacerbate these problems.

Figure D1 Proposed (EDB) wash-up mechanism



Stakeholder views on problem definition

D29 In its submission on the process and issues paper, Horizon Energy identified this as a concern:[427]

> The current DPP mechanism recognises that in any one year there may be an over or under-recovery of allowable revenue, relative to pass through and recoverable costs. The IRIS incentive / penalty value in the recoverable costs also influences the price setting volatility. This 'wash-up amount' is carried over into the following year and used as an input to determine the following year's prices.
>
> This wash-up amount can create a cycle where price adjustments swing around the target revenue values because over and under-collection of revenue is fully compensated for in the later year's prices.
>
> This variability in consumer bills creates uncertainty for consumers and makes it difficult for households to predict future years energy bills.

D30 Similar concerns were identified by First Gas.[428] Conversely, Orion noted that the current mechanism was "working as intended".[429]

Draft decisions

D31 As noted above, we propose a package of changes modelled on the Chorus wash-up and Transpower economic value (EV) account mechanisms. The key features of our proposed approach are:

- D31.1 a 'one big bucket' approach to all mechanisms that true-up for forecast versus actual differences;
- D31.2 a wash-up account that tracks accruals, balances, time-value-of-money, and drawdowns;
- D31.3 the ability for the Commission to specify the pace of drawdown over subsequent regulatory periods;
- D31.4 the ability for suppliers to make early drawdowns of the wash-up balance provided it does not cause price-shocks; and
- D31.5 an implementation approach that where possible references "re-running" the models used to calculate allowable revenue, to simplify drafting.

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427 Horizon Network – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 26-28.

428 First Gas Limited "Submission on IM Review Process and issues paper and draft Framework paper" (13 July 2022), pp. 20-21.

429 Orion "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 85.

D32 We considered but have not proposed incorporating the IRIS and quality incentive recoverable costs within the broader wash-up. Instead, we propose keeping these mechanisms separate. We consider the revenue smoothing limit discussed above is adequate for smoothing the impact of these incentives.

D33 Finally, we have included a "transitional wash-up accrual" in the first two years after these IMs come into effect. This is to allow 'wash-up' amounts accrued under the current wash-up mechanism to be carried forward and recovered or repaid in future.

Stakeholder views on proposed solutions

D34 Both Horizon and First Gas proposed mechanisms where the wash-up was drawn down over the subsequent regulatory period, with First Gas explicitly referencing Transpower's EV account as a model.[430]

How this decision will promote the overarching objectives

D35 We consider this package of changes will:

D35.1 directly better promote the s 52A purpose by reducing revenue volatility that can potentially limit incentives (and ability) to invest;

D35.2 indirectly better promote the s 52A purpose by better implementing other IM policies meant to allocate risk;

D35.3 improve regulatory certainty, consistent with the s 52R IM purpose by giving suppliers and consumers a more predictable revenue path; and

D35.4 reduce compliance cost and complexity through referencing DPP/CPP financial models rather than attempting to replicate the relevant calculations within the determination itself.

Better promoting the s 52A purpose

D36 In terms of direct outcomes from these proposed amendments, consider less volatile cashflows will help maintain incentives to invest, consistent with s 52A(1)(a). Where year-to-year volatility is low, suppliers can be expected to manage their levels of borrowing and investment. However, where the default two-year full draw down of wash-up amounts or the compounding effect of multiple wash-ups lead to significant year-on-year changes, the impact may force supplies to defer or avoid investment that would otherwise be in consumers interests. Moving to a combined and smoothed approach will mitigate this.

[430] Horizon Network – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 29; First Gas Limited "Submission on IM Review Process and issues paper and draft Framework paper" (13 July 2022), p. 21.

D37 On the other hand, deferring recovery to the following regulatory period may also lead to cash-flow constraints. To mitigate this, we have proposed the ability for suppliers to draw on a positive wash-up balance early, provided it does not create a price-shock for consumers (exceed the limit on the increase in forecast revenue from prices).

Better implementing other policies that promote the s 52A purpose

D38 Wash-up mechanisms insulate suppliers and consumers from the revenue consequences of differences between forecast and actual values. This approach avoids windfall gains or losses caused by risks that are not within suppliers' or consumers' control and is consistent with our 'risk allocation' economic principle. Avoiding windfall gains to suppliers helps promote s 52A(1)(d) by avoiding excess profits, while conversely avoiding windfall losses helps maintain incentives to invest under s 52A(1)(a).

D39 We consider our proposed changes better implement the suite of substantive wash-ups, and by doing so better give effect to the outcomes those wash-ups are seeking to promote.

Promoting regulatory certainty

D40 Under this approach, at the start of each DPP or CPP period, suppliers and consumers will have certainty about the path of revenue (including incentives and wash-ups but excluding pass-through costs) in real terms over the course of a regulatory period.

D41 Over the longer term, the fixing carry over to future periods in the IMs (rather than leaving it to the DPP/CPP determination) gives suppliers and consumers certainty that eventually revenues will be recovered or repaid.

Reducing compliance cost and complexity

D42 Consolidating all the various wash-up mechanisms into a single mechanism allows for simpler determination drafting and should help reduce compliance cost. Similarly, referencing models rather than replicating them allows the mechanism to remain unambiguous, while limiting drafting complexity and unintended consequences/potential errors.

Treatment of forecast CPI in the revenue path and wash-up

Problem definition

D43 Currently, differences between forecast and actual inflation for the purposes of indexing the revenue path are dealt with through the main wash-up mechanism on a two-year lag. While this approach is present-value neutral, in a context of higher and less predictable inflation, the delay to the recovery of revenue here may create cashflow problems for suppliers.

D44 This problem would be exacerbated by moving to an 'end of period' wash-up drawdown rather than a two-year rolling drawdown.

Submissions on problem definition

D45 Orion and Wellington Electricity highlighted this problem when submitting on possible improvements to the form of control.[431]

Recommendation

D46 We propose providing for revenue path indexation in two steps:

D46.1 first, with an annual update to forecast allowable revenue at the start of each regulatory year using the most up-to-date RBNZ forecasts of inflation; and

D46.2 second, with a residual wash-up for differences between these updated forecasts and actual inflation, via the mechanism discussed above.

D47 This is the same as the approach taken for Chorus' revenue path.

How this decision will promote the overarching objectives

D48 This decision will help maintain incentives to invest by avoiding suppliers facing cashflow constraints by delaying the recovery of potentially significant amounts of revenue. With a five-year regulatory period, the compounding impact of CPI forecast vs actual differences over the period could be significant to the point where it impacts incentives to invest. Allowing the revenue path to move with inflation each year rather than delaying recovery will help avoid this.

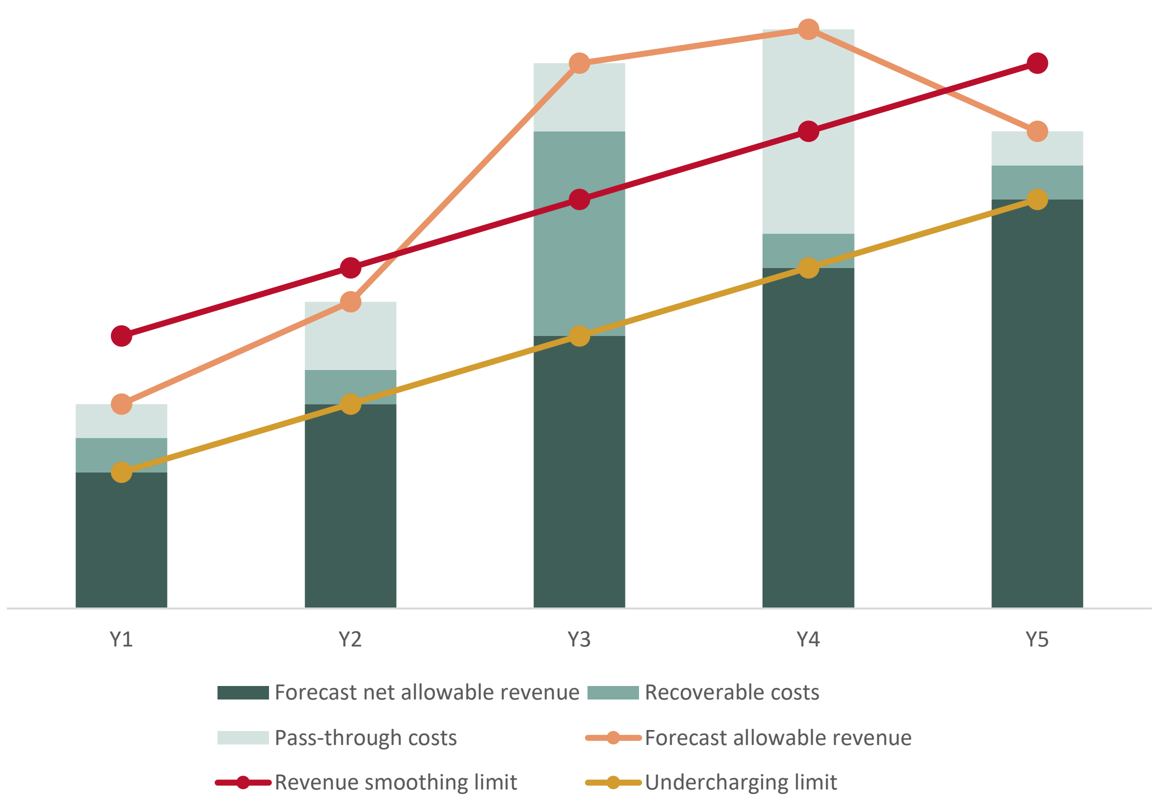
[431] Orion "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 102; Wellington Electricity "Cross-submission on IM Review Process and issues paper, and draft framework paper" (10 August 2022), p. 4.

D49 Similarly, accruing the entirety of the difference between forecast and actual revenue path indexation could lead to significant revenue shocks (in either direction) at the next price-path reset. From a customer perspective, this approach minimises the potential for short-term over-payment with subsequent clawback, contributing to price stability.[432]

D50 We do not consider this change in approach has a significant impact on regulatory certainty or complexity of the regime.

Compliance with the revenue path

Figure D2 Step 1 - calculating limits on revenue



D51 Forecast allowable revenue is the sum of forecast net allowable revenue, recoverable costs, and pass-through costs.

D51.1 Forecast net allowable revenue is defined in the PQ determination and increases at the rate of forecast CPI.

D51.2 Recoverable costs and pass-through costs are defined in the IM and forecast at the start of each year.

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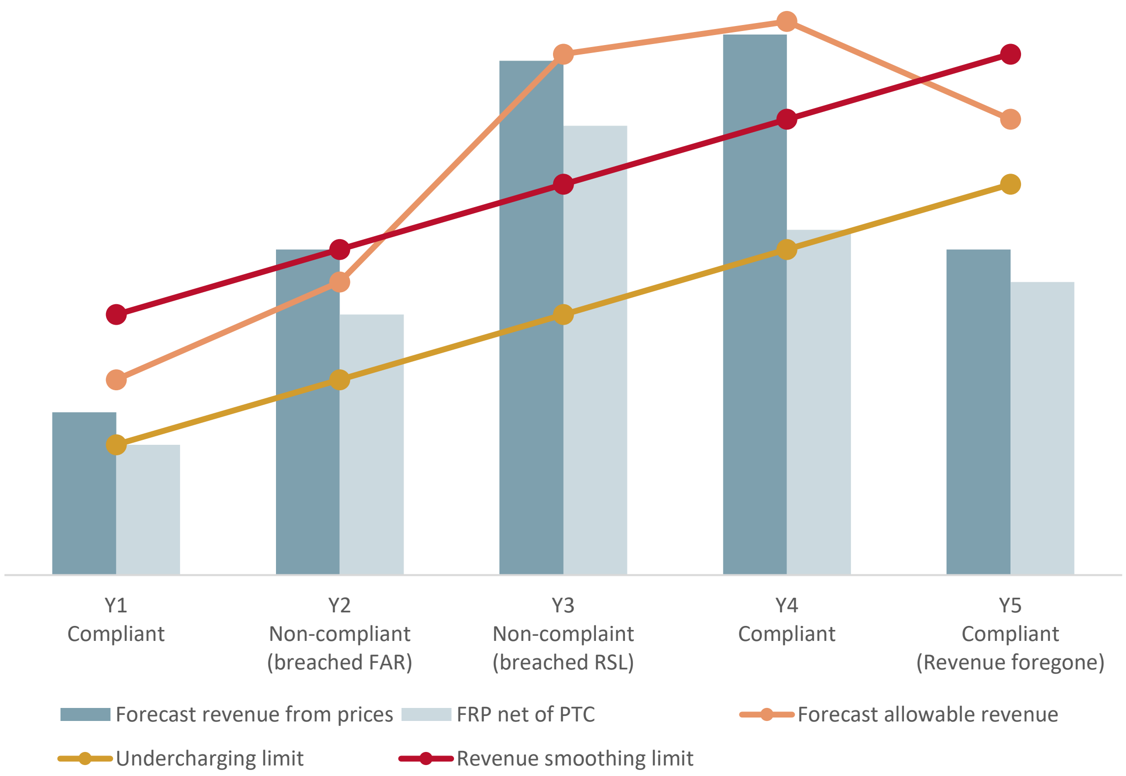
432 As noted above, while price stability sits outside the Part 4 purpose, it is generally valued by consumers; Commerce Commission "Topic Paper 1 form of control and RAB indexation" (20 December 2016), para 65.

D52 The revenue smoothing limit is defined in the PQ determination. In practice this may be defined relative to forecast allowable revenue, as a defined dollar amount, or based on a price-shock formula. Note it is not affected by pass-through costs.

D53 The undercharging limit is defined in the PQ determination. As with the revenue smoothing limit, this may be defined in dollar terms or formulaically.

Figure D3 Step 2 - Assessing compliance with the revenue path



Year one

D54 In year one the supplier is compliant with the primary revenue cap, because forecast revenue from prices (FRP) is less than forecast allowable revenue (FAR). It is also compliant with the secondary revenue control, because FRP net of pass-through costs (PTC) is less than the revenue smoothing limit (RSL). As FRP is less than FAR, the undercharge will accrue to the wash-up.

Year two

D55 In year two the supplier is non-compliant with the primary revenue cap because FRP is greater than FAR.

Year three

D56 In year three the supplier is non-compliant with the secondary revenue cap because FRP net of PTC is greater than the RSL), even though they are compliant with the primary revenue cap.

Year four

D57 As with year one, the supplier is compliant.

Year five

D58 The supplier is compliant. Because FRP is less than the undercharging limit, some revenue will be foregone. The undercharge between FAR and the UCL will be accrued, but the difference between the UCL and FRP will be foregone.

Illustrative revenue path and wash-up formulae

D59 To aid in stakeholder understanding, we have laid out the revenue path and wash-up mechanisms formulaically below. These are incorporated into Subpart 3.1 of the EDB and GTB IMs.

Primary revenue path formulae	
Clause 3.1.1(1)(a)	FRP < FAR FRP means "forecast revenue from prices" FAR means "forecast allowable revenue"
Clause 3.1.1(2)	FRP = ∑ (FP × FQ) + FORI FP means forecast "prices", as defined in the IMs FQ means forecast "quantities", as defined in IMs FORI means forecast "other regulated income", as defined in the IMs
Clause 3.1.1(3)	FAR = FNAR + FPTC + FRC FNAR means "forecast net allowable revenue, as specified in a PQ determination FPTC means forecast "pass-through costs", as defined in the IMs FRC means forecast "recoverable costs", as defined in the IMs
Secondary revenue control formulae	
Clause 3.1.1(1)(b)	FRP - FPTC < RSL FPTC means forecast "pass-through costs", as defined in the IMs RSL means forecast "revenue smoothing limit", as specified in a PQ determination

Wash-up formulae	
Clause 3.1.4(1)	$WAB_t = WAB_{t-1} \times (1 + WACC) + WA - WD - RF + TRA$ WAB means “wash-up account balance”, as defined in the IMs WACC means Post-tax WACC, as specified in the WACC determination WA means “wash-up accrual”, as defined in the IMs WD means “wash-up drawdown”, as defined in the IMs RF means “revenue foregone”, as defined in the IMs TRA means “transitional revenue accrual”, as defined in the IMs
Clause 3.1.4(2)	$WA = AAR - ACR – CODW$ AAR means “actual allowable revenue”, as specified in a PQ determination AR means “actual revenue”, as defined in the IMs CODW means "cost of debt wash-up", as defined in the IMs
Clause 3.1.4(13)	$AR = \sum (AP \times AQ) + AORI$ AP means actual “prices”, as defined in the IMs AQ means actual “quantities”, as defined in the IMs AORI means actual “other regulated income”, as defined in the IMs
Clause 3.1.4(5)	$WD = BWD + WAB$ BWD means “base washup drawdown”, as specified in a PQ determination WAB means “wash-up balance”, as defined in the IMs
Clause 3.1.4(6)	$RF = VRF + CRF$ VRF means “voluntary revenue foregone”, as defined in the IMs CRF means “compulsory revenue foregone”, as defined in the IMs
Clause 3.1.4(7)	If $FRP < UCL$: $VRF = UCL – FRP$ FRP means “forecast revenue from prices”, as defined in the IMs UCL means the “under-charging limit”, as specified in a PQ determination
Clause 3.1.4(9)	$CODW = ORABWV \times Leverage \times COD – ORABWV \times Leverage \times RCOD$ ORABWV means the “opening RAB without revaluations”, as defined in the IMs Leverage means “leverage”, as defined in the IMs COD means “cost of debt”, as defined in the IMs RCOD means “revised cost of debt, as defined in the IMs
Clause 3.1.4(10)	$RCOD = (1 + COD) \div (1 + FI) \times (1 + AI) – 1$ COD means “cost of debt”, as defined in the IMs FI means “forecast inflation”, as defined in the IMs AI means “annual inflation, as defined in the IMs
Clause 3.1.4(11)(a)	$FI = (FCPI_t \div FCPI_{t-1}) – 1$ $FCPI_t$ means forecast CPI for the disclosure year, as defined in the IMs $FCPI_t$ means forecast CPI for the previous disclosure year, as defined in the IMs
Clause 3.1.4(11)(b)	$AI = (CPI_t \div CPI_{t-1}) – 1$ CPI_t means CPI for the disclosure year, as defined in the IMs CPI_t means CPI for the previous disclosure year, as defined in the IMs