COMMERCE COMMISSION
NEW ZEALAND
Te Komihana Tauhokohoko

ISBN: 978-1-991085-66-5
Project no. 17.01/PRJ0045783

PUBLIC version

Financing and incentivising efficient expenditure during the energy transition topic paper

Part 4 Input Methodologies Review 2023 – Final decision

Date of publication: 13 December 2023

4658890v25

Associated documents

Publication date	Reference	Title
13 October 2022	ISBN: 978-1-99-101241-8	Part 4 IM Review 2023 Framework paper
13 December 2023	ISBN: 978-1-991085-64-1	Part 4 IM Review 2023 - Final decision - Summary and context paper - 13 December 2023
13 December 2023	ISBN: 978-1-991085-65-8	Part 4 IM Review 2023 - Final decision - Report on the Input methodologies review 2023 paper - 13 December 2023
13 December 2023	ISBN: 978-1-991085-69-6	Part 4 IM Review 2023 - Final decision - Cost of capital topic paper - 13 December 2023
13 December 2023	ISBN: 978-1-991085-67-2	Part 4 IM Review 2023 - Final decision - CPPs and In-period adjustments topic paper - 13 December 2023
13 December 2023	ISBN: 978-1-991085-68-9	Part 4 IM Review 2023 - Final decision - Transpower topic paper - 13 December 2023
13 December 2023	ISSN: 1178-2560	Airport Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 34
13 December 2023	ISSN: 1178-2560	Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35
13 December 2023	ISSN: 1178-2560	Gas Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 37
13 December 2023	ISSN: 1178-2560	Gas Transmission Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 36
13 December 2023	ISSN: 1178-2560	Transpower Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 38
13 December 2023	ISSN: 1178-2560	Transpower Capital Expenditure Input Methodology (IM Review 2023) Amendment Determination 2023 [2023] NZCC 39

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
Big Six	Collection of 6 largest EDBs - Aurora, Orion, Powerco, Unison, Vector and Wellington Electricity
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 Business
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
FNAR	Forecast Net Allowable Revenue
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
GIFWG	Gas Infrastructure Future Working Group
GPB	Gas Pipeline Business
GTB	Gas Transmission Business

Abbreviation	Definition
GTP	Gas Transition Plan
IBAT	IRIS Baseline Adjustment Term
ID	Information Disclosure
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
INTSA	Innovation and non-traditional solutions allowance
IPA	Innovation project allowance
IPP	Individual price-quality path
IRIS	Incremental Rolling Incentive Scheme
ISP	Integrated System Plan
LCC	Large connection contract
LCI	Labour Cost Index
MAR	Maximum Allowable Revenue
MBIE	Ministry of Business, Innovation and Employment
MGUG	Major Gas Users' Group
MEUG	Major Electricity 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

Abbreviation	Definition
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
TLC	The Lines Company
Totex	Total expenditure (capex and opex)
TPM	Transmission Pricing Methodology
UCL	Undercharging limit
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 final decisions and reasons that relate to regulated suppliers' incentives to spend efficiently. The focus of this paper is on our input methodologies' (IMs) tools and mechanisms, other than the cost of capital, that affect incentives for efficient investment and spending decisions.[1]

Context of this topic

X2 Our analysis and final 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.

X3 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.

X4 Ensuring that regulated suppliers have incentives to innovate, invest and operate efficiently[2] is perhaps more important now than at any point since Part 4 of the Commerce Act 1986 (the Act) was introduced.

X5 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 suppliers have incentives to innovate and invest appropriately.

Chapter 3: Financing and incentivising efficient investment

X6 Chapter 3 presents our review of the IMs that relate to suppliers' incentives and ability to invest efficiently. It includes discussion and 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

X7 Our final 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.

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1 For cost of capital decisions see: Commerce Commission “Part 4 Input methodologies Review 2023 - Final decision - Cost of capital topic paper" (13 December 2023).

2 Section 52A(1)(a) and (b) of the Act.

X8 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

X9 Some EDBs noted concerns about financing upcoming investment and submitted that we should allow them the option to choose to remove RAB indexation.

X10 Our final 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 prices should encourage capacity increases to match consumer demand.

X11 EDBs that face particular challenges, including financeability risks, can apply for a customised price-quality path (CPP) that better meets their particular circumstances and which provides scope for,[3] among other things, an alternative depreciation approach that better promotes the Part 4 purpose. We did not receive evidence substantiating the risk of a widespread financeability problem.

Maintain RAB indexation to inflation for GPBs

X12 For GPBs, stranding risk is a key part of the context. We acknowledge that removing RAB indexation could be used to further mitigate economic network stranding risk supporting incentives to invest, or to address concerns about long-term consumer price escalation which could undermine allocative efficiency in the long term.

X13 We have decided to continue to index GPBs' RABs for inflation because we consider that the above issues are better addressed independently of our approach to RAB indexation through asset life adjustment factors in default price-quality paths (DPPs), and if necessary, the option of changes to the depreciation method through a CPP (see paragraph X31). Given the uncertainty about future demand, we consider that these alternatives can better promote the Part 4 purpose. This is because the extent of any necessary adjustment can be determined at price-quality (PQ) path resets and tailored to the specific circumstances of each GPB to promote the Part 4 purpose.

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[3] Section 53K of the Act.

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

X14 Transpower submitted that it favours keeping its RAB unindexed, or applying hybrid indexation, where only the equity component of the RAB is indexed to inflation.

X15 Our final decision is to index Transpower's RAB to inflation from the fourth regulatory control period (RCP4) onwards.

X16 After reviewing submissions on the draft decision, we now consider that the decision to index Transpower's RAB to inflation is less finely balanced compared to how we understood it at the draft decision stage. This is because:

X16.1 Having published our financial modelling for Transpower with the draft decision, we have not seen evidence in submissions that raises concerns about Transpower's financeability under an indexed RAB approach; and

X16.2 We have not seen evidence in submissions that the implementation and compliance costs are large enough to tip the balance in favour of Alternative A or B, as described in paragraph 3.56, which would delay the implementation of RAB indexation to RCP5 or do a wash-up for Transpower's RAB (no RAB indexation), respectively.

X17 In the current environment and given our understanding of Transpower’s financeability, we no longer have the same concerns about matching the level of revenue to Transpower’s investment needs as we did in 2010. Instead, we consider that the benefits of indexation (protection from inflation and promoting pricing profiles that are more likely to be consistent with allocative efficiency) justify the change. We do not consider that we are trading off dynamic efficiency benefits for allocative efficiency ones, since we consider that Transpower has the incentive and ability to invest.

X18 Our final 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

X19 Our final 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 affects cashflow timing, but in general consider it reasonable to expect suppliers to manage these implications.

X20 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

X21 Given the general uncertainty in future network growth, an issue that has been raised by EDBs is the implications of new connections for expenditure allowances. They argue that the demand for new connections is largely outside of suppliers' direct control, but EDBs are still responsible for part of the cost of these connections (shared with connecting parties through capital contributions).

X22 Our decision is to amend the EDB IMs to provide for a 'new connection wash-up mechanism', applying to the quantity of new connections (washing up the capex amount based on unit costs of different connection types), which CPP applicants may propose to be implemented as part of their CPP.

X23 We do not consider that applying the mechanism to DPPs would better achieve our framework's overarching objectives given the information asymmetry due to the low-cost nature of a DPP. In addition, the mechanism is only intended for suppliers in a specific situation: where there is significant demand quantity risk associated with new connections and for which unit costs can be robustly estimated. Generally, suppliers have other options for addressing demand quantity risk, for example, by changing capital contributions policies or reprioritising expenditure.

X24 The new mechanism would promote the purpose of Part 4 for EDBs on a CPP where there is significant demand quantity risk associated with new connections:

X24.1 Where the mechanism applies, EDBs under a CPP would have incentives to invest to meet demand for new connections while not exposing them to overspends due to connection quantity forecast error, thereby promoting s 52A(1)(a);

X24.2 The mechanism would help control connection costs, promoting the efficient provision of each connection (s 52A(1)(b)). Suppliers have some control of the cost of each new connection and, therefore, specifying connection unit costs in advance of a CPP provides that incentive for efficiency; and

X24.3 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

X25 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.

X26 This context presents a transition risk[4] and has potential implications for how best to address asset stranding risk in a way that promotes the Part 4 purpose.

X27 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 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.

X28 Our final 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.

X29 Keeping otherwise stranded assets in the RAB and allowing for asset life adjustment factors in DPPs to better reflect economic asset lives, maintains the integrity of the Building Blocks Method (BBM) to deliver an ex-ante expectation of real financial capital maintenance (FCM) which in turn incentivises GPBs 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.

X30 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.

X31 We have considered and rejected other options to address asset stranding risk or related concerns about long term consumer price escalation.

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

X31.1 As discussed above, we have decided not to remove RAB indexation to address stranding risk or concerns about long term consumer price escalation. These concerns are better addressed through asset life adjustments in DPPs and, if necessary, through changes to the depreciation method in CPPs. By applying our current DPP and CPP 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.

X31.2 We have decided not to allow 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.

X31.3 We do not consider there is evidence to justify using a front-loaded depreciation method as the default method in all resets at this time. Instead, we consider that the complexity of the analysis and consumer engagement required to justify a change in depreciation method for DPPs – in addition to asset life adjustments – would only be achievable in the context of applications for CPPs at this time.

X31.4 We have not introduced 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.

X32 We have also rejected alternatives that are inconsistent with the ex-ante FCM principle including writing down suppliers' assets from the RAB without prior ex-ante compensation, restricting asset life adjustments to new assets only without prior ex-ante compensation, and relying on safety and reliability standards or social license to operate. These alternatives are not consistent with ex-ante FCM and providing the expectation of normal returns in line with s 52A(1)(a) and (d), and would undermine incentives to invest where continued investment to deliver safe and reliable services remains in consumers' long-term interest.

Topic 3e – Form of Control for GDBs

X33 Our final decision is to maintain the weighted average price cap (WAPC) form of control for GDBs. Compared to the alternative of a revenue cap form of control, a WAPC better promotes s 52A(1)(a) and (b) by providing 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.

X34 We note that there are pros and cons for both types of form of control, and in the absence of convincing evidence in favour of a change to a revenue cap, we consider that, on balance, a WAPC better achieves our IM Review framework's overarching objectives.

Topic 3f - Financeability test in the IMs

X35 Our final decision is not to adopt a financeability test in the IMs because we remain of the view that a financeability test IM would not better achieve our Framework's overarching objectives. We can already consider, and indeed have previously considered, financeability where relevant and not inconsistent with promoting the Part 4 purpose when setting a price path.

Chapter 4: Inflation risk

X36 Chapter 4 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 4a – Inflation forecasting method

X37 Our final 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:

X37.1 for forecasting the RAB revaluation rate, this is the RBNZ forecasts available at the time we determine the risk-free rate and debt premium (used in the weighted average cost of capital (WACC) estimate that applies for a price-quality path). This forecast is a proxy for the market's unobservable inflation expectation inherent in the WACC;

X37.2 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

X37.3 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.

X38 The RBNZ currently forecasts CPI for 13 quarters ahead. For the remaining quarters of the regulatory period, for which forecasts are not produced, we linearly trend to the midpoint of the RBNZ inflation target band (currently two percent) by the end of the forecasting window.

X39 Submitters proposed some alternatives to our draft decision, but none of them presented evidence showing that their preferred alternatives would provide a better forecast of inflation – one that minimises the difference between forecast and actual inflation over the relevant forecast window.[5]

X39.1 Submitters mentioned market-based and survey-based methods as alternatives. The RBNZ inflation forecast is not purely model driven, it does include market data – and other data including survey data – to the extent that the Monetary Policy Committee and forecast team consider it relevant. We understand that this applies to inflation forecasts of six months or more into the future.

X39.2 In relation to submitters' point about adopting the forecasting method used by the Australian Economic Regulator (AER) or Queensland Competition Authority (QCA), no submitter provided evidence that their methods would perform better than our method in New Zealand.

X40 Having considered submissions, we consider that confirming the draft decision as our final decision is likely to better achieve our framework's overarching objectives than alternatives put to us. For the RAB revaluation rate, we consider that our approach 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 4b – Inflation risk allocation and compensation

X41 Our final decisions are to amend the EDB IMs and GTB IMs to:

X41.1 wash-up allowable revenue for the first year of a regulatory period when inflation differs from expected inflation; and

5 Investors' expected inflation is unobservable and must be estimated. 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.

X41.2 ensure that the most up-to-date CPI inflation (actual and forecast) is used when determining forecast net allowable revenue at the start of each regulatory year.[6]

X42 We have decided not to introduce a cost of debt wash-up (CODW) to the EDB and GTB IMs, and to revert to the status quo. This is a change to our draft decision. Following extensive consultation, the main reason supporting our final decision is that the status quo protects both consumers and suppliers from inflation risk.

X42.1 We consider that the regime should not expose consumers to the risk that the real price they pay varies significantly in response to unexpected changes in inflation.

X42.2 The revenue wash-up (together with the rolling forward of the RAB using actual instead of forecast inflation) protects suppliers – equity and debt holders combined – from inflation risk. Through their debt management practices, suppliers' management can protect or expose equity holders – to varying degrees – to the risk of inflation-driven windfall gains or losses. The debt management practices that influence the degree of equity holders' inflation risk exposure include the use of swaps for hedging, debt refinancing timing and extent, use of floating debt and, where available, inflation-linked bonds.[7]

X42.3 In addition, as explained in section 4b, we consider that the status quo better supports new investment during the regulatory period (debt costs are effectively updated each year for actual inflation through the revenue wash-up). This may be particularly valuable in a context where investment is expected to increase significantly.

X43 Finally, the status quo is a simpler, more well-known approach. It is less directive of suppliers' debt management approaches than the alternatives. No changes will need to be made to business systems and there is no mismatch between PQ and ID RABs that would have resulted from the blended CPI alternative that some submitters preferred in our further consultation.

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[6] Commerce Commission "Input methodologies review 2023 – Further consultation on IM Review draft decision on the CODW of EDBs and GTBs" 29 September 2023, para 11.
Note: Where we use the term "regulatory year" we are referring to "disclosure year" for EDBs, and to "pricing year" for GPBs.

[7] Transpower has issued inflation-linked bonds. See [Bloomberg "Transpower Markets NZ$75 Million of Inflation Notes" (19 April 2010)].

Chapter 5: Our approach to incentivising efficient expenditure for EDBs and Transpower

X44 Chapter 5 outlines our final decisions on expenditure incentive schemes that apply under EDBs' and Transpower's price-quality paths.

Topic 5a - Expenditure incentive schemes as tools to mitigate capex bias

X45 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 rather than traditional capex solutions). In this context, we want to ensure that financial regulatory incentives do not distort investment decisions.

X46 Our final decision is to keep the current suite of expenditure incentive schemes for EDBs and Transpower under the IMs as tools to mitigate capex bias arising from financial regulatory incentives, and to not adopt a totex approach to price-quality regulation. We have also made targeted changes to the expenditure incentive mechanisms to improve the workings of the mechanisms.

X47 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 in this review.

Topic 5b - Maintain the current incentive mechanisms as they best balance considerations of effectiveness and understandability

X48 The opex and capex expenditure incentive mechanisms 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.

X49 As part of this review, we assessed whether there are alternative approaches that could better achieve our framework's overarching objectives and our objectives for expenditure incentive schemes. These objectives for expenditure incentive schemes include:

X49.1 providing equal incentive rates for opex and capex;

X49.2 providing consistent incentive rates to make efficiency savings over time;

X49.3 the ability to tailor incentive rates which determine the extent to which efficiency gains are shared with consumers; and

X49.4 removing incentives under a revenue cap to inflate costs in some key years.

X50 Our final 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.

X51 We have considered alternative approaches that might simplify the approach to expenditure incentives, but we consider that the current approach better achieves our IM Review overarching objectives. There were 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.

X52 This decision should be considered alongside the changes to the expenditure incentive mechanisms for EDBs and Transpower we implemented in this IM Review.

Topics 5c to 5i - Specific changes to the EDB and Transpower expenditure incentive mechanisms

X53 Our final decision is to implement several improvements to the current expenditure incentive mechanisms.

X54 The main changes to the expenditure incentive mechanisms are:

X54.1 Applying IRIS in real (CPI-adjusted) terms rather than nominal terms for EDBs: 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.[8]

X54.2 Applying the midpoint WACC as the discount rate in the opex IRIS calculation for EDBs and Transpower: we do not consider that a WACC uplift is necessary for the purposes of discounting for the opex IRIS.

X54.3 We are making changes to Transpower's opex IRIS, including removing the baseline adjustment term, amending the base year adjustment term and amending the year 5 carry-forward calculation: 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. These changes ensure IRIS accurately reflects how we set allowances and allow Transpower to better predict its return from making opex efficiency savings under the IRIS incentive mechanism.

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[8] The Transpower IRIS incentive amounts are already specified in real terms.

X55 We have considered the following issues against our IM Review overarching objectives and have made no changes to the IMs:

X55.1 We considered whether to allow for incentive rates to be set at a price-quality 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.

X55.2 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). If these costs were treated as a recoverable cost (as suggested in submissions), it could create significant price volatility.

X55.3 We do not consider that a change is needed for the treatment of operating leases for incentive purposes.

X55.4 We do not consider that a change to IRIS is needed to account for regulated suppliers that undercharge their maximum allowable revenue (MAR).

X55.5 We continue to consider that the benefits of an IRIS mechanism for GPBs are unlikely to outweigh the costs.

Chapter 6: Innovation incentives for EDBs and Transpower

X56 Chapter 6 presents our review of the IMs that relate to the innovation-specific mechanisms provided for in the EDB IMs. The chapter explains our decision to not amend the EDB IMs to provide for regulatory sandboxes, and our decision to provide for the innovation and non-traditional solutions allowance.

Topic 6a – Regulatory sandboxes for EDBs

X57 We consider the IMs generally enable the desired outcomes of regulatory sandboxes and have not made changes to them for this purpose. We recognise that there may be benefits to trialling innovative approaches involving 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

X58 Our final decision is to amend and expand the current 'innovation project allowance', provided for in the EBD IMs, into the 'innovation and non-traditional solutions allowance' to enable a wider range of schemes to provide better incentives for innovation and non-traditional solutions, at DPP resets or when setting a CPP.

X59 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, as IRIS does not incentivise an EDB to efficiently spend opex in the current regulatory period to defer capex expenditure in a future regulatory period.[9]

X60 Our change to the EDB IMs enables a wider range of options to encourage innovation and non-traditional solutions, which better promotes the Part 4 purpose.

[9] The specific problem surrounding capex deferral using non-traditional solutions is also relevant to Transpower as the same issue arises with Transpower's expenditure incentive mechanisms. We discuss our reasons for making not making changes to the Transpower IMs in Chapter 6 (Topic 6b).

Chapter 1 Introduction

Purpose of this paper

1.1 The purpose of this paper is to share with stakeholders our IM Review 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.[10] 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' incentives and ability to invest efficiently. It includes discussion and 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 presents our review of the IMs that relate to the method for forecasting inflation and exposure to inflation risk and associated compensation;

1.2.4 Chapter 5 outlines our review of 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 decisions related to our expenditure incentive schemes; and

1.2.5 Chapter 6 focuses on specific tools provided for in the IMs for promoting innovation under our regulatory regime. We explain our 'innovation and non-traditional solutions allowance' —which may be used, for example, to improve incentives for expenditure trade-offs between regulatory periods—and regulatory sandbox decisions.

1.3 The table below presents all of our final decisions from our review of the IM policy decisions that are the subject of this topic paper.

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10 For decisions related to the cost of capital see: Commerce Commission "Part 4 Input methodologies Review 2023 - Final decision - Cost of capital topic paper" (13 December 2023).

Table 1.1 Risks and incentives topic paper – decisions 'at a glance'[11]

#	Provision	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: Inflation Risk		
4a	Unchanged IM provisions	Maintain our current method for forecasting inflation
4b	Amended IM provisions	Introduce inflation wash-up on revenue for the first year of a regulatory period
4b	Amended IM provisions	Use the most up-to-date inflation information to determine allowed revenue at the start of each year
4b	Unchanged IM provisions	Revert draft decision. Maintain status quo where annual revenue washup is fully adjusted for CPI inflation
Chapter 5: Our approach to incentivising efficient expenditure for EDBs and Transpower		
5a	Unchanged IM provisions	Not adopt a total expenditure (totex) approach. Maintain current expenditure incentive schemes as tools to mitigate capex bias
5b	Unchanged IM provisions	Maintain current incentive mechanisms as they best balance effectiveness and understandability
5c	Amended IM provisions	Adjust incremental rolling incentive scheme (IRIS) allowances for inflation for EDBs
5d	Unchanged IM provisions	Maintain our approach to setting incentive rates
5e	Unchanged IM provisions	Not to exclude specific expenditure categories from IRIS
5f	Amended IM provisions	Use the midpoint discount rate in the opex IRIS calculation
5g	Unchanged IM provisions	Maintain our current treatment of operating leases
5h	Unchanged IM provisions	Make no change to IRIS for undercharging
5i	Amended IM provisions	Remove the Transpower baseline adjustment term and make two amendments to Transpower opex IRIS
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 to become the 'innovation and non-traditional solutions' allowance

1.4 Alongside this paper, we have published the following models that demonstrate our decisions:

1.4.1 Demonstration model: inflation wash-up. The purpose of this model is to demonstrate the different options we considered to account for the interaction of inflation and the cost of debt:[12]

1.4.1.1 In our IM Review draft decision paper;[13]

11 New provisions and amendments are with respect to the status quo.

12 This model is largely unchanged from the one published for further consultation (Commerce Commission "Input methodologies review 2023 – Further consultation on IM Review draft decision on the CODW of EDBs and GTBs" 29 September 2023). We added sections to show the return on actual assets (in addition to return on RAB) and added an alternative to the blended CPI approach proposed by CEG. Some other minor changes were made which are explained in the model.

13 Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), at Topic 5b – Inflation risk allocation and compensation.

1.4.1.2 In the further consultation on the IM Review draft decision on the cost of debt wash-up adjustment (CODW);[14]

1.4.1.3 In assessing proposals received in submissions[15] on the draft decision and further consultation on the CODW[16]; and

1.4.1.4 In reaching our final decision to maintain the status quo under the current IMs and not amend the EDB and GTB IMs to introduce the CODW.

1.4.2 Demonstration model: an illustration of the incremental rolling incentive scheme (IRIS) for opex that applies to Transpower from RCP4. The purpose of this model is to demonstrate the application of changes we have made to the Transpower opex IRIS.

Our decision package for the IM Review

1.5 This paper forms part of a package of decisions papers on the IM Review. Alongside this paper, we have published:

1.5.1 our EDB, Transpower, GDB, GTB, and Airports IM amendment determinations.

1.5.2 our Summary and Context paper;

1.5.3 our other topic papers, which explain our 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 Report on the IM Review, which summarises for every IM policy decision:

1.5.4.1 any changes we have made;

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14 Commerce Commission "Input methodologies review 2023 – Further consultation on IM Review draft decision on the cost of debt wash-up of EDBs and GTBs" 29 September 2023.

15 CEG "Approach to targeting nominal return on debt" (report prepared for Vector, 9 August 2023), para 22.

16 CEG "'Targeting a nominal cost of debt' - Submission on specific matters for the IM Review 2023 Cost of debt" (report prepared for 'Big Six' EDBs, 17 October 2023), para 100.

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.

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 decisions on risks and incentives.[17]

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:[18]

2.2.1 promoting the Part 4 purpose in s 52A more effectively;[19]

2.2.2 promoting the IM purpose in s 52R more effectively (without detrimentally affecting the promotion of the s 52A purpose);[20] and

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

2.3 In applying the Framework's overarching objectives, we have had regard to whether our 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.[21]

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17 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)", para 2.13-2.14.

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

19 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 section 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.

20 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]".

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

2.4 Several of our decisions (eg, 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.[22] 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.[23]

2.5 In certain contexts, such as our 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).[24]

2.6 We also considered it relevant and consistent with promoting s 52A to have regard to s 54Q of the Act in our 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 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.

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.[25]

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22 Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022)", para 2.22-2.25.

23 Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022)", para 2.22-2.25.

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

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

Context for these 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.[26] The focus of this paper is on the IMs' tools and mechanisms, other than the cost of capital, that affect incentives for efficient investment and spending decisions by price-quality regulated suppliers.[27] 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 Climate change policy 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 initiatives aimed at decarbonising the economy. The National Adaptation Plan contains 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.

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.[28] If so, many existing assets will become redundant or underutilised.

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

[27] For decisions relating to the cost of capital see: Commerce Commission "Part 4 Input methodologies Review 2023 - Final decision - Cost of capital topic paper" (13 December 2023).

[28] 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.

2.13 The pace of this transition and the impact on GPBs remains uncertain, and presents a transition risk,[29] given the many possible pathways for the sector to decarbonise. This is a focus of the planned Gas Transition Plan (GTP).[30]

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[31] 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.

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.[32] Inflation has remained high since then, most recently sitting at 5.6 percent in September 2023.

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

30 The planned GTP is intended to 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. For further information refer to MBIE's website.

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

32 Statistics New Zealand, "Consumer price index: September 2023 quarter" (17 October 2023).

Concerns about cashflows – 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.

2.19.2 Suppliers are also concerned about the availability of cash to help 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.

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 efficiently

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 (chapter 3) and improve efficiency of spend (chapter 5), 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 4).

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 new connection wash-up mechanism for EDBs on a CPP;

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

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' RABs to inflation.[33]

Final decisions

3.4 We have made the following final decisions:[34]

3.4.1 maintain RAB indexation to inflation for EDBs;

3.4.2 maintain RAB indexation to inflation for GPBs;

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

[34] We have not changed the airport services' IMs in relation to RAB indexation.

3.4.3 change the Transpower IMs effective from RCP4 to:

3.4.3.1 index Transpower's RAB to inflation;[35] and

3.4.3.2 enable Transpower to apply for an alternative depreciation approach.[36]

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 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 the profile of prices over time.

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35 This is the same approach as for EDBs and GPBs, where we treat forecast revaluation gains as income at the reset, and the RAB is rolled forward in ID using actual inflation.

36 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 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 potentially inconsistent with their cost of debt, depending on how they chose to manage it. We discuss the debt compensation issue in Chapter 4, Topic 4b.

Draft decisions

3.12 Our final decisions confirm our draft decisions. Our draft decisions were to:

3.12.1 maintain RAB indexation to inflation for EDBs;

3.12.2 maintain RAB indexation to inflation for GPBs;

3.12.3 change the Transpower IMs effective from RCP4 to:

3.12.3.1 index Transpower's RAB to inflation;[37] and

3.12.3.2 enable Transpower to apply for an alternative depreciation approach.

Reasons for our draft decision to maintain RAB indexation to inflation for EDBs

3.13 Our draft decision was to maintain the status quo of indexing EDBs' RABs to inflation.[38]

Our original reasons for indexing EDB RABs remain valid

3.14 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.

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37 This is the same approach as for EDBs and GPBs, where we treat forecast revaluation gains as income at the reset, and the RAB is rolled forward in ID using actual inflation.

38 Note that we also proposed to retain RAB indexation for GPBs. We discussed our reasons for this decision below from 3.47.

3.15 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.[39]

3.15.1 In the draft decision we considered that the inflation protection point remained valid.

3.16 An indexed RAB together with SLD ('standard approach') is a simple, transparent, and well-understood way of calculating depreciation.[40]

3.16.1 In the draft decision we considered that this point remained valid.

3.17 The standard approach supports a relatively flat aggregate pricing profile in real terms over time. 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.[41]

3.17.1 In the draft decision we considered that this point remained valid, and noted that 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)).[42] We noted that other factors in addition to a SLD- indexed RAB affect the pricing profile, such as asset lives and investment profile. Our understanding was 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.

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

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

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

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

3.17.2 We heard – and saw 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 considered this was a reasonable basis for the draft decision, but noted that other relevant factors may have also changed, which may affect the above discussion. We invited evidence on this point.

3.18 The standard approach is consistent with a cashflow profile that is generally consistent with a prudently financed supplier meeting both its 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 its investments, particularly given the treatment of taxation.[43, 44]

3.18.1 In the draft decision we considered that this point remained 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.[45] There would need to be a specific change in circumstances, to result in a situation where an efficient supplier would have difficulty maintaining its benchmark leverage and credit rating. These circumstances are likely to be supplier specific. We noted that under our draft decision, EDBs will maintain the frontloaded cashflow effects from applying our modified deferred tax approach.

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43 The modified deferred tax approach which frontloads cashflows.

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

45 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

3.19 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).[46]

3.19.1 In the draft decision we considered that this point remained valid.

3.20 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.[47]

3.21 We noted this may help improve the financeability of investments, at the margin, for suppliers subject to default/customised price-quality regulation.[48] 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.[49] 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 we 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).[50]

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return required by debt and equity holders for the profile of recovered revenues, efficient EDBs will be financeable". NERA "Financeability considerations under the DPP" 'Appendix D -Submission on IM Review CEPA report on cost of capital' (report prepared for Electricity Networks Aotearoa, 16 January 2023), para 3.

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

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

48 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para 5.2.8.

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

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

3.21.1 In the draft decision we recognised 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 considered that this circumstance is likely supplier specific, and so our view remained:

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

3.21.1.2 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.[51]

3.22 We noted in 2010 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.[52]

3.22.1 In the draft decision we considered that this point remained valid.

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

3.23 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), protecting the overall business returns from the effects of inflation, all other things being equal. This results in an outcome where both consumers and suppliers are protected from inflation risk.

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

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

3.24 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 considered that aggregate pricing that is flat in real terms over time is consistent with allocative efficiency in workably competitive markets.[53]

3.24.1 In our draft decision we considered that these points remained valid.

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

3.25 As mentioned in paragraph 3.10.2 and 3.19, indexing the RAB to inflation is consistent with the suppliers having the incentive to invest, which is consistent with s 52A(1)(a).

3.26 We 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 for the draft decision was that removing indexation is not an appropriate way to resolve cashflow issues for EDBs at this time.

3.27 As discussed in this section, we considered options around regulatory depreciation to support the price path that better promotes the purpose of Part 4.

3.28 However, in general, we did not consider that depreciation should be used to address financeability concerns. We considered that financing the recovery of investment 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.[54] We would only bring forward capital recovery in specific circumstances where we are satisfied that doing so would better promote the Part 4 purpose. A CPP is the appropriate setting to consider this.

53 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.

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

3.29 Furthermore, in the current context, we were not aware of a shortage of capital providers willing to invest in this sector. To the contrary, we continued to see transactions at RAB multiples above one,[55] and improving credit ratings.[56]

3.30 Additional reasons for not using RAB indexation to address financeability concerns for EDBs included:

3.30.1 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;

3.30.2 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

3.30.3 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.[57]

3.31 We considered that 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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55 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 - Final decision - Cost of capital topic paper" (13 December 2023).

56 S&P Global "Research Update: Vector Ltd. Upgraded To 'BBB+' On Strengthening Business Mix; Outlook Positive" (press release, 26 April 2023)

57 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.

3.32 We noted 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.[58] For the reasons above, we did not consider that this would better achieve the overarching objectives of the IM Review compared to the status quo. Specifically:

3.32.1 in the current context of investing ahead of demand, we considered that s 52A(1)(b) would be 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 occurred; and

3.32.2 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, where justified.

Removing indexation risks price shocks

3.33 We noted 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."[59]

3.34 In the present economic context, we considered 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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58 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.

59 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

3.35 An inflation-indexed RAB that is depreciated using the straight-line method, under certain assumptions,[60] is more likely to be consistent with constant real prices, which is likely closer to an allocatively efficient pricing profile.[61]

3.36 In the draft decision we considered that 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. We saw this as consistent with what submitters said and the evidence we saw emerging.[62] In this context, we considered that an indexed RAB approach was 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).[63]

3.37 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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60 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.

61 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.

62 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.

63 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)

3.38 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).

3.39 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.[64]

3.40 We considered that a CPI-indexed RAB depreciated in a straight line was 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.

3.41 Our view at the draft decision was that indexation that supports a more efficient pricing profile is also consistent with efficient electrification. We noted 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."[65]

3.42 Making efficient electrification attractive to consumers is consistent with the 2050 target of net zero greenhouse gas emissions,[66] which we can take into account where relevant and not inconsistent with promoting s 52A.[67]

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64 For example, refer to: 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.

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

66 Sections 5Q and 5ZN(a) of the Climate Change Response Act.

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

3.43 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.[68]

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

3.44 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.

3.45 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).

3.46 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:

3.46.1 We consider that in the absence of evidence of a widespread, industry-wide financeability problem,[69] 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

3.46.2 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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68 Concept Consulting recently found "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. 22.

69 We note the submissions from CEG and NERA, which provided the results of analyses relating to EDB financeability. We respond to these submissions in section 3a.

Reasons for our draft decision to maintain RAB indexation to inflation for GPBs

3.47 Our draft decision was to maintain RAB indexation for GPBs because, as we outline below, we did not consider that changing from the status quo would better achieve the IM Review overarching objectives.

3.48 The concerns that submitters raised on RAB indexation for GPBs were related to how we address asset stranding risk to incentivise efficient investment.[70]

3.49 We did 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.

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

Reasons for our draft decision to 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

3.51 Our draft decision was to change the Transpower IMs, with effect at the RCP4 reset, to:

3.51.1 index Transpower's RAB to inflation; and

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

3.52 As we explain in this section, our view was 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 did, 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.

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70 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), para 21.b.ii, 80, and 81.

3.53 Specifically, we considered 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 discussed in this section, our draft decision was more likely to better promote s 52A(1)(b) in supporting a more efficient price profile, followed by Alternative A and then Alternative B.[71]

3.54 We invited evidence and submissions on our draft decision and the alternatives.

3.55 Our draft decision was 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 invited evidence on the workability of this.

3.56 We also invited submissions on the following two alternatives to our draft decision:

3.56.1 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 4b could be implemented. This would no longer be required once indexation was implemented in RCP5.

3.56.2 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 4b.[72] 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.

3.57 Of the two alternatives, we favoured Alternative A because, for the reasons we outline in this section, we considered 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.

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

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71 We noted that revenues (and therefore cashflows) would likely be affected the most under our draft decision and the least under Alternative B.

72 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.

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

3.59 In our initial setting of the Transpower IMs in 2010, we considered that, among other things, an unindexed approach was appropriate for Transpower because:[73]

> 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.

3.60 As we noted in the Process and issues paper,[74] 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.

3.61 Our reading of the evidence was 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:[75]

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

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

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

> 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.—

3.62 Our understanding at the draft decision was 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.[76] 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.

3.63 At the time of writing the draft decision, Transpower was planning—and had started—grid upgrades to meet forecast demand, including beyond the short term. For example, Transpower's planned capex nearly doubles between now and 2030,[77] 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.[78]

3.64 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 was to index Transpower's RAB from RCP4, rather than delay the change to RCP5 (Alternative A).[79]

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

77 https://www.transpower.co.nz/our-work/industry/our-grid/asset-management. Refer to 'ITP schedules'. Note that this webpage, and the links within it, have been updated since our draft decision.

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

79 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 4b.

3.65 Even if spare capacity did not materially increase in the near term, we considered 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.

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

3.67 Therefore, our view was that indexing Transpower's RAB was 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

3.68 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.[80]

3.69 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.[81]

3.70 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.

80 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.

81 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.

Our view was that the compliance and regulatory costs of indexation were likely lower than the benefits

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

3.72 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.[82]

3.73 Our draft decision recognised that indexing the RAB would be a move away from GAAP-consistent regulatory reporting, which may require internal accounting/system changes. We invited specific evidence and details of the costs of these changes.

3.74 We noted that, 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 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.[83]

3.75 As outlined above (and discussed later in this document at section 4b), 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.[84] This would protect Transpower and consumers from inflation risk, but would have a more limited impact on depreciation and cashflows.

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82 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.

83 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.

84 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.

3.76 However, RAB indexation would also protect Transpower and consumers from inflation risk, and therefore the RAB inflation wash-up outlined in section4b 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.

3.77 Prior to our draft decision, some submitters suggested the approaches to RAB indexation for Transpower and EDBs should be aligned for consistency.[85] 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 did not underpin our draft decision which was based on the reasons outlined above, we invited 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

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

3.79 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.[86]

3.80 We recognised in our draft decision that an indexed RAB, while NPV neutral from the suppliers' perspective, decreases cashflow in the short term, but noted that this does not necessarily imply financeability issues.

3.81 We noted Transpower's submission of a Frontier Economics report on the topic of RAB indexation. In it, Frontier presented an example of an Australian transmission project. We understood that the intention of this is to show how RAB indexation[87]

> 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.

[85] 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.

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

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

3.82 The specific example was the Australian Energy Market Commission's (AEMC) rejection of TransGrid's rule change request aimed at improving financeability of Integrated System Plan (ISP) projects.[88] 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.

3.83 We made the following observations on this Australian development:

3.83.1 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;

3.83.2 Frontier noted that the government had to provide additional finance to support the project going ahead. We considered 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;

3.83.3 we agreed 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;[89] and

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

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

3.83.4 the final AEMC rule introduces greater flexibility to address the risk of financeability challenges that may arise for ISP projects. In particular, it provides 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.”[90] The AEMC further recommends that the AER have regard to the following:[91]

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

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

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

3.83.5 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.[92]

3.84 We 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 was not of Transpower’s actual financial position, but rather assumed Transpower operates according to our benchmark financing assumptions. For example, we assumed Transpower maintains leverage at the benchmark value of 41 percent.

3.85 Our model used 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 was 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.

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

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

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

3.86 Other things equal, we considered our draft decision to index Transpower's RAB to inflation would reduce Transpower's allowed revenues in the shorter term, 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 estimated 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 was 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.[93]

3.87 We noted in the draft decision 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 invited comments on whether Transpower's (benchmark) cash flows would create concerns for its (benchmark) credit rating position. Our modelling at that point indicated that indexation of the RAB may not lead to a financeability problem.[94]

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

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93 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.

94 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.

3.89 Therefore, our draft decision was 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 similarly 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.[95]

3.90 We noted 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 did not propose to change the EDB tax approach, so this specific cashflow timing effect for EDBs would continue. But this provided 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.

Our consideration of stakeholder views on the draft decision

Submissions in support of RAB indexation

3.91 Stakeholders in support of RAB indexation were Powerco (for EDBs and Transpower, not GPBs), Orion, Horizon Energy, MEUG and Contact Energy. They made the following arguments, which we briefly respond to:

3.91.1 RAB indexation protects both suppliers and consumers from inflation risk.[96]

3.91.1.1 We agree with this view.

3.91.2 for EDBs and Transpower, it promotes pricing profiles that are more likely to be allocatively efficient, with smoother prices in real terms; shifts cost recovery to the future, when consensus is that demand will be higher.[97]

3.91.2.1 We agree with this view.

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

96 Major Electricity Users Group (MEUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 21.

97 Major Electricity Users Group (MEUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 21; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 2.

3.91.3 other tools are more appropriate to deal with financeability and asset stranding; RAB indexation is a crude measure to bring forward cashflows.[98]

3.91.3.1 We agree with this view.

3.91.4 for EDBs and Transpower it helps mitigate sharply rising prices for consumers.[99]

3.91.4.1 We note that this is likely true, and that price stability is a factor that consumers tend to value. Our final decision supports a price trajectory that reflects an efficient spreading of costs over time.

3.91.5 provides consistency between EDB/GPBs and Transpower and is a more “traditional” regulatory accounting approach.[100]

3.91.5.1 We note that while this is likely true, we have not based our final decisions on this reason.

Submissions in support of hybrid RAB indexation (indexing the equity component only)

3.92 Transpower supported the hybrid RAB indexation approach (backed by Frontier Economics (Frontier)) as a preferred alternative to RAB indexation. They made the following arguments:[101]

3.92.1 hybrid RAB indexation, where only the equity portion of the RAB is indexed to inflation, better matches revenue to the nominal debt interest payments, which is the basis of the notional entity.

3.92.1.1 As we discuss in the cost of debt washup section, our final decision is to fully wash-up revenue for CPI. This protects consumers from the risk that the real price they pay varies in response to unexpected changes in inflation. A key benefit of this is that it is more likely to be consistent with constant real prices, which is likely closer to an allocatively efficient pricing profile.

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98 Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 47.

99 Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 47.

100 Major Electricity Users Group (MEUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 23; Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 48. We understand that when Contact mentions that RAB indexation is a "more traditional accounting approach" it means that this is a more common regulatory accounting approach, both in New Zealand and overseas.

101 Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 13; Frontier Economics "RAB Indexation" (report prepared for Transpower, 19 July 2023), para 106-110.

3.92.1.2 From suppliers' perspective, this ensures that the firm as a whole (ie, equity and debt holders) is protected from inflation risk. Knowing that the regime fully adjusts revenues for actual inflation, management has the ability to respond as they see fit, via their debt management choices. In relation to the (a) timing of cash inflows to (b) repay debt obligations as they come due, we agree that full RAB indexation (by revaluing the RAB and then deducting these revaluations from revenue) may create a timing mismatch between (a) and (b). However, we do not consider this to be a problem, unless this risked materially increasing suppliers' financing costs. In that case, we could consider accelerating cashflows as part of a CPP.

3.92.2 this would balance certainty and comfort for financeability with the advantages of a fully indexed RAB.

3.92.2.1 As discussed in this chapter, we do not consider that RAB indexation is the right tool to manage financeability risks.

3.92.3 Transpower estimates that the annual nominal revenue reduction from the status quo under a hybrid approach to indexation would be ~$80m compared to ~$140m with a fully indexed RAB.

3.92.3.1 We note Transpower estimates and also that we do not have evidence that Transpower faces financeability risks.

Submissions against RAB indexation

3.93 Stakeholders opposing RAB indexation included the other EDBs that submitted, most GPBs,[102] Transpower, and Drive Electric.

3.94 Below we present the main submission points raised against our draft decisions on RAB indexation and our response, organised by theme.

Efficiency

3.95 Vector submitted the following:[103]

[102] GasNet did not express an explicit view, but its overall position is consistent with unindexing the RAB to reduce stranding risk.

[103] Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 120-121.

> allocative efficiency is principally a function of s 52A(1)(d) rather than (b), and s 52A(1)(d) is achieved whether the RAB is indexed or not because, on either approach, NPV neutrality is maintained. Section 52(1)(b) provides that regulated suppliers should "have incentives to improve efficiency and provide services at a quality that reflects consumer demands". The concept of "incentivising" efficiency in paragraph (b) indicates that the focus of the paragraph is rewarding or compensating suppliers for taking steps within their control that increase efficiency principally in terms of productive and dynamic efficiency. In contrast, the Commission's decision to index the RAB does not "incentivise" suppliers to improve allocative efficiency; it simply defers recovery of capital, which the Commission considers is a more efficient pricing profile. We are therefore not persuaded that there is a link between the Commission's reliance on allocative efficiency as a rationale for indexation and s 52A(1)(b).

3.96 We do not agree because the submission misinterprets s 52A(1)(b). Efficiency is not qualified in s 52A(1)(b) as supplier efficiencies only, or productive and allocative efficiencies only. Improvements in efficiencies can relate to those from a consumer perspective too – eg, through more efficient pricing structures/levels/signals, resulting in more efficient resource allocation decisions by consumers that are to their benefit. This is consistent with the s 52A purpose of promoting the long-term benefit of consumers by promoting the outcomes under s 52A(1)(a) to (d).[104]

3.97 We consider that an allowable revenue path based on an indexed RAB – as opposed to an unindexed RAB – is more likely to result in a more efficient price profile. Such an allowable revenue path incentivises suppliers to comply with that path, resulting in actual prices that are more allocatively efficient (at least in aggregate). Indeed, setting enforceable limits on revenue is a strong incentive on suppliers, breaches of which can result in court-imposed penalties.

3.98 Vector submitted that it saw inconsistency with our reasoning for Transpower's unindexed RAB 2010 decision suggesting we had made different choices despite having same purpose.[105]

> Furthermore, that indexation does not have a strong basis in s 52A is confirmed by the fact that:
>
> a. until now Transpower's RAB has not been indexed; and
>
> b. airports can choose whether or not to revalue their assets, and choose the rate at which they revalue.
>
> In each of those cases, the Commission has made different choices in reliance on the same purpose statement, we would not consider this good regulatory practice. It does however lead to the conclusion that the argument linking indexation to allocative efficiency and therefore to the purpose statement is not that compelling.

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104 The High Court in WIAL endorsed "the three dimensions of economic efficiency - allocative, productive and dynamic - which the s 52A(1) outcomes both reflect and are designed to promote." (at [256] - see also [243] and [14] and [24]).

105 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 123-124.

3.99 Transpower submitted:[106]

> We were surprised by the Commission's draft decision since our investment needs are arguably greater than in 2010 (when the Commission concluded Transpower should have an unindexed RAB), with a significant investment programme required to achieve New Zealand's objective of net zero emissions by 2050. The Commission appears to be rewriting its 2010 reasons for providing Transpower with an unindexed RAB.

3.100 Vector submitted that we placed undue weight on static vs dynamic efficiency.[107]

> As noted above the Commission concluded for Transpower that the dynamic efficiency benefits outweighed the static efficiency benefits. It is difficult to see why this would be any different now for suppliers faced with significant consumer service enhancing investments to make

> As the Commission has acknowledged, EDBs are facing increased investment in the future, so it is unlikely that they are currently at or past the optimal level of investment. In other words, the Commission's reasoning in 2010 and 2016 continues to support resolving trade-offs between dynamic and allocative efficiency in favour of dynamic efficiency.

3.101 On this point about the efficiency effects of RAB indexation, Vector also submitted in relation to GPBs:[108]

> [For EDBs] the long-term dynamic efficiency benefits of ensuring adequate financeability trump those near-term considerations; but we accept there is a weighing-up of competing consideration. However, there is no such trade-off when it comes to GPBs – everything points in the same direction. The same analysis the Commission presents to highlight the potential static efficiency costs associated with departing from indexation for EDBs applies equally – albeit in reverse – to GPBs. The Commission seems unaware of this internal contradiction in its draft decision.

> It would be equally correct to say that, for GPBs, removing RAB indexation so that prices were higher in the near term when demand is higher would move prices closer to the efficient ones. Removing indexation and allowing more front-loaded forms of deprecation would consequently enable GPBs to charge higher prices when more customers are connected, i.e., before increasing numbers transition to electricity in the manner desired. In other words, the short- and long-term interests of gas consumers would be promoted by changing the IMs.

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106 Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 10.

107 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 92, 134.

108 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 110, 111.

3.102 In relation to Transpower, we agree that the past decision not to index Transpower's RAB gave less weight to allocative efficiency relative to other considerations (mainly supporting Transpower's ability to finance investments, which is related to dynamic efficiency, and avoiding the compliance costs associated with a change in valuation approach. A continuation of an un-indexed approach allowed Transpower to prolong the benefits of aligning its regulatory and financial accounting records). Specifically, Transpower's 2008 administrative settlement under the now-revoked Part 4A, which gave effect to an unindexed RAB for Transpower from 2006, noted that:[109]

> "there may be some limited circumstances where an un-indexed approach is preferable for reasons related to investment, such as when capital expenditure requirements face a significant step change in the short term. If such is the case, then such dynamic efficiency considerations may outweigh considerations of allocative efficiency. However, the Commission notes that cashflows are not the only source of funds that businesses have available to cover their efficient capital expenditure requirements, and as a result providing for increased cashflows may not be necessary even where future investment needs appear to be substantial."

3.103 We consider that our draft decision to index Transpower's RAB best promotes the overarching objectives of the IM Review. The main reason is that we consider our draft decision better promotes allocative efficiency (s 52A(1)(b)) and—as we explained in the draft decision and in this section—we have no evidence that it detracts from Transpower's incentives and ability to invest (s 52A(1)(a)), which supports dynamic efficiency. Importantly, we do not consider that we are trading off dynamic efficiency benefits for allocative efficiency ones, since we consider that Transpower has incentives and ability to invest under an indexed RAB. This is especially so when considered together with our decision to enable Transpower to apply for an alternative depreciation approach, where this would better promote the Part 4 purpose.

3.104 So, as we said in the draft decision—and with the benefit of over a decade of observing investment behaviour and outcomes—we no longer have the same concerns as we did in 2010 around supporting investment by matching revenue to capital expenditure.[110] This is despite aspects of the current context being similar to those in 2010 – mainly the substantial investment needs.

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109 Commerce Commission "Decision and Reasons for Not Declaring Control of Transpower New Zealand Limited & Decision to Reset Transpower's Thresholds" (13 May 2008), para 289.

110 As mentioned in paragraph 10.33 of the IM Review Process and issues paper, Transpower's RAB more than doubled between 2008 and 2020. This is consistent with the regime enabling Transpower to invest. In addition, we published our financial modelling for Transpower with the draft decision, which did not show that Transpower was likely to face financeability issues. We have not seen evidence in submissions that raises concerns about Transpower's financeability under an indexed RAB approach. Finally, Transpower's credit rating was upgraded in 2021 (AA) to above our benchmark (BBB+).

3.105 Our modelling demonstrated that, under benchmark assumptions, indexing Transpower's RAB does not lead to a financeability problem – for example, it does not create concerns for its benchmark credit rating position. In the draft decision, we asked for evidence of a potential financeability problem for Transpower; we received no evidence in this regard.

3.106 In the draft decision we explained that our reading of the evidence was that Transpower was doing catch-up investment in 2010, while now it is closer to investing ahead of demand. Frontier (for Transpower) submitted that "this is really a distinction without difference. The key point is that Transpower is facing an investment task that is materially greater than the one it faced in 2010."[111] Catch-up versus anticipatory investment matters for efficiency. We consider that our view expressed in the draft decision is:

3.106.1 Justified in theory: the allocative efficiency effects are different – investment ahead of demand that is funded by current consumers results in near-term price increases that risk worsening allocative efficiency (and results in consumers paying higher-than-efficient prices, which would be exacerbated by not indexing RAB). Catch-up investment has a more muted effect on prices, in aggregate, because an investment of a given size increases prices by less when demand is higher (and results in consumers paying closer-to-efficient prices); and

3.106.2 Supported by the evidence – as we explained in the draft decision, projections are that Transpower's currently planned capex will nearly double between now and 2030, 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. Furthermore, we have no evidence of a financeability issue. At the same time, the evidence before us (including from the Auditor General), which we presented in the draft decision, is that Transpower was at the time of our 2010 decision investing to catch up with demand.

111 Frontier Economics "RAB Indexation" (report prepared for Transpower, 19 July 2023), para. 79.

3.107 In relation to EDBs, we consider that our draft decision to maintain RAB indexation best promotes the overarching objectives of the IM Review. The main reason is that we consider our draft decision better promotes allocative efficiency (s 52A(1)(b)) and—as we explained in the draft decision and in paragraph 3.129 in this section—we have no evidence of an industry-wide financeability problem that would detract from EDBs' ability or incentive to invest (s 52A(1)(a)), which supports dynamic efficiency. That is, we consider that RAB indexation supports both allocative and dynamic efficiency – we have no evidence for the need to trade off one for the other. This is especially so when considered together with EDBs' ability to request a CPP where this would better promote the Part 4 purpose. In any case, since financeability is firm-specific, this is best considered at a PQ reset.

3.108 In relation to airports, the reasoning for not requiring a particular form of RAB indexation for airports reflects that airports are only subject to ID regulation and not PQ regulation.[112] The reasoning therefore has nothing to do with financeability (given airports are not constrained in how they set revenue) but rather about promoting the s 53A ID purpose of ensuring interested persons can assess airport profitability performance. If we do not provide airports with flexibility to reflect their own pricing assumptions (including those relating to revaluation) which they can set as they see fit in their pricing disclosures interested persons would not have meaningful information to assess airports' profitability. This would not be consistent with s 53A.

3.109 In the 2016 IM Review, we changed airport RAB indexation to be dependent on the approach the airport is applying for its pricing.[113] Similarly, any non-standard depreciation methodology used for ID purposes must be consistent with the airport's indexation choice and the airport's choices about its time profile of capital recovery more generally.[114]

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112 Airports are subject to ID regulation only. All we require of airports is that they disclose information that is consistent with the time profile of capital recovery used in setting prices. If an airport uses standard depreciation and revaluation assumptions, it discloses those, and if it uses a non-standard approach, it has to explain its reason (cl 3.4(5) of airports IM).

113 Clause 3.7(6)(b) of the Airport IMs.

114 Clause 3.4(5)(a) of the Airport IMs.

3.110 For example, 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.[115]

3.111 In relation to Vector's point about the impact of GPBs' RAB indexation on allocative efficiency, we acknowledge that removing RAB indexation could help address concerns about long term consumer price escalation which could undermine allocative efficiency in the long term.

3.112 However, as with addressing the related issue of asset stranding, we consider that these concerns are better addressed independently of our approach to RAB indexation.

3.112.1 Removing indexation would not address the fundamental issues which relate to long-term demand uncertainty, rather than inflation uncertainty.

3.112.2 Concerns about asset stranding and long-term price efficiency can be addressed through asset life adjustment factors in DPPs, and if necessary, the option of changes to the depreciation method through a CPP.

3.112.3 We consider that given the uncertainty about future demand for GPBs, the alternatives immediately above can better promote the Part 4 purpose at resets. This is because the extent of any necessary adjustment can be determined at price resets and tailored to the specific circumstances of each GPB to take into account the effect on incentives to invest (s 52A(1)(a)) and allocative efficiency over time (s 52A(1)(b)).[116]

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[115] 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.

[116] As we discuss in topic 3d, we do not consider that there is sufficient evidence to justify allowing changes to the depreciation method in DPPs at this time. Instead, we consider that the complexity of the analysis and consumer engagement required to justify a change in depreciation method – in addition to asset life adjustment factors in DPPs – would only be achievable in the context of applications for CPPs at this time.

3.113 Vector submitted – in relation to EDBs – that we did not analyse the efficiency effects of moving to an unindexed RAB:

> The Commission has not undertaken any analysis of the likely effects on the output of electricity services of moving to an unindexed RAB. Instead, it has simply asserted that an indexed RAB produces prices in theory that are more likely to align to an allocatively efficient pricing profile. That is not the same as demonstrating that an unindexed RAB will result in a misallocation of resources, to the disbenefit of consumers.
>
> If the Commission is going to rely so heavily on allocative inefficiency as a justification for maintaining indexation, it should offer a more concrete analysis of the efficiency loss it expects would result from a short-term increase in prices. That is particularly relevant given the trade-off between allocative efficiency and dynamic efficiency.

3.114 It appears that Vector is suggesting that we should quantify the loss in allocative efficiency (deadweight loss) of changing the current IMs and moving from an indexed to an unindexed RAB, so as to justify maintaining the status quo. Aside from this approach not being a requirement under our decision-making framework, we do not think it is necessary or proportionate to attempt to quantify the effects of (hypothetically) changing our RAB indexation for EDBs and GPBs.

3.115 Among other things, this would require estimates of the price elasticity of demand, both for existing consumers and, crucially, for potential new future consumers (eg, industrial conversions or EV charger connections), as well as price changes for the relevant consumer groups, now and over time (including pricing structures over which the EA has responsibility). Besides being informationally challenging, we do not think it is necessary for the purposes of our IM Review decisions here. We consider our RAB indexation decisions achieve our Framework's overarching objectives for the reasons we set out in this topic 3a.

3.116 Frontier (for Transpower) submitted that the return on debt timing problem, as described immediately below, detracts from efficiency (and intergenerational equity). Their logic:

3.116.1 RAB indexation means that the recovery of debt interest costs are deferred from current to future consumers;

3.116.2 In the standard framework, consumers are required to annually fund the operating costs and depreciation incurred each year. Each group of consumers should pay for the efficient cost of the services that is provided to them;

3.116.3 It is unclear why the same principle should not apply to interest payments on debt.

3.117 We agree that, depending on the extent of investment ahead of demand for EDBs and Transpower, and the proportion of debt used to finance it, some interest costs may be deferred from current to future consumers. However, we do not think that is necessarily a problem; in fact that may be an appropriate and efficient spreading of capital costs—which include interest costs—over time, and may promote s 52A(1)(b). This is similar to recovering most of the capital (ie, regulatory depreciation is highest) when the network provides most of the value to consumers, as per the concept of economic depreciation.[117]

3.118 Furthermore, we do not think that the 'principle' that Frontier raised is valid in the context of investment ahead of demand. This is because requiring current consumers to pay interest costs for debt used to finance investments ahead of demand is in effect requiring consumers today to pay for the costs of services that will be provided to consumers in the future.

Cashflows and financeability arguments

3.119 We first briefly state the main points raised in submissions and then provide a combined response to them.

3.120 Frontier (for Vector) submitted that our draft decision creates cashflow and financeability pressures;[118] detracts from incentives to invest at a time where investment is needed.[119]

> "it is not enough that a proposed project is considered to be NPV=0, so that it eventually provides investors with the required return over its life. Financeability also requires that the project can be financed in the way that the Commission has assumed in setting the allowed return. This, in turn, requires a cash flow allowance each year that is sufficient to maintain the benchmark credit rating at the benchmark level of leverage throughout the life of the project.
>
> …the annual revenue allowance always assumes that the regulator's benchmark financing parameters will be achieved…But for any year in which that cannot be achieved, the regulatory allowance will be insufficient to cover the costs incurred by the benchmark firm. Either debt will be issued at a lower rating or some debt finance will be replaced by equity. In either case, the required return is higher than the BBB+ return on debt allowance provided by the regulator.

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[117] Economic depreciation is the period-by-period change in the market value of an asset. The market value of an asset is equal to the present value of the income that the asset is expected to generate over the remainder of its useful life.

[118] Transpower submitted that the equity portion of Transpower's capex in each of RCP4 and 5 could be more than $2 billion. This is a "hugely significant" equity-raising task, which is further exacerbated by the transition to an indexed RAB.

[119] Frontier Economics "Regulatory financeability" (report prepared for Vector, 19 July 2023), para 57, 64, 74, 75.

> The problem arises because the regulatory model assumes, without ever checking, that the annual regulatory allowance is sufficient to support the benchmark financing parameters every year. Where the allowance is insufficient to support the benchmark financing parameters, there is a shortfall that can never be recovered – as set out above.
>
> In this situation, the regulatory allowance is less than the costs incurred by the benchmark firm and the NPV=0 principle, and consequently ex ante FCM, fails."

3.121 Transpower raised:[120]

3.121.1 the possible reduction in its credit rating causing increased borrowing costs (although no evidence was provided to substantiate this point); and

3.121.2 The impaired capacity for Transpower to pay a dividend to the government as shareholder and potentially a need for equity injections.

3.122 Vector submitted that the Commission made the decision to maintain the status quo for EDBs without properly investigating financeability challenges.[121]

3.123 In relation to CPPs as a solution, Vector submitted:

> Primarily, as the name suggests, a CPP should be a 'customised' solution catering for a particular customer's bespoke needs. For example, if a customer has capital investment requirements that diverge markedly from its peers a tailored price/quality path makes perfect sense. But the issues we have discussed hitherto are not unique; they are ubiquitous. Every GPB faces the problem of declining demand. Every EDB is confronting financeability issues as investment levels multiply. These are the 'default' circumstances. Financeability issues for EDBs and Transpower and declining demand for GPBs are 'default' circumstances, so should be dealt with at DPPs, not CPPs.

3.124 Our response to the above points in relation to financeability is as follows: we first note that cashflows are not the only source of funds that businesses have available to cover their efficient capital expenditure requirements, and as a result, providing for increased cashflows may not be necessary even where future investment needs appear to be substantial. In the case of a prudent and efficient supplier of the regulated service, there may be circumstances where the regulator may have to accelerate cashflows to uphold ex-ante FCM. In a situation where such a supplier faces those circumstances, failure of the regulator to accelerate cashflows could detract from s 52A(1)(a). This is consistent with our view at the draft that a decision to frontload cashflow for financeability reasons should be informed by specific evidence (eg, a supplier-specific financeability assessment). And that 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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120 Transpower "Input Methodologies Review 2023: Draft Decisions" (19 July 2023), para 138.

121 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 34.

3.125 Assuming the firm can raise more debt and equity,[122] those circumstances may arise when the firm-specific financing costs materially exceed the regulatory WACC due to insufficient cashflow. To explain:

3.125.1 We use assumptions on leverage and credit rating (benchmark assumptions) to set the WACC.[123] These are based on a sample of relevant comparator firms and are tested using reasonableness checks, to identify the opportunity cost of capital that investors face.

3.125.2 Our starting point is to set a price path that promotes the Part 4 purpose, including by using the opportunity cost of capital (ie, regulatory WACC). Financing investment under the price path is primarily the responsibility of suppliers.

3.125.3 The resulting net cashflows over time may result in situations where retained earnings are insufficient to fund capital expenditure and the supplier may need to raise more capital—including equity— for example, when investment requirements increase sufficiently during growth phases.

3.125.4 We assume that a prudent and efficient supplier can raise capital and finance its capital expenditure at a cost equal—or not materially different to—the regulatory WACC.[124]

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122 Given current ownership structures, this is not a given for some EDBs. But as we said in the draft decision, potential capital raising constraints from ownership arrangements are not related to our regulatory regime.

123 The use of the average leverage of the sample addresses the leverage anomaly.

124 Due to the anomaly associated with the SBL-CAPM, whereby the WACC increases when leverage increases because the increase in the equity beta more than offsets the lower weight to the cost of equity, we assume the benchmark firm has the average leverage and average equity beta of the comparator sample.

3.125.5 Even where the supplier funds its assets using a mix of debt and equity that results in a leverage position different from the benchmark leverage (eg, because the supplier needs to raise more equity to maintain its credit rating), the financing cost should not be materially different to the regulatory WACC (except in specific situations, such as when the bankruptcy risk is sufficiently high). This is a well-established finding of corporate finance theory.[125] Furthermore, the High Court's observations from the 2013 merits appeal below are consistent with a view that there is a range—rather than a specific point—of leverage where the firm-specific financing costs are not materially different to the regulatory WACC:[126]

> The point where the cost of capital stops declining and starts increasing must vary from firm to firm (or all would employ the same leverage), but the curve may well be more or less flat over some range of leverages so that a firm is more or less indifferent as to its leverage within that range, or considers factors other than its cost of capital in choosing its leverage.
>
> …Moreover, and unlike the Commission, we do not consider that in the real world WACC is invariant to leverage. Rather, we consider that – at least initially – WACC can be understood to decline with leverage. We note that in reaching our conclusion we have made no assumptions about what causes the WACC to behave in that way as leverage increases. It may be a combination of tax effects and costs of financial distress (assuming the costs of financial distress can be considered part of the WACC).
>
> …Nevertheless, we consider that the typical firm will have a view that below a certain point its leverage is too low and, above a certain point, too high. Within that range it seems highly likely that the firm's cost of capital is at a minimum (or close enough to it to satisfy the firm).

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[125] See for example: Joseph E. Stiglitz (1969) "A Re-Examination of the Modigliani-Miller Theorem" The American Economic Review, Vol. 59, No. 5 (Dec), pp. 784-793.

[126] *Wellington International Airport Ltd and Ors v Commerce Commission* [2013] NZHC 3289, at [1608] – [1610].

3.126 Frontier submits that "…for any year in which [the benchmark parameters] cannot be achieved, the regulatory allowance will be insufficient to cover the costs incurred by the benchmark firm". As mentioned, we use the average leverage of the sample (ie, "benchmark leverage") to address the leverage anomaly. We do not consider that regulated suppliers must match the benchmark assumptions, or that they need to raise capital in the same proportions as the benchmark. Rather, we consider that an individual supplier can deviate from the leverage assumption used to calculate the WACC without a material impact to its financing costs. Furthermore, so long as the supplier has viable business prospects (eg, demand for its services is stable or growing), a temporary shortfall in net cashflow (eg, due to a capex surge) is unlikely to result in credit rating downgrades, noting that it is within the supplier's control to mitigate this risk (eg, it can rely less on debt and more on other sources of finance to fund capex, such as retained earnings or fresh equity).[127]

3.127 Finally, the circumstance where we agree that the regulator should consider accelerating cashflows to uphold ex-ante FCM is where there is no leverage level at which the prudent and efficient firm can achieve financing costs that are not materially different from the regulatory WACC. This likely involves large-enough credit rating downgrades (or a high risk thereof). In other words, where there is an inconsistency between the cashflow assumptions of our regulatory accounting and the cashflow needs of the benchmark firm, and when this inconsistency is great enough to cause a consequence for financing costs. We note our view aligns with the one that the AER recently expressed "it is very important to recognise that assessments by credit rating agencies, and ultimately investment decisions, are undertaken on a different basis to assessments based purely on regulatory models."[128]

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127 Our understanding is that credit rating agencies only partially base their assessment on quantitative factors such as financial metrics (40% weight in the case of Moody's), with the remainder of their assessment based on qualitative, subjective factors, such as the regulatory environment, ownership model and financial policies. So a supplier may be able to maintain its credit rating when quantitative outcomes (eg, its financial metrics) deteriorate, as long as they are offset by the qualitative assessment. Furthermore, credit rating agencies in the past have been willing to 'look through' temporary dips in financial metrics. NERA "Financeability consideration under the DPP: Electricity Networks Association" (16 January 2023), appendix A; Australian Energy Regulator (AER) "Submission to the Accommodating Financeability in the Regulatory Framework consultation paper" (3 August 2023), pages 5, 6.

128 Australian Energy Regulator (AER) "Submission to the Accommodating Financeability in the Regulatory Framework consultation paper" (3 August 2023), page 6.

3.128 For Transpower, we have no evidence in front of us that Transpower is at a point where it faces credit downgrades, or a significant-enough risk thereof. Our modelling for the draft decision showed that point does not materialise (assuming benchmark leverage) even with a move to an indexed RAB in the context of a large capex programme – for example, Transpower's interest cover ratio still stays at a point where they are unlikely to be downgraded.

3.129 For EDBs, the evidence is more mixed. However, we do not have evidence of an industry-wide financeability problem that would likely be a necessary condition to consider unindexing RABs, as this would be a non-exempt-EDBs-wide measure.[129] Before the draft decision, CEG and NERA provided the results of analyses relating to EDB financeability. This painted a mixed picture: CEG showed that the five largest EDBs were projected to be able to fund the required capex by foregoing dividends;[130] while NERA concluded that "financeability problems could exist given the regulatory framework and operating environment of EDBs."[131] NERA's analysis was based on averaging the inputs to the building blocks model (eg RAB, asset lives, expenditure).[132] However, financeability is firm-specific, so NERA's evidence does not allow us to ascertain whether their results relate to one or many suppliers. Furthermore, as the submission discusses in its appendices, quantitative factors – such as the ratios NERA calculated – are only part of credit rating agencies' assessments (in the case of Moody's, the assessment places a minority of the weight on them).[133] Therefore, our view is that this evidence does not show a specific financeability problem for the notional firm that NERA constructed, nor an industry-wide one.

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129 Noting our position in the draft decision that “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. We would only bring forward capital recovery in specific circumstances where we are satisfied that doing so would better promote the Part 4 purpose.”

130 CEG "Estimating the WACC under the IMs" 'Appendix C -Submission on IM Review CEPA report on cost of capital' (report prepared for Electricity Networks Aotearoa, February 2023)

131 NERA "Financeability considerations under the DPP" (report prepared for the Electricity Networks Association, 16 January 2023), para 7.

132 NERA "Financeability considerations under the DPP" (report prepared for the Electricity Networks Association, 16 January 2023), para 120.

133 NERA "Financeability considerations under the DPP" (report prepared for the Electricity Networks Association, 16 January 2023), table 11.

3.130 We received no new quantitative evidence in submissions on our draft decision substantiating the risk of an industry-wide financeability problem. Frontier submitted analysis (based on "indicative revenue modelling" and assuming a 10% limit on annual nominal revenue increases) that showed that an 'aggregate EDB' based on benchmark assumptions (aggregate of the Big Six EDBs' revenue) would fail three different financeability metrics every year until 2029 (two metrics) and 2030 (the other metric) – funds from operation interest cover ratio, fund from operation net debt ratio, and retained cashflow net debt ratio.[134] As we explain below, we do not consider that Frontier's analysis amounts to evidence of an industry-wide financeability problem.

3.130.1 Our view is that financeability is firm-specific, so as just mentioned in relation to NERA's analysis, Frontier's evidence does not allow us to ascertain whether their results relate to one or many suppliers. In addition, as mentioned in paragraphs 3.125 and 3.126, this is not necessarily a problem as long as it is not sustained and suppliers can raise equity (vary leverage) to maintain the credit rating without a material deterioration of their financing costs (noting that quantitative ratios are only part of credit rating agencies' assessments [in the case of Moody's, the assessment places a minority of the weight on them]).

3.130.2 Furthermore, the 10% limit on annual nominal revenue increases that Frontier has assumed will apply, because it applied in DPP3, was not specified in the IMs. The IMs would have instead allowed us to determine a different limit, or no limit at all, at the DPP reset (or when setting a CPP) if that would better promote the Part 4 purpose. The same is true of the revenue smoothing limit, which replaces the limit on annual nominal revenue increases.[135] Our ability to vary this parameter at a PQ reset means that Frontier's analysis, which assumed a 10% limit, carries less weight.

3.131 In the absence of evidence of an industry-wide financeability problem, CPPs remain the preferred means of enabling a PQ path that better meets an individual supplier's particular circumstances, in line with s 53K. The setting of the X factor at PQ resets is another tool that could help mitigate potential short-term financeability issues within a regulatory period.

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[134] Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), pp. 31-33.

[135] Attachment D of this paper sets out our final decision to replace the replace the "limit on the increase in forecast revenue from prices" with a "revenue smoothing limit".

3.132 We note that our IM Review in-period adjustments decisions and new connection wash-up mechanism (for EDBs on a CPPs) can support financeability by increasing allowable revenue (and cashflows) in response to demand increases and certain other changed circumstances.

3.133 For GPBs, we discuss below (at 3.166) and in topic 3d why we consider that asset stranding risk and concerns about long-term consumer price escalation are better addressed independently of our approach to RAB indexation.

Workably competitive market analogies

3.134 Frontier (for Transpower) submitted that it is questionable whether an approach (indexing the RAB) that results in the following outcomes can reasonably be considered to reflect “outcomes in competitive markets”: (1) suspends dividends over the course of the following decade; (2) increases equity raising requirements; and (3) alters prices so that part of the current interest bill is paid by future consumers. In Frontier's view, it is reasonable to suggest that a commercial entity operating in competitive markets would seek to avoid making a material change in its approach that would produce the above outcomes.

3.135 Frontier (for Vector) submitted that “regulation should promote the outcomes that occur in competitive markets. The focus is on outcomes that do occur in real-world competitive markets and not on conjecture about what investors in a regulated firm could or should do…Capital expenditure is only made in real-world competitive markets for projects that are commercially viable…Commercial viability requires an acceleration of cash flows or government subsidy”.

3.136 Transpower made the following argument that seeks to rationalise the fact that two EDBs supported RAB indexation: it is consistent with outcomes in a workably competitive market, where different investors and suppliers will have different appetite for risk and different views about risk management.

3.137 These arguments relate to what we would expect to see in a workably competitive market (WCM). We explain our response below.

3.138 A first point to note is that our task under s 52A is not to promote all the outcomes that might be observed in workably competitive markets. Rather, we must promote certain specified outcomes that workably competitive markets tend towards – those listed in s 52A(1)(a)–(d). Even those are subordinate to the overriding direction in s 52A(1) to promote the long term-benefit of consumers: we must only promote those specific outcomes to the extent that doing so promotes the long-term benefit of consumers. Similarly, while insights from the operation of hypothetical markets where there is workable competition might be useful, what matters under Part 4 is promoting the long term-benefit of consumers by promoting the outcomes under s 52A(1)(a)-(d).[136] This point overlays our analysis that follows.

3.139 Looking at suppliers' arguments above, it seems they are, to some extent, back to front.

3.140 In a workably competitive market, market dynamics and outcomes, such as the trajectory of demand and price, drive the type of investor that invests in the sector (eg, investment time horizons, dividend vs. capital growth expectations, risk appetite etc.), not the other way around. We would expect that infrastructure markets attract investors that have long time horizons for recouping their investment. The scale of investment required may mean that, for some suppliers, investors can no longer rely on the same level of dividends, at least in the short term. This may attract a different mix of investors.

3.140.1 We note as significant that Powerco supports RAB indexation for EDBs. Powerco is 58% owned by QIC which states that "Investing for the long-term is in our DNA, enabled by our stable ownership by the Queensland Government".[137]

3.140.2 We also note additional evidence in submissions of investor [frustrated] appetite to invest in the sector:[138]

> Investors such as Harbour Asset Management have an appetite to supply capital that enables decarbonisation. The ownership structure of many of the EDBs, particularly the smaller EDBs, severely limits their access to capital; some barely have the ability to alter pay-out ratios let alone attract fresh equity capital. Access to debt capital is limited without the access to equity. Consolidation by those with stronger access to funding may provide a solution.

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136 *Wellington International Airport Ltd and Ors v Commerce Commission* [2013] NZHC 3289, at [235] – [237], [507], [529], [623] and [627(c)].

137 https://www.qic.com/About-QIC/Who-we-are. Accessed 21 November 2023.

138 Harbour Asset Management "Submission on the IM Review 2023 Draft Decisions" (19 July 2023).

3.141 In a workably competitive market, market dynamics also constrain individual supplier choices and behaviour (eg, whether investment (and potentially new equity) is required), and not the other way around. For example, firms tend to be constrained in their ability to raise prices.[139] If they need to invest to remain competitive, since they cannot materially increase price, they might need to use retained earnings, reduce dividends, raise capital, or a combination of the three.

3.142 Finally, in a competitive market, consumers are generally not expected to pay for services in advance of those services being provided.

3.143 Therefore, we would not expect a firm in a competitive market to be able to determine the price trajectory of its output (and therefore cashflows), nor to alter prices so that the firm can match the current investors' desired return profile type or achieve their preferred investment and equity raising strategy.[140]

3.144 However, we agree with the point that capital expenditure is only made in real-world competitive markets for projects that are commercially viable, and that cashflow timing may affect commercial viability to the extent that it affects financing costs.

3.145 To the extent that existing investors have a preference for steady dividends, the upcoming surge in investment requirements may present a tension if it results in reduced dividend payouts. Oxera (for the Big Six EDBs) submitted that "that investors in a company undergoing large scale investment may expect to receive more of their return as growth of its equity value. However, we do not expect a resilient, notionally structured, company that is performing in line with our determinations to totally forego dividends."[141] We note that, in times in the past 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.[142] Similarly, investors in Chorus in the early years of the fibre rollout forewent some dividends in favour of growth of Chorus's equity value. We consider that, as long as there is no binding constraint on raising equity, the suppliers can maintain some level of dividend payments where required.

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139 Commerce Commission "Misuse of Market Power Guidelines" (March 2023), page 4.

140 Workably competitive markets can deliver a variety of outcomes to investors. Firms in such markets do suspend dividends in growth phases, raise equity to fund expansion, and have deferred recoupment. In any event, RAB Indexation maintains a real constant recovery profile which is not inconsistent with outcomes in workably competitive markets. If financeability concerns arise, there are mechanisms to deal with that.

141 Oxera "Response to Commission's draft decision for IM Review 2023 on the cost of capital" (report prepared for 'Big Six' EDBs', 19 July 2023), page 92.

142 Radio New Zealand "Transpower to resume paying dividends" (29 February 2012).

Implementation cost and complexity argument (Transpower only)

3.146 Transpower raised “potentially significant operational implementation challenges that we would need to work through with the Commission and the Electricity Authority. These challenges may lead to additional costs and affect the proposed timing of implementation (for RCP4). We also expect amendments may need to be made to the Electricity Industry Participation Code to provide certainty and clarity of how indexation is expected to be reflected through the new TPM, which sets charges at asset-level.”

3.147 Our draft decision acknowledged the potential implementation and compliance costs associated with indexing Transpower’s RAB. We asked for evidence and details of these cost changes. Transpower did not provide any evidence or details to support the above claim of "potentially significant operational challenges".

Other arguments

3.148 Vector submitted that our Inflation forecasting framework has been poor, and that an unindexed RAB removes inflation uncertainty.[143]

3.148.1 We have demonstrated that our approach protects both consumers and suppliers from inflation risk – other things equal our revenue and RAB washups deliver constant real revenues (for suppliers) and prices (for consumers) when actual inflation differs from forecast.

3.148.2 We disagree with Vector's point that an unindexed RAB removes inflation uncertainty. With an unindexed RAB that is not washed up for actual inflation,[144] the supplier will tend to earn the expected nominal return (which incorporates an implicit inflation forecast in the nominal WACC). Nominal prices to consumers will be based on the expected inflation, but the real prices will vary with actual inflation. The supplier will be exposed to the risk that actual inflation is lower or higher than expected. Frontier, in a report prepared for Transpower, estimated that Transpower lost $340m over RCP3 because actual inflation was lower than forecast.[145]

143 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 104.

144 We have demonstrated in our published model as part of the draft decision that a revenue wash-up alone is not sufficient to fully protect against inflation risk. There needs to be RAB wash-up too. We also showed that that an indexed RAB (washed up with actual inflation), and the unindexed RAB that is rebased at the reset achieve the same inflation-adjusted return over the life of the assets. The difference between the approaches is only a revenue timing one. See Risks and incentives topic paper: Demonstration model stylised impact of different RAB indexation approaches - June 2023.

145 Frontier Economics “RAB indexation: Report for Transpower” (Report prepared for Transpower, 7 July 2022), p.12.

3.149 In the context of GPBs, Vector submitted that removing indexation reduces stranding risk.[146]

3.149.1 Bringing forward recovery of capital costs by definition reduces stranding risk. However, as discussed below (paragraph 3.167), we consider that stranding risk is best addressed independently of our approach to RAB indexation.

3.150 Transpower submitted that an example of a consequential impact of indexing their RAB would likely be a reduction in the contract terms length that Transpower offers to EDBs and other customers.[147]

3.150.1 It is not clear to us how this potential impact would undermine the overarching objectives of the IM Review and make retaining the status quo a better outcome under our Framework. As we understand it, the example Transpower uses illustrates a transfer between consumers of the regulated service – everyone's prices are higher on average under an unindexed RAB while particular EDB(s) benefit from more favourable financing terms. If this was to be unwound, everyone's prices would be lower on average in the short to medium term (driven by an indexed RAB), and particular EDB(s) might lose out on the favourable financing terms. We consider that the efficiency benefits of an indexed RAB are sufficient to justify the change.

3.151 Transpower makes up 10% of the average household's electricity bill and therefore the indexation of Transpower's RAB is unlikely to have a noticeable impact on consumers' electricity bills.[148]

3.151.1 We have not based our final decision on the price level, considered in isolation. Rather, our final decision supports a price trajectory that reflects an efficient spreading of costs over time.

Final decisions

3.152 Our final decisions confirm our draft decisions, to maintain RAB indexation for EDBs and GPBs, and to introduce RAB indexation for Transpower and enable it to apply for an alternative depreciation approach, as outlined in paragraph 3.4.

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[146] Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 109.

[147] Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 12.

[148] Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 133.

How the decision best promotes the overarching objectives of the IM Review

3.153 We consider that all the reasons that supported the draft decisions for EDBs, GPBs and Transpower still apply. Those reasons are outlined above for each sector, under the sections called "Reasons for our draft decisions…". Therefore, we confirm those reasons underpin our final decision, with the below exception and clarification.

3.154 The exception is that, after reviewing submissions to the draft decision, we now consider that the decision to index Transpower's RAB to inflation is less finely balanced compared to how we understood it at the draft decision stage. This is because:

3.154.1 Having published our financial modelling for Transpower with the draft decision, we have not seen evidence in submissions that raises concerns about Transpower's financeability under an indexed RAB approach; and

3.154.2 We have not seen evidence in submissions that the implementation and compliance costs are large enough to tip the balance in favour of Alternative A or B, as described in paragraph 3.56.

3.155 The clarification is the following: in our draft decision reasons for indexing Transpower's RAB, we had a sub-section called "Our 2010 decision to not index Transpower's RAB was based on factors that have become less significant".[149] Some submitters focused on the scale and nature of Transpower's capital investment now compared to the past.[150] We clarify that one key factor that we consider has become less significant is our concern about matching the level of revenue to Transpower’s investment needs. This is because of our current understanding – informed by financial modelling – of Transpower's financeability under benchmark assumptions. We mention this in paragraph 3.66 of this paper and paragraphs X21 and 3.76 of the draft decision.

3.156 So, importantly, the efficiency benefits of RAB indexation together with the lack of evidence that Transpower would face financeability issues under an indexed RAB, means that we do not consider that we need to trade off allocative efficiency for dynamic efficiency.

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[149] Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper. Part 4 Input Methodologies Review 2023 – Draft decisions" (14 June 2023), page 49.

[150] See for example Frontier Economics "RAB Indexation" (report prepared for Transpower, 19 July 2023), section 4.2.

3.157 This section is a summary, and only presents the main reasons for maintaining our draft decision as the final decision. We have taken into account the relevant arguments and submissions put forward and have set out our reasoning in more detail above.

3.158 These reasons apply to each of our decisions on EDBs, GPBs and Transpower. Where a different context applies to a specific sector, and this matters for the reasons, we make that clear in the text.

Promote Part 4 purpose

3.159 In relation to s 52A(1)(b), our position is that an indexed RAB is more likely to be consistent with constant real prices, which in the context of EDBs and Transpower, is likely closer to an allocatively efficient pricing profile.[151]

3.160 As we explained in the draft decision, the short-term risk of an unindexed RAB (or a partially indexed one) in a context of investment ahead of demand – which is the context that applies to EDBs and Transpower – is pricing outcomes that are less consistent with an efficient pricing profile, contrary to s 52A(1)(b). 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.

3.161 Similarly, the longer-term risk of an unindexed RAB in a context where demand has increased significantly – which is the context that applies to EDBs and Transpower – is that consumers face lower average longer-term prices, when they should face higher prices, as congestion increases in networks. This can also lead to inefficient consumption, contrary to s52A(1)(b).

[151] Note that a revenue profile does not exist in a vacuum - it exists alongside other things, including distribution pricing regulation and the TPM. The revenue profile is just an input to pricing (which has the potential to promote allocative efficiency, to the extent that retailers reflect those in electricity prices). Capital contributions are also part of the prices that consumers face.

3.162 Also, RAB indexation reduces real price uncertainty for consumers over time. This is because, all other things being equal, the price will more closely track inflation compared to an unindexed RAB. We consider that this effect supports efficient investment and consumption decisions by consumers by providing a better basis for planning long-term capital investments (eg, industrial processes that use electricity as an input). This is consistent with the view that Chorus submitted: "the growth in customer prices [could] diverge materially from the growth in CPI (and, over the medium-term, the incomes of consumers) which we do not think is in the long-term interest of consumers."[152]

3.163 In relation to s 52A(1)(a) and (d), our position is that RAB indexation affects the timing, rather than the net present value of cashflows for suppliers.[153] Introducing or removing indexation of the RAB is NPV neutral with respect to suppliers' WACC, 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)) under both approaches.

3.164 Indexing the RAB to inflation maintains the value of suppliers' RAB in real terms over time, which is desirable in what are capital-intensive long-lived assets. This is consistent with the view expressed by Powerco (partly owned by an investor with an explicit long term investment horizon – see paragraph 3.140.1).

3.165 We note that there may be exceptional circumstances where the extent of changes in cashflow timing could create financeability concerns for some suppliers. For example, as explained above from paragraph 3.124, situations where the firm-specific financing costs for a prudent and efficient supplier materially exceed the regulatory WACC due to insufficient cashflow. This could be associated with a risk of credit rating downgrades. In this case, the NPV=0 principle, and consequently ex-ante FCM, fails. As discussed, we do not consider changes to RAB indexation to be the appropriate tool to address financeability risks or issues.

3.166 For GPBs, stranding risk is a key part of the context. We acknowledge that removing RAB indexation could help further mitigate economic network stranding risk supporting incentives to invest, or address concerns about long term consumer price escalation which could undermine allocative efficiency in the long term.

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152 Chorus "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 8. We note that Chorus submitted this in the context of the cost of debt inflation wash-up. But the same point applies to an indexed vs unindexed RAB. Growth in real price and CPI will diverge over time if the RAB is not indexed to actual inflation.

153 Note that we can also protect suppliers and consumers from inflation risk without indexing the RAB.

3.167 However, we confirm our view from the draft decision that asset stranding risk is better addressed independently of our approach to RAB indexation. Similarly, concerns about long term consumer price escalation are better addressed independently of our approach to RAB indexation for GPBs through asset life adjustment factors in DPPs, and if necessary, by changing the depreciation method in CPPs.

3.168 We consider that given the uncertainty about future demand for GPBs, that these alternatives can better promote the Part 4 purpose at resets. This is because the extent of any necessary adjustment can be determined at price resets and tailored to the specific circumstances for each GPB to promote the Part 4 purpose (as discussed at paragraph 3.112).

3.169 As we discuss in topic 3d, we do not consider that there is sufficient evidence to justify allowing changes to the depreciation method in DPPs at this time (paragraph 3.431). Instead, we consider that the complexity of the analysis and consumer engagement required to justify a change in depreciation method – in addition to asset life adjustment factors in DPPs – would only be achievable in the context of applications for CPPs at this time.

Promote IM purpose

3.170 In relation to s 52R, we consider that our final decision best promotes certainty in relation to the rules, requirements, and processes. In the case of EDBs and GPBs, there is no change. For Transpower, we have based the detailed IM drafting on the EDB and GPB determinations, which is well understood and tested.

Reduce compliance and regulatory costs

3.171 Transpower provided no detail or evidence to support its claim that there could be "potentially significant operational implementation challenges."

3.172 Since there is no change for EDBs and GPBs, there should be no compliance and regulatory costs for them as a result of this decision. Suppliers did not raise compliance and regulatory costs concerns with the status quo.

Topic 3b – Implications of IRIS for cashflow timing

3.173 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 we received prior to our draft decision suggested that the IRIS cashflow timing implications may distort EDBs’ investment decisions.

Final decision

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

3.175 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

3.176 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.

3.177 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:

3.177.1 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

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

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

Draft decision

3.179 Our draft decision was to make no IM change to alter the cashflow timing of IRIS. We considered that IRIS cashflow timing consequences can be appropriately dealt with, if deemed necessary, through general in-period cashflow timing tools (smoothing).

Reasons for our draft decision

3.180 Below we set out the reasons for our draft decision.

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

3.181 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.

3.182 Wellington Electricity correctly pointed out that the IRIS has multi-year cashflow implications.[154] However, we considered that these cashflow implications:

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

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

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

3.183 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.

3.184 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.

3.185 As we discuss in chapter 5, we consider our incentive mechanisms are an important part of our regulatory regime. In general, we considered the cashflow implications are an acceptable result of providing better expenditure incentives.

Cashflow timing is best considered in aggregate

3.186 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.

3.187 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: [155]

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[154] 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.

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

> 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.

3.188 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.[156]

3.189 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 made workability enhancements to these IM 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 s 52A(1)(a).

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

3.190 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 acknowledged that the *detailed* workings of the incentive mechanisms that give 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.

3.191 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.

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

3.192 We noted that 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, cashflow problems may arise.

3.193 As part of a separate process, we explained we intended 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

3.194 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.

3.195 Wellington Electricity submitted:[157]

> 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.

3.196 EDBs expect the scope for opex/capex substitution to increase (refer to paragraphs 5.39 to 5.43). 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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157 Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), pp. 15-16.

3.197 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 that might impact investment choices if the cashflow timing between the two solutions is significantly different.

3.198 As we explain in chapter 5, 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 solution 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 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.

3.199 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.

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

3.201 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-forward amounts 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

3.202 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 3.187 to 3.188 above.

3.203 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).

Stakeholder views on our draft decisions

3.204 Vector submitted:[158]

> In Vector's opinion the IRIS cash flow timing may:
> • exacerbate cash flow problems for businesses (undue financial hardship) that therefore distort suppliers' investment decisions, or result in price shocks for consumers; and
> • distort suppliers' investment decisions to favour solutions that have better cash flow implications.
>
> The Commission notes that smoothing all cash flow-sensitive factors (in aggregate) is more effective than an IRIS specific mechanism.
>
> Vector believes that IRIS needs refining to allow capex cost savings in future regulatory periods that have resulted in investments made in the current regulatory period (innovation or purchase of flexibility services), to be rewarded.
>
> We recommend that if the Commission maintains this approach, it must consider how this exacerbates cash-flow issues through other mechanisms such as the form of control and keeping EDBs' RABs indexed. Please see those sections of our submission for further details.

3.205 Transpower submitted:[159]

> We have not faced any issues managing cashflow timing of our own IRIS, however we note our IRIS is different to the EDBs in several ways, and so cannot comment on this issue with respect to EDBs. Our own IRIS cashflows are predictable (notwithstanding the baseline adjustment term) and known ahead of time. Additionally, the smoothing of our maximum allowable revenue mitigates any in-period revenue volatility that might be caused by IRIS carry forward amounts.

3.206 Wellington Electricity submitted that:[160]

> We agree that any volatility in cashflows introduced by the IRIS should be considered in aggregate with other cashflows fluctuations which create a difference between an EDBs cash outgoings and overall regulatory cashflow.

3.207 Wellington Electricity also submitted that: [161]

> We believe that networks should be modelling the cash flow implications of the IRIS. These workings will be included as part of a network's Compliance Statements disclosure and we would support including the impact of the IRIS in the Information Disclosures (IDs). Incentives and penalties in response to cost effecting performance is an important part of a network's performance reporting which is currently missing in the IDs.

3.208 We also received a submission on whether to include IRIS within the revenue smoothing limit, which we discuss in Attachment D.

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158 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 52.

159 Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 30.

160 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 11.

161 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 12.

Analysis and final decision

3.209 Our final decision confirms our draft decision. We have considered submissions on our draft decision and do not consider that they put forward any alternatives that would better achieve our framework's overarching objectives than our draft decision.

3.210 As noted in our draft decision, given that cashflows from IRIS are predictable, EDBs ought to be able to address any concerns related to cashflows, noting that the relative size of IRIS-related cashflows have a low likelihood of creating cashflow issues or distorting decisions on their own.

3.211 Related to this decision:

3.211.1 Our other decisions on the workings of the IRIS mechanisms are set out in Chapter 5.

3.212 Our decision to introduce a mechanism that enables a wider set of incentive schemes, including to improve incentives for opex/capex substitution across regulatory periods is discussed in Chapter 6 'Topic 6b – Encouraging innovation and non-traditional solutions'.

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

Final decision

3.213 Our decision is to amend the EDB IMs to provide for a 'new connection wash-up mechanism', applying to the quantity of new connections (washing up the capex amount based on unit costs), which CPP applicants may propose to be implemented as part of their CPP. The mechanism will allow for different types of connections with different unit costs to more realistically reflect the mix of connection types of outturn demand.

Problem definition

3.214 Given the general uncertainty in future network growth, an issue that has been raised by EDBs is the implications of new connections for expenditure allowances. The demand for new connections is largely outside of suppliers' direct control, but EDBs are still responsible for part of the cost of these connections (shared with connecting parties through capital contributions).

3.215 In some circumstances, large, unexpected quantities of new connections above those forecast for a price path could result in negative incentive adjustments for suppliers which are exposed to new connection demand. Alternatively, unexpected quantities of new connections below those forecast could result in consumers paying too much and suppliers being overcompensated through positive incentive adjustments.

3.216 We currently apply a revenue cap for EDBs but note that price caps have favourable incentive properties in terms of removing demand quantity risk.[162]

Background

3.217 In the IM Review, we have identified a range of connections-related issues that arise in the context of price-quality regulation, and we are addressing these through changes to in-period adjustment mechanisms to price paths.[163] There are also existing DPP reopener provisions in the EDB IMs for 'Unforeseeable major capex projects' and 'Foreseeable major capex projects' that have a primary driver of meeting demand.

3.218 The EDB reopener provisions (which we have extended in this IM Review), and the large connection contract mechanism we are introducing in this IM Review, are relevant for large connection-driven projects. The mechanism discussed in this section is meant to address the situation where an EDB on a CPP identifies significant quantity risk associated with generally routine growth (not large) in connections and for which unit costs can be robustly estimated.

Draft decision

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

Draft reasons

Stakeholder views prior to our draft decision

3.220 In response to our Process and issues paper, 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.[164]

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162 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. 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.

163 In Chapter 3 of the CPP and In-period Adjustment Mechanisms Topic Paper (Figure 3.3), we provide an overview of the connection-related IM changes we have made, provide examples of circumstances relevant to certain suppliers, and set out potential solutions to address issues that arise in those circumstances (Table 3.3).

164 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. 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.

3.221 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.[165]

3.222 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.[166]

3.223 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.[167]

3.224 A 'connection capex volumetric uncertainty mechanism' was also raised as a potential IM change by Frontier in a report for the Big Six:[168]

> Mechanism similar to the connection capex mechanism that applies to Chorus under the fibre regime.
>
> -Baseline allowance, including connection capex than is relatively certain. Connection capex unit costs and connection types.
>
> - 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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165 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).

166 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.

167 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.

168 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.

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

3.225 Our draft decision was 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.

3.226 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.

3.227 Based on the characteristics of connection capex, we considered that the forecast and actual outputs (quantity of connections) could be objectively quantified and specified in advance of the activity taking place in the regulatory period. We considered that implementing a wash-up mechanism would involve:

3.227.1 a forecast of the number of new connections (determined ex-ante for a CPP);

3.227.2 a unit cost per connection (determined ex-ante for a CPP); and

3.227.3 the wash-up mechanism that provides for the difference between the forecast number of connections and actual number of connections, multiplied by the unit cost per connection.

3.228 In practice, we considered 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).

3.229 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 also base our implementation on this mechanism and apply learnings from the fibre approach so far.[169]

3.230 We proposed the wash-up mechanism would be symmetrical for over- and under-forecast connection volumes. Therefore, if connections were over-forecast, there would 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.

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[169] 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.

3.231 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.[170] We therefore consider that the wash-up mechanism should only apply to new connections.

3.232 We would need unit cost data for each standard new connection to apply this mechanism. We considered this would only be possible under a CPP, given the scrutiny applied and information requirements. We considered 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.[171]

3.233 Below we discuss how we considered that the mechanism would promote the purpose of Part 4.

3.233.1 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).

3.233.2 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.[172]

3.233.3 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 face higher electricity costs for connections that were not required.

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

[171] See the 'alternatives considered' section for the alternative approaches that we considered for this issue.

[172] Under the status quo, these costs would be in scope of the IRIS mechanism, which would provide an overall incentive to control costs at an aggregate level.

Treatment of connection capex wash-up amounts

3.234 To implement the wash-up amounts, we considered two main options for the treatment of the difference from the baseline connection capex allowance:

3.234.1 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.

3.234.2 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).

3.235 Operating the mechanism through the wash-up provisions would mean that the cost difference from the baseline new connection allowance (net of capital contributions) would enter the RAB and 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 IRIS does not apply to Chorus' PQ path and so its expenditure is subject only to the natural incentive.

3.236 A recoverable cost approach is simple to automatically apply every year and efficient performance is incentivised through the ex-ante unit cost per connection. However, the downside of this approach would be that the cost difference from the baseline new connection allowance would 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 would not be shared with consumers.

3.237 We considered 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.

3.238 For consistency with the capex IRIS, the practical implementation of the wash-up mechanism would correct the capex allowance (as the mechanism already adjusts actual capex and revenue for volume differences).[173]

[173] 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

3.239 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.

3.240 We decided that 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.

3.241 EDBs can change capital contribution policies to address the risk of overspending on connection capex or make gains by 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.

3.242 We could 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

3.243 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.

3.244 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.

Stakeholder views on our draft decisions

3.245 Submissions on our draft decisions were generally supportive of the introduction of the new connection wash-up mechanism. Issues were raised around the practicability of setting unit costs and whether the mechanism should extend to a DPP as well as a CPP.

3.246 MEUG supported the intent of the mechanism and believed that there is an opportunity to learn from its application to Chorus but note the importance of setting it up robustly so that it works smoothly for EDBs.[174]

3.247 Wellington Electricity noted that the mechanism as defined in the draft decision may not always suit EDBs that are making CPP applications, and so should be an optional mechanism.[175] It states:[176]

> We also think that the new growth that does come from new connections will mostly come from gas conversions (where the news loads will usually be too large to provide from existing connections). These new connections will vary in size and cost and will make calculating a standard cost reflective of the actual capex spend difficult. Excluding these connections from the washup calculations would mean the remaining capex (driven by population growth) would then be immaterial when offset by capital contributions. A washup calculation-based connections, could add unnecessary complexity and provide little benefit for some networks.
>
> We do see the merits in applying the washup if it was capturing a material portion of capex growth and that growth was uncertain. Rather than being prescriptive about applying a washup mechanism or other tools to reduce the impact of forecast error, the CPP could provide the flexibility for a supplier to propose using the tools as part of their application.

3.248 Some submissions were supportive of our intent to introduce mechanisms to address connection growth uncertainty but were concerned about how the process would be applied in practice, particularly the use of a single unit cost.[177] Aurora Energy noted:[178]

> The mechanism relies on determining a fixed unit cost for each 'standard' new connection. In practice, it will be difficult to define a 'standard' new connection. The cost of new connections can vary significantly depending on connection type (capacity, location, density of subdivisions etc). Using a single fixed unit cost as the basis for calculating a wash-up could lead to a significant under, or over-recovery of costs if the mix of new connections during the regulatory period is different to the mix of new connections during the assessment period.

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174 Major Electricity Users Group (MEUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 7.

175 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Section 3.1.3.

176 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 12.

177 For example, Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 5-6. Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 14.

178 Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 18.

3.249 Similarly, Wellington Electricity noted that developing an appropriate standard cost may become more difficult as customers transition from gas to electricity and as electricity becomes the primary energy source for new connections.[179] It submitted that customer connection sizes and connection costs will become more variable.

3.250 A number of submissions suggested that we extend the connections mechanism to DPPs.[180] As Alpine Energy stated:[181]

> we would encourage the Commission to consider extending the connection volume wash-up mechanism to capture DPPs as well as CPPs. We believe the Commission has a wealth of data from past information disclosures, and we are happy to provide any additional supporting information, either via s53ZD notice or through the DPP consultation process, to see this mechanism captured in the DPP IMs and more specifically from DPP4 onwards.

3.251 Wellington Electricity considered whether the wash-up mechanism would be suitable for low-voltage (LV) network reinforcement capex:[182]

> While this type of investment would suit a washup (high volumes of individual upgrades and low-cost variability that would suit a standard cost), washing up any capex spend differences would disincentive flexibility (the benefits of deferring capex would be washed up).

3.252 Aurora Energy submitted that it would like clarification on how the proposed wash-up mechanism would work in practice alongside EDBs' capital contribution policies, as some EDBs may amend their policies to reflect the unit cost and avoid being underfunded.[183]

3.253 Aurora in its submission suggested that we wash up 'the dollar value of new connection capex' where a supplier can demonstrate that it has applied the capital contributions policy consistently.[184] This appears to be recommending that EDBs get washed up for actual expenditure (ie, achieve cost pass-through), and the cost is passed directly on to consumers. Similarly, Powerco and ENA suggested that if we do not extend the mechanism to a DPP we should exclude these costs from the capex IRIS (and therefore achieve cost pass-through of connection costs).[185]

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179 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 14.

180 For example, see Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 263-268; Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Section 5.4; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 4-5.

181 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 43.

182 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 14.

183 Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 19.

184 Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 20.

185 See Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 5 and Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Section 5.4.

3.254 Alpine Energy submitted that the outturn capex amounts should flow through the building blocks (return on capital) mechanism, rather than the difference being recovered through a 'recoverable cost', to avoid any unintended consequences:[186]

> we believe that the capex estimates should flow through the building blocks (return of capital) construct to avoid any unintended outcomes. We believe that the Commission could potentially follow an approach identical to the capex wash-up mechanism whereby the Commission estimates the difference in building blocks allowable revenue (BBAR), driven by the outturn in connection capex, with the recovery flowing through the aggregate wash-up calculations.

Analysis and final decision

3.255 We consider that a wash-up mechanism based on the number of new connections can remove demand risk for suppliers related to new connections and lead to benefits for consumers.

3.256 The mechanism we have decided to implement aims to reduce demand quantity risk from new connections for EDBs under a CPP that applies this mechanism. The mechanism therefore replicates a desirable incentive property of a weighted average price cap in the context of applying a revenue cap.

A CPP applicant will be able to propose that we include the mechanism in a CPP that they are proposing

3.257 Wellington Electricity suggested that the new connection wash-up mechanism should be optional for EDBs (see paragraph 3.247 above). Under our final decision, a CPP applicant will be able to propose that we include the mechanism in a CPP that they are proposing, but it will not apply by default. If a CPP applicant's types of connections are not well suited to this type of mechanism, it may not be suitable to include it in the relevant CPP.

Increasing the scope of connection types related to new connections

3.258 Following submissions, we considered whether applying one 'standard' unit cost to all different types of new connections is the most appropriate way to implement the mechanism. Having a single unit cost for new connections could lead to a significant under- or over- recovery of costs if the mix of new connections over the regulatory period materially differs from the type or mix of connections reflected in the single unit cost. Therefore, our decision is that the mechanism allows for different unit costs for each type of connection.

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186 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 42.

3.259 We consider that allowing for more than one unit cost for different connection types, similar to the approach used for Chorus, will more accurately represent efficient costs, while also recognising and better accommodating a change in mix of new connection types over time. The purpose of the mechanism is to mitigate demand risk for new connections-related expenditure, so there should be a link between the unit cost of each connection type and the corresponding connection quantity.

3.260 For example, an EDB applying for a CPP could propose separate unit cost for different types of connections, such as residential new connections, commercial connections, or new public EV chargers (that require a new ICP and may not be suited to another in-period adjustment). Connection capex subject to the mechanism would then be washed up for the outturn demand, based on the unit cost of each type, during the regulatory period.

3.261 While providing for a wash-up of multiple types of connections-related expenditure could introduce some complexity, it will more accurately represent efficient costs while allowing for different mixes of connections over a regulatory period. We consider that this is appropriate under a CPP as we are able to apply a proportionate amount of scrutiny, tailored to the particular circumstances of the individual supplier.[187]

3.262 We consider that extending the new connection mechanism to allow for multiple connection types better promotes incentives to invest (s 52A(1)(a)) compared with our draft decision. Using one unit cost for all types of connections could disincentivise investment in more expensive types of connections if the mix is different than forecast – particularly where those more expensive types of connections are more cost-effective overall and in consumers' long-term interest.

Allowing for the new connections wash-up mechanism in a DPP

3.263 A number of submitters suggested that we extend the mechanism from only applying to a CPP to also applying to EDBs on a DPP.

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[187] Section 53K of the Act.

3.264 Our final decision is unchanged from our draft decision in this respect. We do not consider that applying the mechanism to DPPs would better achieve our framework's overarching objectives given the information asymmetry due to the low-cost nature of a DPP. In addition, the mechanism is only intended for suppliers in a specific situation: where there is significant demand quantity risk associated with new connections and for which unit costs can be robustly estimated. Generally, suppliers have other options of addressing demand quantity risk, for example, changing capital contributions policies or reprioritising expenditure.

3.265 Submitters considered that we could use s 53ZD notices to gather information on historical connection costs. However, as noted above and in our draft decision, without appropriate scrutiny or if there was a change in mix of connection types, this could lead to incorrect unit costs during a regulatory period.

3.266 We consider that, relative to the status quo of connections expenditure being subject to IRIS, introducing the new connection mechanism for a DPP may improve incentives to invest (s 52A(1)(a)). However, if the unit costs are set incorrectly based on insufficiently robust information from EDBs, this may not better promote the Part 4 purpose as it may provide potential disincentives to invest appropriately (s 52A(1)(a)), or lead to excessive profits (s 52A(1)(d)).

3.267 As noted in our draft decision, gathering, assessing and analysing connection cost information for all non-exempt EDBs would not be consistent with the relatively low-cost DPP approach under s 53K. There would also be opportunities for gaming with less oversight under a DPP compared with a CPP. Under a CPP, we can get additional assurance on the relevant aspects of the mechanism from an independent verifier and can implement detailed disclosure requirements to monitor that the mechanism is working as intended.

3.268 We do not consider this would be appropriate for a DPP based on the lack of scrutiny or historical information that we have on connection types and costs. We intend to propose changes to collect better information on connections as part of our ID requirements. Collecting a robust and consistent historical dataset of connections type and cost information may allow flexibility of these mechanisms in the future.

Applying the connection cost wash-up mechanism to low-voltage networks

3.269 In its submission, Wellington Electricity considered whether the connection cost wash-up mechanism would be suited to LV reinforcement capex. Wellington Electricity concluded that washing up any capex difference would disincentivise EDBs pursuing network flexibility solutions and shifting of demand.[188]

3.270 We agree with Wellington Electricity that the disincentives for using flexibility solutions means that applying the mechanism to LV networks may not be in the long-term interests of consumers. We also reiterate that the mechanism will not be automatically included in a CPP by default. This will instead be something we decide in the context of determining a CPP that is specific to the particular circumstances (including connection types) of the applicant.

Implementation of the connection cost wash-up mechanism

3.271 As noted in paragraph 3.252 above, Aurora Energy seeks clarification on the treatment of capital contributions and the new connections cost wash-up mechanism. For a CPP regulatory period where the mechanism is applied, we would likely take the EDB's historical and forecast capital contribution proportion of expenditure into account in the unit cost. We have the flexibility to determine a unit cost for each type of connection to be applied in the mechanism at a CPP. Therefore, the unit cost(s) would reflect EDBs' expected capital contributions during a CPP.[189]

3.272 In response to Alpine Energy's submission on the treatment of the mechanism, we wash up the applicable new connection-related commissioned assets for the actual quantity of new connections (using an ex-ante unit cost). Our approach to this wash-up is consistent with the overall approach to specifying regulatory allowances through the building blocks.[190]

3.273 In response to Alpine Energy's suggestion for the new connection wash-up mechanism to work through the building blocks mechanism, we consider that our implementation of the mechanism gives effect to outcomes similar to those working through the BBAR mechanism. The forecast new connections quantities are washed up during a regulatory period (based on ex-ante unit cost) and earn a return on and of capital as if we had forecast the actual amounts.

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188 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 14-15.

189 We would use the expected capital contribution proportion for each connection type over the CPP period to set the unit cost for each connection type. Therefore, we would still wash up for the actual quantity of connections for each type, and the unit cost would reflect the proportion of total cost that a supplier will cover.

190 See Attachment D for more information on the implementation of the wash-up mechanisms.

3.274 In response to the Aurora Energy and Powerco suggestions to wash-up for actual new connection capex, we do not consider that this would be to the long-term benefit of consumers. As previously noted, some drivers of connection expenditure clearly are within a supplier's control. With no incentive to control costs it could lead to inefficient costs, increasing the cost to consumers.

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

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

3.276 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.

3.277 This section describes our final decision and reasons for IMs relating to how we address asset stranding risk for GPBs.

Final decision

3.278 Our final decision is that retaining our current approach to addressing asset stranding risk better promotes our IM Review framework's overarching objectives than alternatives.

3.279 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)).

3.280 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.

3.281 Continuing to allow for asset life adjustments factors in DPPs to better reflect economic asset lives maintains the integrity of the BBM to deliver an ex-ante expectation of real FCM which in turn incentivises GPBs to invest and innovate in line with s 52A(1)(a).

3.282 By applying these existing DPP 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.

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

3.283.1 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 (paragraph 3.166).

3.283.2 We have decided not to allow alternative depreciation methods in DPPs at this time. Allowing alternative methods to straight-line depreciation in DPPs would likely add significant complexity to the DPP process (contrary to s 53K).[191] Alternative methods remain available in CPPs where the result would better promote the Part 4 purpose.

3.283.3 We have not introduced 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).

3.284 We have also rejected the alternatives of writing down suppliers' assets from the RAB, restricting asset life adjustments to new assets only without prior ex-ante compensation, and relying on safety and reliability standards or "social licence to operate". These alternatives are not consistent with ex-ante FCM and providing the expectation of normal returns in line with s 52A(1)(a) and (d), and would undermine incentives to invest where continued investment to deliver safe and reliable services remains in consumers' long-term interest.[192]

Problem definition

3.285 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).

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191 Section 53K of the Act provides that the purpose of default/customised price-quality regulation is to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances.

192 The High Court has approved of our application of the FCM and NPV=0 principles and their relationship with the s 52A purpose of Part 4 (see *Wellington International Airport Ltd v Commerce Commission* [2013] NZHC 3289, at [256]).

3.286 The risk of 'asset stranding' is a problem if it results in deferral of otherwise efficient investment or in underinvestment. '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.

3.287 Asset stranding risk can lead to underinvestment where there is an expectation of losses from investment due to asset stranding risk despite there being sufficient willingness to pay from consumers 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.

3.288 In the remainder of this section, we outline how our current IMs (the IMs immediately prior to the IM Review 2023) address the problem of asset stranding risk for GPBs and potential issues that may arise.

A key element of our historical approach has been to retain assets that are no longer required in the RAB until they are fully depreciated

3.289 Since the Part 4 regime was established in 2010, the IMs have permitted suppliers to retain assets that are no longer required in the RAB until they are fully depreciated.[193] We noted at the time that for "various reasons, the use of an asset, or demand for the service that asset provides may fall away unexpectedly during the asset's lifetime. Where this happens, the asset becomes 'stranded'."[194]

3.290 When setting a DPP, we allow suppliers to recover asset 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.

3.291 The expectation that individual assets will stay in the RAB until fully depreciated addresses asset stranding risk thereby supporting incentives to invest and innovate in line with s 52A(1)(a) and the ex-ante FCM principle.[195]

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193 This means that assets that would otherwise be economically stranded assets do not become economically stranded. Suppliers can continue to depreciate the asset over its remaining regulatory asset life until fully depreciated even if the asset has no remaining physical asset life.

194 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) – Reasons Paper" (December 2010), para E11.1.

195 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.

3.292 This means that 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.[196]

Economic network stranding risk can be addressed separately to support ex-ante FCM

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

3.293.1 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.

3.293.2 The risk is asymmetric because GPBs profits are constrained on the upside (because Part 4 regulation caps revenue or average prices), 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.

3.294 In the case of GPBs there are risks of economic network stranding as a result of changes in climate change policies or consumer preferences.[197] For example:

3.294.1 policy-led restrictions on gas pipeline usage that would limit consumers' access to gas pipelines;

3.294.2 that in the future the cost of alternative fuels or energy sources decline relative to delivered natural gas, which essentially caps individual consumers' willingness to pay for natural gas;

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

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[196] 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.

[197] We discussed this further in Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 — Final Reasons Paper" (31 May 2022), para 6.57 and para C49-C54, and Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths — Reasons Paper" (31 May 2022), para 3.31 - 3.36.

3.294.4 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.

3.295 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.

Current IMs incentivise investment by allowing for the risk of network stranding to be mitigated

3.296 If economic network stranding risk is material, it needs to be addressed when applying the BBM to support 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 3.294 relating to decarbonisation) which are not accounted for in the parameters that determine the WACC. We discuss this matter further in the “Analysis and final decision” section below (from paragraph 3.403).

3.297 Non-systematic risk of stranding needs to be specifically addressed. Ex-ante FCM can be supported through measures that bring forward cashflows 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).[198]

3.298 Under the current IMs, economic network stranding risk can be mitigated.

3.298.1 An asset life adjustment factor can be applied 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. This meant that the depreciation input into the BBM remained fit for purpose so that we could continue to apply the BBM to support ex-ante FCM.

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

3.298.2 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.

3.299 Changing asset lives or the depreciation method does not lead to excessive GPB profits (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.

3.300 The current IMs do not provide for ex-ante compensation at the time of a price-quality path reset and GPBs have never received ex-ante compensation in the past for non-systematic asset stranding risk under regulatory settings.

Managing the risk of consumer price shocks

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

3.301.1 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.

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

3.302 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).

3.303 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.[199]

[199] Section 53P of the Act.

3.304 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.

3.305 We discuss this matter further in the “Analysis and final decision” section below (paragraph 3.444).

Other concerns raised by stakeholders prior to our draft decision

3.306 A number of other concerns were raised in relation to the current IMs for addressing stranding risk prior to the draft decision. These included arguments that in submitters’ views, the current IMs:

3.306.1 result in price outcomes which are inconsistent with outcomes in competitive markets where stranding risk is borne by suppliers;[200]

3.306.2 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”;[201]

3.306.3 “may incentivise wasteful investment in assets by suppliers who should be reducing investment”;[202]

3.306.4 are “directly contrary to limiting excessive profits” and that stranding risk is already compensated for in the WACC;[203, 204]

[200] 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.

[201] 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.

[202] 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.

[203] 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.

[204] 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.

3.306.5 mean that present consumers are subsidising future consumers and not delivering fairness or equity for current consumers;[205]

3.306.6 will result in unsustainable price increases;[206] and

3.306.7 are too discretionary with respect to asset life adjustments to “constitute or properly form part of input methodologies”.[207]

3.307 In our draft decision, we noted the following in response to concerns that our current approach of keeping assets in the RAB is inconsistent with what would occur in workably competitive markets.

3.308 Where appropriate, we can draw relevant insights from workably competitive markets. However, our task under the Part 4 purpose is to promote the specific outcomes under s 52A(1)(a)-(d) in the market for the regulated service.[208]

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

3.308.2 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, paragraph 3.336).

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

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205 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.

206 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".

207 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 not "constitute or properly form part of input methodologies".

208 *Wellington International Airport Ltd v Commerce Commission* [2013] NZHC 3289, at [623] and [627(c)].

3.310 While we acknowledged that changes to asset lives that affect depreciation have varied impacts on individual consumers,[209] such changes reduce the likelihood of asset stranding occurring in the first place. This means that consumers pay more cost-reflective charges over time which mitigates the risk of consumer price shocks in future regulatory periods. This may in turn be more equitable for consumers over time. We discuss this point further at paragraph 3.435.

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

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

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

3.312 We noted 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.

3.312.1 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.[210]

3.312.2 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.[211]

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209 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.

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

211 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.

3.312.3 However, we did not consider that it is possible to quantify 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).[212]

3.312.4 We concluded that 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.

3.313 In response to our draft decision, submitters reiterated some of these concerns (see "Stakeholder views on our draft decision"). We respond in the "Analysis and final decision" section below (from paragraph 3.387).

Draft decision

3.314 In our draft decision we proposed to maintain our current approach to addressing asset stranding risk (outlined in the problem definition section above).

3.315 We noted that 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 considered our existing approach better promotes the Part 4 purpose. We concluded:[213]

> 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.

Draft decision reasons

3.316 We begin this discussion of our reasons for our draft decision by providing an overview of the alternatives that we considered prior to making our draft decision and then we summarise submitters views on the alternatives that we considered.

3.317 We then explain our reasons for the following parts of our draft decision.

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212 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.

213 Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), para 3.202

3.317.1 We proposed not to transition to a regime where stranded assets are removed from the RAB.

3.317.2 We proposed retaining our existing approach to adjusting asset lives at this time.

3.317.3 We proposed retaining our existing depreciation method for DPPs at this time.

3.317.4 We proposed not introducing an ex-ante compensation mechanism for DPPs.

Alternatives we considered for our draft decision

3.318 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).[214]

3.319 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.[215] These included:

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

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

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

3.320 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.

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214 Commerce Commission "Input methodologies review 2023 - Options to maintain investment incentives in the context of declining demand" (20 December 2022).

215 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).

3.321 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.

3.322 The first alternative option we considered was 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 explained why we do not consider this alternative would better promote the Part 4 purpose than the current approach of keeping assets in the RAB.

3.323 We 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).

- 3.323.1 Changes to our approach to adjusting asset lives. This includes:
  - 3.323.1.1 options raised in the Options paper to better align regulatory asset lives with economic asset lives; and
  - 3.323.1.2 changes that restrict or remove our ability in DPPs to adjust asset lives to better reflect economic asset lives.
- 3.323.2 Changes to the depreciation method. This includes:
  - 3.323.2.1 the option raised in the Options paper to allow alternative depreciation methods for individual assets; and
  - 3.323.2.2 another tool that we considered that would allow front and back loading of depreciation at DPPs without changing the underlying depreciation method.
- 3.323.3 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.

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

3.324.1 The current IMs do not allow for stranded assets to be removed from the RAB, unless they have been fully depreciated.[216] We have not provided ex-ante compensation in the past.

3.324.2 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 where continued investment remains in consumers' long-term interests and they are willing to pay for that investment.

3.325 Similarly, we rejected 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, as this would not be in consumers' long-term interests.

3.325.1 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.

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

3.326 We 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".[217] 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.

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

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

3.327 In the current context, we were not 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. We noted that 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.

3.328 This does not amount to an ex-post assurance of FCM for sunk investment. While we considered 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.[218]

3.329 Finally, we noted that suppliers submitted that we should remove RAB indexation which would bring forward cashflows for GPBs. We considered RAB indexation separately from our approach to addressing stranding risk as is not directly relevant to how we address stranding risk, and our reasons for retaining a CPI-indexed RAB for GPBs are discussed in topic 3a.

Stakeholder views on the alternatives we considered for our draft decision

3.330 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.[219]

3.330.1 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).[220,221]

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218 For example, if demand were to drop quickly GPBs may be exposed to unmitigated economic network stranding risk for the RAB as a whole.

219 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.

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

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

3.330.2 Vector supported allowing changes to the depreciation method for individual assets (Option C).[222] Powerco agreed in principle but had concerns about complexity.[223] 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 having alternative depreciation types will assure a better match to the long-term demand profile”.[224]

3.330.3 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.[225] Firstgas expressed concern about complexity of the options presented.[226]

3.330.4 MGUG and Greymouth Gas wanted stranded assets removed from the RAB (Option E), but absent any ex-ante compensation (Option D).[227]

3.330.5 Suppliers (Firstgas, Vector and Powerco) favoured removing RAB indexation which would front-load cashflows relative to current IMs.[228]

3.330.6 MGUG and Greymouth Gas submitted that we should remove existing provisions to adjust asset lives.[229,230]

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

223 Powerco “Submission on IM Review Options to maintain investment incentives in the context of declining demand paper” (10 February 2023), p. 3.

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

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

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

227 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 8-20.

228 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.

229 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.

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

3.330.7 MGUG submitted 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.[231]

3.330.8 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".[232]

3.330.9 Methanex also submitted that we should reconsider why the IMs allowing asset life adjustment for GPBs are different to those which apply for EDBs which require suppliers to apply for any adjustments.[233]

3.330.10 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.[234]

3.330.11 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".[235]

3.331 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:[236]

> …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.

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231 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.

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

233 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.

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

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

236 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.

3.332 Frontier went on to state that:[237]

> 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 decided not to transition to a regime where stranded assets are removed from the RAB

3.333 We considered the alternative 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). We assessed this option and concluded that such a change would be highly unlikely to better achieve our IM Review framework's overarching objectives than the status quo.

3.334 We noted the following points.

3.335 There are pros and cons to this alternative. Changing IMs to allow stranded assets to be removed from the RAB may partly address some of the issues 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.

3.336 Potential benefits of such an approach include:

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

3.336.2 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

3.336.3 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.

3.337 But the more certain costs of changing include:

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237 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.

3.337.1 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));

3.337.2 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

3.337.3 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.

3.338 We also noted that we can continue to mitigate the risk of price shocks for current and future consumers without fundamentally changing our approach (3.303).

3.339 In conclusion, the potential benefits of changing the approach are outweighed by the more certain costs of changing. These costs would exist even if a change in approach only applied to a subset of assets.

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

3.340 We 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.

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

3.341.1 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).

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

3.342 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.

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

3.344 We noted the following points.

3.345 Further refinements to how default asset lives are determined for new assets entering the RAB (eg, Option A) may be appropriate prior to future resets. However, we considered 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.[238] Changing the IMs now in these circumstances would not promote certainty in terms of the IM purpose under s 52R.

3.346 We also considered 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.

3.347 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.

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[238] 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 could revisit this matter after we have received ID data from the adjustment factors applied in the DPP3 reset.

3.347.1 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).

3.347.2 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.

3.348 We noted in the Options paper that we could consider applying the BBM consistent with ex-ante FCM, in ways that treat asset lives differently for sunk versus incremental investments, provided that we also offered ex-ante compensation for existing assets to support ex-ante FCM. However, we did not consider that IM changes to support such decisions at resets would better promote the Part 4 purpose.

3.348.1 While we could in principle, 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.

3.348.2 We discussed in our draft reasons why we rejected the option of introducing an ex-ante compensation mechanism in DPPs including the challenges with estimating appropriate compensation (3.358).

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

3.349 We noted Methanex's specific request that we reconsider why we have taken a different approach for adjusting asset lives for EDBs compared with GPBs.[239] We considered that given the context for GPBs, our current approach was likely to better promote the Part 4 purpose than an approach that would require suppliers to individually apply for asset life adjustments. We considered 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.

3.350 We agreed that any adjustments should be based on a strong evidential basis and be consulted on with stakeholders as part of resetting a DPP. We stated that the current IMs allow this, and that it reflects our intended approach to adjustments. We noted the following points:

3.350.1 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.

3.350.2 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.[240]

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

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

3.351 We 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.

3.352 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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239 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.

240 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.

3.353 Following the release of the Options paper, we also considered whether to allow depreciation loadings in DPPs.[241]

3.353.1 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 52A purpose.

3.353.2 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.

3.354 Our draft decision was 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).

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

3.354.2 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).

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

3.355 We noted that 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 proposed not introducing an ex-ante compensation mechanism for DPPs

3.356 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.

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

3.357 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.

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

3.357.2 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.

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

3.358.1 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).

3.358.2 There are significant consequences of estimation error for ex-ante compensation (ie, under investment or excessive profits) (discussed in paragraph 3.337 above).

Stakeholder views on our draft decision

3.359 We received submissions on different elements of our draft decision for addressing asset stranding risk for GPBs. Submissions included views on:

3.359.1 the general approach to maintaining incentives to invest in the current context, underpinned by the ex-ante FCM principle;

3.359.2 the extent of economic network stranding risk under the current IMs; and

3.359.3 the mechanisms in the IMs to address asset stranding risk in DPPs and CPPs.

3.360 For the rest of this topic, we first summarise submitters' views on these issues. We then present our analysis of the issues raised and reasons why we have retained the approach we proposed in our draft decision.

Views on the general approach to maintaining incentives to invest in the current context

3.361 In our draft decision, we proposed retaining IMs that are underpinned by the ex-ante FCM principle. We rejected options that were not consistent with ex-ante FCM including writing down the value of suppliers' assets in the RAB, and/or restricting asset life adjustments to new assets only, without prior ex-ante compensation. We also rejected moving to a regulatory approach that compensates suppliers for asset stranding risk in advance and removes stranded assets from the RAB (consistent with the ex-ante FCM principle). We assessed this option and concluded that such a change is highly unlikely to better achieve our IM Review overarching objectives.

3.362 In response, suppliers reiterated their views on the importance of the ex-ante FCM principle for incentivising investment in the context of an expected decline in demand.

3.362.1 The Gas Infrastructure Future Working Group (GIFWG) (which comprises Firstgas, Powerco, and Vector as members) submitted on modelling which shows potential economic network stranding under some scenarios, "reinforces the importance of the Commission continuing to focus on the financial capital maintenance principle in its future decision making".[242]

3.362.2 GasNet "support the draft IMs decision to maintain the current approach to address stranding risk by retaining the stranding assets in the RAB and applying accelerated depreciation to ensure ex-ante FCM is maintained over the regulatory period".[243]

3.363 Suppliers also expressed concerns about the negative consequences of insufficient investment incentives:

3.363.1 The GIFWG expressed concern that if "there is a real prospect that the unrecovered capital value of those assets will be removed from the RAB, then this could defer otherwise sensible decisions to rightsize networks – potentially resulting in continued inefficient ongoing expenditure that could otherwise be avoided".[244]

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242 Gas Infrastructure Future Working Group (GIFWG) "Letter to the Commission" (17 July 2023), p. 2.

243 GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 17.

244 Gas Infrastructure Future Working Group (GIFWG) "Letter to the Commission" (17 July 2023), p. 4.

3.363.2 Oxera on behalf of Firstgas, Powerco and Vector state there is a risk of an "unorderly" transition leaving "businesses and residential consumers without gas supply when alternatives are not yet available" and also meaning that demand outpaces the capacity of electricity networks" which "could lead to network quality issues on the electricity side".[245]

3.363.3 Similarly, Vector submits that suppliers want the transition to be "as orderly as possible" concluding that "it is vital those businesses receive proper assurances that they will earn a reasonable return throughout a managed transitional period and their assets will not be stranded".[246]

3.363.4 GasNet stated that "[d]espite the expected decline in demand, continuous investment and maintenance is required to ensure that the gas network continues to provide a safe and reliable supply of natural gas until its phased out as part of the GTP. In our view, this would require [a] regulated supplier to be sufficiently compensated for the uncertainties involved".[247]

3.364 However, MGUG had concerns with our approach to incentivising investment and our application of the ex-ante FCM principle on a number of grounds:

3.364.1 MGUG disagreed with our interpretation of our task under the Part 4 purpose as promoting the specific competitive outcomes under s 52A(1)(a)-(d) in the market for the regulated service. Rather, MGUG considers that our "primary duty is to promote outcomes consistent with competitive markets, making sure that they include those in paragraphs (a) to (d)".[248]

3.364.2 MGUG reiterates its view that keeping otherwise stranded assets in the RAB is inconsistent with what would occur in workably competitive markets. MGUG considers that this transfers stranding risk to consumers and submits that stranded assets should be removed from the RAB without prior ex-ante compensation.[249]

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245 Oxera "Response to Commission's draft decision for IM Review 2023 on the cost of capital relating to gas sector" (report prepared for FirstGas, Powerco & Vector, 19 July 2023), para 3.66-3.69

246 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 11.

247 GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 9.

248 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 53.

249 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 30a-30b.

3.364.3 MGUG also submits that the draft decision does not set a "boundary on the FCM concept" which "creates a moral hazard opportunity for suppliers".[250]

3.364.4 MGUG suggests any incentive should apply only to "new investment pertaining to long term safety and reliability" and that "there is no 'incentive' achieved by extending it across sunk assets".[251, 252]

3.364.5 MGUG submits that our application of the ex-ante FCM principle shows no distinction between a "return guarantee, and expectation of a return" and assumes a "regulatory compact or bargain".[253]

3.364.6 MGUG suggests that we already provide ex-post FCM, and so "equity betas are no longer relevant and WACC is essentially equivalent to a bond valuation".[254]

3.364.7 MGUG "see no argument for an ex-ante risk premium. This falls into the same camp as ex-post compensation for investment bets that don't pay off".[255]

3.365 MGUG and Greymouth Gas also suggest that safety and reliability standards and other incentives such as "social license to operate" may be sufficient to incentivise efficient investment.[256]

3.365.1 Greymouth submits that we have "not addressed how much cost is related to safety" and have "not addressed or explained why non-minimal investment should be incentivised in the context of declining demand".[257]

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250 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 30c.

251 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 27a.

252 We note that MGUG oppose allowing asset life adjustments for sunk assets but support some adjustments for incremental investments. Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 7b and para 40c.

253 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 30b.

254 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 32c.

255 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 40d.

256 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 27c.iii.

257 Greymouth Gas "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 1.

3.365.2 MGUG suggests it “is not necessary or proven that incentives to innovate are needed, or desired by consumers”.[258]

3.365.3 MGUG states that there “is no evidence that incentives for reliability are not already sufficiently strong to ensure that consumers will continue to benefit from reliable and secure supply of gas pipeline services”.[259]

3.365.4 MGUG suggests that “GPB asset management programs (AMPs) provide sufficient transparency on asset risks and measures that support minimum integrity levels”.[260]

Views on the risk of economic network stranding under the current IMs

3.366 We received a wide range of views on the outlook for gas pipelines. In general, there was agreement that natural gas volumes would decline as New Zealand transitions to net zero emissions.

3.367 However, there was disagreement over the likely implications for the risk of economic network stranding. Submitters raised a number of factors which could influence the materiality of economic network stranding risk, including:

3.367.1 Current supplier and consumer behaviour including suppliers’ investment plans and continued growth in new connections.[261]

3.367.2 Potential network repurposing to biogas or hydrogen.[262]

3.367.3 The potential distinction between falling volumes of natural gas and falling demand for the services gas pipelines provide.[263]

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258 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 27b.

259 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 27c.

260 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 27d.

261 For example, Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 34d; FirstGas "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 2; Frontier Economics "Response to MGUG submission" (report prepared for FirstGas, Powerco & Vector, 9 August 2023), p. 13.

262 For example, Gas Infrastructure Future Working Group (GIFWG) "Attachment - Gas Transition Analysis Paper" (13 June 2023), pp. 4-5; Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 38c.

263 For example, Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 55, Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para 41; FirstGas "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 1.

3.367.4 Potential decommissioning liabilities.[264]

3.367.5 Government policy changes relating to climate change.[265, 266]

3.367.6 Uncertainty about the supply/availability of natural gas and policies that restrict its production and usage.[267]

3.367.7 Consumer ability and willingness to pay as gas volumes decline, and the potential distinction between falling volumes and falling revenue.[268]

3.367.8 Differences in risk profile between networks, especially between the GTB and the GDBs.[269]

3.367.9 Concerns about extreme price escalation as gas volumes decline, leading to an increased risk of disconnections and further price increases (ie, a 'death spiral').[270]

3.367.10 Concerns that IM and DPP adjustments to regulatory depreciation might themselves "have the perverse and unintended outcome of accelerating the decline of the underlying revenue base, increasing the risk of a premature stranding event actually occurring".[271]

3.368 Both suppliers and major users also submitted views on when and how stranding risk should be assessed.

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264 For example, GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 13.

265 For example, GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 7; Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 90-91, and Frontier Economics "Response to MGUG submission" (report prepared for FirstGas, Powerco & Vector, 9 August 2023), p. 12.

266 Appendix 2 of Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), provides a documentation of "various views on the future of gas in NZ" from domestic and international policy agencies.

267 For example, Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 4 and Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 34a.

268 For example, Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 34b and Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 5.

269 For example, Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 4.

270 For example, GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 41.

271 Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 5. See also Greymouth Gas "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 1.

3.369 Firstgas, Powerco and Vector jointly submitted modelling produced by the GIFWG which considered many of the factors above. Firstgas, Powerco and Vector stated that they "strongly encourage the Commission to explore the profile of future cost recovery over the longer term – similar to what the Working Group has attempted – to better understand whether future losses could be expected or not".[272]

3.370 The GIFWG modelling considered the potential unrecovered RAB under four scenarios including full winddown, LPG conversion, biomethane blending and a "business as usual" scenario[273]. The GIFWG report stated a number of findings including that:

3.370.1 "assuming no change to current regulatory settings or Government intervention" that a full winddown or LPG conversion scenario "exposes gas pipeline businesses to material cost recovery risk";[274]

3.370.2 "biomethane blending appears to mitigate that risk, largely because of the ongoing operation of the gas pipelines"; and that[275]

3.370.3 DPP3 asset life adjustments "mitigate under-recovery somewhat".[276]

3.371 Firstgas, Powerco and Vector state that "although there are clearly limitations with this type of analysis" the GIFWG modelling "at least raises the question as to whether GPBs can expect to recover their efficient investment costs" which might "undermine efficient investment in gas pipelines".[277]

3.372 MGUG also expressed views on the need for more modelling. MGUG submits that for the IM Review the "draft Determination should not be completed without circulation of modelling showing a wider range of scenarios, to reflect real world uncertainty about international policy and agreements as well as local developments".[278]

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272 Gas Infrastructure Future Working Group (GIFWG) "Letter to the Commission" (17 July 2023), p. 4.

273 See Gas Infrastructure Future Working Group (GIFWG) "Attachment - Gas Transition Analysis Paper" (13 June 2023), p. 13 for full descriptions of the scenarios.

274 Gas Infrastructure Future Working Group (GIFWG) "Attachment - Gas Transition Analysis Paper" (13 June 2023), p. 4.

275 Gas Infrastructure Future Working Group (GIFWG) "Attachment - Gas Transition Analysis Paper" (13 June 2023), p. 28.

276 Gas Infrastructure Future Working Group (GIFWG) "Attachment - Gas Transition Analysis Paper" (13 June 2023), p. 29.

277 Gas Infrastructure Future Working Group (GIFWG) "Letter to the Commission" (17 July 2023), p. 3.

278 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 66.

3.373 MGUG proposed that we should follow the AER's approach when assessing asset stranding risk. MGUG suggest that doing so would provide "a better appreciation if there is an expected trade-off between short term pain and long term gain".[279] MGUG proposed:[280]

3.373.1 Suppliers should be responsible for demonstrating stranding risk and justifying any adjustments to regulatory settings "leaving the regulator to be persuaded".[281] MGUG also suggests that to justify shorter economic lives for new investments suppliers should "justify why that is more efficient than opting for OPEX, or less durable CAPEX alternatives".[282]

3.373.2 To demonstrate stranding risk, suppliers should "provide plausible future energy scenarios that covers a spectrum of outlooks from the most pessimistic to the most optimistic for their networks, and to estimate the likelihood (probability) of each scenario".[283] These scenarios should not "be bound by a definition of pipeline services tied to only transport of natural gas".[284]

3.373.3 Suppliers should "actively and meaningfully engage with their customers on the range of available options and reflect customers' feedback in their proposals".[285]

3.374 Similar to MGUG, Methanex expressed concerns that the IM Review had not addressed how asset stranding risk should be evaluated in the future. Specific issues raised by Methanex included:[286]

3.374.1 How to "define the basis on which the phase-out of gas should be assumed" given a "complete phaseout of natural gas is neither a requirement of, nor consistent with, the 2050 net zero carbon target".

3.374.2 How to assess the potential for alternative uses of gas pipelines.

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279 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 105.

280 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 68-76.

281 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 69.

282 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 40c.

283 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 69.

284 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 70.

285 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 73.

286 Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 3.

3.374.3 How to account for “the nature of demand for gas pipeline services among different customer types and geographic locations”.

3.375 Methanex suggested that “appropriate analysis” would include, “multiple sensitivity analyses of future feasible pipeline revenues”, an “assessment of the ‘willingness to pay’ of different user segments” and “price elasticity assessments for pipeline tariffs”.[287]

3.376 We also note related concerns from MGUG, Greymouth and Methanex about the statutory definition of ‘natural gas’ as it is applied under the IMs.[288] These concerns relate to a misunderstanding about our ability (under current legislation) to account for the likelihood and potential value of gas pipeline networks if they are repurposed to use hydrogen or biogas and the impact of potential changes in legislation. We clarify this point further at paragraph 3.423 below.

Views on mechanisms in the IMs to address stranding risk

3.377 We 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). We received a mixed response to our draft decision.

3.378 As discussed above, MGUG and Greymouth gas were opposed to the overall approach to addressing asset stranding risk (paragraph 3.364 above).

3.379 MGUG also expressed concerns with the asset life adjustments mechanism in the IMs and how they were applied in DPP3. It expressed the following views.

3.379.1 That asset life adjustments may lead to NPV-positive outcomes for suppliers. MGUG stated that “there is no obligation on suppliers to operate their assets exclusively for carriage of natural gas in the future” and that this creates an opportunity for them to achieve an NPV-positive outcome if “suppliers decided that [a] gas other than natural gas is more profitable to transport”.[289]

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287 Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 5.

288 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 59, Greymouth Gas "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 1, and Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 4.

289 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 40b and 42a.

3.379.2 That asset life reductions in general are unambiguously NPV-negative for consumers as a whole and that the DPP3 asset life reductions were welfare reducing.[290] MGUG submitted that consumers and major users' individual discounts rates are typically much higher than the suppliers' WACC.[291]

3.379.3 That asset life adjustments could increase barriers to entry and "block competition" if they result in lower prices in the future.[292]

3.380 MGUG suggested the following as potentially better alternatives to applying asset life adjustments to address stranding risk.[293]

3.380.1 IM changes to address asset stranding risk should be deferred until the risk is more imminent – or stranding actually occurs.

3.380.2 Existing or new reopener provisions to address concerns about underinvestment in maintaining safe and reliable assets.

3.381 We also note that MGUG expressed concerns that the asset life adjustment mechanism in the IMs "simply allowed suppliers (but did not mandate that they should) to apply accelerated depreciation to their RAB" and so "conferred an option right on suppliers".[294] However, this is not how the IMs work. As we explain in the Analysis and final decisions section below, we determine the extent of adjustment at DPPs, and once the DPP is set, suppliers must pass the adjustment through to individual assets in the RAB (paragraph 3.438).

3.382 Similarly, MGUG submitted that "allowing accelerated depreciation" shifts a "greater fixed cost burden onto consumers".[295] However, as we explained in our draft decision (paragraph 3.299) and reiterate in our Analysis and final decisions section below (paragraph 3.432), changes to depreciation only change the timing and not the value of capital recovery.

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290 For example, see Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 81.

291 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 42b and 93-95.

292 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 106-110.

293 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 120-125.

294 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 78.

295 Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para 38.

3.383 Methanex expressed support for the decision to not make further IM changes for the GTB stating that "the current approach is sufficiently flexible", but also expressed some concerns about the current IMs.[296]

3.383.1 Methanex did not consider that the alternatives proposed were "sufficiently mature to enable full evaluation and, to the extent that they could be evaluated, did not offer a clear benefit in addressing possible asset stranding risks compared to the current methodology".

3.383.2 Rather Methanex considered that the alternatives to the status quo "have the potential to increase complexity, uncertainty, cost and risk".

3.383.3 Methanex welcomed "the acknowledgement that asset lives can be extended under the current framework" submitting that maintaining the current approach "will simplify the process of future adjustment and compensation if asset stranding risks are found to be lower than assumed in the DPP3 price reset".

3.383.4 However, Methanex expressed concern about NPV neutrality for consumers noting that "revision of asset lives alone may not be sufficient to compensate current consumers for costs incurred during a period of excess supplier revenue" because "consumers would be expected to have a higher WACC than suppliers".

3.384 Suppliers reiterated their support for continuing to allow asset life adjustments in DPPs.[297] However, they expressed concerns that the IMs did not allow for alternative depreciation methods in DPPs and that we rejected moving to an unindexed RAB.

3.384.1 Firstgas, Powerco and Vector jointly submitted that "more needs to be done" to address economic network stranding risk in the IMs than under our current approach.[298]

3.384.2 Vector submitted that stranding risk cannot be fully addressed under the current IMs and that we should move to an unindexed RAB to reduce economic network stranding risk as well as make available front-loaded depreciation methodologies in DPPs.[299]

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296 Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 1-2.

297 For example, Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 106 and Gas Infrastructure Future Working Group (GIFWG) "Letter to the Commission" (17 July 2023), pp. 2-3.

298 Gas Infrastructure Future Working Group (GIFWG) "Letter to the Commission" (17 July 2023), p. 4.

299 For example, Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 144.

3.384.3 Vector also submitted that removal of indexation and adoption of more front-loaded depreciation under the DPP would lead to more efficient prices because revenues would be "higher in the near term when demand is higher" as costs would be recovered from the "largest possible pool of consumers" and that this would promote the short- and long-term interests of gas consumers.[300]

3.384.4 Vector did not consider that CPPs "represent a viable solution". Vector expressed concerns that CPPs are "extremely costly and impractical", and that any CPP application may be likely to be rejected. Rather, Vector considered that every "GPB faces the problem of declining demand" and that these "are the 'default' circumstances" and should therefore "be dealt with under the default price path".[301]

3.384.5 Entrust (majority shareholder in Vector) submitted that RAB indexation could "work against accelerated depreciation".[302]

3.384.6 Powerco recommended we reconsider our decision to retain indexation for GPBs at this or the next IM Review.[303]

3.384.7 GasNet expressed concern that the proposed IMs provided "limited ways to address the greater risk of asset stranding, incentives and options to address demand risks".[304]

3.384.8 GasNet submitted that alternative depreciation methods such as tilted annuity should be allowed in DPPs and that doing so is "more likely to result in an aggregate profile that better reflects total demand expectations" and will support short- and long-term price stability.[305]

3.385 GasNet also encouraged us to reconsider our decision not to amend the asset life adjustment mechanism for new or existing assets at this time. GasNet stated that "making these changes in the IMs will provide more certainty and predictability of cost recovery support".[306]

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300 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 110-111.

301 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 112-114.

302 Entrust "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 5.

303 Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 7.

304 GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 9.

305 GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 21-24 and 43.

306 GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 19-20.

3.386 We also received submissions from Chorus and MEUG commenting on our approach to addressing asset stranding risk for GPBs.

3.386.1 Chorus “support the availability of the entire suite of risk mitigation measures” including ex-ante compensation and suggested that “mitigation settings need regular adjustment”.[307]

3.386.2 MEUG stated that “indexation should not be used as a proxy to address other issues facing the sector, such as financeability or in the case of the gas pipeline businesses, the risk of asset stranding. The Commission has other tools available to address these issues, either at the sector basis, or on a case-by-case basis for individual suppliers.”[308]

Analysis and final decision

3.387 Our final decision is to retain the draft decision for addressing asset stranding risk for GPBs in the context of declining demand.

3.388 We stand by our reasons from the draft decision. The following discussion clarifies our position in response to submitter views on the draft decision.

The ex-ante (real) FCM principle provides a framework for promoting s 52A(1)(a)-(d) outcomes but provides no ex-post guarantee of normal returns

3.389 As we explained in our IM Review framework, the ex-ante real FCM principle is that regulated suppliers should have the ex-ante expectation of earning their risk-adjusted cost of capital (ie, a ‘normal return’), and an ex-ante expectation of maintaining their financial capital in real terms over timeframes longer than a single regulatory period.[309]

3.390 We remain of the view that our task is to promote the specific outcomes under s 52A(1)(a)-(d) in the market for the regulated service. In doing so we must balance them, and exercise judgement.[310] The ex-ante FCM principle provides a framework for promoting s 52A(1)(a)-(d).

3.391 Application of this principle does not guarantee that suppliers will make normal returns or guarantee full capital recovery for GPBs over the economic lifetime of pipeline assets.

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307 Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 3.

308 Major Electricity Users Group (MEUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 22.

309 Commerce Commission “IM Review 2023 - Decision-making Framework paper (13 October 2022), para 4.7.

310 *Wellington International Airport Ltd v Commerce Commission* [2013] NZHC 3289, at [684].

3.392 Suppliers are provided the opportunity to earn a normal return on their investments; but we cap prices and revenues, not profits, so ex-post profits depend on a wide range of factors.

3.393 And as we have previously stated, our framework only provides for an expectation of FCM where it assists us in promoting the Part 4 purpose.[311] For example, if demand were to drop quickly, GPBs may be exposed to unmitigated economic network stranding risk for the RAB as a whole.

3.394 Under our current approach, sunk assets remain in the RAB between regulatory periods, and so suppliers' financial capital is maintained in real terms between regulatory periods.

3.395 However, as we discussed in the draft, ex-ante FCM could also be supported by compensating for asset stranding risk in advance.

3.396 In this case, suppliers would still have an ex-ante expectation of maintaining their financial capital despite the risk they cannot recover their full RAB, because suppliers would receive compensation in advance for the risk that assets become economically stranded.

We consider assets should continue to remain in the RAB until they are fully depreciated

3.397 MGUG expressed concern that our current approach may create a "moral hazard opportunity for suppliers". We considered this factor in our draft decision when discussing the merits of potentially transitioning to a regime where suppliers are exposed to the risk that stranded assets might be removed from the RAB (with ex-ante compensation).

3.398 As we discussed in the Options paper and noted in our draft decision, being exposed to the risk of assets being removed from the RAB may result in stronger incentives to innovate and improve efficiency in line with s 52A(1)(b). For GPBs, it may provide an additional financial incentive for suppliers to avoid or mitigate the risk of asset stranding. This is because asset stranding would result in negative financial impacts.

311 As stated in our IM Review decision-making framework paper, we do not consider the key economic principles (including ex-ante FCM) amount to a 'regulatory compact' between us and regulated suppliers that might bind us to accepting the outcome of applying the principles to a proposed decision. Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022), para 4.27.

3.399 However, in response to our draft decision we also note concerns raised by the GIFWG that exposure to the risk that individual assets could be removed from the RAB could "defer otherwise sensible decisions to rightsize networks – potentially resulting in continued inefficient ongoing expenditure that could otherwise be avoided".[312]

3.400 We remain of the view expressed in the draft decision that the potential benefits of changing our approach (including potential – although far from definite efficiency gains) are outweighed by the more certain costs of the alternative approach – primarily, the difficulties involved in estimating ex-ante compensation, where the risk of estimation error would likely result in either under investment or excessive profits and the difficulties that would be involved in regularly assessing asset values in the RAB.

3.401 Our current approach is expected to best promote the specific outcomes under s 52A(1)(a) to (d). It may not replicate all the potential behaviours of workably competitive markets, but that is not required under the s 52A purpose statement.[313] Whether or not assets would be impaired or stranded in competitive markets (noting that submitters have not put forward evidence that this would necessarily be the case), is something that we may consider, but our objective is to promote the outcomes in s 52A.

3.402 We note that MGUG considers that by continuing to allow assets to remain in the RAB that would otherwise be stranded assets, we are transferring stranding risk to consumers. In response we reiterate that the Part 4 regulatory regime has always placed the risk of stranding for individual assets in the RAB with consumers. This was a deliberate decision we made in 2010, as the approach that would best promote the Part 4 purpose.[314] We explicitly considered and rejected allocating stranding risk to suppliers.[315]

The WACC does not compensate for risks relating to the climate change response for GPBs

3.403 We remain of the view that, if it is material and asymmetric, asset stranding risk for individual assets and the network as a whole needs to be either mitigated or compensated for, to support ex-ante FCM.

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312 Gas Infrastructure Future Working Group (GIFWG) "Letter to the Commission" (17 July 2023), p. 4.

313 *Wellington International Airport Ltd v Commerce Commission* [2013] NZHC 3289, at [623] and [627(c)].

314 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) - Reasons paper" (December 2010), para E11.2 and section E11 generally.

315 Commerce Commission "Input Methodologies (Electricity Distribution and Gas Pipeline Services) - Reasons paper" (December 2010), para E11.13.

3.404 Keeping individual assets in the RAB mitigates stranding risks for individual assets, but as we explained in our draft decision (3.293), suppliers may still be exposed to an asymmetric risk of economic network stranding. The risk is asymmetric because GPBs' profits are constrained on the upside, but not the downside.

3.405 The WACC can compensate for systematic stranding risk but does not compensate for non-systematic risk.

3.405.1 If the risk is entirely systematic then the best estimate of WACC should be sufficient to support normal returns. Systematic stranding risk should be reflected in a higher asset beta.

3.405.2 However, if the risk is at least partially non-systematic, then the best estimate of the WACC provides no compensation for that additional non-systematic risk.

3.406 As we explain above, GPBs are potentially exposed to (asymmetric) non-systematic risk of economic network stranding as a result of changes in climate change policies or consumer preferences which require mitigation or compensation (paragraph 3.293). These risks are not compensated for through the WACC.

3.407 Investor diversification cannot address the investment incentive problem that arises from suppliers being exposed to asymmetric non-systematic risk of economic network stranding.

3.407.1 If this risk to suppliers is material and not addressed independently from the WACC then the present value of expected future cashflows discounted at their cost of capital will be less than the cost of the investment.

3.407.2 Under these circumstances, suppliers would not face financial incentivises to invest and would therefore be unlikely to commit funds to incremental investments.

3.407.3 The risk can be mitigated by bringing forward cashflows (asset life reductions achieve this). However, if the risk remains material, suppliers would also need ex-ante compensation to support ex-ante real FCM.

How we treat sunk assets affects incentives for incremental investment

3.408 Under our current approach, keeping sunk assets in the RAB (regardless of whether the assets remain fully utilised) is fundamental to supporting an expectation of ex-ante FCM and normal returns and incentives for incremental investment, in line with s 52A(1)(a) and (d).

3.409 This is because expected returns and incentives for incremental investment depend on how we value sunk assets.

3.409.1 When deciding to invest in incremental investments, suppliers anticipate that by the next regulatory period, the current period's incremental investments will be sunk assets.

3.409.2 Suppliers then anticipate how sunk assets will be valued at future resets – specifically that undepreciated assets will remain in the RAB with their value indexed for CPI inflation when the RAB is rolled forward in ID each year.

3.410 The key point here is that it is not possible to provide appropriate incentives to make incremental investments in long-lived assets like gas pipelines without also having regard to how we treat sunk assets. For example, restricting asset life adjustments to new assets only, without also making provisions to offer ex-ante compensation for existing assets, would not support ex-ante FCM. It is not credible to say we will provide ex-ante FCM for new assets without continuing to support ex-ante FCM for sunk assets. In addition, any alternative that treats new investments differently from sunk investment would likely add complexity, which would be inconsistent with the relatively low-cost nature of DPPs under s 53K. The added complexity may also create uncertainty for suppliers as to how different assets will be treated in the future, potentially undermining s 52R.

3.411 Rather, the incentives necessary to promote s52A(1)(a) depend on us continuing to support ex-ante FCM for sunk assets. If, ex ante, suppliers have an expectation of FCM for all assets, there will be incentives for them to continue investing in incremental assets, consistent with s 52A(1)(a).

No plausible alternative to ex-ante FCM for promoting s 52A(1)(a)-(d) has been put forward

3.412 Proposals such as writing down suppliers' assets from the RAB without compensation and restricting asset life adjustments to new assets only, without also making provisions to offer ex-ante compensation for sunk assets (paragraph 3.364), would undermine the credibility of the regime to provide an ongoing expectation of ex-ante FCM. This could deter further investment at a time when continued investment remains in consumers' long-term interests and consumers are willing to pay for that investment.

3.413 Furthermore, safety legislation and existing financial (and social licence) interests are unlikely to provide sufficient incentives to invest where suppliers did not have an ex-ante expectation of FCM. We consider that the likely outcome of such an approach would be to incentivise suppliers (and/or their investors) to leave the industry. This could result in unmet demand, despite consumers otherwise being willing to pay for continued investment, which would be at odds with s 52A(1)(b). Taking this approach for GPBs may also have detrimental impacts on investment in other regulated sectors.

3.414 And also in any event, these other interests do not cover the full range of investments needed to meet consumer demand where consumers are willing to pay for the service.

3.414.1 This could include system growth and new connections where consumers are willing to pay cost reflective prices for the service.[316] We noted in the gas DPP3 reset, Powerco submitted that payback periods for new connections ranged from 3 years for new commercial connections to 19 years for new residential connections.[317]

3.414.2 It could also include investment as suggested by suppliers that supports an "orderly transition".[318] For example, suppliers may choose to close parts of networks rather than invest to maintain a safe and reliable network, despite consumers being willing to pay to maintain those gas assets.

3.414.3 We also note that simply relying on GPB AMPs to support a "minimum integrity level" as suggested by MGUG would not address these concerns about underinvestment in the current context as suppliers would not have an ex-ante expectation of FCM.[319]

3.415 And finally, from a practical perspective, for the IM Review we must ensure the IMs enable us to appropriately incentivise efficient investment at future resets, in a manner that achieves our IM Review overarching objectives.

3.415.1 As we noted in our draft decision, our final IM Review decision will only directly affect consumer prices at future price-quality path resets (DPP4 is due in 2026).

3.415.2 We cannot predict now what the demand will be for new connections at future resets.

3.415.3 Nor can we predict now what investment will be needed in future regulatory periods above minimum safety standards that would promote the long-term benefit of consumers.

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316 Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 - Final Reasons Paper" (31 May 2022), para C57.

317 Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 - Final Reasons Paper" (31 May 2022), para B78.

318 For example, Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 20.

319 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 27d.

3.416 Consequently, we remain of the view that we have not been provided with any alternative IMs that would promote the s 52A(1) outcomes better than continuing to have IMs that are underpinned by the ex-ante FCM principle.

We have focussed our attention on ensuring that the IMs can appropriately address economic network stranding risk at future resets

3.417 Economic network stranding risk depends on a wide range of factors. There is clearly a high level of uncertainty about the current extent of economic network stranding risk, let alone the risk at future resets.

3.418 As noted above (3.415), the IMs need to enable us to appropriately address asset stranding risk at future resets. Because of this, the relevant question for the IM Review is not the extent of stranding risk now, but what the risk of economic network stranding will be at future resets.

3.419 While we acknowledge economic network stranding risk may (or may not) be material at future resets, we remain of view that it is not possible to quantify in advance of future resets the extent to which it could undermine incentives to innovate and invest at the time of future resets (to which the IMs would apply if unchanged).

3.420 Therefore, our approach to addressing economic network stranding risk in the IM Review has been on ensuring that the IMs can appropriately address economic network stranding risk at future resets, and we have not attempted to quantify the current extent of stranding risk.

3.421 We acknowledge that there remains uncertainty about how asset stranding risk will be evaluated at future resets. The current IMs do not prescribe how we will determine asset life adjustment factors so that regulatory asset lives better reflect economic asset lives and promote the Part 4 purpose in DPPs. And they do not prescribe how we would determine adjustments to asset lives or the depreciation method in CPPs. These features reflect the level of uncertainty about the future and the need for flexibility in the IMs to address matters as they are at each reset.

3.422 In considering whether and (if so) how to adjust asset lives in future resets, we envisage working closely with stakeholders. The current IMs are sufficiently flexible for us to adapt our approach over time, potentially incorporating the concepts raised by MGUG and Methanex if doing so is in consumers' long-term interests and compatible with our regime.[320]

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[320] We note Frontier Economics "Response to MGUG submission" (report prepared for FirstGas, Powerco & Vector, 9 August 2023), p.15 compares and contrasts our approach with the approach taken by the AER. Frontier expressed some concerns about the workability of MGUGs proposal.

3.423 With respect to concerns about the statutory definition of 'natural gas' as it is applied under our regulatory regime, we note that the current statutory definition does not limit our ability under the current IMs to give appropriate weighting to future scenarios where networks are repurposed, in our decision making. For example, in DPP3, we gave weight in our decision to adjust asset lives to account for the possibility of repurposing by considering that there may be residual value if the regulated service were to cease.[321, 322]

3.424 We acknowledge that there may be legislative changes at some point which impact on the definition of 'natural gas'. Such changes could affect how we set price paths under the DPP or CPP – for example, by expanding the scope of expenditure that is covered by the regulatory regime. If future legislative changes require adjustments to the IMs, that can be addressed at the time.

3.425 We will continue to consider potential repurposing (and also other relevant factors such as those listed above (paragraph 3.367) in future resets, working within the legislative frameworks that exist at future resets.[323]

We confirm our draft decisions on the mechanisms in the IMs to address stranding risk at this time

3.426 Our final decision has five key elements for addressing asset stranding risk for GPBs:

3.426.1 We have maintained a regulatory approach where assets remain in the RAB rather than becoming economically stranded.

3.426.2 We have reaffirmed our decision to address asset stranding risk independently of our approach to inflation.

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321 Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 - Final Reasons Paper" (31 May 2022), para D39.

322 We note GasNet's suggestion that we consider the role of decommissioning liabilities in the IMs (GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 13). No specific issues have been raised in this context in relation to how we address asset stranding risk for GPBs. We note that decommissioning liabilities may be a relevant factor for estimating potential residual value and for determining the extent of economic network stranding risk at price resets under the current IMs.

323 We note GasNet's suggestion that we test how possible IM amendments relate to the net zero emissions target (GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 10). In response, we note that we have made our IM Review decisions on addressing asset stranding risk for GPBs in the context of the expected decline in demand for natural gas. Climate change policies (including the 2050 target) are a part of that context.

3.426.3 We have the retained the current IMs which allow us to apply an asset life adjustment factor in DPPs if doing so better reflects economic assets lives and promotes the Part 4 purpose.[324]

3.426.4 We have rejected allowing alternative depreciation methods in DPPs. Alternative methods remain available in CPPs where the result would better promote the Part 4 purpose.

3.426.5 We have not introduced 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).

3.427 We do not disagree with suppliers' views that, in addition to asset life adjustments, changes to a front-loaded depreciation method and/or removing RAB indexation could be used to further mitigate economic network stranding risk, or to address concerns about long term consumer price escalation which could undermine allocative efficiency in the long term.

3.428 However, we disagree that allowing alternative depreciation methods in DPPs or no longer indexing the RAB for inflation best promotes the IM Review framework's overarching objectives at this time.

3.429 We confirm our view from the draft decision that asset stranding risk is better addressed independently of our approach to RAB indexation (RAB indexation is discussed in topic 3a). Removing indexation would not address the fundamental asset stranding issue which relates to long-term demand uncertainty, rather than inflation. Similarly, concerns about long term consumer price escalation are better addressed independently of our approach to RAB indexation for GPBs through asset life adjustment factors in DPPs, and if necessary, by changing the depreciation method in CPPs. We consider that given the uncertainty about future demand for GPBs, that these alternatives can better promote the Part 4 purpose at resets. This is because the extent of any necessary adjustment can be determined at price resets and tailored to the specific circumstances for each GPB to promote the Part 4 purpose.

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324 We note GasNet supports further refinement of the asset life adjustment mechanism ahead of the next DPP reset (GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 19-20). For the IM Review our decision remains to leave unchanged the details of the asset life adjustment mechanism until we can assess the impacts of the gas DPP3 decision in ID as further changes may prove unnecessary. Changing IMs now in these circumstances would not promote certainty in terms of the IM purpose under s 52R.

3.430 As we outlined above, allowing alternative depreciation methods as well as asset lives in DPPs would add significant complexity at DPP resets, which would not be consistent with s 53K. Instead, we consider that the complexity of the analysis and consumer engagement required to justify a change in depreciation method – in addition to asset life adjustments – would only be achievable in the context of applications for CPPs at this time.

3.431 We note that suppliers do not consider that CPPs are a practical solution to their concerns. However, we do not consider there is sufficient evidence to justify allowing changes to the depreciation method in DPPs at this time.

3.431.1 We recognise that in the future alternative depreciation methods may be justified in DPPs. For example, it may become clear that asset life adjustments to better reflect economic asset lives are insufficient to promote the Part 4 purpose.

3.431.2 However, we do not consider there is currently sufficient evidence to justify allowing changes to the depreciation method in DPPs given the significant complexity it would add at DPP resets.

3.431.3 Nor do we consider that there is evidence to justify using a front-loaded depreciation method as the default method in all resets. As we explained in the Options paper, there is no simple relationship between the depreciation method for individual assets and the implied aggregate depreciation profile.[325] The actual long-term profile of depreciation could depend more on the extent of future investment than on the depreciation method itself.

3.431.4 Consequently, we consider that straight-line depreciation remains the appropriate default method that will continue to apply for DPPs at this time.

3.432 We note MGUG and Methanex's concerns that asset life adjustments are not NPV neutral for consumers and transfer stranding risk to consumers.

3.433 In response, we first note that to the extent that suppliers maintain an ex-ante expectation of real FCM, asset life adjustments (and other changes to cashflow timings) are NPV neutral for suppliers. This means that they cannot themselves lead to excessive profits for suppliers or impose additional costs on consumers they did not already expect to bear in aggregate.

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[325] Commerce Commission "Input methodologies review 2023 - Options to maintain investment incentives in the context of declining demand" (20 December 2022), para 3.17.

3.434 We acknowledge that changes to asset lives that affect depreciation have varied impacts on individual consumers. 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. And we are acutely aware that consumer price adjustments resulting from asset life adjustments at price resets will factor into consumers' decisions on whether to continue to use gas over the long term.

3.435 However, we consider that continuing to allow for asset life adjustment factors in DPPs is ultimately about promoting long-term consumer benefits.

3.435.1 Having IMs that allow us to apply an asset life adjustment factor in DPPs if doing so better reflects economic asset lives and promotes the s52A purpose is an appropriate response to addressing the risk of economic network stranding and to ensure that suppliers continue to invest where it is efficient to do so.

3.435.2 Consumers cannot benefit from a service that no longer exists if underinvestment leads to early network winddown. Adjustments may be NPV negative for some consumers, however consumers as a whole benefit from incentives to invest where continued investment to deliver safe and reliable services remains in consumers' long-term interest.

3.435.3 As we discussed at paragraph 3.310 of our draft decision, adjustments to better reflect economic asset lives mean that consumers pay more cost-reflective charges over time, which mitigates the risk of consumer price shocks in future regulatory periods. This may in turn be more equitable for consumers over time because expected cost recovery between current and future consumers will be more proportionate to expected demand for gas pipeline services by current and future consumers if assets lives are updated to better reflect economic asset lives.

3.436 With respect to MGUG's concerns that suppliers may have an NPV-positive outcome if networks are repurposed, we note in the first instance that we only provide an *ex-ante* expectation of normal returns, but more importantly, we can take into account the residual value from repurposing when adjusting asset lives (as we did in DPP3).

3.437 Asset life adjustments to reflect economic asset lives are NPV neutral with respect to the WACC for suppliers. Even a decision to shorten asset lives beyond economic assets lives would remain NPV neutral under regulatory settings. However, a decision to leave asset lives longer than economic asset lives would result in an expected NPV-negative outcome for suppliers and so undermine incentives to invest because of how the BBM works (paragraph 3.441).

3.438 In respect to MGUG's concern that the asset life adjustment mechanism in the IMs “simply allowed suppliers (but did not mandate that they should) to apply accelerated depreciation to their RAB” and so “conferred an option right on suppliers”, we note this is not how the IMs work.[326]

3.438.1 We determine the extent of any asset life adjustment factor in a DPP, and we must be satisfied that applying an adjustment factor would better reflect economic asset lives and doing so would better promote the purpose of Part 4 of the Act.

3.438.2 And as we have explained previously (see for example paragraph 3.39 to 3.43 in the Options paper), once the DPP is set, suppliers must pass the adjustment through to individual assets in the RAB. While suppliers always have the option to price below the price or revenue cap, they must pass through the adjustment to individual assets. The availability of asset life adjustments in the IMs confers no additional optionality to suppliers to defer capital recovery.

3.439 We note MGUG’s concerns that asset life adjustments that result in relatively lower prices in the future could increase barriers to entry and “block competition” to gas pipeline services in the future. MGUG did not provide evidence on the likelihood of such competition. In response we note that the IMs only allow us to apply an asset life adjustment factor at DPPs if doing so would better reflect assets economic lives and better promote the purpose of Part 4. Asset life adjustments were necessary in DPP3 to continue to apply the BBM to support ex-ante FCM to maintain safe and reliable networks and promote the Part 4 purpose.

3.440 Finally, we address MGUG’s proposed alternatives to allowing for asset life adjustment in the IMs.

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326 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 78.

3.441 MGUG suggested that we should defer taking actions to address asset stranding risk until the risk is more imminent – or stranding actually occurs. We disagree with the implication that asset life adjustments should not be allowed for in the IMs until the risk is more imminent or stranding occurs. Once stranding occurs it is too late to take action.

3.441.1 As we discussed above (3.295), while economic network stranding itself may not be imminent, the risk of stranding in the future can immediately undermine incentives to invest, contrary to s 52A(1)(a).

3.441.2 Prior to DPP3, regulatory asset lives were based on physical asset lives. However, physical asset lives are no longer a reasonable proxy for economic asset lives.

3.441.3 In the case of DPP3, regulatory asset lives were greater than economic asset lives, and so asset life reductions were necessary to apply the BBM to support ex-ante FCM and promote incentives to invest under s 52A(1)(a). IM changes were necessary to avoid generating a flawed price path that would otherwise fail in its designed operation, which is to provide for an ex-ante expectation of normal returns on all investments, in line with s 52A(1)(a) and (d).

3.441.4 At future resets we may need the ability to adjust asset lives in DPPs to promote the s 52A purpose to apply the BBM to support ex-ante FCM and promote incentives to invest. It may be appropriate to lengthen asset lives in subsequent DPPs, depending on the circumstances and the current mechanism allows for this. For example, if it became clear that long-term demand for gas pipelines would decline at a slower rate than currently expected.

3.442 Reopeners cannot address concerns about underinvestment in the current context.

3.442.1 Within-period reopeners cannot address the long-term risk of economic network stranding that arises from having regulatory asset lives that clearly exceed economic asset lives.

3.442.2 Even with the availability of reopeners, suppliers would not expect to make a normal return on incremental investments and so are unlikely to have the appropriate incentives to invest.

3.442.3 Similarly, relying on the availability of CPPs would not address the immediate incentive problem that comes from having regulatory asset lives that clearly materially exceed economic asset lives. A 'business-as-usual' application of the BBM in DPPs would generate a flawed price path and not provide an ex-ante expectation of FCM, which, contrary to s 52A(1)(a), would immediately undermine suppliers' incentives to invest.

3.443 Rather, allowing for an adjustment to asset lives under the DPP as well as under a CPP reflects the fact that the issue of concern – the implications of climate change response on the gas pipeline industry – is sector-wide and affects all five regulated suppliers. Allowing for it to be addressed in the more generic DPP makes practical sense. In contrast, leaving this to be dealt with only by way of a CPP would be less efficient and costly to both suppliers, the Commission, and ultimately consumers, given supplier's costs of a CPP application are passed through to consumers.

We will continue to manage the risk of consumer price shocks at future resets

3.444 We note major user and energy retailer submissions expressed concerns about the extent of price increases in gas DPP3 in the context of asset life adjustments.

3.444.1 Contact stated that they had "recently seen a price increase from First Gas for 2023/24 of over 30%, despite the 10% price shock limit" and that "last year Vector gas had an almost 20% price increase for the 2022/23 year". Contact stated that "not only have these increases resulted in substantial price rises for end customers, but notification about them has also often come through so late that it has been a shock in every sense of the word".[327]

3.444.2 Methanex stated it "has been exposed to pipeline tariff cost increases of over 10% in 2022 and more than 30% in 2023". Methanex expressed concern these increases will make its "operations less competitive globally". Consequently, Methanex states that the Commission needs to "deepen" our assessment of stranding risk and "avoid the risk of unnecessarily undermining the competitiveness of NZ industrial consumers".[328]

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327 Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 33-35.

328 Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 5-6.

3.444.3 MGUG stated that collectively its "four members are facing a 43% increase ($14 million) in gas transport costs since the start of DPP3. $10 million will be added to transport next year on top of a $4 million increase for this year".[329] MGUG also commented on residential price increases stating that it "seems [transparent] that price impacts are not "smoothed", and some households have already experienced significant price shocks. MGUG note as an example that for low user households in the Vector distribution system "fixed connection fees have increased 68% from 41c/day to 68.8c/day ($100 per year increase)".[330]

3.445 We also note submitter concerns that price shocks could accelerate network stranding.[331] We responded to this point in our draft decision, by noting that in general, we can manage the risk of consumer price shocks independent of how we address asset stranding risk (paragraph 3.301). This does not mean that asset life adjustments will not affect consumer prices, but rather, that we can smooth price adjustments resulting from asset life adjustments over multiple years and cap increases within regulatory periods if appropriate (as we did in gas DPP3).

3.446 However, there are some limitations. For GPBs, we only limit weighted average prices or revenues. Individual GPB tariffs can be restructured or rebalanced in ways that mean individual tariffs can increase (or decrease) by a much greater extent than the average change in maximum allowed revenues. We also note that we do not control how GPB price increases are passed through to mass market end-consumers.

3.447 The risk of consumer harm from price shocks is a concern for us and should also be a concern for suppliers. Suppliers should be actively managing these concerns with major users and retailers. With respect to the IM Review, we note that for GPBs any decision to cap or smooth increases is solely determined within the relevant DPP (or CPP) determination and is not a decision for the IM Review. We will continue to monitor concerns about consumer price shocks, and welcome ongoing dialogue with all stakeholders on this important matter.

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329 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 92.

330 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 99-100.

331 Greymouth Gas "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 1 and Methanex "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 5.

Topic 3e – Form of control for GDBs

3.448 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 the 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.

3.448.1 Under a weighted average price cap (WAPC), the within-period demand risk falls on suppliers. If demand varies, 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.

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

3.449 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.[332]

Final decision

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

Problem definition

3.451 The issue we considered in this IM Review is whether the form of control for GDBs, a WAPC, remains appropriate in the context of the expected decline in demand for gas in the longer term. There is considerable uncertainty about the pace and extent of this decline (paragraph 2.13).

Draft decision

3.452 Our draft decision was to maintain the status quo of a WAPC for GDBs.

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[332] We discuss the form of control for Transpower, EDBs and the GTB in part 3 of Commerce Commission "Part 4 Input Methodologies Review 2023 - Final decision - Report on the IM Review 2023" (13 December 2023).

Draft reasons

3.453 Our view was 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, we considered that changing GDBs' 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.

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

3.455 In the remainder of this section, we explain our draft decisions considerations:

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

3.455.2 inter-regulatory period price stability and tariff structuring under a WAPC;

3.455.3 consistency with the GTB form of control; and

3.455.4 growing demand through new connections.

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

3.456 Our main reason for retaining the current GDB form of control in our draft decision was 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 reduces the risk of inefficient expenditure (both capex and opex), consistent with s52A(1)(b). We considered 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.

3.457 We considered 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.[333] This is because a WAPC 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, to ensure 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.

3.458 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 (see from paragraph 2.10). Taking these into account makes incentivising efficient expenditure more important in determining the right form of control for GDBs.

3.459 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.

3.460 Under a revenue cap, once the price-quality path is set, suppliers have lower financial incentives to spend to retain customers or provide services at a quality they demand and stronger incentives to reduce costs. With a falling demand these stronger incentives to reduce costs may reduce their focus on providing services at a quality that customers demand.

3.461 Although suppliers can also be expected to manage their expenditure under a revenue cap, their incentives to spend efficiently to provide services at a quality consumers demand, and to optimise their 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. Whereas, under a revenue cap suppliers can increase prices to recover revenue up to the revenue cap.

3.462 We considered 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).

[333] Commerce Commission "IM Review 2023 - Decision-making Framework Clarification note- s5ZN of the CCRA" (21 December 2022), p. 1.

3.463 Our risk allocation principle was also relevant to our draft decision.[334] Under that principle, we ideally allocate risks to suppliers or consumers depending on who is best placed to manage them. Managing risks includes:

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

3.463.2 taking actions to mitigate the costs of occurrence; and

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

3.464 Having regard to this principle, we considered that suppliers can mitigate the cost and/or absorb the impact on profitability of the demand risk by adjusting their expenditure (opex and capex).[335] 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.

3.465 In response to our consultation prior to our draft decision, Vector, First Gas and Powerco submitted in favour of moving to a revenue cap for GDBs.[336] Quantity forecasting risk was raised as a significant issue in the submissions on our Process and issues paper.[337] Vector stated that there is a "significant quantity forecasting risk" in the current environment, which provides a "disincentive for efficient investment".[338]

3.466 Despite the quantity forecasting risk, in our draft decision we considered a WAPC would better promote the Part 4 purpose compared to a revenue cap. We considered GDBs:

3.466.1 are better placed than consumers to manage the risk and consequences of demand forecast error;

3.466.2 being exposed to manageable risk under a WAPC is likely to provide stronger incentives to invest and operate efficiently;

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334 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.

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

336 Vector "Submission on the Process and issues paper" (11 July 2022), para 60; 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 Powerco – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 7.

337 For example, Vector "Submission on the Process and issues paper" (11 July 2022), para 62-66.

338 Vector "Submission on the Process and issues paper" (11 July 2022), para 65.

3.466.3 can, to some extent, manage the demand risk by adjusting spending on opex and capex; and[339]

3.466.4 can manage connection numbers (influence demand through connections and reconnections), but not demand quantities from existing connections.

3.467 We acknowledged 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.

3.468 We also noted that revenue caps do not eliminate the need for demand forecasts. When assessing expenditure, we are also 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 lives and/or the depreciation method.

3.469 While a WAPC exposes suppliers to demand (quantity forecasting) risk, we did not consider there was a risk of GDBs not investing in the network as a result of our choice of form of control.[340]

Price stability and tariff restructuring

3.470 We noted that a WAPC provides consumers with more price stability within a regulatory period, on average, but a higher likelihood of between-period instability if large revenue corrections are needed.[341]

3.471 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.

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

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

340 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), para 4.7.

341 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.

3.473 We considered 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 in distribution networks means that peak charging signals are less valuable in gas than electricity.[342]

Consistency with the GTB form of control

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

3.475 We noted 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 had no evidence that it would do so.

Growing demand through new connections

3.476 Some suppliers' submissions before our draft decision stated that the WAPC's incentives to grow demand through new connections are 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 considered promoting incentives to invest efficiently (for example, in ensuring the safety and reliability of a network) is important while gas is still used. We considered a WAPC form of control is better suited to this than a revenue cap.

Stakeholder views on our draft decision

3.477 GDBs and MGUG submitted on our draft decision, which was that a revenue cap would better promote the long-term benefit of consumers than the current WAPC.

3.478 Frontier (for Vector) submitted that there are “significant challenges associated with forecasting demand accurately at the present time”.[343] Frontier (for Vector) submitted that a consequence of being unable to forecast demand accurately over a regulatory period is that under a WAPC GDBs may over/under-recover their efficient costs which may result in windfall gains and losses.[344] Frontier (for Vector) also submitted that: [345]

342 First State Investments "Input Methodologies Review: Form of Control" (24 March 2016), p. 3.

343 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), para 35.

344 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), para 46-57.

345 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), para 56.

If GDBs expect that they may not recover all of their efficient costs (due to the difficulties of forecasting demand accurately for the purposes of setting a WAPC), then this would violate the FCM principle. That, in turn, could deter efficient investment by GDBs in regulated assets. This would ultimately be to the long-term detriment, rather than benefit, of consumers.

3.479 Other issues raised by Frontier (for Vector) included:

3.479.1 potential inability to manage demand risk effectively by adjusting expenditure or increasing fixed charges;[346]

3.479.2 compliance cost and complexity;[347]

3.479.3 inter-period stability versus intra-period stability;[348]

3.479.4 concerns that the incentives under a WAPC are inconsistent with decarbonisation objectives; and[349]

3.479.5 financeability concerns resulting from the choice of form of control.[350]

3.480 Frontier (for Vector) suggested that the “combination of a revenue cap and the ‘overs and unders’ account" modelled on EDBs and the GTB would address these concerns and be “a relatively low-cost change for the Commission to make”.[351]

3.481 Vector also suggested an alternative approach of introducing a demand reopener if we were to retain a WAPC.[352]

346 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), paras 139-146.

347 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), para 115.

348 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), para 137.

349 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), paras 42-45.

350 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), paras 58-70.

351 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), para 18-19.

352 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 171.

3.482 MGUG supported our draft decision on form of control for GDBs.[353] With respect to demand forecasts MGUG stated that “forecasting is not highly problematic for GPBs in the context of gas transition”.[354] MGUG submitted that GDBs “have the ability to influence demand through their gas connection policies, and their tariff structures”.[355] MGUG questioned the relevance of arguments made by Frontier (for Vector) about price stability, to the decision on form of control for GDBs.[356]

3.483 MGUG also noted in its cross-submission: [357]

> It seems to us that the Commission has not addressed the conflict of interests that arise for integrated EDB and GDB providers. We have seen nothing to protect gas consumers from an EDB preference to move gas customers onto electricity (as appears to be the case for Vector).

Analysis and final decision

3.484 Our final decision is to maintain the WAPC form of control for GDBs. 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.

3.485 We note that there are pros and cons for both types of form of control, and in the absence of convincing evidence in favour of a change to a revenue cap, we consider that, on balance, a WAPC better achieves our IM Review framework's overarching objectives.

Efficient costs and excessive profits

3.486 In response to Frontier's (for Vector) submission that suppliers under a WAPC may over/under-recover their efficient costs, which can result in windfall gains and losses, we note that we provide for ex-ante FCM, not ex-post FCM.[358]

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353 Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para X3.

354 Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para X3.b.

355 Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para 39.

356 Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para 38.

357 Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para 57.

358 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.

3.487 We also note that regardless of the form of control, ex-post efficient costs will depend on demand outcomes.

Forecasting difficulty

3.488 Given the uncertainty around how the decarbonisation transition path will unfold, we acknowledge demand forecasting could become more difficult. However, this is the case under both a WAPC and a revenue cap. With both forms of control, we provide for ex-ante FCM based on forecasts of expenditure, which reflect assumptions about short- and long-term demand.

3.489 Demand and expenditure are linked. In our view, the issue of the demand forecast error is not solved by switching to a revenue cap. If demand diverges significantly from forecast, suppliers' options to manage the risk include tailoring their expenditure.

3.490 In order to help mitigate the short-term demand risk we have the option of continuing to apply 4-year regulatory periods rather than 5- years regulatory periods.

3.491 We note that in response to our draft decision for GDBs, Vector stated that it is “difficult to reconcile the draft decision with the Commission’s choice to switch EDBs to a pure revenue cap at the previous IM reset”. Vector stated that “[o]ne of the chief reasons this change was made was to ‘remove the quantity forecasting risk, and therefore any potentially detrimental effect of that risk on EDBs’ incentives to spend efficiently”.[359]

3.492 We do not consider our 2016 reasons for preferring a revenue cap for EDBs provide justification for moving GDBs to a revenue cap at this time. We note that there are material differences between GDBs and EDBs and that the circumstances for EDBs in 2016 were very different to the current circumstances for GDBs.[360]

3.493 In our 2016 analysis on form of control for EDBs, we considered demand risk from two perspectives:

3.493.1 'Demand uncertainty risk' — the inherent uncertainty in future demand over the time period of the price-quality path.

359 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 169.

360 These differences include gas being a more discretionary fuel — so without the additional incentive provided by a WAPC, this could lead to fewer consumers using gas even if they considered it to be a more efficient option for them. Another difference would be regarding the tariff restructuring where, unlike in the electricity sector, we are not aware of issues that would prevent GDBs reforming their tariffs.

3.493.2 'Quantity forecasting risk' — the extent to which our forecast diverges from the supplier's own expectations.

3.494 In the 2016 IM Review, we changed the form of control for EDBs from a WAPC to a pure revenue cap as there were three key problems raised with the WAPC for EDBs:

3.494.1 quantity forecasting risk, which suppliers said was unmanageable;

3.494.2 disincentive to pursue energy efficiency and demand-side management (contrary to s 54Q); and

3.494.3 potential disincentives to tariff restructuring.

3.495 At that time, we considered that the quantity forecasting risk was a more significant problem than the other two points mentioned in 3.494.2 and 3.494.3, as it could lead to incentives for suppliers to underspend inefficiently, contrary to s 52A(1)(a) and (b).[361]

3.496 However, we also acknowledged that changing to a revenue cap would expose consumers to more demand uncertainty risk.[362]

3.497 Our decision to move to a revenue cap for EDBs reflected the trade-offs at the time for EDBs.

3.497.1 Our primary concern was potential underinvestment due to constant price revenue growth (CPRG) forecast error. Consistent with s 52A(1)(a) and (b), we considered that incentives for efficient expenditure were the “most important aspect when considering the differences between revenue caps and price caps… because they expose suppliers to demand risk differently”.[363]

3.497.2 We concluded that moving to a pure revenue cap would remove the quantity forecasting risk for both suppliers and consumers “because quantity forecasting for setting the price-path would no longer be necessary”.

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361 Commerce Commission "Input methodologies review decisions — Topic paper 1 — Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016), para 40.

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

363 Commerce Commission "Input methodologies review decisions — Topic paper 1 — Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016), para 67.

3.498 Unlike in 2016, our main concern for GDBs is now demand uncertainty risk. This differs from the main concern we had with quantity forecasting risk for EDBs that prompted us to change EDBs form of control in the 2016 IM Review. In the current context, moving to revenue cap for GDBs would expose consumers to more demand uncertainty risk and not eliminate the need for demand forecasts at price resets. Short- and long-term demand forecasts would still be needed to set expenditure allowances.

3.499 The need for demand forecasts under either form of control also explains why we do not favour introducing a demand reopener without also reopening the expenditure forecast. A reopener would shift some of the demand uncertainty risk to consumers and we consider that GDBs are best placed to manage this within-period demand risk (as they do under a WAPC). We consider our reasons why we did not introduce a demand reopener in DPP3 still hold and these are described below in paragraphs 3.505 and 3.508.

3.500 In conclusion, we do not consider that concerns about forecasting difficulty provide justification for changing the form of control for GDBs. In the absence of strong evidence for a change in the form of control, we consider that the status quo is the best option in terms of achieving our IM Review framework's overarching objectives.

Adjusting expenditure and inability to increase fixed charges to manage the risk

3.501 With regards to adjusting expenditure to manage risk, we note that suppliers' AMPs and expenditure plans are regularly updated during regulatory periods. Suppliers are able to reevaluate expenditure plans to account for new information relevant to them.

3.502 We also note MGUG agreed with our draft decision on form of control for GDBs.[364] MGUG also stated that consumers' “best long-term interests (both for gas and electricity) is served by confidence that the price/quality path will reflect and send the right signals about efficiency, including signals we should act on, in relation to consumers' own investment in gas dependant assets”.[365]

3.503 Our view remains unchanged from the draft decision, that on balance a WAPC is more likely to promote efficient expenditure by GDBs in the context of expectations of declining demand/uncertain pace of decline.

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[364] Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), X 3.

[365] Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para 56.

3.504 In terms of the fixed charges, there might be limitations for tariff restructuring, but we are not aware of issues and we have not observed any since the DPP3 reset. We note for example that Vector increased fixed charges and according to MGUG household fixed connection fees have increased 68% from 2022 to 2023.[366]

Demand reopener under a WAPC as proposed by Vector

3.505 Vector proposed an alternative to the status quo: a WAPC and a demand reopener (ie, reopening the constant price revenue growth forecasts only) if actual demand turned out to be below or above the underlying forecast by a pre-specified margin (eg, 10%).[367] Vector and Frontier submitted that this is a similar approach to that applied by the AER (the economic regulator for the gas network sector in Australia).[368]

3.506 We have considered and decided not to implement the alternative of a demand reopener under a WAPC.

3.507 We consider the reasons why we rejected the demand reopener in DPP3 still hold: "Under a WAPC GDBs bear the upside, and the downside, of the within-period demand risk. It is our view that GDBs are best placed to manage this within-period demand risk, and therefore should bear this risk. Maintaining a WAPC while introducing demand reopeners would shift some downside risk to consumers, while GDBs would still benefit if they were to outperform the CPRG forecast. In our view this would not be to the long-term benefit of consumers."[369]

3.508 In addition, given the uncertainty about the pace and extent of declining demand for GPBs, we do not consider that it would be in consumers' interests to reopen the CPRG forecasts without also reconsidering expenditure forecasts in these circumstances.

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366 Major Gas Users Group (MGUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 100.

367 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 171.

368 We note that the AER has not introduced a demand reopener. A supplier could apply for a mid-period variation to its access arrangement under the existing National Gas Rules if "the trajectory of its demand is substantially different to our final decision". Australian Energy Regulator "Evoenergy Access Arrangement 2021 to 2026 - Attachment 12 Demand - Final decision" (April 2021), p. 27.

369 Note that in DPP3 we also introduced capex reopener provisions for "expenditure associated with demand growth or risk events". The capex reopener provisions only apply to specific projects and programmes and not general demand variations from forecasts. Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2022 - Final Reasons Paper" (31 May 2022), para 5.35 and para E45-E46; Commerce Commission "Amendments to input methodologies for gas pipeline businesses related to the 2022 default price-quality paths — Reasons Paper" (31 May 2022), para 3.8 - 3.10.

Compliance cost, complexity

3.509 While some submitters claimed there would be lower compliance costs and complexity in changing the form of control, there was no specific evidence offered, and we are not otherwise persuaded a change would have this effect.

3.510 We remain of the view 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 in distribution networks means that peak charging signals are less valuable in gas than electricity.

Inter-period stability versus intra-period stability

3.511 In practice we can only provide a degree of price certainty for one regulatory period at a time. Starting price adjustments at future resets depend on a number of inputs, many of which are only known closer to the time of a reset. It is possible that inter-period price movements could be greater under a revenue cap (eg, a decline in WACC offsets the starting price impact of a decline in demand).

3.512 A WAPC provides some short-term price stability for consumers during a period of significant uncertainty (noting that GPB charges are only one component of gas prices paid by consumers, which also reflect components that are outside the scope of Part 4 such as the cost of gas). We note MGUG submitted in favour of retaining the WAPC for GDBs.[370]

Other issues raised

3.513 There were also points raised about the incentives for new connections and growth under a WAPC being inconsistent with decarbonisation objectives. In particular Frontier (for Vector) suggests that the "financial incentives imposed on GDBs to maximise revenues" through new connections and growth "may result in action by GDBs that makes consumer switching to electricity less attractive than it otherwise would be, thus slowing the pace of New Zealand's energy transition".[371]

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370 Major Gas Users Group (MGUG) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para X3.

371 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), para 42-45.

3.514 In response:

3.514.1 We do not consider the choice of form of control remains a primary driver of new connections and volume growth for GDBs.[372] The marginal incentive to increase connection numbers and grow throughput provided by a WAPC is likely to be significantly diminished as natural gas use is expected to decline over the long-term. As Frontier noted "we think that GDBs' ability to influence demand is significantly constrained by Government policy to reduce consumption of fossil gas over time. In these circumstances, it is unclear that application of a WAPC would incentivise GDBs effectively to pursue demand growth."[373]

3.514.2 For the above reason, we do not consider that continuing to apply a WAPC relative to a revenue cap would be inconsistent with decarbonisation objectives,[374] and we consider that a WAPC better promotes the Part 4 purpose than a revenue cap.

3.514.2.1 We consider that the stronger incentives under a WAPC for efficient expenditure by GDBs to ensure consumers continue to receive services at a quality they demand, in line with s 52A(1)(b) are most relevant for promoting the Part 4 purpose and are not inconsistent with decarbonisation objectives.

3.514.2.2 In the context of decarbonisation, efficient investment by GDBs will help ensure that networks continue to provide a safe and reliable supply of natural gas until they are no longer needed.

3.515 Another point raised was financeability. Frontier (for Vector) submitted that GDBs may face financeability concerns in those periods when efficient costs are under recovered materially. In particular, Frontier (for Vector) submitted that if under-recovery is sufficiently large, cashflows may be too low to support the benchmark credit rating and lead to a financeability constraint.[375]

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372 In the 2016 IM Review, we stated that our main reason for maintaining the WAPC was to incentivise new gas connections and grow throughput. Commerce Commission "Input methodologies review decisions — Topic paper 1 — Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016), para 221.

373 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), para 136.

374 As outlined above at paras 3.456 - 3.458, we have taken account of the permissive considerations under s 5ZN (particularly the ERP and 2050 target) in our decision on GDBs' form of control because we considered them relevant and not inconsistent with promoting s 52A in this context.

375 Frontier Economics "The merits of introduced a revenue cap for gas distribution businesses" (report prepared for Vector, 6 April 2023), para 69.

3.516 In response we note that we consider that GDBs are better placed than consumers to manage within-period demand risk. If demand diverges significantly from forecast, suppliers' options to manage the risk include tailoring their expenditure. We also note that in DPP3 we decided to shorten the regulatory period to 4 years, which could also help mitigate the effects of unexpected changes in demand. Lastly, CPPs are available if signs of a specific issue arise.

3.517 MGUG asserted we had “not addressed the conflict of interests that arise for integrated EDB and GDB providers”. MGUG saw “nothing to protect gas consumers from an EDB preference to move gas customers onto electricity (as appears to be the case for Vector)”. We consider our regulatory regime promotes the long-term benefit of gas consumers by supporting continued investment in gas pipeline services where consumers demand those services, including by:

3.517.1 using a WAPC form of control which provides suppliers with a stronger incentive (than a revenue cap) to tailor expenditure to changes in demand, such that consumers that value gas supply can continue to benefit from it, in line with s 52A(1)(a) and (b); and

3.517.2 setting cost of capital IMs and a provision for asset lives to better reflect economic lives that align with ex-ante FCM and provide an expectation of normal returns, consistent with s 52A(1)(a) and (d).

Topic 3f – Financeability test in the IMs

Final decision

3.518 Our final decision is to not adopt a financeability test in the IMs.

Problem definition

3.519 In the IM Review process prior to our draft decision, several suppliers submitted that we should adopt a financeability test in the IMs. Their submissions were accompanied by expert reports. After considering these submissions and expert reports, our draft decision was to not adopt a financeability test in the IMs. Suppliers submitted further submissions and expert reports disagreeing with our draft decision.

3.520 We summarise below relevant points put to us before our draft decision[376] and then set out our draft decision. We then summarise relevant points put to us on our draft decision, before setting out our final decision.

[376] 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

3.521 As with the draft decision, the scope of our final decision here is limited to suppliers' recommendation that we adopt a financeability test in the IMs to use when setting a price path. It does not address the full suite of IM policy decisions and mechanisms that may be relevant to the financeability of regulated services.

Stakeholder views provided prior to our draft decision

3.522 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.

3.523 In response to our Process and issues paper and draft IM Decision-Making Framework paper, Aurora, the ENA, Powerco, Vector, and Wellington Electricity 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.[377, 378]

3.524 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."[379]

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).

377 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.

378 As examples of financeability tests, Aurora (Aurora, "Commerce Commission Part 4 Input Methodologies Review 2022 - Process and issues paper" (11 July 2022), at n 22) 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.

379 Vector, "Vector submission on IM Review 2023: Draft Framework Paper" (11 July 2022), para 130.

3.525 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.”[380]

3.526 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. [381] The funding of this expenditure will put pressure on EDBs’ cash flows.” The ENA recommended:[382]

3.526.1 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

3.526.2 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.

3.527 Vector recommended introducing a financeability assessment in line with the approach set out in Oxera Consulting LLP’s (Oxera) report for the Big Six EDBs.[383] 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.

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380 Transpower, “Input Methodologies Review 2023: Cross submission – Draft Framework Paper and Process and issues paper” (3 August 2022), p. 2.

381 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).

382 ENA, “Rate of Return Issues – Submission on IM Review CEPA report on cost of capital” (3 February 2023), p. 20.

383 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).

3.528 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.[384]

3.529 NERA therefore advocated we:[385]

> 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 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.

3.530 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."[386] 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:[387]

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[384] 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.

[385] 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), pp. 2-3.

[386] 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.

[387] 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), pp. 61-62.

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.

Draft decision – no financeability test in the IMs

3.531 Our draft decision was that we did not consider adopting a financeability test in the Part 4 IMs would achieve our IM Review overarching objectives. This was 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. [388, 389]

3.532 We first outlined our understanding of financeability and then explained our reasoning for not adopting a financeability test in the IMs.

3.533 '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.

3.534 While all suppliers can in principle raise debt and equity, their ability to do so in practice will depend on their specific circumstances.

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388 Commerce Commission, "Decision on Aurora Energy's proposal for a customised price-quality path" (31 March 2021).

389 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.

3.535 We considered 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.

3.536 We noted 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.

3.537 In the draft decision, we considered 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).

3.538 However, as noted above, our view was that 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.

3.538.1 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.[390] 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.

3.539 We noted that a practical challenge in testing a regulated supplier's 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.[391]

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390 Commerce Commission, “Decision on Aurora Energy’s proposal for a customised price-quality path” (31 March 2021), at paras G146-G150.

391 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

3.540 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.[392]

3.541 In considering financeability, we indicated we would expect to assess a range of factors, including:

3.541.1 to the extent relevant, the characteristics of the benchmark (efficient) firm in terms of target credit rating and financeability metrics, and the actual firm;

3.541.2 the likelihood and costs of potential underinvestment (harm to consumers' long-term benefit under s 52A);

3.541.3 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

3.541.4 the likelihood and magnitude of additional sources of finance.

Stakeholder views on our draft decision

3.542 In its submission on our draft decision, Wellington Electricity disagreed that we did not need a "formal financeability test in the IMs because [the Commission] can already have regard to financeability if they judge it's needed."

3.543 Wellington Electricity considered a financeability test should not be applied subjectively, but rather, applied consistently and objectively "to ensure that the IMs and the price setting both maintain financeability." Wellington Electricity considered that adopting a financeability test IM would ensure the test is considered consistently and ensure networks are adequately funded and incentivised to invest.[393]

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.

392 Section 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.

393 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 8, 10, 16, 17, and 18.

3.544 Wellington Electricity recommended we develop a benchmark cashflow model to test whether networks will have to increase their equity funding as they invest in new capacity. The model could also be used to test for financeability, and network AMP disclosures could provide the future cashflows needed to develop this model.

3.545 Orion urged us to build financeability into our modelling when setting the next DPP period to ensure EDBs are adequately compensated and financeability issues do not arise, specifically for EDBs who will be required to raise additional debt to fund operations.[394]

3.546 The ENA suggested we "enshrine into the IMs, a test of the equivalence between, the Commission-approved revenue allowances with cashflows that would result in that EDB achieving a BBB+ credit rating."[395]

3.547 The ENA considered:[396]

3.547.1 section 53P(8)(a) provides for us to consider both the impact on consumers of significant price shocks, and the ability of networks to fund investment; and

3.547.2 the financeability of investment must be a core consideration of any regulatory regime, so we must ensure that this is explicitly accounted for in our decision-making.

3.548 Unison could not see "the harm of inserting a financeability or equity issuance test into the IMs. The Commission has confirmed it can, and has, considered financeability (so the only downside appears to be restricting the Commission's discretion by providing certainty that it will be addressed – as envisaged by s 53P(8)(a)). It is also unclear what Part 4 outcomes weigh against providing certainty about alleviating the financial hardship of EDBs, yet balance in favour of certainty to minimise price shocks (also envisaged by s 53P(8)(a))."[397]

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394 Orion "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 11.

395 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 14, and, Electricity Networks Aotearoa (ENA) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 2.

396 Electricity Networks Aotearoa (ENA) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 2.

397 Unison "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 17.

3.549 Unison submitted there is "UK precedent for both using a "benchmark regulated network" to undertake a financeability test and aiming up on the cost of equity."[398] The ENA[399] and PwC for Vector [400] also noted Ofgem and IPART provided precedents for financeability testing.

3.550 Oxera for the Big Six EDBs considered "[the Commission] considers that it should not be concerned about the impact that company-specific decisions have on the companies. However, we explain below that regulatory determinations also play a big role in companies' financeability. Therefore, it is important that the [Commission] looks at the drivers of a financeability problem, if it is identified, and undertakes an assessment of whether any such problems are due to company-specific inefficiencies or suboptimal financial decisions, or if they arise due to low regulatory allowances."[401]

3.551 Oxera and Wellington Electricity considered PQ resets are an appropriate stage to carry out financeability testing, but that we should also consider financeability in IM Reviews given the scope for IMs to impact financeability.[402] Oxera observed: "For example, the cost of capital allowance and its components show whether a benchmark (efficiently run) company would have sufficient profits (determined by the cost of capital allowance) to cover its interest expenses (which are supposed to be broadly aligned with the cost of debt allowance, adjusted for the notional gearing). Where the cost of capital is insufficiently higher than the cost of debt, the benchmark company's interest cover ratio could be too low to raise financing on reasonable terms."[403]

3.552 Oxera submitted that "other reasons why a benchmark company with a regulatory package that follows the NPV = 0 principle may encounter financeability challenges are related to cash-flow misalignments."[404]

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398 Unison "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 17.

399 Electricity Networks Aotearoa (ENA) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 3.

400 PwC "Including a financeability test in Input Methodologies for electricity distribution businesses" (report prepared for Vector, 19 July 2023), p. 8.

401 Oxera "Response to Commission's draft decision for IM Review 2023 on the cost of capital" (report prepared for 'Big 6' EDBs', 19 July 2023), pp. 87-88.

402 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 16-17.

403 Oxera "Response to Commission's draft decision for IM Review 2023 on the cost of capital" (report prepared for 'Big 6' EDBs', 19 July 2023), p. 88.

404 Oxera "Response to Commission's draft decision for IM Review 2023 on the cost of capital" (report prepared for 'Big 6' EDBs', 19 July 2023), p. 88. See also Oxera "Response to Commerce Commission's draft decision for IM Review 2023 on cost of capital" (report prepared for Vector, 9 August 2023), p. 10.

3.553 Powerco recommended the adoption of a "financeability test on a benchmark company that proves the cost of capital settings determined in the IMs will enable the company to maintain the required credit rating throughout each regulatory period. This would ensure EDBs and GPBs receive sufficient funding for decarbonisation and increased electrification".[405]

3.554 Powerco highlighted the following financeability issues raised by Oxera:[406]

3.554.1 If a financeability concern is identified only when revenues are set, the Commission will not be able to use the WACC allowance as a potential remedy.

3.554.2 Two options to overcoming the challenges of running a financeability test at the setting of the price-quality path have been proposed including flexibility in WACC setting methodologies at a price/quality reset and undertaking provisional cashflow forecasts.

3.554.3 Providing equity issuance costs while assuming that dividends are paid is supported by international precedent.

3.555 Powerco considered "a financeability test is one tool to reveal the alignment between allowances for (rapid) investment and ability to fund it (including the impact of price change limits, if any)."[407]

3.556 Frontier Economics for Vector considered that "a model whereby investors are asked to effectively commit to a project before knowing how the regulator will determine whether a financeability problem exists, or how any such problem would be addressed, will be insufficient to support efficient investment".[408]

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405 Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 11.

406 Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 12.

407 Powerco "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 2.

408 Frontier Economics "Regulatory financeability" (report prepared for Vector, 19 July 2023), p. 18.

3.557 To illustrate the above point, Frontier Economics pointed to an approach the Australian Energy Market Commission (AEMC) proposed in which the Australian Energy Regulator would have discretion to accelerate regulatory cashflows in an NPV-neutral manner to address a financeability problem. In its June 2023 Rule Change Request, Energy Networks Australia expressed concern that "if investors cannot be certain that the regulatory framework would properly identify and address financeability problems at the time the regulator makes revenue determinations for actionable ISP projects, then they may decline to commit to such projects or not proceed at all thereby denying consumers the associated benefits and impeding the energy transition".[409]

3.558 Frontier Economics noted an alternative. Energy Networks Australia proposed: "a fully-transparent formulaic approach. This approach sets out a formula that would be used to determine whether or not the annual regulatory allowance would be sufficient to support the regulator's benchmark credit rating at the regulator's benchmark level of leverage."[410]

3.559 PwC for Vector submitted that:[411]

3.559.1 The purpose of the IMs is to promote regulatory certainty as stated in s 52R of Part 4 of the Commerce Act. Regulatory certainty is consistent with the s52A purpose of regulation to provide suppliers and investors' confidence to invest in long-lived regulated infrastructure. Including a financeability test in the IMs is consistent with both of these objectives and aligns with international regulatory practice. Importantly, it complements other proposed changes to the IMs to address cash flow and financeability concerns for electricity distributors in the context of the energy transition.

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409 Frontier Economics "Regulatory financeability" (report prepared for Vector, 19 July 2023), p. 18. See also Energy Networks Australia "Ensuring the Financeability of Actionable ISP Projects" (9 June 2023), p. 2.

410 Frontier Economics "Regulatory financeability" (report prepared for Vector, 19 July 2023), p. 19.

411 PwC "Including a financeability test in Input Methodologies for electricity distribution businesses" (report prepared for Vector, 19 July 2023), pp. 3 and 9.

3.559.2 The decision not to include a financeability test in the IMs because financeability can be considered otherwise is not compelling. The s 52R purpose of the IMs is to promote regulatory certainty. One [of] the largest sources of uncertainty at present is the ability of electricity distributors to fund the investments needed to facilitate the energy transition in Aotearoa New Zealand....Knowing for certain that electricity distribution business financeability is a factor that will be considered when regulated revenue caps are set will provide more confidence to electricity distributors, investors and funders to invest in the long-lived infrastructure necessary to deliver Aotearoa New Zealand's energy transition.

3.559.3 We therefore submit that a financeability test should be included in the IMs to better meet the objectives of the IMs and the Part 4 regulatory framework. Including a financeability test in the IMs would also better give effect to s 53P(8)(a) by ensuring that both the price shock and financial hardship criteria are addressed in the IMs.

3.560 Vector echoed PwC's views above and asked us "as part of [our] final decision [to] categorically set out [our] views on how [we] would both assess whether a financeability problem exists and then go about remedying any such problem. Vector considers that good regulatory practice, taking into account the regime's overarching purpose of promoting certainty, is to do so within an IM that is then binding on [us]".[412]

3.561 Vector likewise considered that adding a financeability test IM "would ensure that regulated suppliers have certainty that the regulatory regime will support the funding requirements so critical to support investment in the energy sector. With the significant investments needed for decarbonisation, having such a test would provide clarity to companies and facilitate the transition to a low-carbon future."[413]

3.562 Wellington Electricity and Orion also endorsed PwC's views above.[414] Orion noted "the industry is facing significant uncertainty and investment need, and that financeability is highly likely to be an issue leading up to 2030. We believe the Commission has a role to ensure financeability from its decision making. We do not believe that appropriate testing is put in place to ensure certainty that EDBs will be able to fund the necessary investment during DPP4." [415]

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412 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 28, and, Vector "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), pp. 19-20.

413 Vector "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 1.

414 Orion "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), pp. 4-6, and, Wellington Electricity "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), pp. 4-5.

415 Orion "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), pp. 4-6

3.563 Transpower and Aurora also disagreed with our draft decision and advocated we introduce a financeability test into the IMs.[416]

Final decision – no financeability test in the IMs

3.564 We have considered submitters' views and decided to confirm our draft decision to not adopt a financeability test in the IMs. We engage with relevant points submitters raised on our draft decision and reasons as follows.

3.565 In response to Wellington Electricity's view that putting a financeability test in the IMs would ensure the test is applied consistently and objectively:[417]

3.565.1 We do not consider that adopting a uniform approach to financeability testing across all circumstances would be consistent with promoting s 52A. As outlined at paragraph 3.538 of our draft decision, we can only consider financeability where it is relevant and not inconsistent with promoting s 52A in a particular context. Hence, whether or not a financeability test was in the IMs, we would still need to establish in each context whether considering financeability was relevant and not inconsistent with promoting s 52A.

3.565.2 Codifying a financeability test in the IMs is not necessarily the same as promoting certainty as to how we would apply and use the information from such a test.[418]

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416 Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 30, and, Aurora Energy "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 1.

417 These points also apply to Vector and Wellington Electricity's suggestions that adopting a financeability test would give regulatory certainty and ensure networks are adequately funded and are incentivised to invest.

418 *Wellington International Airport Ltd and Ors v Commerce Commission* [2013] NZHC 3289, at [362] – [363].

3.565.3 By contrast, our preferred approach of considering financeability where relevant and not inconsistent with promoting s 52A in a particular context has the advantages of letting us consider financeability when appropriate, in a way that is most appropriate to the context – which requires judgement. For example, we considered the net cashflow analysis we did in setting Aurora's CPP was a better indication of Aurora's ability to finance its regulated business than simply assessing a change in revenues.[419] Our preferred approach would give us the flexibility and scope to use a different measure or form of analysis, if appropriate, in a different context.[420]

3.566 The ENA, Unison, and PwC for Vector pointed to s 53P(8)(a) of the Act as justification for adopting a financeability test in the IMs and ensuring the IMs accounted for price shock and financial hardship criteria. We do not consider a financeability test IM is needed to give effect to s 53P(8)(a) or that s 53P(8)(a) envisages us including a financeability test in the IMs. We explain why as follows:

3.566.1 Section 53P(8)(a) permits us to set alternative rates of change for a particular supplier on a DPP as an alternative, in whole or in part, to the starting prices set under s 53P(3)(b) if, in our opinion, this is necessary or desirable to minimise any undue financial hardship to the supplier or to minimise price shock to consumers.

3.566.2 Section 53P(8)(a) provides the basis for setting an alternative rate of change to the DPP starting prices set under s 53P(3)(b). Section 53P(8)(a) is not a general statutory direction requiring us to consider financeability across all our decision making. Unlike s 52T(1), s 53P(8)(a) does not prescribe matters for us to include in the IMs.

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419 Commerce Commission, "Decision on Aurora Energy's proposal for a customised price-quality path" (31 March 2021), para G146-G150.

420 We note our preferred approach of having flexibility and scope to use a different measure or form of analysis, if appropriate, in a different context, aligns with the AER's preferences regarding a mechanism for accommodating financeability in its regulatory framework (see Australian Energy Regulator (AER) "Submission to the Accommodating Financeability in the Regulatory Framework consultation paper" (3 August 2023), pp. 2, 14).

3.567 Oxera for the Big Six EDBs suggested that in approaching financeability we look at the drivers of a financeability problem. Both Oxera and Powerco suggested we assess whether our cost of capital settings are sufficient to enable a supplier to raise finance on reasonable terms. We already apply reasonableness checks in reviewing our cost of capital parameters.[421] However, we consider both suggestions could be relevant to how we approach considering financeability, where we decided it appropriate to do so. The same applies to:

3.567.1 the ENA's suggestion that we test the equivalence between our revenue allowances and cashflows that would result in an EDB achieving a BBB+ credit rating;

3.567.2 Orion's suggestion that we build financeability into our modelling when setting the next DPP; and

3.567.3 the overseas precedents for financeability testing that Unison, the ENA, and PwC for Vector pointed us to – though we would need to take account of differences in the statutory framework.[422]

3.568 Powerco, Oxera and Wellington Electricity suggested we consider financeability not just at a PQ reset, but also in our statutory IM Reviews. If we decided considering financeability was relevant and not inconsistent with promoting s 52A in an IM Review, we could do so.

3.569 Frontier Economics for Vector cautioned against "a model whereby investors are asked to effectively commit to a project before knowing how the regulator will determine whether a financeability problem exists".[423] We do not consider this point or Frontier Economics' example from the AEMC properly reflect how we set a price path under Part 4. Specifically:

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421 For example, see Commerce Commission "Input methodologies review 2023 – Final decision – Cost of capital topic paper" (13 December 2023), Chapter 7.

422 For example, s 3A(2)(b) of the Electricity Act 1989 (UK) imposes a duty on Ofgem to have regard to the need secure that licence holders are able to finance the activities which are the subject of obligations imposed under the relevant legislation. Under the same Act, Ofgem can and does impose conditions on licence holders relating to revenue ringfencing and minimum capital requirements. Part 4 of our Act has no duty equivalent to s 3A(2)(b) of the Electricity Act 1989 (UK) or powers to impose related requirements such as revenue ringfencing and minimum capital requirements.

423 Frontier Economics "Regulatory financeability" (report prepared for Vector, 19 July 2023), p. 18.

3.569.1 We do not set a price path on a project-by-project basis. Rather, our historical practice at DPP resets has been to set a price path using a building blocks approach applying NPV=0 and ex-ante FCM to give the expectation of normal returns. The price path is set for the whole regulatory period and may only be reopened in the circumstances specified in the IMs.[424]

3.569.2 The price path sets a fungible allowable revenue and does not specify the inputs for supplying the regulated service. Both the IMs and the price path are set to promote the outcomes of the Part 4 purpose, including that suppliers have incentives to innovate and to invest, including in replacement, upgraded, and new assets.[425] This, together with the regulatory depreciation settings which determine the time profile of capital recovery, is a clear and strong signal to investors of what they can expect by investing in regulated service providers.

3.569.3 In setting a price path, it would also be open to us to consider financeability where relevant and not inconsistent with promoting s 52A, as outlined in our draft decision.

3.570 PwC for Vector's view outlined above was that adopting a financeability test IM would better promote ss 52A and 52R. PwC suggested that "Knowing for certain that electricity distribution business financeability is a factor that will be considered when regulated revenue caps are set will provide more confidence to electricity distributors, investors and funders to invest in the long-lived infrastructure necessary to deliver Aotearoa New Zealand's energy transition."[426] In addition to the related points set out above, we consider:[427]

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424 Sections 52T(1)(c)(ii) and 53ZB(1) of the Act.

425 Section 52A(1)(a).

426 PwC "Including a financeability test in Input Methodologies for electricity distribution businesses" (report prepared for Vector, 19 July 2023), p. 9.

427 These points also apply to Vector and WE*'s suggestions outlined above that adopting a financeability test would give regulatory certainty and ensure networks are adequately funded and are incentivised to invest.

3.570.1 Section 52R of the Act provides that the purpose of the IMs is to promote certainty in relation to the rules, requirements and processes of Part 4 regulation. Parliament directed us to set IMs on the list of matters in s 52T(1) of the Act, which does not include financeability. As the Courts have previously confirmed, s 52R and the promotion of certainty does not require matters outside s 52T(1) to be specified as IMs;[428]

3.570.2 We exercise our discretion at a PQ reset by setting a price path applying IMs designed to promote certainty under s 52R and by applying NPV=0 and ex-ante FCM to give the expectation of normal returns. We apply reasonableness checks in reviewing our cost of capital parameters.[429] For other matters not covered by the IMs but relevant to PQ setting (opex, quality), we have published frameworks that, while they are not IMs, still make those decisions more transparent to stakeholders and over time improve the predictability of our decisions.[430] Our confirmation that we can already consider financeability where appropriate, in a way that is most appropriate to the context in question, and have done so in the past, provides appropriate certainty for consumers and suppliers;

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428 The IMs do not prescribe how we are set the actual price path for a DPP, CPP or IPP. This is left to our judgement at every PQ reset. This was the subject of challenge when the IMs were first set, where Vector argued that these matters must be dealt with in advance in the IMs. That was rejected by the Court of Appeal and Supreme Court (see *Commerce Commission v Vector* [2012] NZCA 220; [2012] 2 NZLR 525 and *Vector v Commerce Commission* [2012] NZSC 99; [2013] 2 NZLR 445. Quality standards are also not prescribed by IMs but are left to be set at a PQ reset.

429 For example, see Commerce Commission “Input methodologies review 2023 – Final decision – Cost of capital topic paper” (13 December 2023), at Chapter 7.

430 See for example: Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft decision" (29 May 2019), Chapter 3 for the approach to DPP resets generally; paragraphs 5.15-5.29 our approach to setting revenue in the first year of the regulatory period; 7.13-7.28 our approach to quality; and; Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision" (27 November 2019), Chapter 3 for the approach to DPP resets generally; paragraphs 5.15-5.29 for our approach to setting revenue in the first year of the regulatory period; 7.13-7.27 for our approach to quality.

3.570.3 As outlined above at paragraph 3.538 from our draft decision, financeability concerns may relate to the whole firm (eg, credit rating, ownership structure, or ability of the firm to service debt). By contrast, our role under Part 4 is to regulate the price and quality of regulated services,[431] promoting the s 52A(1) outcomes for the long-term benefit of consumers of those services. This does not extend to ensuring the financeability of the business supplying the regulated service, where issues can arise from factors that have nothing to do with Part 4 – for example, poor performance of unregulated business units, or financial management decisions such as excessive dividend payments or excessive leverage. We cannot monitor or address financeability issues arising from the supply of unregulated goods and services and we have no direct control over suppliers' financial management decisions (eg, dividends).[432]

3.570.4 It follows that adopting a mandatory financeability test IM to test for something we cannot properly monitor and regulate:

3.570.4.1 would be unlikely to better promote ss 52A and 52R which relate solely to regulation of the price and quality of a regulated service; and

3.570.4.2 could give suppliers greater scope and incentives to increase short-term cashflows in a way that is potentially not to consumers' long-term benefit.

3.571 Vector requested we "categorically set out [our] views on how [we] would both assess whether a financeability problem exists and then go about remedying any such problem."[433] As noted above, we can consider financeability where it is relevant and not inconsistent with promoting s 52A in a particular context. In the case of the EDB DPP4 reset, for example, the threshold of 'where relevant and not inconsistent with promoting s 52A' is something that we would address and assess in the context of the reset process.

431 Section 52 of the Act.

432 As outlined in n 422 above, this contrasts with Ofgem's statutory duty and powers relating to financeability.

433 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 28.

Chapter 4 Inflation risk

Purpose and structure of this chapter

4.1 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).

4.2 This chapter covers two topics:

4.2.1 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.[434]

4.2.2 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 4a – Method for forecasting inflation

4.3 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 decision on the method for forecasting inflation for the purposes of setting price-quality paths.

Final decision

4.4 Our final 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.

[434] 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.

4.5 This timing falls into three categories:

4.5.1 for forecasting the RAB revaluation rate, 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);

4.5.2 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

4.5.3 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.[435]

4.6 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.

4.7 This section deals principally with the timing of forecasts as they relate to the RAB revaluation rate. The detailed changes about how the revenue path operates during the period are dealt with in Attachment D.

4.8 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

4.9 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:

4.9.1 The market's inflation expectation inherent in the WACC (where the forecast of CPI is being used to forecast revaluations); or

4.9.2 actual inflation (where the forecast is being used to index the RAB or update the revenue path).

4.10 Using the best CPI forecast is particularly important in the current uncertain and volatile inflationary environment.

[435] See topic 4b for our decision to ensure that the most up-to-date CPI inflation (actual and forecast) is used when determining forecast net allowable revenue at the start of each regulatory year.

4.11 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.

4.12 Where there are ex-post CPI wash-ups (including updating the revenue path and 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.

4.13 The market's inflation expectation is unobservable and must be estimated.[436] Our key assumption is that the best estimate of the market's inflation expectation 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).[437]

4.14 Therefore, our objective is to identify the option for forecasting inflation that minimises the difference between forecast and actual inflation over the forecast window.

4.15 Prior to the draft decision, stakeholders had submitted that we should review our approach to CPI forecasting, so it results in more accurate and credible forecasts.

Stakeholder views prior to the draft decision

4.16 ENA:[438]

> 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.

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[436] See discussion from paragraph 4.46 for why relying on market-derived inflation forecasts is an unreliable measure of the market's inflation expectation.

[437] Queensland Competition Authority "Inflation forecasting final position paper" (October 2021), p. 27.

[438] Electricity Networks Aotearoa "Submission on IM Review Process and Issues paper and draft Framework paper" (11 July 2022), p. 12.

4.17 Aurora:[439]

> 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.

4.18 Vector:[440]

> 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.

4.19 Vector submitted a memorandum from Motu, written in 2020 (before the pandemic) that among other things found the following:[441]

> 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.

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439 Aurora Energy "Submission on IM Review Process and Issues paper and draft Framework paper" (11 July 2022), para 51, 52.

440 Vector "Submission on the Process and issues paper" (11 July 2022), pp. 21, 22.

441 Motu "Memorandum: Performance Inflation Forecasting Problem" – 'Submission on IM Review CEPA report on cost of capital' (prepared for Vector, 9 November 2020).

4.20 Subsequently, Vector submitted a March 2023 update to the 2020 Motu memorandum, which stated the following:[442]

> 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.

Draft decision

4.21 Our draft decision was to maintain the status quo: forecasting the CPI for the regulatory period by using the most recently available RBNZ CPI forecasts at the relevant time.

Draft decision reasons

4.22 In our draft decision, we proposed 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.

4.23 Our view was 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 4.13, 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).

4.24 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.[443]

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442 Motu "Update on the Difficulties of Forecasting Inflation. Memorandum to Vector New Zealand from John McDermott" (13 March 2023), p. 2.

443 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.

4.25 For clarity, our draft decision retained a 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 proposed to continue to linearly trend to the midpoint of the RBNZ inflation target band (currently two percent) by the end of the forecasting window.

4.26 We considered 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

4.27 We considered the following alternatives:

4.27.1 RBNZ forecast for Q1 to Q8, then trend to two percent by Q20;[444]

4.27.2 RBNZ forecast for Q1 to Q4, then trend to two percent by Q20;

4.27.3 glide-path that trends to a 'rules-based anchor point' at end of the forecasting window;

4.27.4 market-derived forecasts;

4.27.5 survey-derived forecasts; and

4.27.6 model-derived forecasts.

4.28 Below we expand on each of the alternatives considered in our draft decision and explain the reasons why we proposed to maintain the status quo.

RBNZ forecast for Q1 to Q8, then trend to two percent by Q20

4.29 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.

4.30 The rationale behind using fewer forecasts—stop using Q9 to Q13 forecasts—would be twofold:

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444 Q20 for a five-year regulatory period. It would be Q16 for a four-year regulatory period.

4.30.1 the accuracy of RBNZ's CPI forecasts is highest for Q1 and decreases the further out in time we go.[445] 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

4.30.2 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.[446]

4.31 This option is also consistent with the Australian Economic Regulator's (AER) approach,[447] and largely consistent with the QCA's approach.[448]

4.32 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).

4.33 However, we considered 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.

4.33.1 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.

4.33.2 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.

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445 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.

446 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.

447 Australian Energy Regulator "Final position paper Regulatory treatment of inflation" (December 2020).

448 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).

4.33.3 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).[449]

4.33.4 The RBNZ evidence footnoted in paragraph 4.30.2 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.

4.34 We noted 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.

4.35 However, we expected that, given its statutory mandate and track record, the RBNZ would have 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 4.61).

RBNZ forecast for Q1 to Q4, then trend to two percent by Q20

4.36 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.

4.37 This option more extensively applies the rationale in paragraph 4.30.1, reflecting that short term inflation forecasts are more accurate.

4.38 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).

4.39 We considered that using only four quarters of RBNZ forecasts (Q1 to Q4) when it produces 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 4.61). It would be a material departure from the status quo, and for the reasons at paragraphs 4.23 and 4.24 above, would not promote s 52A as well as the status quo if it resulted in greater differences between forecast and actual inflation.

449 Reserve Bank of New Zealand "Monetary Policy Statement" (February 2023), p.57.

Glide-path that trends to a 'rules-based anchor point' at end of the forecasting window

4.40 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.

4.41 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:[450]

4.41.1 less than or equal to two percent, the anchor point could be set at 2.25 percent;

4.41.2 between two percent and three percent, the anchor point could be set at 2.5 percent; and

4.41.3 greater than or equal to three percent, the anchor point could be set at 2.75 percent.

4.42 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.

4.43 We noted that Frontier Economics considers "the QCA approach is the best available method for determining the regulatory inflation parameter".[451]

4.44 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.

4.45 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 continued 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

4.46 This option would use bond yield data and inflation swap data to derive inflation expectations.

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450 Queensland Competition Authority "Inflation forecasting final position paper" (October 2021), p. 36.

451 Frontier Economics "Return on capital, inflation and financeability" (11 March 2022), para 167.

4.47 Conceptually, inflation expectations derived from market data should accurately reflect investors' true inflation expectations.

4.48 The QCA's recent review of inflation forecasting has a helpful explanation of the two market-based methods – bond breakeven and inflation swaps:[452]

> 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.[453]
>
> 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.[454] For example, the 10-year inflation swap rate measures market expectations of average inflation over the next 10 years.

4.49 While this approach is conceptually appealing, we ruled this option out for the following reasons.

4.49.1 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.[455] Specifically:

4.49.1.1 yields on nominal government bonds can include a premium for bearing inflation risk which can distort the implied inflation forecast; and

4.49.1.2 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.

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452 Queensland Competition Authority "Inflation forecasting final position paper" (October 2021), p. 18.

453 The Fisher equation outlines the relationship between the nominal interest rates, expected inflation and real interest rates.

454 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.

455 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.

4.49.2 The more recent Australian evidence we are aware of has confirmed the above two issues, in addition to many others.[456]

4.50 We noted that while the reasons outlined below, used in the last IM Review to discard this option, did not seem to apply as strongly now, our judgement was that the above reasons still justified rejecting this option, on balance.

4.50.1 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.

4.50.2 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.

4.51 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. [457] This methodology is prescribed for the purposes of valuing long-term assets and liabilities on the Crown balance sheet.[458] 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.[459]

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456 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.

457 Vector Communications "Submission to the Commerce Commission Fibre Input Methodologies Project" (28 January 2020), para 54.

458 The Treasury "CPI inflation assumption review for 30 June 2021" (5 July 2021).

459 Section 26W(3)(a) of the Public Finance Act 1989.

4.52 An additional reason for not relying on market-derived forecasts was 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.[460]

4.53 We noted that, as we understood it, the RBNZ inflation forecast is not purely model driven, so it does include market data to the extent that the Monetary Policy Committee and forecast team consider it relevant.[461]

4.54 We responded to Vector/Motu's points, which they used to support a change to a market-based method. For the reasons below, we were not persuaded by these submissions.

4.55 In its 2020 memo, Motu stated that the market-implied method performed better than the alternatives.[462] Looking at the evidence presented in that memo (figures 2 and 3), we noted the following:

4.55.1 We agreed 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 did not know whether – or the extent to which – the RBNZ forecasts were included, which is what our status quo method uses.

4.55.2 From looking at these figures, it was not clear to us which method performed better in the period 2016 to 2020. We understood 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).

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460 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).

461 Reserve Bank of New Zealand Te Putea Matua (2020) "Monetary Policy Handbook", version 2, 1 September, p. 53.

462 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.

4.56 In its 2023 memo, Motu submitted that all forecasting methods delivered poor performance.[463] It no longer supported the market-derived method, and it provided no new or updated evidence on their relative performance. We considered 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.

4.57 Finally, Motu also submitted that "inflation expectations have become unanchored". This point was important to us 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 differed materially from two percent, and this resulted in inflation outcomes that were also materially different from two percent, then this would be a weakness of the current method. We provided the latest data at the time on inflation expectations from RBNZ:[464]

> 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.
>
> 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.

4.58 Looking at this evidence, we agreed that one and two-year ahead inflation expectations were above the two percent target (although the two-year ahead one had returned to within the target band of one percent to three percent), but five and 10-year-ahead ones were closer to two percent rather than three percent. Our reading of the data was that, rather than a "broken businesses' belief in price stability"[465] and inflation expectations becoming fully unanchored, businesses expected 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).

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463 Motu "Memorandum: Update on the Difficulties of Forecasting Inflation"(prepared for Vector, 13 March 2023).

464 Reserve Bank of New Zealand "Survey of expectations (Business) - April 2023" (12 May 2023), p. 1.

465 Motu "Memorandum: Update on the Difficulties of Forecasting Inflation"(prepared for Vector, 13 March 2023), p. 3.

4.59 To conclude, we considered that it is possible that over any given period, one or other method will, ex post, have more accurately predicted past inflation. However, we saw no evidence that, ex ante, any of the other methods were 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

4.60 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.[466] We also included within this option professional forecasters (eg, banks).

4.61 There is evidence that RBNZ forecasts for one and two years ahead are as good or better than those of non-RBNZ forecasters:[467, 468]

> 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'.
>
> …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.

4.62 Furthermore, we understood that RBNZ uses survey information to inform its model-based inflation forecasts.[469]

4.63 Beyond the RBNZ's forecasting horizon (currently 13 quarters ahead), survey-derived inflation expectations remained anchored around the two percent midpoint.[470] Therefore, there was likely to be little difference between the status quo and using this survey data.

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466 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"

467 Reserve Bank of New Zealand "Evaluating the Reserve Bank's Forecasting Performance" (November 2022), p. 21.

468 Reserve Bank of New Zealand "Evaluating the Reserve Bank's Forecasting Performance" (June 2016), p. 10.

469 Gunes Kamber, Chris Mcdonald, Nick Sander and Konstantinos Theodoridis "A structural model for policy analysis and forecasting: NZSIM" (November 2015). s 5.

470 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"

Model-derived forecasts

4.64 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).[471]

Stakeholder views on the draft decision

4.65 Below we present the main submission points and alternatives to our draft decision that stakeholders proposed.

4.66 The ENA submitted that "this single-point forecast risk can easily be mitigated by averaging the RBNZ forecast with a second forecast of inflation derived from the market expectation of inflation."[472] It considered that we should reassess our draft decision on the inflation forecasting method.

4.67 GasNet submitted that the Commission should: [473]

> revise how it deals with inflation, similar to recent approaches adopted by the Australian Energy Regulator (AER) and the Queensland Competition Authority. Regulation needs to be predictable and provide certainty, which may require the NZCC to be more flexible to ensure long term outcomes for consumers.

4.68 Vector, drawing on an expert report from Motu, submitted that forecasting inflation "even a few months ahead, is challenging. Knowing where inflation will be over the next five years Is immense. The problem is particularly acute now {given] the secular forces whose impact on inflation is very uncertain, if not unknowable". Vector proposed that "the materially better approach would be to dispense with indexation altogether", a view that it repeated in its cross-submission.[474]

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471 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).

472 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 14.

473 GasNet Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 8.

474 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 32-33.

4.69 Motu (for Vector) submitted that "the RBNZ only provides a genuine inflation forecast six months ahead. The remaining 30 months of their projections reflect an assumed transition to two percent. The RBNZ always shows inflation heading to two percent, irrespective of the circumstances."[475] Motu proposed the following:

> Rather than use the Reserve Bank forecasts, a more valid regulatory approach would be to remove the inflation uncertainty altogether. The first best option is to stop indexing of RAB to forecast inflation and leave the RAB not linked to any inflation forecast. Such a change would remove a great deal of unnecessary uncertainty from the process, improving future incentives for investment.
>
> Of course, inflation forecasts would still be required for other smaller areas, such as how to inflate operational expenditure over the regulatory period. But even here, mindlessly adopting an approach designed for creating policy options seems problematic, and better choices are available. For example, survey measures of inflation can be used to improve the Reserve Bank Forecasts.

4.70 Transpower agreed with our draft decision to maintain the status quo method for forecasting inflation.[476]

4.71 Wellington Electricity considered that more work needs to be done to explore better forecast methods, or methods of removing the need to forecast inflation. They also submitted the following:[477]

> We disagree with the proposed approach of using a mechanical glide path which is shown to return to the long-term average quicker than past inflation movements. We think that a market expectation of inflation forecast should be used to inform the glide path period that the RBNZ forecast doesn't cover. While we recognise the weaknesses in using this as a primary forecasting tool, we think a market expectation of inflation would provide a more accurate prediction of the later forecast years that the RBNZ does provide, than simply applying linear glide path assumption.

4.72 Alpine Energy submitted:[478]

> The Commission's draft decision is to retain the current inflation forecasting method risks generating significant forecasting errors and is unlikely to be fit for purpose. Using the best CPI forecast is particularly relevant now due to the uncertainty in the current economic climate.
>
> We suggest the Commission further explores and tests various alternative approaches in forecasting CPI, especially the glide-path and survey approaches in estimating long term inflation projections. There are various alternatives that the Commission can consider as applied by regulators overseas.

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475 Motu "July 2023 memorandum on inflation forecasting" (report prepared for Vector, 19 July 2023), pp. 1-3.

476 Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 32.

477 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 23.

478 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 25-29.

> A survey approach will de-risk the reliance of a single point forecast and ranks highly in terms of relative congruence as professional forecasters invest substantial time and effort to ensure their models track changes in information relating to the formation of inflation expectations. Further, a combination of a survey approach and a glide-path could also be considered as an alternative, similar to the Commission's approach in estimating the TAMRP.

Analysis and final decision

4.73 As we explained in the draft decision, we need to use forecasts of inflation for ex-ante indexing the revenue path and forecasting RAB revaluation gains when the RAB is indexed to inflation (which is a separate decision to this one).

4.74 We partially agree with Alpine Energy that "[d]iscrepancies between actual inflation and the Commission's expected inflation puts pressure on EDBs financeability metrics as it will mean funding the delta until the revenue wash-up can be realised." [479] We note that discrepancies can also provide windfall gains to suppliers until the revenue washup takes effect. As we mentioned in the draft decision and in paragraph 4.12, a forecast that is close to outturn also minimises the size of any overpayment by consumers, which contributes to price stability, a factor that consumers tend to value. Hence the importance of having accurate inflation forecasts.

4.75 Submitters proposed some alternatives to our draft decision, but none of them presented evidence showing that their preferred alternatives would provide a better forecast of inflation – being one that minimises the difference between forecast and actual inflation over the relevant forecast window.

4.76 Submitters mentioned market-based and survey-based methods as alternatives. As mentioned in paragraph 5.51 of the draft decision, the RBNZ inflation forecast is not purely model driven, it does include market data —and other data including survey data—to the extent that the Monetary Policy Committee and forecast team consider it relevant. We understand that this includes beyond six months ahead.

4.77 In relation to submitters' point about adopting the forecasting method that the AER or QCA have adopted, no submitter provided evidence that their methods would perform better than our method in New Zealand.

4.78 Having considered submissions, we consider that confirming the draft decision as our final decision is likely to better promote the overarching objectives of the IM Review than alternatives put to us.

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479 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 25-29.

Topic 4b – Inflation risk allocation and compensation

Final decisions

4.79 Our final decisions are to:

4.79.1 make no change to the EDB and GTB IMs to introduce a cost of debt wash-up (CODW) and instead maintain the status quo under the current IMs;[480]

4.79.2 confirm our draft decision to amend the EDB IMs and GTB IMs to wash-up allowable revenue for the first year of a regulatory period when inflation differs from expected inflation;[481] and

4.79.3 confirm the change we proposed to our draft decision (in our further consultation) to the EDB and GTB IMs to ensure that the most up-to-date CPI inflation (actual and forecast) is used when determining forecast net allowable revenue at the start of each regulatory year.[482]

Problem definition

4.80 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, consistent with s 52A(1)(a) and (d).[483]

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480 As with our draft decision, our final decision on the CODW only concerns the EDB IMs and GTB IMs. As we noted in our draft decision, the GDB IMs and Transpower IMs do not require amendments to enable us to introduce a CODW, which in both cases could be done as a decision we make in resetting the relevant PQ path, if we decided that doing so would better promote the Part 4 purpose (see Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), at n 344).

481 As with our draft decision, our final decision to amend the IMs to wash-up allowable revenue for the first year of a regulatory period only applies to the EDB IMs and GTB IMs. As we noted in the draft decision, this has not been an issue for GDBs because we have set their allowable notional revenue for the first year using lagged actual inflation. Likewise, no IM change is needed to provide for this in the case of Transpower as the Transpower IMs would allow us to do so at the reset, if we decide at that point that it would promote the Part 4 purpose (see Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), at para 5.95).

482 Commerce Commission "Input methodologies review 2023 – Further consultation on IM Review draft decision on the CODW of EDBs and GTBs" 29 September 2023, para 11.

483 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]).

4.81 As mentioned in topic 4a (method for forecasting inflation), we use inflation forecasts in our regulatory regimes for ex-ante indexing the revenue path (price path for GDBs) and forecasting RAB revaluation gains (for EDBs and GPBs, and for Transpower from RCP4 under our RAB indexation decision in topic 3a). We then annually wash up the revenue path (price path for GDBs) for actual inflation (for Transpower, currently we only partially wash up for actual inflation on opex and capex only, which does not fully compensate Transpower for unexpected inflation. See the third finding below) and roll forward the RAB (for EDBs and GPBs, and for Transpower from RCP4) also using actual inflation. Therefore, the intention is that the regime insulates consumers and suppliers from the risk that inflation forecast and outturns differ – consumers face prices that are constant in real terms and suppliers (equity and debt holders combined) earn the expected real normal return, which supports the expectation of real FCM.

4.82 The unexpected increase in inflation since the last IM Review has sharpened our and stakeholders' focus on the way our regulatory regime assigns inflation risk between suppliers and consumers.[484]

4.83 We reviewed the annual revenue wash-up process and made four main findings (outlined below), which our final decisions are based on:

[484] Note that when we discuss 'inflation' throughout this Chapter we are referring to economy-wide CPI inflation.

4.83.1 The first finding was that the effect of our revenue wash-ups on suppliers' financing costs depends on their financing choices - which we refer to as 'debt management choices'.[485] To explain, our approach to indexing the RAB together with setting a nominal WACC effectively sets a real WACC at the beginning of the regulatory period.[486] Using the building blocks model, this produces an ex-ante revenue allowance for the period that targets a real return (ie, equal to the real WACC). Subsequently, we annually wash up allowed revenue for actual inflation.[487] This maintains the real value of allowed revenues to suppliers (and prices to consumers) and delivers a real return during the regulatory period. While the wash-up adjusts the revenue side, we do not recalculate the building blocks costs side – the WACC and its underlying risk-free rate. The effect on suppliers' financing costs depends on their debt management choices. Given inflation outturns, the returns that equity holders receive will be driven by these debt management choices (we referred to the effects on suppliers as 'windfall gains and losses' in earlier consultations in this IM Review process).

4.83.1.1 For example, if a supplier fully fixes the nominal risk-free rate component of the cost of debt for the length of the regulatory period, and actual inflation is higher than forecast, then its equity holders will receive higher real returns. This is because the revenues it receives are fully adjusted for higher actual inflation, while the debt costs it faces remain the same (at the lower level at which it hedged, consistent with the lower expected inflation at that time). Conversely, if a supplier issues inflation-indexed bonds or uses floating debt, then its equity holders' real returns will be broadly unchanged when actual inflation is higher than expected.[488] This is because the debt costs it faces will more closely track inflation, as will the revenues.

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485 This is related to the 'debt compensation problem' which we considered in the 2016 IM Review.

486 We do this by applying a nominal WACC to an inflation-indexed RAB which, ex-ante, is revalued using forecast inflation. These forecast revaluations are deducted from allowed revenues to avoid double compensation for inflation.

487 The RAB inflation wash-ups (ie rolling it forward using actual instead of forecast inflation) also affects revenue, but not until the following PQ reset, so it takes longer to affect revenue than the annual revenue wash-up.

488 Transpower has issued inflation-linked bonds in the past, see: Bloomberg "Transpower Markets NZ$75 Million of Inflation Notes" (19 April 2010).

4.83.2 The second finding of our review is that we do not wash-up EDB and GTB revenue for inflation in the first year of a regulatory period. 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.[489] This has not been an issue for GDBs because we have set their allowable notional revenue for the first year using lagged actual inflation.[490]

4.83.3 The timing of the revenue and RAB wash-ups is not immediate. Therefore, to the extent that actual inflation differs from forecast, there is a risk of overpayment by consumers or financial pressure for suppliers until the wash-ups take effect. As part of our further consultation on the cost of debt wash-up we found that we could use more up-to-date consumer price index (CPI) information (actual and forecast) when determining forecast net allowable revenue at the start of each regulatory year.

4.83.4 The third finding was that we do not wash-up Transpower's revenue, nor adjust its RAB, for actual inflation. Currently, a partial wash-up is made for actual inflation on opex and capex only, which does not fully compensate Transpower for unexpected inflation.

4.83.5 The fourth finding was that the IRIS mechanism can provide positive or negative incentive amounts for cost changes that are not within suppliers control (ie, due to economy wide inflation).

Draft decisions

4.84 Our draft decisions were to amend the EDB IMs and GTB IMs to:

4.84.1 address the first issue by introducing a CODW to exclude from the annual revenue wash-up the difference between:[491]

4.84.1.1 the return on debt for the year (including forecast inflation); and

4.84.1.2 the return on debt for the year updated for actual inflation;

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[489] As discussed in [Incenta Economic Consulting "Options to address the gap in CPI inflation correction" (report prepared for Chorus, 11 July 2022)].

[490] Clause 3.1.1(2)(a) and Schedule 4 of the Gas Distribution Services Default Price-Quality Path Determination 2022 [2022] NZCC 19.

[491] Our draft decision noted that the GDB IMs and Transpower IMs do not require amendments to enable us to introduce a CODW, which in both cases could be done as a decision we make in resetting the relevant PQ path, if we decided that doing so would better promote the Part 4 purpose (see Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), n 344).

4.84.2 address the second issue by washing-up allowable revenue for the first year of a regulatory period when inflation differs from expected inflation.[492]

4.85 To address the third issue of the inconsistency we found in the regulatory treatment of Transpower versus EDBs in terms of inflation risk exposure at a RAB level and at a revenue level, our draft decision:[493]

4.85.1 outlined an adjustment that would be needed at the revenue level to address the inconsistency for Transpower; and

4.85.2 was that, 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 put forward two alternatives to our draft decision that could be adopted if, after taking account of submissions on our draft decision to index Transpower's RAB, we decided doing so would better achieve our Framework's overarching objectives.[494]

4.86 To address the fourth issue we found relating to the IRIS mechanism and costs that are uncontrollable due to inflation, our draft decision at Topic 4c proposed amendments to the EDB IM and Transpower IMs to calculate the opex and capex incentive amounts based on IRIS allowances (adjusted for actual CPI) compared with actual expenditure.[495]

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492 Our draft decision to amend the IMs to wash-up allowable revenue for the first year of a regulatory period applied only to the EDB IMs and GTB IMs. As we noted in the draft decision, this has not been an issue for GDBs because we have set their allowable notional revenue for the first year using lagged actual inflation. Likewise, no IM change is needed to provide for this change in the case of Transpower as the Transpower IMs would allow us to do so at the reset, if we decide at that point that it would promote the Part 4 purpose (see Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), para 5.95).

493 Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), para 5.102-5.112.

494 Our draft decision noted that the current Transpower IMs would allow us to provide for the RAB inflation wash-up and the revenue adjustment in the IPP as EV account entries for the purpose of the forecast EV adjustment, if we decided at that point that it would promote the Part 4 purpose. The RAB inflation wash-up would not be a revaluation. See Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), para 5.109.

495 Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), Topic 4c - Adjust IRIS allowances for inflation, para 4.135-4.161. This is Topic 5c of this paper.

Draft decision reasons

Stakeholder views prior to our draft decision

4.87 We raised the issues related to inflation in Chapter 5 of the Process and issues paper.[496] Submissions in response raised two main concerns.

4.88 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.

4.88.1 Frontier's report for Transpower explained that the cashflow allowance to EDBs and GPBs can, under certain circumstances, be insufficient to pay the full amount of interest each year.[497]

4.89 Suppliers submitted that this is a debt compensation issue associated with the current treatment of EDBs and GPBs (ie, inflation indexation of the RAB). We considered that the debt compensation issue only arises when inflation is less than expected.

4.90 As we explain later in this section, in our draft decision we considered that the current annual revenue wash-up could be improved because it created excessive variation in net cashflows (windfall gains and losses) and was inconsistent with the assumption that suppliers can hedge the risk-free rate component of the cost of debt for the regulatory period. We considered our proposed change would also mitigate the debt compensation issue.[498]

4.91 The debt compensation issue has been used as an argument for unindexing EDBs' and GPBs' RABs to inflation, in line with the current treatment of Transpower's 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.[499] However, for the draft decision we considered that our proposed change to the annual revenue wash-up dealt with the debt compensation issue and better achieves our IM Review overarching objectives.

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496 Commerce Commission "Part 4 Input Methodologies Review 2023 Process and issues paper" (20 May 2022), para 5.184-5.225.

497 Transpower NZ Ltd "Submission on IM Review Process and issues paper and draft Framework paper" (RAB indexation –11 July 2022), pp. 8-9.

498 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.

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

4.92 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.[500] 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.

4.93 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).

4.94 We summarised points raised by submitters and discussed and made draft decisions on them in topic 3a, rather than in this section.

4.95 Our draft decisions were based on our Findings 1 to 4 outlined above and discussed below, and in each case involved:

4.95.1 considering our previous decisions and reasoning;

4.95.2 developing a demonstration model to show how NPV=0 is achieved under the different regulatory accounting methods considered in this section; and

4.95.3 assessing our proposed solutions against our IM Review decision-making framework.

4.96 We published the demonstration model used for the draft decisions on our website.

Finding 1. The annual revenue wash-up for PQ-regulated suppliers can create windfall gains/losses (debt compensation issue)

4.97 Our first finding in the draft decision was that the annual revenue wash-up for inflation can cause PQ-regulated suppliers to earn excess revenue when inflation is higher than expected and have a revenue shortfall when inflation is lower than expected.

4.98 We highlighted the issue of debt compensation in our Process and issues paper.[501]

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500 Our proposed change to the annual revenue wash-up would be required irrespective of the form of indexation applied to suppliers (eg, full indexation, hybrid indexation or no indexation).

501 Commerce Commission "Part 4 Input Methodologies Review 2023 Process and issues paper" (20 May 2022), para 5.195.

4.99 As we assume debt costs can be 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, to the extent that their debt management was as assumed. In that situation, the annual revenue wash-up could create a cashflow concern.[502]

4.100 There would be no cashflow concern (but rather over-compensation) when inflation is higher than predicted, because in that situation the annual revenue wash-up would create excess revenue (again, to the extent that their debt management was as assumed). This is because debt costs would be fixed in nominal terms but the annual revenue wash-up in effect assumes debt costs are variable.

4.101 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.[503]

4.102 However, during the current regulatory period, inflation has been higher than expected and this may result in overcompensation for EDBs and GPBs.[504]

4.103 We calculated the net effect for Vector over the period 2015-16 to 2021-22 was -$3 million. Based on the latest Reserve Bank forecasts, the net benefit to Vector over the period 2022-23 to 2024-25 is forecast to be $166 million.[505]

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502 In the extreme this could give rise to bankruptcy which 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.

503 Frontier Economics "Regulatory inflation and return on debt allowances: Note prepared for New Zealand Commerce Commission" (17 May 2021), p. 3, 4. Frontier is not explicit in its analysis on the extent to which it assumed that suppliers fixed their nominal cost of debt at the beginning of the regulatory period. We understand that it made this assumption in estimating these losses.

504 However, offsetting this, 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 5c for our proposal to change the IRIS mechanism from nominal to real).

505 In the draft decision there was a typing error on the dates. It read "the net benefit to Vector over the period 2015-16 to 2024-25 is $166 million", while it should have read "the net benefit to Vector over the period 2022-23 to 2024-25 is $166 million. See Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), at para 5.87. In this analysis we have assumed that Vector fixed its debt costs in nominal terms.

4.104 Our view at the draft decision was 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 noted the submission by Frontier Economics which proposed we change the IMs to address this inconsistency.[506]

4.105 We also noted Competition Economist Group's (CEG) report to Vector, which indicated 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.[507]

4.106 In addition to CEG's point that suppliers cannot hedge their portfolios to the real return, there were two other reasons why we considered this issue needed to be addressed (for the next PQ reset). The first was because it can cause windfall gains and losses. The second was that it is possible over time that the under and over-compensation may not balance out. We noted in our draft decision that 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.

4.107 For the draft decision, we proposed amending the IMs for EDBs and the GTB to include a CODW to adjust the annual revenue wash-up to account for debt servicing costs being fixed in nominal terms. No IM change was needed to provide for this in the case of Transpower and GDBs, as their IMs would already permit us to do so at the IPP and DPP reset, respectively,[508] if we decided at that point that it would promote the Part 4 purpose.

4.108 The proposed CODW would mean that 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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506 Frontier Economics "Regulatory inflation and return on debt allowances" (note prepared for New Zealand Commerce Commission, 17 May 2021), pp. 5-6.

507 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.

508 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).

4.109 Conversely, when inflation is lower than expected, the annual revenue wash-up would not decrease revenue for the entire amount of inflation.

4.110 The proposed change was designed to protect suppliers that fix their debt in nominal terms 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

4.111 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 in Chorus' submission, where the first year of the regulatory period for Chorus's fibre PQ path happened to coincide with a year of unexpectedly high inflation.[509] This has not been an issue for GDBs because we have set their allowable notional revenue for the first year using lagged actual inflation.[510] As with finding 1, no IM change was needed to provide for this in the case of Transpower as the IMs would allow us to do so at the reset, if we decided at that point that it would promote the Part 4 purpose.

4.112 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.

4.113 However, this has highlighted that a supplier faces the risk that our inflation forecasts result in years when inflation is much higher than expected.

4.114 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).

4.115 In the draft decision, we proposed 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 (or if it drops unexpectedly), EDBs and the GTB would have their revenue adjusted.

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509 As discussed in Incentia Economic Consulting "Options to address the gap in CPI inflation correction" (report prepared for Chorus, 11 July 2022).

510 Clause 3.1.1(2)(a) and Schedule 4 of the *Gas Distribution Services Default Price-Quality Path Determination 2022* [2022] NZCC 19.

4.116 We noted 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.[511] This option was 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 agreed 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

4.117 Our third finding for the draft decision was 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.

4.118 At the revenue level, we outlined at paragraph 4.125 the adjustment that would be needed under our draft decision to address this inconsistency.

4.119 At the RAB level, we explained in the draft decision that 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 explained in this section of our draft decision what would need to change if, after taking account of submissions, we decided it would better achieve our IM Review overarching objectives to adopt:

4.119.1 Alternative A (more favoured): as outlined at paragraph , under this alternative, we would delay RAB indexation to start from RCP5 onwards and implement for RCP4 a RAB inflation wash-up.

4.119.2 Alternative B (less favoured): as outlined at paragraph 3.56.2, under this alternative, we would retain the status quo (not indexing Transpower's RAB) and implement for RCP4 the RAB inflation wash-up.[512]

4.120 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.

511 Incenta Economic Consulting "Options to address the gap in CPI inflation correction" (report prepared for Chorus, 11 July 2022), s 4.3.

512 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.

4.121 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. [513]

4.122 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"[514]

4.123 Inflation has since turned out to be more variable than expected. There are now significant consequences for Transpower for not washing-up inflation.

4.124 Transpower had not submitted on this matter prior to the draft decision.[515]

4.125 To address the 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, we considered the adjustments that would be needed were:

4.125.1 a wash-up for Transpower's RAB for actual inflation; and

4.125.2 an annual revenue wash-up.

4.126 No IM change would be needed to provide for either of these as the Transpower IMs would already permit us to do so at the IPP reset, [516] if we decided at that point that it would promote the Part 4 purpose.

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513 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.

514 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.

515 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.

516 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.

4.127 We demonstrated in our modelling for the draft decision, which we 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.[517] 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.

4.128 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 $610 million to Transpower (the RAB would have been higher with a wash-up). By contrast, in RCP2, actual inflation was lower than forecast, so the estimated effect was approximately positive $120 million to Transpower.[518]

4.129 As we noted in topic 3a of our draft decision, 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)). However, for the reasons we discussed in topic 3a, we considered our draft decision (to index Transpower's RAB with effect at the RCP4 reset) was 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

4.130 Our fourth finding was that the current opex IRIS mechanism for Transpower and EDBs, and current capex IRIS for EDBs, penalised suppliers for costs incurred that are uncontrollable due to inflation.[519] We addressed this issue in topic 5c of the draft decision for EDBs and Transpower.

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[517] 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.

[518] 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. It is calculated by dividing the forecast closing RAB for DPP2 and DPP3 by the forecast CPI index and multiplying it by the actual or updated forecast CPI index as at October 2023.

[519] Transpower's capex incentive mechanisms already take actual CPI into account in the incentive calculations.

Stakeholders' views on draft decisions

4.131 Submitters raised issues with our proposal to introduce the CODW. The main concerns were that, under certain circumstances, the cost of debt adjustment we proposed could create significant volatility in annual revenue and add to cashflow sufficiency concerns (Competition Economists Group (CEG) for the Energy Networks Association (ENA) and CEG for Vector Limited (Vector)).[520]

4.132 In their submission, CEG (for Vector) submitted that they did not consider that our proposal was NPV=0.[521] CEG for the ENA (and repeated in CEG for Vector) proposed two alternative solutions: [522]

4.132.1 First proposed option

Simply don't escalate the debt portion of the RAB by inflation at all (either within the financial model or the RAB roll-forward model) so there is no forecast error to correct; or

4.132.2 Second proposed option

Apply the same forecast inflation used in the financial model in the RAB roll-forward model for the debt portion of the RAB

4.133 Wellington Electricity,[523] Vector,[524] Chorus,[525] ENA[526] supported our proposed change to the EDB IMs and GTB IMs to wash up revenue for inflation in the first year of a regulatory period.

4.134 Submissions received on the draft decision to wash-up Transpower's RAB for actual inflation and to introduce an annual revenue wash-up are summarised and discussed in topic 3a (from paragraph 3.91) rather than in this section.

4.135 Submissions received on the draft decision to adjust IRIS allowances for actual CPI are summarised and discussed in topic 5c (from paragraph 3.91) rather than in this section.

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520 Competition Economists Group for the Electricity Networks Association "Response to 2023 IM draft decision on cost of capital" (July 2023), section 6; and Competition Economists Group for Vector "NZCC proposed approach to targeting a nominal return on debt" (August 2023), section 2.

521 CEG "Approach to targeting nominal return on debt" (report prepared for Vector, 9 August 2023), pp. 12-13.

522 Competition Economists Group for the Electricity Networks Association "Response to 2023 IM draft decision on cost of capital" (July 2023), para 221.

523 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 3.3.2.2.

524 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 172.

525 Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 12.

526 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 5.2.

Further consultation relating to the CODW

4.136 After taking account of submissions on our draft decision, we published a consultation paper seeking further feedback on two changes that related to the CODW we proposed in our draft decision, and the way it interacts with the overall revenue wash-up for actual inflation during the regulatory period (further consultation).[527]

4.137 In the further consultation paper, we agreed with submissions on the draft decision that changes to the draft wash-up mechanism as a whole could further reduce volatility and mitigate cashflow delays.

Our further consultation proposed two changes to our draft decision

4.138 In the further consultation, we proposed revising our draft decision on the CODW with two further changes to the EDB and GTB IMs (revised draft decision):

4.138.1 a change to ensure all of the most up-to-date consumer price index (CPI) information (actual and forecast) is used when determining forecast net allowable revenue at the start of each regulatory year; and

4.138.2 changes to smooth the accumulation of the CODW.

4.139 We considered both of these changes would achieve our framework's overarching objectives by better promoting the s 52A(1)(a) limb of the Part 4 purpose. The changes would do so by mitigating cashflow and revenue volatility concerns about the revenue and CODW, identified by stakeholders in submissions on our draft decision.

Alternatives considered to address concerns raised about our draft decision

4.140 In the further consultation, we considered the two alternatives proposed by submitters (hybrid RAB indexation and indexation based on forecast inflation for the debt portion of the RAB), as well as a modified version of one of these alternatives (blended CPI approach). We assessed these alternatives against our Framework, including:

4.140.1 the economic principle of ex-ante real FCM in relation to the RAB which gives suppliers the opportunity to earn a normal return on their efficient investments, consistent with s 52A(1)(a) and (d); and

4.140.2 achieving NPV=0 in relation to net revenue (related to ex-ante real FCM), which is also consistent with s 52A(1)(a) and (d).

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[527] Commerce Commission "Input methodologies review 2023 – Further consultation on IM Review draft decision on the cost of debt wash-up of EDBs and GTBs" (29 September 2023).

4.141 For the reasons explained in our further consultation paper, we concluded that our revised draft decision (incorporating the two amendments at paragraph 4.138) was preferable to the alternatives in terms of achieving our Framework's overarching objectives.[528, 529]

Stakeholder views on our further consultation

4.142 CEG for the Big Six EDBs submitted that our options in the draft decision and further consultation paper would impose costs on suppliers because they would have to try to align their debt management practice with our assumptions. CEG also submitted that these debt management costs would be greater under our preferred washup option than under the blended CPI option.[530]

4.143 CEG submitted that our options in our further consultation paper do not achieve NPV=0 because they do not account for any unexpected debt associated with investment being financed at the prevailing cost of debt rather than the cost of debt expected at the reset.[531]

4.144 CEG proposed a modification to the blended CPI option that:[532]

4.144.1 washes up revenue for the full amount of inflation, which is a higher amount than the blended CPI when outturn inflation is higher than forecast (lower amount when outturn inflation is lower than forecast);

4.144.2 adjusts the RAB at the reset for a lesser amount than the blended CPI when outturn inflation is higher than forecast (higher amount when outturn inflation is lower than forecast); and

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528 Commerce Commission "Input methodologies review 2023 – Further consultation on IM Review draft decision on the cost of debt wash-up of EDBs and GTBs" (29 September 2023), para 42-55.

529 Alongside our further consultation paper, we published an extended version of the demonstration model we published with the draft decision to reflect our preferred option (the revised draft decision) and the other options we considered to smooth the accumulation of the CODW (see Commerce Commission "Input methodologies review 2023 - Risks and incentives: Demonstration model: Inflation wash-up options to account for the fixed cost of debt" – 29 September 2023).

530 CEG "'Targeting a nominal cost of debt' - Submission on specific matters for the IM Review 2023 Cost of debt" (report prepared for 'Big Six' EDBs, 17 October 2023), para 78-85.

531 CEG "'Targeting a nominal cost of debt' - Submission on specific matters for the IM Review 2023 Cost of debt" (report prepared for 'Big Six' EDBs, 17 October 2023), para 75-77.

532 CEG "'Targeting a nominal cost of debt' - Submission on specific matters for the IM Review 2023 Cost of debt" (report prepared for 'Big Six' EDBs, 17 October 2023), para 94-107.

4.144.3 the adjusted returns included in revenue and RAB adjustment add up to the expected blended WACC. The returns overall are the same as achieved with the blended CPI option but with a higher proportion of the return in revenue (cash returns) rather than RAB increases (non-cash returns).

4.145 Chorus raised the concern that unexpected debt financing associated with investment would not be at the cost of debt assumed at the reset.[533]

4.146 CEG submitted that we should focus on indexation if we want to achieve a revenue path consistent with a fixed nominal cost of debt, rather than on adjustments to the annual revenue wash-up.[534]

4.147 CEG considered that we should not use complexity as a reason for choosing the cost of debt washup over the blended CPI. CEG considered the blended CPI option is "far superior".[535] Their underlying concern was that the revised draft decision in our further consultation creates greater challenges for suppliers in terms of their debt management practices than does the blended CPI option. Chorus raised a similar point – that the revised draft decision creates debt management challenges.[536]

4.148 Chorus proposed the cost of debt adjustment be optional because some suppliers choose not to hedge the cost of debt at the reset.[537] Alpine Energy made the point that hedging the cost of debt may not be practical for some suppliers.[538]

4.149 Chorus submitted that the proposal would remove the alignment between consumer electricity prices and the CPI, which they argue would not be in the long-term interest of consumers. They also noted that if it applied to Chorus there could be a stranding risk given that their competitors would not face a cost of debt wash-up.[539]

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533 Chorus "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 7.

534 CEG "'Targeting a nominal cost of debt' - Submission on specific matters for the IM Review 2023 Cost of debt" (report prepared for 'Big Six' EDBs, 17 October 2023), para 12-25.

535 CEG "'Targeting a nominal cost of debt' - Submission on specific matters for the IM Review 2023 Cost of debt" (report prepared for 'Big Six' EDBs, 17 October 2023), para 3e-3f.

536 Chorus "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 7.

537 Chorus "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 6.

538 Alpine Energy "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 16.

539 Chorus "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 8.

4.150 Chorus submitted that the proposed IMs assume the MAR model would be rerun to account for inflation differences, but we assumed the allowable revenue would be adjusted for unexpected inflation. Chorus sought clarity in that respect.[540]

4.151 Transpower, in its submission on the further consultation, supported the 5-year smoothing option; although Transpower also submitted that it thinks the hybrid approach is an option.[541] In its cross-submission, Transpower proposed that the problem caused by suppliers having a fixed nominal cost of debt should be fixed by either changing the form of indexation to hybrid indexation or by applying the blended CPI method, rather than an annual revenue adjustment (in the form of the revised draft decision).[542] Transpower also agreed with CEG that there would be "ramifications on suppliers who do not follow the Commission's assumed hedging strategy".

4.152 Vector, in its submission on the further consultation, proposed that a better option than the revised draft decision or the blended CPI option is to remove indexation so that inflation forecasting is not an issue.[543] In its cross-submission, Vector submitted that we should focus on removing the requirement to forecast inflation instead of changing the annual revenue wash-up mechanism. Vector also considered it was uncertain how unexpected new capital expenditure, for example through a re-opener, would be treated under the proposals. In addition, Vector submitted that suppliers who choose not to manage their debt portfolio in the way we assume could be penalised, and supported giving suppliers the option of whether the proposals apply to them.[544]

4.153 Alpine Energy submitted that we should consider how suppliers can be compensated for the historical over-forecasting of inflation.[545]

4.154 ENA supported updating the CPI when forecasting allowable revenue.[546]

[540] Chorus "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 10-11.

[541] Transpower "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), p. 1.

[542] Transpower "Cross-submission on specific matters for the IM Review 2023 Cost of debt" (27 October 2023), p. 1.

[543] Vector "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 19.

[544] Vector "Cross-submission on specific matters for the IM Review 2023 Cost of debt" (27 October 2023)

[545] Alpine Energy "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 8.

[546] Electricity Networks Aotearoa (ENA) "Cross-submission on specific matters for the IM Review 2023 Cost of debt" (27 October 2023), p. 1.

4.155 Unison cross-submitted that a materially better alternative to the revised draft decision is CEG's amended blended CPI model and that the revised draft decision increases the risk of underinvestment and increases the complexity of debt management.[547]

4.156 Powerco submitted that the revised draft decision does not address the debt compensation problem. They considered that the revised draft decision would be a "significant step backwards to the status quo". They supported CEG's blended CPI method, but noted that if that is not adopted, then we should not make any changes and come back to this issue on the next IM Review. Further, Powerco submitted that:[548]

> EDBs have debt portfolios that vary in both tenor and rate structure, with debt raising occurring throughout regulatory periods as debt matures. The Commission's assumption that EDBs fix all their debt costs at the beginning of a regulatory period in the reference period does not reflect reality.

Analysis and final decisions

4.157 As outlined in paragraph 4.79, our final decisions are to:

4.157.1 make no change to the EDB and GTB IMs to introduce a CODW and instead revert to the status quo under the current IMs;[549]

4.157.2 confirm our draft decision to amend the EDB IMs and GTB IMs to wash-up allowable revenue for the first year of a regulatory period when inflation differs from expected inflation;[550] and

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547 Unison "Cross-submission on specific matters for the IM Review 2023 Cost of debt" (27 October 2023)

548 Powerco "Cross-submission on specific matters for the IM Review 2023 Cost of debt" (27 October 2023), pp. 2-3.

549 As with our draft decision, our final decision on the CODW only concerns the EDB IMs and GTB IMs. As we noted in our draft decision, the GDB IMs and Transpower IMs do not require amendments to enable us to introduce a CODW, which in both cases could be done as a decision we make in resetting the relevant PQ path, if we decided that doing so would better promote the Part 4 purpose (see Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), at n 344).

550 As with our draft decision, our final decision to amend the IMs to wash-up allowable revenue for the first year of a regulatory period only applies to the EDB IMs and GTB IMs. As we noted in the draft decision, this has not been an issue for GDBs because we have set their allowable notional revenue for the first year using lagged actual inflation. Likewise, no IM change is needed to provide for this in the case of Transpower as the Transpower IMs would allow us to do so at the reset, if we decide at that point that it would promote the Part 4 purpose (see Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), at para 5.95).

4.157.3 confirm the change we proposed to our draft decision (in our further consultation) to the EDB and GTB IMs to ensure that the most up-to-date CPI inflation (actual and forecast) is used when determining forecast net allowable revenue at the start of each regulatory year.[551]

4.158 We explain our final decisions and engage with relevant points submitters raised on our draft decision and revised draft decision, as follows.

Our final decision to not introduce a CODW into the EDB IMs and GTB IMs and revert to the status quo

4.159 Following extensive consultation, we have concluded that, on balance, maintaining the status quo likely better promotes the objectives of the IM Review than our revised draft decision or alternatives put to us in consultation. The main reason for this decision is that, having taken account of submitters' views on our draft decision and further consultation, we now consider the status quo would better protect both consumers and suppliers from inflation risk. We explain why as follows.

4.159.1 For consumers, we consider that the regime should not expose them to the risk that the real price they pay varies significantly in response to unexpected changes in inflation. Under the alternatives to the status quo, there could be extended periods where real prices are either higher or lower than they would be under the status quo. We agree with Chorus that such variance is not in the long-term interest of consumers.[552] By contrast, constant real prices over time promote allocative efficiency when the flow of benefits to consumers is also constant, in line with s 52A(1)(b). Relatedly, we consider that constant real prices better support consumer-side efficient investment and consumption decisions by providing a better basis for planning long-term capital investments, which also promotes s 52A(1)(b). We note that some consumers may prefer less nominal price volatility for the same expected real average price over the longer term, while some others may prefer more nominal price volatility but a constant real price at any point in time.[553] Our judgement is that, other things equal, delivering constant real prices at every point in time better promotes the Part 4 purpose. The status quo would achieve that better than the alternatives.

551 Commerce Commission "Input methodologies review 2023 – Further consultation on IM Review draft decision on the CODW of EDBs and GTBs" 29 September 2023, at para 11.

552 Chorus "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 8.

553 Consumers can transfer the risk of nominal price volatility to other parties. For example, this is part of the services that electricity retailers offer.

4.159.2 For suppliers, the status quo approach achieves ex-ante real FCM (NPV=0) when the price path is set, for all suppliers, whatever their debt management practices. In addition, the revenue wash-up, together with the rolling forward of the RAB using actual instead of forecast inflation, maintains the real value of allowed revenues.[554] This protects suppliers – equity and debt holders combined – from inflation risk, in line with s 52A(1)(a) and (d). Through their debt management practices, suppliers' management can protect or expose equity holders – to varying degrees – to the risk of inflation-driven windfall gains or losses. The debt management choices that influence the degree of equity holders' inflation risk exposure include the use of swaps for hedging, debt refinancing timing and extent, use of floating debt and, where available, inflation-linked bonds.

4.159.3 Indeed, in our 2022 confidential debt survey, we observe that suppliers employ a variety of debt management practices. Smaller EDBs tend to rely more heavily on floating debt than larger ones.[555] The annual revenue wash-up fully adjusts the real revenue path set at a PQ reset for actual inflation. In doing so, it is consistent with all of the suppliers' costs increasing by inflation (ie, floating debt with regards to the cost of debt).[556] The combined effect of actual inflation outcomes, the revenue wash-up and the different debt management choices may create cashflow challenges for some suppliers, and windfall gains or losses for equity holders.

4.159.4 However, we consider that debt management choices are a matter for suppliers to decide on. In particular, it is a matter for suppliers to choose the extent to which they use interest rate swaps to align their nominal cost of debt to the regulatory period (and to what proportion of outstanding debt), leave debt floating, or follow a different strategy.

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554 We note Powerco's observation on this point that: "We believe that unless a proposed mechanism proactively addresses the underlying issue, it should not be implemented, anything else would be a significant step backwards to the status quo, where EDBs are compensated for 100% of the debt portion of RAB in line with actual inflation." (see Powerco "Cross-Submission on further consultation relating to the draft decision on the cost of debt wash-up for EDBs and GTBs" (27 October 2023), p. 2).

555 This is the confidential debt survey referred to in our cost of capital draft decisions, Commerce Commission "Input methodologies review 2023 - Draft decision - Cost of capital topic paper" (14 June 2023), at para 3.35.

556 We have established in our demonstration model (published alongside this paper, refer para 1.4) that our current annual revenue wash-up mechanism is consistent with debt being treated as if the real interest rate is fixed with a tenor that is the length of the regulatory term, with the nominal interest rate floating with inflation.

4.159.5 We note that in the draft decision and the further consultation we mentioned that there is an 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.[557] We have evolved our view, and we no longer consider that there is an inconsistency. Rather, we calculate benchmark cost of debt and suppliers have the option (and compensation) to match it if they want to.[558]

4.160 The alternatives to the status quo (including our revised draft decision) would increase complexity and compliance costs to the regime. We note that the status quo does not create a mismatch with ID, as would be the case with the blended CPI option, which would result in a disconnect between the ID RAB and the PQ RAB (the ID RAB would continue to be indexed for the full CPI while the PQ RAB would be indexed by the blended CPI). Under the status quo, there is no need to make such changes. Furthermore, we use the CPI to index other components of the regime that are indexed to inflation, rather than a more complex blend with additional adjustments.

4.161 Submissions to our draft decision and further consultation raised a number of relevant points. We respond to these points below.

4.162 Chorus submitted that the proposals in the draft decision and further consultation would remove the alignment between consumer electricity prices and the CPI, which they argued would not be in the long-term interest of consumers. For the reasons in paragraph 4.159, we agree that constant real prices better promote the purpose of Part 4. We also agree that the alternatives to the status quo could result, at any given point in time, in consumer prices that do not reflect the change in CPI. This possible outcome is not a concern under the status quo because revenue is adjusted for actual inflation.

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557 Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper: Part 4 Input Methodologies Review 2023 - Draft decision" (14 June 2023), at para 5.88.

558 We note CEG's view in this respect that our options in the draft decision and further consultation paper would impose costs on suppliers because they would have to try to align their debt management practice with our assumptions about the cost of debt. CEG also submitted that these debt management costs would be greater under our preferred washup option (see CEG "'Targeting a nominal cost of debt' - Submission on specific matters for the IM Review 2023 Cost of debt" (report prepared for 'Big Six' EDBs, 17 October 2023), para 78-85). We consider our final decision to reinstate the status quo gives suppliers the ability to minimise such costs, because we calculate benchmark cost of debt and suppliers have the option (and compensation) to match it if they want to.

4.163 We note that the alternatives to the status quo may also deliver prices that reflect the change in CPI, but only over uncertain periods of time, assuming that the inflation forecasts are unbiased. However, even where inflation forecasts are unbiased, under the alternatives, there may be periods of several years where electricity lines price changes do not reflect the change in the CPI, like the period between 2011 and 2021, where inflation was consistently below 2 per cent (except for two quarters).

4.164 Several submitters raised concerns that changes to the annual revenue wash-up mechanism increase the complexity of suppliers' debt management operations and may create cashflow issues (Unison mentioned the risk of underinvestment). They submitted that the alternatives to the status quo would place a requirement on suppliers to align their debt management practices with those assumed under the proposed cost of debt wash-up.[559] Alpine Energy, Chorus and Vector submitted that some suppliers choose not to do the hedging that we provide an allowance for. We have considered stakeholders views carefully. We consider that the status quo is well-known and understood. Maintaining it means that suppliers will not be required – nor will they need to respond – by changing existing debt management strategies, It is probably the least complex approach. For these reasons, we consider that compared to the alternatives, the status quo would better achieve the third objective of our IM Review framework – reducing compliance, complexity and regulatory costs without detrimentally affecting the promotion of the Part 4 purpose.

4.165 CEG, Vector and Chorus submitted that capital expenditure throughout the regulatory period is funded at the prevailing cost of debt rather than the cost of debt assumed at the PQ reset. To the extent that they differ, this would mean that NPV=0 would not be achieved. We consider that the annual revenue wash-up is consistent with floating debt (at the real interest rate set at the PQ reset and adjusted for actual inflation). In turn, this is reasonably consistent with new investment being financed at prevailing rates and for refinancing of existing debt to also be made at prevailing rates. Therefore, under the status quo, the existing revenue wash-up better supports new investment during the regulatory period (equivalent to a more up-to-date debt estimate). This may be valuable in a context where investment is expected to increase significantly, consistent with s 52A(1)(a).

559 CEG "'Targeting a nominal cost of debt' - Submission on specific matters for the IM Review 2023 Cost of debt" (report prepared for 'Big Six' EDBs, 17 October 2023).

4.166 To the extent that suppliers want to depart from being exposed to the prevailing cost of debt, we note that our regime provides for them to pursue different debt management practices. As we explain in Chapter 3 of the Cost of Capital Topic Paper, we provide for the costs of hedging the risk-free rate as part of our overall debt issuance and associated cost allowance for the cost of capital. This allowance is considered sufficient to provide for the costs suppliers may incur in aligning the risk-free rate of their existing debt portfolio to the rate prevailing during the averaging period prior to the reset, in hedging the debt financing costs associated with new capital expenditure, as well as any unexpected capital expenditure, over the course of the price period. Our debt issuance costs and allowance assumes that suppliers will enter into two fixed-floating interest rate swaps per year, and this cost is part of the annual cost of capital.

4.167 Vector and Transpower consider that either removing indexation or moving to hybrid indexation is preferable to the options we presented in our further consultation paper. We explain in our decisions on topic 3a why we have decided to not change the form of indexation that applies to EDBs and GPBs and why we are indexing Transpower RAB's to inflation from RCP4. In addition, the alternative of not indexing the RAB does not remove the need to forecast inflation (we need a forecast to ex-ante index the revenue path) or to account for unexpected inflation (we need ex-post wash-ups to be more consistent with ex-ante real FCM and to achieve NPV=0).[560] While Vector and Transpower have submitted that the form of indexation could be changed to remove inflation risk, we have demonstrated that this is not the case.

[560] If there are no inflation wash-ups, and inflation forecasts and outturns are expected to differ, then a supplier cannon expect real FCM. To achieve NPV=0, a supplier on an indexed or unindexed RAB would need to have two adjustments to account for the difference between forecast and actual inflation: an adjustment to their annual revenue and an adjustment to their RAB at each PQ reset.

4.168 We disagree with Vector's point that an unindexed RAB removes inflation uncertainty. With an unindexed RAB that is not washed up for actual inflation,[561] the supplier will tend to earn the expected nominal return (which incorporates an implicit inflation forecast in the nominal WACC). Nominal prices to consumers will be based on the expected inflation, but the real prices will vary with actual inflation, exposing them to inflation risk. The supplier will also be exposed to the risk that actual inflation is lower or higher than expected. Frontier, in a report prepared for Transpower, estimated that Transpower lost $340m over RCP3 because actual inflation was lower than forecast.[562]

4.169 A concern CEG raised was that when the RAB is revalued for inflation, suppliers adjust their debt to maintain the benchmark leverage. The regulatory model does not support this outcome. While unexpected inflation increases the absolute value of the debt portion of the RAB, it also increases revenue.[563] As costs and revenue increase by the same amount (in present value terms) there is no need for suppliers to adjust their financing requirements.

4.170 As a cross-check, we have also checked whether there is any evidence in Vector's annual report that Vector has acted in a way suggested by CEG, that is, by increasing its debt when the RAB is revalued for inflation. [564] We have found no evidence that this occurs in practice. We therefore do not agree with CEG's criticism that the options in our further consultation paper create a problem because they do not account for suppliers adjusting their debt positions to maintain the benchmark leverage when the RAB is revalued.

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561 We demonstrated in our published model as part of the draft decision that a revenue wash-up alone is not sufficient to fully protect against inflation risk. There needs to be RAB inflation wash-up too. We also showed that that an indexed RAB (washed up with actual inflation), and the unindexed RAB that is rebased at the reset achieve the same inflation-adjusted return over the life of the assets. The difference between the approaches is only a revenue timing one. See Risks and incentives topic paper: Demonstration model stylised impact of different RAB indexation approaches - June 2023.

562 Frontier Economics “RAB indexation: Report for Transpower” (Report prepared for Transpower, 7 July 2022), p. 12.

563 Note that when the RAB is revalued for unexpected inflation at the end of a regulatory period, there is no offsetting adjustment to revenue as this adjustment has, in effect, already happened through the annual revenue adjustment mechanism.

564 See property, plant and equipment (PPE) and borrowings information in the financial statements of Vector "Annual Report 2023"" (24 August 2023), pp. 55-103.

4.171 We note that CEG considered that the blended CPI option was preferable to our revised draft decision because it creates fewer challenges for suppliers' debt management practices. We agree that the blended CPI option would more closely align revenue to the assumption of a fixed nominal cost of debt compared to the revised draft decision. However, as explained, we consider that the status quo creates fewer challenges than any of the alternatives and better achieves our framework's overarching objectives.

4.172 CEG submitted that most of the cashflow concern associated with inflation is due to indexing the RAB. This may be true early in the life of an asset, but it is offset in an NPV sense later in the life of an asset. However, our consideration here is on the effects of unexpected inflation which will not have an overall effect on the indexation-related cashflow concern raised by CEG.

4.173 CEG proposed a modification to the blended CPI option that has revenue adjusted by the full amount of inflation and the RAB adjusted at the reset for a lesser amount than the blended CPI (or a greater amount if inflation is lower than expected) to account for no adjustment to revenue (other than to provide for the actual inflation rate). The RAB adjustment would only account for the expected inflation rate on the expected debt portion of the RAB, not the actual debt portion of the RAB.

4.174 CEG's proposed option uses various simplifying assumptions, including ignoring tax implications and the impacts of capex and depreciation on the RAB. It achieves NPV=0 in its submitted form, but adding tax, depreciation, and capex will introduce significant complexity to the calculations.[565]

4.175 Alpine Energy proposed that we provide compensation for the historical over-forecasting of inflation. We do not consider it appropriate to make changes to the IMs to compensate for losses incurred in the past. Knowing the regulatory rules that applied during the relevant period (ie, revenue wash-up for full CPI), suppliers decided the debt management practices as they saw fit. In doing so, they may have decided to expose their equity holders to the risk that inflation differed from forecast (or from the value inherent in the interest rate at which they hedged/fixed). Providing compensation for past losses would amount to bailing suppliers out for decisions that they made, and would transfer the risk and losses to consumers. That would not promote the Part 4 purpose for the long-term benefit of consumers.

565 Refer to our demonstration model published alongside this paper (described at para 1.4 above) where we have shown CEG's proposed approach as well as the options that were considered in reaching our final decision.

4.176 CEG and Vector submitted that the demonstration model published for consultation does not achieve NPV=0. We do not consider there are issues with the model demonstrating NPV=0 for the status quo or alternative options. In CEG's proposed solution they achieve internal rate of return (IRR) results consistent with the demonstration model.[566],[567]

Our final decision to introduce a revenue wash-up for the first year of a regulatory period when forecast and actual inflation differ

4.177 Wellington Electricity,[568] Vector,[569] Chorus,[570] and the ENA[571] supported our proposed EDB IM change to wash up revenue for inflation in the first year of a regulatory period.

4.178 Our final decision is to wash up EDBs' and GTBs' revenue for inflation to account for any variation between forecast and outturn inflation for the first year of a regulatory period. [572] This better gives effect to the regime's intention to insulate consumers and suppliers – equity and debt holders combined – from the risk that inflation forecasts and outturns differ. This supports the expectation of real FCM, in line with s 52A(1)(a) and (d).

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566 CEG "'Targeting a nominal cost of debt' - Submission on specific matters for the IM Review 2023 Cost of debt" (report prepared for 'Big Six' EDBs, 17 October 2023), para 105.

567 Transpower commented that the depreciation calculation in the demonstration model is not IM compliant. To demonstrate the impact of the proposed alternatives over the useful lives of the assets, we had to make various simplifying assumptions to fully depreciate the RAB by year 10. Without the assumption to depreciate the revalued opening RAB, rather than just the opening RAB, the RAB could not be fully depreciated by year 10. We briefly explained the approach to fully depreciate the RAB in our simplifying assumptions in the model but could have been clearer on our approach to calculating depreciation. This will not have any impact on the demonstration of NPV=0 for any of the modelled alternatives.

568 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), section 3.3.2.2.

569 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 172.

570 Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 12.

571 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 5.2.

572 As with our draft decision, our final decision to amend the IMs to wash-up allowable revenue for the first year of a regulatory period only applies to the EDB IMs and GTB IMs. As we noted in the draft decision, this has not been an issue for GDBs because we have set their allowable notional revenue for the first year using lagged actual inflation. Likewise, no IM change is needed to provide for this in the case of Transpower as the Transpower IMs would allow us to do so at the reset, if we decide at that point that it would promote the Part 4 purpose (see Commerce Commission "Input methodologies review 2023 - Draft decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (14 June 2023), at para 5.95).

Our final decision to use the most up-to-date CPI inflation (actual and forecast) to determine forecast net allowable revenue at the start of each regulatory year

4.179 ENA supported the proposal to ensure the most up-to-date consumer price index (CPI) information (actual and forecast) is used when determining forecast net allowable revenue at the start of each regulatory year.[573]

4.180 Alpine Energy supported our response to reduce revenue path volatility (this change mitigates revenue volatility risks) but suggested an unspecified simpler approach should be considered.[574]

4.181 Our final decision is to change the general wash-up mechanism to index the revenue path (ex-ante) using two years of inflation ((Forecast Net Allowable Revenue t-2 x (1+actual CPIt-1) x (1+updated forecast CPIt)). This will use as much up-to-date information about inflation as is available. In doing so, it will reduce the delay for the wash-up to take effect, mitigating the risk of overpayment by consumers or financial pressure for suppliers.

4.182 We discuss in Attachment D the implementation of our final decision to retain an annual approach to updating CPI forecasts, with the CPI increment based on the most up-to-date CPI information (actual and forecast).

573 Electricity Networks Aotearoa (ENA) "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), p. 1.

574 Alpine Energy "Submission on specific matters for the IM Review 2023 Cost of debt" (17 October 2023), para 9.

Chapter 5 Our approach to incentivising efficient expenditure for EDBs and Transpower

Purpose and structure of this chapter

Purpose of this chapter

5.1 This chapter outlines our decisions on the IMs affecting the incentives that EDBs and Transpower have to make efficient expenditure decisions under their price-quality paths. This is 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).

5.2 In this Chapter we outline our final 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

5.3 Many of the submissions in response to our May 2022 Process and issues paper provided feedback on our approach to expenditure incentives. As such, a key focus of this IM Review was the review of our current approach to expenditure incentives and how we could evolve our approach. One change we considered was moving away from setting expenditure allowances for opex and capex and instead adopting a totex approach to setting expenditure allowances. Stakeholder feedback on our draft decisions generally supported incremental changes to our current expenditure incentive mechanisms rather than a more fundamental overhaul.

5.4 Our 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.

5.5 We reviewed the effectiveness of expenditure incentives applying in price-quality paths by:

5.5.1 reviewing the objectives for our expenditure incentives, including whether their importance has changed in light of the changing energy landscape; and

5.5.2 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

5.6 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.

5.7 In Table 5.1 below we list key documents we shared with stakeholders.

Table 5.1 Key documents related to expenditure incentives

Title	Description	Link
Part 4 Input Methodologies Review 2023 – Process and issues paper (20 May 2022)	Chapter 5 discussed 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 discussed 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

5.8 In this chapter we explain:

5.8.1 how our regulatory regime incentivises expenditure;

5.8.2 our 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);

5.8.3 our decision to keep the current suite of expenditure incentive mechanisms for EDBs and Transpower after considering alternative expenditure incentive mechanisms;

5.8.4 our decisions for specific changes to EDBs' current expenditure incentive schemes to improve their working and application; and

5.8.5 our decisions for specific changes to Transpower's opex IRIS.

Summary of our final decisions

5.9 The tables below summarise our final decisions and the main policy reason for the decisions. The analysis behind the decision and reasoning why the decision promotes the overarching objectives of our IM Review framework is detailed in the body of the Chapter.

Table 5.2 Final decisions on the approach to expenditure incentives

Topic	Final decision	Reason	Applicable to
Topic 5a – 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 5b – 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 5.3 Final decisions applying to current expenditure mechanisms

Topic	Final decision	Reason	Applicable to
Topic 5c – 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
Topic 5d – Maintain our approach to setting incentive rates	Make no change to 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 5e – Not to exclude specific expenditure categories from IRIS	Make no change to provide for the flexibility 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 5f – 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 67^{th} 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 5g – Maintain our current treatment of operating leases	Make no changes to 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 5h – 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 5i – targeted improvements to Transpower opex IRIS, including removing the baseline adjustment term	Remove the baseline adjustment term (IBAT) for Transpower's opex incentive calculation. Amend Transpower's base year adjustment term. Amend year 5 carry forward amount 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

5.10 This section outlines our approach to setting expenditure incentives for suppliers that are subject to price-quality regulation.

5.11 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.

5.12 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 are to the detriment of 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.[575]

5.13 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:

5.13.1 providing equal incentive rates for opex and capex;

5.13.2 consistent incentive rates to make efficiency savings over time;

5.13.3 tailoring incentive rates and the extent efficiency gains are shared between suppliers and consumers; and

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

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575 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.

5.14 The priority of these objectives of the expenditure incentive mechanisms has changed since the last IM Review.

5.14.1 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).[576] 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 not exceeding their maximum allowable revenue).[577]

5.14.2 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.

5.15 The expenditure incentive mechanisms are a key component of our regulations for price-quality regulated EDBs and Transpower (GPBs are not subject to expenditure incentive mechanisms). An important focus of this IM Review was to assess whether the current mechanisms promote the Part 4 purpose better than alternatives.

5.16 We consider that the current mechanisms generally work well against the objectives of an expenditure incentive mechanism, but there is room for technical refinements, which we discuss later in this chapter.

5.17 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.

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576 See below for a further description of how the current incentive mechanisms work.

577 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. See Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision" (27 November 2019), para X81.

5.18 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 were of the view that equivalence, does not apply. We respond to some of these submission points further in Topic 5a and Attachment B of this paper.

5.19 Wellington Electricity noted that there is equivalence within a regulatory period but for certain expenditure trade-offs across regulatory periods this may not hold. Our solution to this point is discussed in Chapter 6.

5.20 Feedback from submissions on our draft decision was that submitters were broadly supportive of retaining the overall mechanics of the IRIS mechanisms. Some suppliers noted that the level of complexity is necessary to achieve desired outcomes and that equalising incentives across opex and capex will be important in the future as non-wire solutions provide a viable alternative to building traditional capacity.

5.21 There is an interaction between the approach to setting expenditure allowances, in-period adjustments during a regulatory period (such as reopeners) and the expenditure incentive mechanisms. Taken together, we consider that our overall package of decisions works to produce the outcomes for consumers that achieve our IM Review overarching objectives. Based on this, we have made targeted changes to the expenditure incentive mechanisms to provide for these outcomes.

5.22 For an overview of the how the expenditure incentive mechanisms work for EDBs, see our staff working paper (which includes references to previous IRIS decisions).[578]

5.23 For background on Transpower's expenditure incentive mechanisms, see Table 5.4 below.[579]

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578 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.

579 Note that Transpower's opex IRIS is the same as the EDBs DPP IRIS mechanism, except that it has an additional functionality to reflect Transpower's forecasting approach. Our final decision is to remove the existing baseline adjustment term for Transpower's opex IRIS and amend the workings of the mechanism as explained in Topic 5i.

Table 5.4 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

5.24 Stakeholder feedback we received prior to, and on, our draft decisions has been valuable in understanding key areas of concern related to the expenditure incentive mechanisms and has informed our decisions. Some stakeholder suggestions are relevant to our price-quality and information disclosure regulation and we may consider these as part of those processes.

5.25 Key themes from stakeholders during the IM Review included:

5.25.1 In submissions on our draft decision, there was limited support for moving from the traditional approach to setting allowances (ie, based on opex and capex) to a total expenditure (totex) approach. Earlier in our IM Review, a number of submitters held the view that a totex approach could be a possible way to address capex bias due to financial regulatory incentives and to increase flexibility between opex and capex.

5.25.2 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.

5.25.3 In feedback on our draft decisions, some submitters expressed acceptance that the level of complexity of the expenditure incentive mechanisms is warranted to achieve the desired outcomes. During earlier phases of the IM Review, submitters had made several suggestions to make the expenditure incentive mechanisms easier to understand, which we considered in our draft decisions.

5.25.4 Ex-ante allowances are not fit for purpose when uncertainty is increasing and when some types of expenditure are outside of suppliers' reasonable control. This is particularly the case with connection capex where demand (quantity of new connections) is outside of suppliers' control and subject to forecast error.

5.25.5 The impact of inflation on revenue from the opex and capex IRIS is not under suppliers' control.

5.25.6 Our expenditure incentive mechanisms do not support efficient opex/capex trade-offs across regulatory periods.

5.25.7 Some stakeholders are concerned about the impact of IRIS incentive amounts on supplier cashflows.

5.25.8 Submitters proposed various other technical refinements to the current expenditure incentive mechanisms.

Topic 5a – Maintain the current expenditure incentive schemes as tools for mitigating capex bias

Final decision

5.26 Our final 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

5.27 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.

5.28 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.

5.29 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 5b).[580] 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

5.30 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.

5.31 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.

5.32 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

5.33 In the box below we set out how we define capex bias.

Figure 5.1 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).

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[580] 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).

5.34 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.[581] 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 considered this issue

5.35 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.

5.36 Powerco submitted that:[582]

> 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.

5.37 Wellington Electricity submitted that its early modelling indicates that:[583]

> 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.

5.38 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.[584]

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581 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)

582 Powerco "Submission on Expenditure incentives EDB workshop" (6 December 2022).

583 Wellington Electricity "Submission on Expenditure incentives EDB workshop" (6 December 2022).

584 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.

Capex bias is most relevant for non-exempt electricity distributors

5.39 We consider that the issue of a 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.

5.40 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.

5.41 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.[585]

5.42 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 5.51.

5.43 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.[586]

Draft decision

5.44 Our draft decision was to keep the current suite of expenditure incentive schemes for EDBs and Transpower as tools for mitigating capex bias due to financial regulatory incentives.

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585 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 14.

586 Commerce Commission "Input methodologies review decisions, Consolidated Reasons paper" (20 December 2016), p. 15.

Draft decision reasons

5.45 From a regulatory approach viewpoint, the draft decision meant maximum allowable revenues for the DPP/CPP would 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.

5.46 From suppliers' viewpoints, under the draft decision 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.

5.47 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.

5.48 Our draft decision reflected our view that our current tools for mitigating capex bias due to regulatory financial incentives — the pre 2023 IM Review 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 5.3 to 5.23.

5.49 The followings decisions are related to the Topic 5a draft decision:

5.49.1 Topic 3b – Implications of IRIS for cashflow timing;

5.49.2 Topics 5b to 5i in this chapter;

5.49.3 Topic 6b – Encouraging innovation and non-traditional solutions; and

5.49.4 the WACC percentile decisions, discussed in Chapter 6 of the Cost of Capital topic paper.[587]

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[587] Commerce Commission "Part 4 Input methodologies Review 2023 - Final decision - Cost of capital topic paper" (13 December 2023).

5.50 Submissions prior to our draft decisions 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.[588]

Stakeholder views prior to our draft decision: capex bias under current expenditure incentive schemes

5.51 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.

5.52 For example, the ENA submitted:[589]

> 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.

5.53 Orion submitted that it:[590]

> 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.

588 We note that analysis of capitalisation is a focus area for the AER. Australian Energy Regulator "How the AER will assess the impact of capitalisation differences on our benchmarking - Draft Guidance note" (October 2022).

589 Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 10.

590 Orion "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 74.

5.54 The Boston Consulting Group report recommended that:[591]

> 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.

5.55 In our November/December 2022 consultation we shared our capex bias problem definition. Submitters generally agreed with our problem definition. However, Vector submitted:[592]

> 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.

5.56 We also sought to better understand whether capex bias arises due to shortcomings with our current expenditure incentive schemes.

5.57 In response to our engagement, Orion, Powerco, and Wellington Electricity and Nera on behalf of the Big Six EDBs submitted that the opex and capex IRIS provide for equivalence and hence opex/capex substitutability within regulatory periods.[593]

5.58 Vector, Wellington Electricity and Nera on behalf of the Big Six 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 prior to our draft decision: using totex approach to address capex bias

5.59 In response to our November/December 2022 consultation 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.

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591 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.

592 Vector "Submission on Expenditure incentives EDB workshop - Attachment A" (6 December 2022), para 7.

593 Powerco "Submission on Expenditure incentives EDB workshop" (6 December 2022); Orion "Submission on Expenditure incentives EDB workshop" (6 December 2022); Wellington Electricity "Submission on 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)

5.60 Horizon Networks submitted that:[594]

> 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.

5.61 Transpower submitted in response to our Process and issues paper, and reiterated this view in its submission in response to our 7 November 2022 workshop:[595]

> 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.

5.62 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.[596] Vector submitted:

> 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.

5.63 We discuss these submissions further in Attachment B.

Draft decision reasons - alternative solution considered: totex approach

5.64 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.

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594 Horizon Energy Group "Submission on Expenditure incentives EDB workshop" (8 December 2022)

595 Transpower NZ Ltd "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022)

596 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.

What we mean by 'totex approach'

5.65 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.

5.66 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.[597]

5.67 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.[598] 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.

5.68 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.[599] IRIS similarly does not address this issue.

5.69 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.[600]

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597 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).

598 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.

599 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 13.3.

600 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).

Experience with totex approach in other jurisdictions

5.70 In preparing our draft decision, we also considered experience in other jurisdictions and have also considered the wider context for those regulatory choices.

5.71 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.[601] Since then, the AER has chosen to evolve its existing opex/capex- based building block regimes rather than pursue a totex approach.[602]

5.72 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.

5.73 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.

5.74 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.[603] It is not possible to determine the change that would have occurred had there already been expenditure incentive schemes in place similar to ours.

5.75 Other relevant context that impacts the relevance of Ofgem's and Ofwat's experience to Part 4 includes:

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601 We understand that part of the AER's decision for continuing with an opex/capex-based approach were the constraints under their statutory framework.

602 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).

603 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.

5.75.1 Ofgem's approach to setting expenditure allowances 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.[604]

5.75.2 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.

5.76 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.[605] CRU explained its decision as follows:[606]

> 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.

5.77 We discuss the 'flexibility mechanism' the CRU adopted as another alternative solution considered at 5.90.

Longer term considerations

5.78 While our draft decision did not provide for a totex approach, we considered that a change in mindset that has been attributed in UK to the shift to a totex approach is also desirable for New Zealand infrastructure sectors:[607]

> 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.

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604 Frontier Economics, "Total expenditure frameworks, A report prepared for the Australian Energy Market Commission" (December 2017), pp. 29-30.

605 Commission for Regulation of Utilities,"PR5 Regulatory Framework, Incentives and Reporting" (22 July 2020), p. 35.

606 Commission for Regulation of Utilities "Price Control 5 Strategy" (30 June 2021), p. 39.

607 Ellen Bennet "Has totex done its job?" (25 June 2019) Utility Week.

5.79 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 approach as a means of addressing capex bias

5.80 A key question for this IM Review was: would moving to a totex approach better achieve our Framework's overarching objectives than the status quo in terms of addressing capex bias?

5.81 In our draft decision we applied our Framework to this question as follows.

Promoting the Part 4 purpose in s 52A more effectively

5.82 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.

5.83 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).

5.84 In our draft decision, we did 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:

5.84.1 the status quo IRIS operates as intended in addressing capex bias due to equalising financial regulatory incentives;

5.84.2 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

5.84.3 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.[608]

5.85 For completeness, we noted 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).

Promoting the IM purpose in s 52R more effectively (without detrimentally affecting the promotion of the s 52A purpose)

5.86 A significant change to the IMs would be required to enable a totex approach. In the short term, uncertainty would increase compared to the status quo (noting that we did not consider this short-term increase in uncertainty was a major factor in our draft decision, as giving significant much weight to this over other overarching objectives may result in status-quo bias).

5.87 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.[609] 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)

5.88 In our draft decision we explained that we did 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.

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608 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.

609 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).

5.89 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.[610] Applying our third IM Review overarching objective of reducing compliance costs, other regulatory costs, or complexity, we considered adopting a totex approach would be significantly more costly (both from a financial cost and opportunity cost perspective) than retaining IRIS.

Draft decision reasons - alternative solution considered: 'flexibility mechanism'

5.90 Instead of adopting a totex approach as discussed at 5.65 above, the CRU adopted the 'flexibility mechanism' which allows a business to reallocate allowances between opex and capex (bi-directional).[611] 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.

5.91 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').

5.92 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.[612]

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610 Our current rules and processes generally reflect Generally Accepted Accounting Principles (GAAP). Refer to chapter 5 of the staff working paper for an overview of some of the implementation matters for ID regulation, price-quality regulation and input methodologies. "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).

611 Commission for Regulation of Utilities "Price Control 5 Strategy" (30 June 2021), p. 39.

612 We discuss our solution to improve incentives for cross-regulatory period expenditure trade-offs in Topic 6b.

5.93 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.

5.94 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. Therefore, our draft decision was to not propose a flexibility mechanism approach for dealing with capex bias.

Stakeholder views on our draft decision

5.95 Submissions generally supported our draft decision to keep the current suite of expenditure incentive schemes for EDBs and Transpower as tools for mitigating capex bias due to financial regulatory incentives.

5.96 Harbour Asset Management submitted:[613]

> In appraising the regime, we sought to understand whether the IRIS framework is as practically useful as the totex framework proposed by some. We were particularly interested to ensure the most efficient solution to changing technology is incentivised, be that investing in higher-capacity plumbing or higher ongoing spending on operating systems. Feedback was that IRIS is less complex and therefore we agree with the Commission's suggestion to retain this mechanism. It appears to incentivise EDBs while fairly sharing any efficiency gains.

5.97 In Vector's April 2023 submission[614] it referred to three conceptual components of a totex regime set out in NERA's report prepared in response to our November/December 2022 consultation:[615]

> Totex assessment/forecasting: the regulator does not distinguish between capex and opex when assessing efficient levels. Instead, the regulator reviews total costs (or expenditure). This would address the more procedural aspect of any potential bias whereby it is easier to ask for capex – if a joint allowance is being asked for and assessed, the issue should fall away.
>
> Totex incentives: requires companies to have equal incentives to reduce costs, irrespective if the savings are in capex or opex. This would address any potential within period bias towards capex as there is no issue around equivalent retention rates if there is a single allowance for the purpose of calculating incentives payments.

613 Harbour Asset Management "Submission on the IM Review 2023 Draft Decisions" (19 July 2023), pp 1-2.

614 Vector "Incentivising efficient expenditure for EDBs" (6 April 2023), pp 3-4.

615 NERA Economic Consulting "Innovation under the DPP - potential barriers and solutions" (report prepared for 'Big six' EDBs, 20 December 2022), p. 21.

Totex revenue recovery: revenue allowances comprise two sources: fast money (does not enter RAB) and slow money (enters RAB). A totex approach to the split between fast and slow money divorces the capitalisation rate from the actual shares of capex and opex. A totex revenue profile therefore removes companies' incentives to over- capitalise to take advantage of a cost of capital allowance that may exceed the true cost of capital.

5.98 Vector also submitted:[616]

…the first two components are attractive but the third is the one we need to be very cautious in considering if the Commission does wish to continue the totex debate. And instead of focussing on the all-encompassing UK totex regime, we should instead refer to Germany and the Netherlands where only the first one (Germany) or two (Netherlands) components are adopted.

5.99 In its July 2023 submission on our draft decisions, Vector submitted that we should not abandon the idea of improving our current incentive schemes and that it considers the discussion should continue finding better ways to tackle the substitution of opex and capex that is in the best interest of consumers.[617]

5.100 Wellington Electricity submitted that, in the short term, retaining the IRIS mechanisms along with incentives for flexibility provide the best solution:[618]

We agree with the Draft IM Decision narrative that it will be important for EDBs to be able to substitute capex and opex going forward as non-wire solution provide alternatives to building traditional capacity in response to emissions-reduction-related demand increases (the non-wire solutions enabling a network to defer when expensive wire solutions are built). That substitution should incentivise whatever is the most effecting solution – what solution (or combination of solutions) provides the lowest long-terms cost. We also agree that the IRIS does not allow opex/capex substitution across regulatory periods, an issue which is well defined in Attachment C to the Financing & Incentivising Paper.

5.101 In terms of the application of the IMs in the context of price-quality paths, Wellington Electricity submitted: [619]

We don't think a long-term solution has been found to the opex/capex substitution issue and more work is needed to solve the issue. We disagree with relying on allowances to fund flexibility is a viable long-term solution because of the difficulty of accurately forecast when flexibility will be a better solution to traditional wire solutions and the difficulty in forecasting how much customers will pay for those services. Inaccurate forecasts do not provide incentives for networks to make efficient cost choices (the difficulty in forecasts flexibility allowances is discussed below).

We agree that the proposed Draft IM Decision of a combination of retaining the IRIS and introducing allowances and incentives for flexibility (including allowances and incentives to develop LV Management needed for EDB's to incorporate flexibility) is the best combination of options identified. In the short term, these would help to incentivise flexibility and support their development.

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616 Vector "Incentivising efficient expenditure for EDBs" (6 April 2023), pp 3-4.

617 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 51.

618 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 18.

619 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 18.

5.102 Alpine Energy submitted that:[620]

> …the status quo in terms opex and capex allowance within the DPP should prevail, with the Commission placing greater emphasis on supplier forecast when setting expenditure allowances.

5.103 Transpower supported our draft decision to maintain the current suite of expenditure incentive schemes for EDBs and Transpower as tools for mitigating capex bias due to financial regulatory incentives, and submitted:[621]

> While we consider the existing incentive schemes as working broadly as intended, we note that volumetric capex programmes (which appear to be more like maintenance), investor bias, capitalisation changes and subjective judgements, such as the baseline adjustment term (in its current form), can lead to actual or perceived incentives being unequal across opex and capex.
>
> We ask that the Commission continue to monitor the application of the totex approach in overseas jurisdictions and use the significant lead time to the 2030 price-reset to assess the regulatory costs and benefits of both options on their own merits. We noted in our July 2022 submission that "[w]hile the costs of change will be created in the short term a future totex approach should create option value for the dynamic efficiency to be realised under technological change. Even if the timeline is too short to implement for 2025 then 2030 could be a good starting point for a changed regime."

5.104 Orion submitted that:[622]

> We still believe that there is value in exploring a Totex approach and provide more simplicity in the IRIS mechanism between Capex and Opex substitution.

Analysis and final decision

5.105 Our view is that maintaining the existing suite of expenditure incentive schemes for EDBs and Transpower, as tools for mitigating capex bias due to financial regulatory incentives, better promotes the objectives of the IM framework than the alternatives we considered. The reasons for our final decision are the same as outlined in our draft decision (refer to paragraphs 5.45 to 5.94 above).

5.106 Submissions generally supported our draft decision to not adopt a totex approach. Submissions did not propose any alternative approaches that would overcome the issues that we noted in the draft decision with moving to a totex approach and better achieve our Framework's overarching objectives. Therefore, we have decided not to change our draft decision to maintain our current expenditure incentive mechanisms to deal with capex bias (and to encourage other objectives) discussed in paragraphs 5.45 to 5.94 above.

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620 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para. 33.

621 Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 32.

622 Orion "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 12.

5.107 Transpower encouraged us to continue monitoring the use of a totex approach in other jurisdictions and assess the costs and benefits of the current approach and a totex approach for use in the 2030 price reset.

5.108 In addition, other points raised in submissions included:

5.108.1 Orion suggested we provide more simplicity in the IRIS mechanism for capex and opex substitution.

5.108.2 Vector submitted that we should continue to investigate finding better ways to tackle the substitution of opex and capex in the best interest of consumers; and

5.108.3 Vector submitted that we should not abandon the idea of improving our current expenditure incentive schemes.

5.109 We touch on these submission points in other parts of this topic paper:

5.109.1 Our decision to maintain the current expenditure incentive mechanisms for opex and capex (including options for simplification) are discussed in 'Topic 5b – Maintain the current incentive mechanisms as they best balance considerations of effectiveness and understandability'.

5.109.2 Our decision to introduce a mechanism that enables a wider set of incentive schemes, including to improve incentives for opex/capex substitution across regulatory periods is discussed in 'Topic 6b – Encouraging innovation and non-traditional solutions'.

Topic 5b – Maintain the current incentive mechanisms as they best balance considerations of effectiveness and understandability

Final decisions

5.110 Our decision is to maintain 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).

5.111 This decision should be considered together with the IM changes 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 (discussed below).

Problem definition

5.112 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.

5.113 From discussions with EDBs, we consider that the understanding (and confidence IRIS works as intended) matters most at:

5.113.1 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).

5.113.2 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.

5.114 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.

5.115 This section explains why we consider alternative, simpler approaches would not achieve the objectives of the incentive schemes (outlined above in paragraph 5.13) and achieve our IM Review overarching objectives better than the current mechanisms. In the sections that follow (Topics 5c to 5i) we provide reasons for specific changes related to the current expenditure incentive mechanisms for price-quality regulated EDBs and Transpower.

Draft decision

5.116 Our draft decision was also to maintain 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).

Draft decision reasons

Stakeholder views prior to our draft decision

5.117 Some suppliers 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 stated:[623]

> 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.

5.118 There were suggestions to simplify the incentive schemes, but no proposed changes to the high-level working of the mechanisms. Suggestions 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 stated:[624]

> 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).

5.119 However, Vector considered that the complexity of the current mechanisms is warranted to achieve the desired outcomes for consumers:[625]

> 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.

5.120 Powerco and Orion submitted that we should investigate the use of a totex-based incentive mechanism that could simplify the incentive scheme for stakeholders.

[623] Aurora Energy "Aurora Energy – Submission on Expenditure incentives EDB workshop" (6 December 2022), para 15.

[624] Wellington Electricity "Wellington Electricity – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 10.

[625] Vector "Vector – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 6.

5.121 Orion stated:[626]

> 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.

5.122 Powerco also supported considering a totex incentive scheme similar to Ofgem's. It also considered that the issues raised in our staff working paper were manageable:[627]

> 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.

Reasons for our draft decision

5.123 We considered that no new 'simple' incentive mechanisms were 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.

5.124 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.

5.125 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).

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[626] Orion "Orion – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 10.

[627] Powerco "Powerco – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 8.

5.126 We considered that 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 considered that retaining the mechanisms that promote the objectives of the incentive scheme, and better achieves our IM Review overarching objectives.

5.127 We acknowledged that IRIS is complicated and, as discussed at paragraph 3.190, certain detailed aspects can be difficult to understand intuitively. We noted our intention 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.

5.128 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 recognised 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).

Draft decision – Alternative approaches considered – simplified incentive scheme

5.129 As noted in the Wellington Electricity submission in paragraph 5.118 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.

5.130 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.[628] Some examples of expenditure incentives used by international regulators include:

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[628] 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.

5.130.1 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).[629] 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).[630]

5.130.2 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.[631, 632]

5.131 We considered 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.

5.132 The ability of other regulators to use cost efficiency benchmarking arguably allows for less emphasis on expenditure incentives to reveal efficient spending. However, we noted that 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).

5.133 We stated that 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.

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629 For an overview of the AER's current expenditure incentives, see the guidelines on its website.

630 AER "Review of incentives schemes for networks - Draft Decision" (December 2022), p. 5-7.

631 ERA "Framework and approach for Western Power's fifth access arrangement review - Final decision" (9 August 2021), s 7 and 8.

632 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.

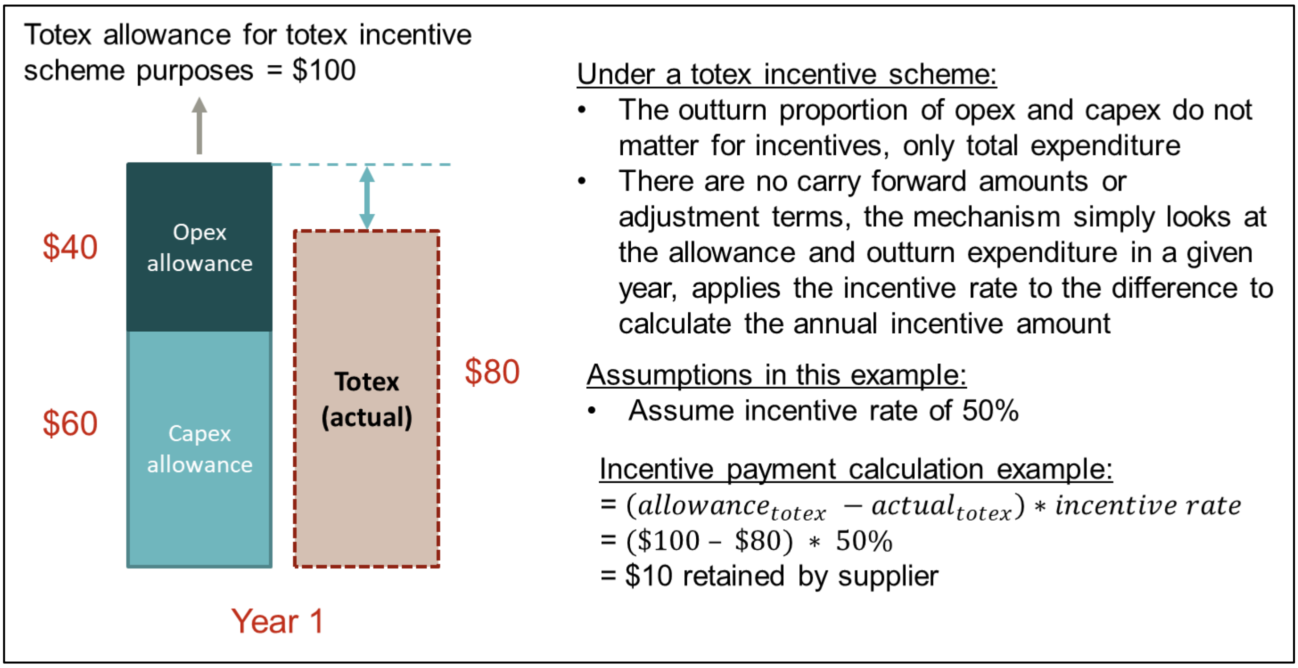
Draft decision – alternative approaches considered – totex incentive scheme (for incentive purposes only)

5.134 In our staff working paper, we mentioned the idea of applying incentives at a totex level (based on 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).[633] Below we refer to this approach as a 'totex incentive scheme'.

5.135 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).

5.136 Figure 5.2 below provides an example of how a totex incentive scheme could apply (in this case on a year-by-year assessment).

Figure 5.2 Example of a totex incentive scheme



5.137 The main advantage of a totex incentive scheme is the simplicity of application. However, in meeting the objectives of an incentive scheme outlined in 5.13, the benefits of a totex incentive scheme are significantly reduced compared with applying an opex and capex IRIS:

633 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.

5.137.1 incentives between opex and capex are not equalised;

5.137.2 there are not consistent incentive rates over time;[634] and

5.137.3 there are incentives to inflate expenditure in the base year.[635, 636]

5.138 Overall, we concluded that a totex incentive scheme was 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.

5.139 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

5.140 Without a totex approach for setting expenditure allowances (considered in topic 5a 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).

5.141 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.[637]

5.142 A totex incentive scheme does not equalise incentives for opex and capex, which is one of the key outcomes of the current IRIS. We considered that providing neutral incentives was important given the scope for opex solutions is expected to increase and we want suppliers to focus on efficient solutions.

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634 A simple incentive amount applying every year (no carry forwards) would result in suppliers being exposed to the 'natural incentive' for opex and capex.

635 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.

636 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.

637 Frontier Economics "Why Totex? Discussion paper" (24 July 2018), s 2.2.1.

Consistent incentive rate during a regulatory period

5.143 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.

5.144 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.[638]

5.145 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.[639]

Incentives to inflate expenditure in certain years

5.146 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.

5.147 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.

5.148 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.

Stakeholder views on our draft decision

5.149 Submissions on our draft decision were broadly supportive of retaining the existing expenditure incentive mechanisms.

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638 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.

639 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.

5.150 Alpine Energy supports our draft decision to maintain the overall mechanics of the IRIS mechanisms. It notes:[640]

> Whilst we acknowledge that the IRIS workings are complex and less intuitive than other mechanisms in the draft IMs, we believe the level of complexity and detail is necessary to achieve the desired outcomes.

5.151 Aurora Energy suggested that the application of the IRIS mechanisms be paused during this period of transition, as the basis for the IRIS mechanisms rely on reliable cost forecasts.[641]

5.152 Chorus noted that we proposed a number of technical changes to the existing IRIS mechanisms but had not reduced the practical complexity. It stated:[642]

> We recommend the Commission further considers ways of simplifying the scheme and/or making it more comprehensible to achieve its intended purpose.

5.153 ENA supported our draft decision to not propose material changes to the overall workings of the existing IRIS mechanisms.[643] ENA noted that changes should be made to the IRIS mechanisms only in situations where other mechanisms are not available or do not fully address the objectives of the expenditure incentive mechanisms.

5.154 In response to maintaining the core workings of the IRIS mechanisms, Vector stated:[644]

> As we approach the next reset, we do not believe the Commission should close the door on welcoming new incentive schemes which could provide materially better alternatives.

5.155 Wellington Electricity supported our draft decision to maintain the IRIS incentive mechanisms in the short term which provide for equalisation of the opex and capex incentive rates.[645]

Analysis and final decision

5.156 Submissions on our draft decision were broadly supportive of retaining the existing expenditure incentive mechanisms for EDBs and Transpower.

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640 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 30.

641 Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 21-28.

642 Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 8.

643 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Section 6.3.

644 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 184.

645 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Section 3.2.2.

5.157 Some submitters suggested that we simplify the expenditure incentive mechanisms to reduce practical complexity but did not propose any solutions on how we do this. We have considered how we could simplify the existing mechanisms or whether other simpler mechanisms could achieve the objectives of expenditure incentive mechanisms and our Framework's overarching objectives. As other submissions noted, the level of complexity is necessary to achieve the desired outcomes.

5.158 We have not been presented with an alternative expenditure incentive mechanism that better meets the overarching objectives of the IM Review framework. We consider that our amendments to the workings of the existing mechanisms, as well as other additions such as the new connection wash-up mechanism for CPPs, improve the incentive outcomes for consumers and suppliers.

5.159 Aurora Energy suggested that we pause IRIS as we go through this 'transition period'. Stopping the IRIS mechanisms for a regulatory period would simply mean that the incentive rate varies across the regulatory period, rather than being constant. This would also lead to differing incentives between opex and capex solutions, which may result in a bias for one type of expenditure over another that is not in the interests of consumers.

5.160 Under a revenue cap, suppliers are still exposed to over- and underspends within the regulatory period (which, without IRIS, can also create other perverse incentives). This issue is also tied to allowing for effective reopener, wash-up and flexibility mechanisms which are important for suppliers to recover costs that are justified and in the long-term interests of consumers. We have extensively reviewed these in-period adjustments as part of the IM Review.

5.161 Overall, we consider that maintaining the core workings of the existing expenditure incentive mechanisms, with some amendments, will better achieve our Framework's overarching objectives. Efficiency and neutrality between opex and capex are going to be important factors in the future for electricity networks, and we consider that our expenditure mechanisms will provide these for the long-term benefits of consumers.

Specific changes to EDB expenditure incentive schemes

5.162 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 final decisions improve the expenditure incentives on regulated suppliers and will continue to provide incentives that better achieves the overarching objectives of the IM Review.

5.163 We have summarised our draft decisions on the specific changes to the EDB expenditure incentive mechanisms in Table 5.3 above. We explain the reasoning for our draft decisions in more detail later in this section.

Topic 5c – Adjust IRIS allowances for inflation

Final decision

5.164 Our final decision is to calculate the opex and capex incentive amounts based on IRIS allowances (adjusted for actual CPI) compared with actual expenditure for EDBs.

5.165 For Transpower, we are changing our draft decision and are not providing for inflation adjusted IRIS allowances in the IMs, as we can already provide for these in an IPP determination under the current IMs.[646]

5.166 Our updated approach for EDBs is as follows:

5.166.1 set nominal opex and capex allowances based on specific cost inflators at a DPP reset;[647]

5.166.2 deflate IRIS allowances using forecast CPI to calculate the allowances in real terms; and

5.166.3 wash up for actual CPI ex-post to calculate the allowance to compare with actual spend.

Problem definition

5.167 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.

[646] In their submission on the draft decision (Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 30), Transpower submitted that real allowances are already provided in the IPP determination, Commerce Commission "Transpower Individual Price-Quality Path Determination 2020 [2019] NZCC19" (14 November 2019), Clause 33.1.

[647] For example, producers price index (PPI) and labour cost index (LCI) for opex, capital goods price index (CGPI) for capex.

5.168 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).

5.169 If outturn inflation differs from forecast inflation at the reset:

5.169.1 Revenue throughout the regulatory period is washed-up for unexpected CPI inflation. We do this to maintain the purchasing power of suppliers' allowed revenue.

5.169.2 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.

5.170 Specifically, the IRIS mechanism operates in the following way.

5.170.1 The IRIS allowance is fixed for a regulatory period in nominal terms (although there are reopeners during the period).

5.170.2 If costs vary from the allowance, the IRIS mechanism results in either a positive or negative incentive adjustment.

5.170.2.1 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.

5.170.2.2 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.

5.171 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.

5.171.1 nominal revenue in the current regulatory period will be higher due to the revenue-washup mechanism (it will be constant in real terms);

5.171.2 nominal operating costs will be higher due to economy-wide inflationary pressures (they will be constant in real terms);

5.171.3 nominal revenue in the next regulatory period will be lower due to the carry-forward negative incentive adjustment associated with the IRIS mechanism; and

5.171.4 overall, net revenue in (real) present value terms will be lower than expected at the reset.

5.172 The opposite occurs in the situation where inflation has caused operating costs to be lower than expected.

5.173 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.

Draft decision

5.174 Our draft decision was to calculate the opex and capex incentive amounts based on IRIS allowances (adjusted for actual CPI) compared with actual expenditure for both EDBs and Transpower.

Draft reasons

5.175 Our draft decision was to calculate the opex and capex incentive amounts based on IRIS allowances (adjusted for actual CPI) compared with actual expenditure. This would remove the impact of economy-wide inflation on incentive amounts for opex and capex.

Stakeholder views

5.176 The ENA noted the impact of high inflation on IRIS carry-forward amounts:[648]

> 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.

5.177 Additionally, the ENA suggested that the IRIS mechanism should be changed to reflect that inflation is outside of EDB's control:[649]

> 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.

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648 Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 9.

649 Electricity Networks Association "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 10.

5.178 Horizon also submitted on the impacts of inflation on IRIS:[650]

> 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.

Our view

5.179 We 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.

5.180 We note the Australian Economic Regulator and Economic Regulation Authority have IRIS-type allowances that are set in real dollars.[651, 652] An option was 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).

5.181 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.

5.182 We also noted 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.[653] 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.

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650 Horizon Networks "Horizon Network – Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 21.

651 For an illustration, see the Gain Sharing Mechanism for Western Power's access arrangement, at s 7.4.

652 For an illustration, see the Operating Expenditure Efficiency Carryover Mechanism for Jemena's access arrangement, at s 12.

653 For more information see Martin Lally "Review of further WACC issues" (22 May 2016), s 3.3.

5.183 We noted 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 were set in real rather than nominal dollars.

5.184 Overall, we considered that our proposal to set the IRIS allowances in real terms would contribute to protecting suppliers from uncontrollable economy-wide inflation risk where they cannot manage this risk.

5.185 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 have generally calculated the ex-ante nominal opex IRIS allowance for PQ-regulated EDBs by taking the real opex 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).

5.186 We could 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.

5.187 Our draft decision was 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.

Draft decision - alternative solutions considered

5.188 As noted above, the alternative approach that we considered was still changing to real IRIS allowances, but washing up for specific cost inflators (eg, as noted above 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.

5.189 On the surface this may seem 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.

5.190 The revenue wash up assumes that general inflation (CPI) would be reflected in all costs (including opex and capex), which is outside of suppliers' control, so is washed up for.

5.191 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.

5.192 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 considered 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.

Submissions on our draft decisions

5.193 We received multiple submissions that were supportive of our draft decision to provide CPI-adjusted IRIS allowances.[654] For example, Wellington Electricity submitted:[655]

> We support the Draft IM Decision to calculate the opex and capex incentive amounts based on IRIS allowances (adjusted for actual CPI) compared with actual expenditure. This will reduce the risk that EDBs are rewarded or penalised for inflation forecast errors in the IRIS calculation which are outside of the network's control.
>
> We also support updating the opex and capex IRIS allowances based on CPI because it ensures consistency with the revenue inflation wash-up. We think the differences between washing up with the inflation measures used to set the IRIS and using CPI will probably be immaterial and keeping consistency with the revenue inflation washup is more important.

5.194 Transpower was also supportive of the draft decision, noting that this was already in place for Transpower.[656]

5.195 Alpine Energy supported our proposal to introduce inflation-adjusted allowances for incentive purposes, but submitted that we should use the cost inflators used to set a DPP rather than CPI:[657]

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[654] For example, see Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 14; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 5.

[655] Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 21.

[656] Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 30.

[657] Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 37-39

> Fundamentally, we do not foresee an issue with the approach of converting nominal allowances to real dollars, and subsequently using ex-post escalation rates to convert real dollars back to nominal dollar IRIS allowance for the explicit purpose of adjusting the IRIS allowances for inflation. However, Alpine Energy does not agree with the Commission's proposed use of the forecast CPIs to convert nominal IRIS allowances to real dollars and subsequently using the ex-post CPI to calculate the nominal dollar allowances. We believe the use of CPI is fundamentally inconsistent as the DPP opex allowances are based on a mix of labour cost index (LCI) and producer price index (PPI), whilst the capex allowances are based on the capital goods pricing index (CGPI).
>
> Alpine Energy is of the view, that the Commission should instead consider using the forecast values of LCI, PPI, and CGPI cost inflators used in setting the DPP allowances to deflate opex and capex IRIS allowances respectively. Subsequently, using the ex-post LCI, PPI and CGPI to convert the real IRIS allowances to nominal dollars. We believe this approach is more consistent with the DPP process and would avoid any potential adverse outcomes relating to escalations and de-escalations.
>
> Given that industry wide inflation is beyond the control of regulated suppliers and the fact that commercial contracts are potentially based on escalation rates that differ from LCI, PPI and CGPI; the more pragmatic and realistic approach would be to set the IRIS allowances in real dollars and allow regulated suppliers to convert the nominal dollars in line with true cost escalation faced by regulated suppliers. This would better promote outcomes consistent with workable competitive markets.

5.196 Unison supported the approach suggested by Alpine Energy in its cross-submission submitting:[658]

> Unison supports that the adjustment should be consistent with how the allowances have been inflated – taking DPP3, the inflation method was opex by weighted average of all industries LCI (60%) and PPI (40%), and capex, all industries CGPI.

Analysis and final decision

5.197 There was broad support in submissions for our draft decision to adjust IRIS allowances for inflation, with some differences in opinion on the preferred type of inflator to apply.

5.198 Alpine Energy supported by Unison, proposed that, rather than adjusting IRIS allowances for CPI, that we use LCI and PPI for the opex allowance and CGPI for the capex allowance (consistent with how we have historically applied cost escalation when setting expenditure allowances at a DPP).

5.199 We consider that our reasons from the draft decision regarding the use of CPI as the inflator for IRIS allowances remain valid. As explained in our draft decision, we proposed to inflate IRIS allowances by CPI to maintain consistency with the revenue path wash-up.

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658 Unison Networks "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 1.

5.199.1 The revenue path gets washed up for CPI to maintain its real value (taking into account uncontrollable economy-wide inflation). If the revenue path and IRIS allowances are washed up using different indices, then there may be differences in the real return recovered if there are differences between the indices.

5.199.2 We are not changing our approach to applying CPI for the revenue wash-up to wash up for economy-wide inflation and maintain revenue in real terms. Therefore, it remains appropriate to ensure consistency by also washing up IRIS allowances for CPI.

5.200 We consider that suppliers should not be exposed to uncontrollable economy-wide inflation, but they should have incentives to control those cost increases that are reasonably within their control. CPI is used as a proxy for uncontrollable economy wide inflation which suppliers will be exposed to. LCI, PPI and CGPI are more reflective of costs relevant to suppliers. We consider that suppliers have more control over these specific costs. Exposing them to these costs provides incentives to efficiently manage them – they may be able to substitute between different goods and services to control for cost changes. While there may be inflation associated with each of these measures that is uncontrollable, we consider that it is not practical to separate controllable and uncontrollable costs from these indices.

5.201 Therefore, for EDBs on a DPP, our final decision is to retain our draft decision and provide IRIS allowances that are washed up for actual CPI.

5.202 Transpower already has inflation-adjusted allowances in the IPP determination. Changing the current arrangements to move this to the IMs risks unintentionally impacting other parts of the revenue wash-up that interact with the IRIS allowance. We consider that moving the inflation adjustment to the IMs is unlikely to better achieve our Framework's overarching objectives.

5.203 Our final decision for Transpower is to change our draft decision and not provide for inflation-adjusted allowances in the Transpower IMs as we can already provide for these in an IPP determination under the current arrangements.

Topic 5d – Maintain our approach to setting incentive rates

Final decision

5.204 Our 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 at a PQ reset and instead retain the opex incentive rate being set through the IMs for EDBs and Transpower.

Problem definition

5.205 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.

5.206 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.

5.207 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.

5.208 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.

5.209 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.

Draft decision

5.210 Our draft decision was 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.

Draft reasons

Stakeholder views prior to our draft decision

5.211 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 stated:[659]

> 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

5.212 We considered that the status quo of retaining a retention period of five years for the opex IRIS mechanism would promote the Part 4 purpose and balance uncertainty to suppliers and changes in the external environment.

5.213 The benefits of retaining the fixed five-year retention period for the opex IRIS are that this:

5.213.1 reflects the natural incentive strength if a supplier were to make a saving or overspend at the beginning of a five-year regulatory period;

5.213.2 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

5.213.3 is the approach that suppliers have become accustomed to for the working of the mechanism, a change could further complicate understanding.

5.214 In addition, we noted that a retention period of five years is consistent with the strength of the incentive that is applied by the AER.

5.215 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.

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[659] Transpower "Transpower NZ Ltd – Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2021), p. 31.

Alternative solutions considered - Setting the opex incentive rate at a PQ reset

5.216 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.

5.217 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.

5.218 The downside of this approach would be the uncertainty associated with it. Suppliers would not know in advance what the incentive strength would 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.

5.219 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.

5.220 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.

Alternative solutions considered - Fixed opex and capex incentive rates in the IMs

5.221 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.

5.222 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.

5.223 While this would provide consistency in incentive rates between regulatory periods, there would also be practical issues:

5.223.1 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

5.223.2 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).

Alternative solutions considered - Fixed capex incentive rate with varying opex rate

5.224 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.

5.225 CEPA for the AEMC discusses this issue:[660]

> …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.

5.226 We did not propose 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).

Stakeholder views on draft decision

5.227 Alpine Energy supported our draft decision to maintain the opex incentive rate as a function of the retention period and the WACC for the respective DPP regulatory period.[661] Alpine Energy considered that the retention period of five years in the IMs should remain consistent with the DPP period to better align the IRIS incentive mechanism with the price-quality regulation.

5.228 Wellington Electricity supported our draft decision to retain the current approach to setting incentive rates.[662]

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660 Cambridge Economic Policy Associates (CEPA) "Expenditure incentives faced by Network Service Providers - Final report" (25 May 2018), p. 52.

661 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 33.

662 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Section 3.2.4.

5.229 Vector suggested that an approach by IPART could be worth investigation for how we set incentive rates:[663]

> Under IPART's approach, the present value of opex and capex efficiency gains/losses (assumed to be permanent) is calculated and the business retains a fixed share (20%) of these opex and capex gains/losses (regardless of the price determination period and WACC). This provides a constant business share of efficiency gains/losses that is equal between opex and capex. This option could provide a materially better alternative and should be explored further by the Commission ahead of its final decision.

Analysis and final decision

5.230 Submissions were generally supportive of retaining the current approach of the incentive rate being determined by the retention period and discount rate (WACC).

5.231 We have investigated the IPART approach noted by Vector and consider that this approach is similar to our current expenditure incentive mechanisms in some respects, but overall represents a change in approach to assessing expenditure over- and underspends. It applies a similar approach to capex savings but opex savings are treated differently to the opex IRIS.

5.232 Our understanding of the IPART approach to opex savings is that it:[664]

5.232.1 identifies incremental opex savings every year (as IRIS does);

5.232.2 assumes that the opex savings or overspends are permanent in nature (ie, continue into perpetuity) and calculates the NPV of the total saving into perpetuity;

5.232.3 calculates the 'financing benefits/costs' due to the supplier under- or overspending its allowance within a regulatory period; and

5.232.4 applies the incentive rate (eg, 20%) to the total saving (permanent saving minus the financing benefit/costs).

5.233 We consider that the IPART approach for opex savings does not provide an overall improvement on the current opex IRIS approach as we explain below. Its practical implementation of incentive rates does also not appear to be simpler than the IRIS mechanism. Therefore, we do not consider that a change in approach would better meet the overarching objectives of the IM Review.

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663 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 195.

664 Independent Pricing and Regulatory Tribunal (IPART) "Water regulation handbook" (April 2023), Section 6.4.

5.234 Our final decision is to retain our existing approach to setting incentive rates because:

5.234.1 IPART's approach assumes that all savings are permanent in nature, while IRIS allows for permanent as well as temporary savings.

5.234.2 While it may appear that IPART's approach results in an incentive rate that does not vary with the WACC, when the discount rate (WACC) changes between regulatory periods, the discount rate used to calculate the NPV of savings will also change. Therefore, the total NPV of savings into perpetuity will still vary with the WACC over time, but a constant incentive rate will be applied to the total savings. We consider that it is appropriate that the level of sharing between suppliers and consumers reflects current business conditions through the discount rate.

5.234.3 Compared to the potential unknown implementation challenges of a change to the IPART approach, there is also regulatory certainty in applying an approach that suppliers and the regulator know and understand, consistent with the s 52R IM purpose.

5.234.4 We continue to consider that the incentive rate from making a saving, which is subsequently retained for five years, results in an appropriate sharing between suppliers and consumers.

Topic 5e – Not to exclude specific expenditure categories from IRIS

Final decision

5.235 Our final decision is to retain our draft decision to not change our current approach of applying the expenditure incentive mechanisms to all categories of opex and capex allowances.

5.236 The application of this decision to our price-quality path reopener IM Review decisions is discussed in Chapter 7 of our *CPP and in-period adjustment mechanisms* topic paper.

Problem definition

5.237 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.

5.238 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.

5.239 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).[665] Large expenditure categories being treated as recoverable costs can lead to significant price volatility.

5.240 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).

Stakeholder views prior to our draft decision

5.241 Orion recommended the following suggestion to exclude certain categories of expenditure from entering IRIS:[666]

> 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.

5.242 Wellington Electricity states:[667]

> 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.

5.243 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.[668]

Draft decision

5.244 Our draft decision was to not change our current approach of applying the expenditure incentive mechanisms to all categories of opex and capex allowances.

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665 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.

666 Orion "Orion – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 9.

667 Wellington Electricity "Wellington Electricity – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 9.

668 Horizon Energy "Horizon Energy Group – Submission on Expenditure incentives EDB workshop" (8 December 2022), p. 7.

Draft reasons

5.245 Our general approach to providing incentives for suppliers in our regime is that:

5.245.1 we provide an overall level of opex and capex that a prudent EDB would require; and

5.245.2 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.

5.246 We also noted 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.[669]

5.247 The AER noted this in reference to its capex incentive mechanism:[670]

> 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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669 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.

670 AER " Explanatory Statement - Capital Expenditure Incentive Guideline for Electricity Network Service Providers" (November 2013), p. 51.

5.248 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):[671]

> 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.

5.249 We noted that we 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.

5.250 Related to this issue, we proposed some draft decisions around connection expenditure:

5.250.1 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).[672] 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.

5.250.2 We also proposed to introduce a large connection contract mechanism for EDBs, similar to 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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671 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), p. 279.

672 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.

5.251 We considered that excluding some expenditure categories from the incentive mechanisms would result in increased complexity of the regime through:

5.251.1 different expenditure categories being subject to different incentives, which also increases the importance of classification of expenditure; and

5.251.2 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 would create implementation costs and make it harder to understand.

5.252 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 and non-traditional solutions allowance' which is treated as a recoverable cost. Therefore, we proposed no changes to the IMs to exclude innovation allowances from IRIS.

Alternative approaches considered

5.253 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).[673]

5.254 This would be similar but slightly different to the current recoverable costs mechanism whereby costs 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.

5.255 This issue is also related to the connection capex volume wash-up mechanism that we have implemented for a CPP, but not for a DPP (see Topic 3c above).

5.256 We considered that providing for the exclusion of certain expenditure categories from IRIS 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.

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673 As noted above, this was also a reason for proposing to introduce large connection contracts for EDBs, which take new connections that meet certain criteria outside of the regulatory asset base and revenue.

5.257 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 considered that an alternative option could be to allow capex 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.

5.258 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).

5.259 However, given the lack of incentives on suppliers for cost efficiency for the specific categories of expenditure, increased complexity of implementing different categories with different incentive rates, and other mechanisms available in the regime, we considered that keeping the status quo would better promote the Part 4 purpose.

Stakeholder views on our draft decision

5.260 We received six submissions and one cross-submission on our draft decision to not exclude any additional expenditure categories from IRIS. Most submissions disagreed with our draft decision, particularly for consumer connections, which submitters felt were outside of the control of businesses and should therefore be excluded from IRIS.

5.261 Multiple suppliers disagreed with our draft decision, as they consider that the quantity of consumer connections remains outside their control. Vector[674] submitted that:

> The Commission has considered allowing for the exclusion of some expenditure categories from IRIS at a reset (e.g., where costs are outside an EDB's control). However, it has not moved forward with any changes noting that it would lead to increased complexity.
>
> We do not believe that complexity is a valid excuse for not improving IMs that may deliver better outcomes for suppliers and consumers. If complexity is a valid test, then many of the mechanisms we already have in place such as IRIS would need significant change. The IMs purpose is set out in s52R it does not include simplicity.

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674 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 196-198.

> New customer connection growth is outside of the control of EDBs. However, the IRIS penalises networks if new customer growth and the resulting expenditure is more than the allowances provided, or rewards EDBs if the expected growth does not eventuate – the penalties and rewards are primarily based on customer decisions and are mostly unrelated to cost efficiency.
>
> We recommend once again that the Commission excludes ‘consumer connections’ from IRIS.

5.262 Drive Electric submitted:[675]

> Lowering (or removing) the IRIS incentive rate for connections – this weakens the reward for outperforming forecasts (including through efficiency gains) but also reduces the cost recovery risk should connections outpace forecast. This would soften what we see as a key driver for EDB capital contribution policies.

5.263 Wellington Electricity proposed an alternative implementation that they considered would protect suppliers from uncontrollable costs without adding much complexity. They submitted:[676]

> Rather than treating as a passthrough, we think the cost could be left in the allowances and removed from the IRIS calculation – adjusting the IRIS from the IRIS opex and removing them from actual costs when calculating the IRIS impact.
>
> A similar adjustment is already made for the right-of-use assets. We don’t think this would make the DPP reset much more complex as a similar adjustment is already made.

5.264 Not all suppliers disagreed with our draft decision. Transpower agreed with our position that only costs that are truly uncontrollable should be passed through, as allowances are designed to be fungible.[677]

Analysis and final decision

5.265 Two categories of expenditure were mentioned by suppliers as categories they considered should be excluded from IRIS.

5.265.1 Multiple submissions mentioned consumer connection capex as being outside of the control of suppliers, and noting the risk of negative IRIS adjustments based on consumer decisions which are not under the reasonable control of the EDB.

5.265.2 The other category mentioned is insurance costs, which Wellington Electricity considered outside of its control.

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675 Drive Electric "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 8.

676 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 22.

677 Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 31.

5.266 Vector characterised our decision to not exclude certain categories of expenditure from IRIS as a complexity issue. While excluding categories of expenditure from IRIS would add significant complexity, it is not the main reason for our decision. We consider the impact on incentives and efficiency - and the implications for promoting s 52A for the long-term benefit of consumers - to be more important.

5.267 We consider our draft reasons for not excluding customer connections from IRIS remain valid. While there may be some uncertainty surrounding consumer connections, we consider that between the tools available to suppliers (such as reprioritisation of expenditure and adjustments to capital contribution policies) and the connection-related tools that we have introduced in our final decisions (including the 'new connection wash-up mechanism' in a CPP, amendments to price-path reopeners and the LCC) suppliers can sufficiently mitigate the risk of significant new connections that are not forecast.[678]

5.268 Wellington Electricity submitted that rather than passing through uncontrollable costs directly, we could treat them in a similar manner to right of use assets, keeping the expenditure in allowances, but removing them from IRIS calculations.[679] We consider that our reasons for not excluding expenditure categories from IRIS also apply to Wellington Electricity's proposal.

5.269 We also note that the Electricity Authority, as the regulator of distribution pricing, is consulting on targeted reforms to distribution pricing, including connection charges and role of capital contributions in the funding of investments.

5.270 We explain our decision for making no change to IMs relating to insurance (including self-insurance) for EDBs or GPBs in our Report on the Review 2023.[680]

Topic 5f – Use the midpoint discount rate in the opex IRIS calculation

Final decision

5.271 Our 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 under the EDB IMs and Transpower IMs.

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678 Refer to Topic 3c in Chapter 3 above for further discussion on the new connection wash-up mechanism and refer to Chapter 8 of our *CPP and in-period adjustment mechanisms* topic paper for further discussion on the large connection contract (LCC) mechanism.

679 The reason right of use assets are subject to specific treatment in IRIS is explained from para 5.288.

680 Commerce Commission "Report on the IM Review 2023– Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), Decision SP03.

Problem definition

5.272 Under the current IMs, 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.

5.273 The discount rate in the opex IRIS is simply the discount rate for cash-flows that suppliers receive in the future. We want to equalise incentive rates between opex and capex, to the conceptually correct discount rate that is as close as possible to the supplier's internal discount rate, otherwise there may be differing incentives between opex and capex savings.

Draft decision

5.274 Our draft decision was 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 under the EDB IMs and Transpower IMs.

Draft reasons

Stakeholder views

5.275 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.[681]

5.276 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:[682]

> 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

5.277 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.

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681 Pat Duignan "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

682 Pat Duignan "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

5.278 Our best estimate of the cost of capital at the beginning of a price-quality path is the midpoint WACC. We did 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.

5.279 We proposed 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 cashflows.

Alternative solutions considered

5.280 We have considered whether retaining the current approach (setting the discount rate equal to WACC applied for a price-path) remains appropriate.

5.281 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.

5.282 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).

Stakeholder views on our draft decision

5.283 Alpine Energy supported our draft decision to use the midpoint discount rate in calculating the opex incentive rate.[683]

5.284 The ENA disagreed with our draft decision to use the midpoint WACC for IRIS calculations.[684] The ENA considered that the opex IRIS should use the DPP WACC applied to set the revenue allowance for regulatory and internal consistency.

683 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 12.

684 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Section 6.3.

5.285 Vector noted that, while the change is unlikely to be particularly material, the discount rate may distort decision-making if it differs from a supplier's WACC:[685]

> If the Commission's best estimate of the WACC is to adopt the 65th percentile, then for internal consistency the same WACC estimate should be used as the discount rate for the IRIS.

Analysis and final decision

5.286 Some submissions disagreed with using the midpoint WACC as the discount rate because this was inconsistent with the WACC applied to set the revenue allowance. We consider that the WACC applied for setting revenues and the discount rate for opex spend are used for separate purposes and do not need to be the same.

5.287 In response to Vector's submission point that the WACC with an uplift is our best estimate, we refer back to our draft decision reasoning that our best estimate of the cost of capital at the beginning of a price-quality path is the midpoint WACC. The WACC uplift was introduced for the purpose of reducing the risk of underinvestment. However, this is not relevant to setting the discount rate on opex, where we remain of the view that using the midpoint vanilla WACC will better achieve our Framework's overarching objectives.

Topic 5g – Maintain our current treatment of operating leases

Final decision

5.288 Our 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

5.289 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).[686]

Draft decision

5.290 Our draft decision was that no change to the current mechanism was required to account for the treatment of right of use assets/operating leases.

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685 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 200-203.

686 For a full discussion of our reasoning for making this change, see Commerce Commission "Treatment of operating leases – Final decisions paper" (13 November 2019).

Reasons for our draft decision

Stakeholder views prior to our draft decision

5.291 In its submission on the Process and issues paper, Wellington Electricity states: [687]

> 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.

5.292 Wellington Electricity described this issue as a low review priority but suggested that we review the IFRS 16 adjustment to exclude the added complexity.

5.293 We analysed this issue in detail during our decisions on the treatment of operating leases. We considered that, even though our solution leads to additional complexity, the benefits of maintaining right-of-use leases as opex ultimately outweighs the volatility and timing mismatch of treating the leases as capex.[688]

5.294 We noted that we had not been provided with any evidence that suggested that our updated treatment of leases for incentive purposes was not working, or that alternatives that would better achieve the IM Review overarching objectives.

Stakeholder views on our draft decision

5.295 Vector suggested that we remove operating leases and software as a service (SaaS) costs expenditure from the IRIS calculation.[689] Vector states:[690]

> Vector believes that the requirement to maintain separate accounting and regulatory treatment adds to the disclosure burden and creates greater risk of error.
>
> With operating leases falling under 'forecast opex' we believe that IRIS will unduly penalise EDBs for expenditure that is difficult to predict. If an EDB's offices move to a different location during a DPP, increasing overhead costs and leading to an overspend of opex allowances, they will face an IRIS penalty. Vector is in the process of moving their Auckland head office and was unable to forecast this change ahead of DPP3 with no signed contracts in place to justify the increased costs.

687 Wellington Electricity "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 16.

688 For further explanation, see Commerce Commission "Treatment of operating leases - Draft decisions and reasons paper" (28 August 2019), Chapter 7.

689 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 204-209.

690 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 206-207.

Analysis and final decision

5.296 In response to Vector's submission, we assumed that its proposal to 'remove operating leases and SaaS expenditure from the IRIS calculation' meant that these costs are to be passed-through straight to consumers. Just removing the costs from the IRIS mechanism would mean that suppliers are still exposed to over- and underspends, only at a varying incentive rate over the regulatory period.

5.297 The use and cost of operating leases are within the control of suppliers and can be an alternative to capex investments. Removing any incentive to control costs on any operating leases could lead to perverse incentives and inefficient spend that is passed on directly to consumers.[691]

5.298 We consider that the current treatment of operating leases as opex, rather than capitalising as capex, will minimise the impact of forecast error (as it does not use an amount capitalised based on forecast cashflows for the assumed life of the lease), better matching the timing of ongoing spend and provide incentives for efficiency.

5.299 In response to Vector's submission point on SaaS also being impacted by changing accounting rules, we note that the IRIS treatment of SaaS in future regulatory periods will follow the GAAP accounting treatment.

5.300 Our final decision is to confirm our draft decision to maintain our existing treatment of operating leases, for the same reason as in the draft: we have considered this issue in depth previously and we have no evidence that a change in approach would better achieve the IM Review overarching objectives.

Topic 5h – Make no change to IRIS for undercharging

Final decision

5.301 Our final decision confirms our draft decision, which was to make no changes to IRIS for suppliers undercharging their MAR.

Problem definition

5.302 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.

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691 For example, suppliers could decide not to invest in planned capex and inefficiently take on more operating leases because the increased costs are passed on to consumers and not borne by the supplier.

5.303 We discussed this issue in the setting of DPP3.[692] 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.

Draft decision

5.304 Our draft decision was 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.

Draft reasons

Stakeholder views prior to our draft decision

5.305 TLC submitted that our approach to voluntary undercharging does not incentivise EDBs to do so:[693]

> 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.
>
> …
>
> 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).

Our view

5.306 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.

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[692] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), para E114-E132.

[693] The Lines Company "The Lines Company – Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 2.

5.307 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.

5.308 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.

5.309 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.

5.310 We also noted 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).

Stakeholder views on the draft decision

5.311 We only received one submission on undercharging, from Vector,[694] who agreed with our draft decision to make no changes for undercharging.

Analysis and final decisions

5.312 As noted above, there were no submissions that suggested a change from our draft decision. Our final decision is to confirm our draft decision and make no change to IRIS for suppliers that undercharge their MAR. We do not consider that such a change would better promote our IM Review overarching objectives.

Specific changes to Transpower expenditure incentive schemes

5.313 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).

694 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 210-211.

5.314 We have summarised our final decisions on the specific changes to the Transpower expenditure incentive mechanisms in Table 5.3 above. We explain the reasoning for our final decisions in more detail later in this section.

Topic 5i – Transpower opex IRIS

Final decision

5.315 Our decision is to remove the IRIS baseline adjustment term (IBAT) from Transpower's opex IRIS and make IM changes to Transpower's opex IRIS to:

5.315.1 amend the base year adjustment term to align IRIS with the timing of IPP reset processes;

5.315.2 better align IRIS with how we set opex allowances in an IPP; and

5.315.3 provide better efficiency incentives and certainty during a regulatory period.

5.316 We outline the technical changes to Transpower's opex IRIS, based on the AER's EBSS model,[695] in the reasoning below.

Problem definition

5.317 Prior to 2017, the Transpower opex IRIS mechanism assumed that any permanent savings made up to and including year 4 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 4 savings in the forecast.[696]

5.318 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).[697]

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695 AER "Efficiency benefit sharing scheme" (29 November 2013). We note that the EBSS has been in place since 2013, but is regularly reviewed, most recently in 2023, which can be found here: AER "Review of incentive schemes for regulated networks" (28 April 2023)

696 If year 3 savings are not incorporated in the IPP forecast, then the IRIS mechanism will over-reward savings (and over-penalise overspends) made in year 4 based on the IRIS assumptions pre-2017. Absent an adjustment, the reward for permanent savings would be almost twice the intended amount.

697 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).

5.319 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).

5.320 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).

5.321 During Transpower's RCP3 IPP reset process, there was an $110 million difference between Transpower's proposed incentive amount and our draft decision.[698] 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.

Draft decision

5.322 Our draft decision was to remove the IBAT for Transpower's opex incentive calculation and to set Transpower's opex IRIS to be same as the DPP opex IRIS for EDBs.

Reasons for our draft decision

Stakeholder views prior to our draft decision

5.323 Transpower noted on the IBAT:[699]

> 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

5.324 We noted that, 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.

698 Transpower NZ Ltd "Transpower submission on Draft IBAT decision" (21 August 2019), p. 3.

699 Transpower "Transpower NZ Ltd – Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 1.

5.325 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.

5.326 The expenditure forecasts that underpinned the expenditure allowances for RCP3 were informed by base-step-trend forecasts prepared by Transpower.[700]

5.327 If Transpower continued 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 (assuming a year 4 base year).[701] This removes the need for the baseline adjustment term and associated uncertainty surrounding the 'differences-in-penultimate-year' term that is determined by us.

5.328 The existing opex IRIS mechanism provided 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.

5.329 We considered that removing the baseline adjustment term, with effect from the RCP4 reset onwards, would:

5.329.1 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).

5.329.2 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.

5.330 For the reasons outlined above, we considered that removing the baseline adjustment term would better achieve the IM Review overarching objectives than alternative implementation options.

700 Transpower used also bottom-up approaches to inform its forecasts.

701 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.

Alternatives considered

5.331 We considered whether we should keep the IBAT in place for Transpower's incentive calculations but considered that this was not appropriate given:

5.331.1 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

5.331.2 the complexity and uncertainty created by the mechanism could have a negative impact on Transpower's incentives to seek efficiencies.

Stakeholder views on our draft decision

5.332 We received three submissions on our draft decision to remove IBAT from Transpower's opex IRIS, two from Transpower and one from Vector.

5.333 Transpower in its submissions agreed with the decision to remove the IBAT, but pointed out issues with the specific implementation of the opex IRIS: [702]

> …we do not agree that an "opex IRIS approach [like that] applied in the EDB DPP" is appropriate for Transpower for the following reasons: our understanding is the Commission has misinterpreted our RCP4 proposal document. In the proposal, we refer to updating numbers from 2021/22 to 2022/23 (or Year 2 to Year 3 of RCP4), instead of Year 3 to Year 4 as suggested by the Commission. We intend to use Year 3 as the base year for RCP4. we do not believe an opex IRIS approach like that applied in the EDB DPP appropriately manages temporary savings in the base year when a base-step-trend (BST) approach is used. This is because the overcompensation in the Year 4 IRIS carry forward is not offset by a lower allowance in Y6-Y10, as the allowance for the succeeding regulatory period is set using the BST and not Year 4 actuals.
>
> Our understanding is AER's Efficiency Benefit Sharing Scheme (EBSS) has mechanisms in place to appropriately compensate suppliers in this circumstance. We ask that the Commission review the EBSS and assess its appropriateness for Transpower for managing the above issue.

5.334 In its cross-submission, Vector disagreed with Transpower's submission on the implementation issues Transpower raised:[703]

> On IRIS, Transpower does not agree that an "opex IRIS approach [like that] applied in the EDB DPP" is appropriate for them. Vector does not understand why Transpower should be treated differently to EDBs. We therefore agree that the Commission is right to apply this rule to Transpower.

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[702] Transpower's two submissions on this matter were substantively the same. Transpower "Email to IM Review providing written submission" (28 June 2023); Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 145-147.

[703] Vector "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 41.

Analysis and final decision

5.335 Our final decision is to remove the IBAT and make IM changes to Transpower's opex IRIS to:

5.335.1 amend the base year adjustment term to align IRIS with the timing of IPP reset processes;

5.335.2 better aligns IRIS with how we set opex allowances in an IPP; and

5.335.3 provide better efficiency incentives and certainty during a regulatory period.

5.336 The implementation of the above three changes is based on the AER's EBSS.[704] We have published a model alongside our final decision that illustrates our implementation of the final decision.[705]

5.337 Below we explain how our decision to change the working of Transpower's opex IRIS provide benefits to both Transpower and consumers.

Removing IBAT achieves our Framework's overarching objectives

5.338 For the same reasons as in our draft decision set out between paragraphs 5.323 and 5.330 above, we consider removing the IBAT will achieve our Framework's overarching objectives by better promoting s 52A(1)(a) and (b) and reducing complexity and compliance costs (without harming the promotion of s 52A).

Alignment with timing for IPP processes

5.339 We agree with Transpower's submission (see paragraph 5.333) that the IRIS needs to align with the opex base year used in its expenditure proposals. At the time of determining Transpower's expenditure allowances, the latest available year of actual expenditure (given consideration to other processes) is year 3. Transpower submitted that opex forecasts assumed in the IRIS mechanism should reflect year 3 actuals, whereas our draft decision assumed year 4 as the base year for the opex IRIS.

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704 The current version of the EBSS was implemented in 2013 and most recently reviewed in April 2023. The EBSS and IRIS are very similar with both schemes using incremental savings each year to incentivise efficiency and equalise marginal incentives across a regulatory period.

705 Refer to Commerce Commission "Part 4 IM Review Risks and incentives: Demonstration model: Changes to Transpower's opex IRIS" published alongside our 2023 IM Review final decision.

5.340 We have accordingly adopted year 3 as the base year for Transpower's opex IRIS. This ensures that the assumptions in the opex IRIS model are consistent with how we set Transpower's expenditure allowance for an IPP and sets the link between regulatory periods. An inconsistency between the base year used in expenditure forecasts and the IRIS base year would lead to inconsistent incentive strength across the regulatory period.[706]

5.341 Implementing IRIS to align with the opex base year in Transpower's expenditure proposal (when combined with the three necessary related changes above to how we set expenditure allowances) ensures that Transpower is subject to constant marginal incentives across the regulatory period.

5.342 Ensuring IRIS provides consistent incentives rates to make efficiency savings is one of the objectives of our expenditure incentive mechanism (refer to paras 5.10 - 5.14) and this change better achieves our Framework's overarching objectives by better promoting s 52A(1)(a), (b) and (c).

Alignment with how we set opex allowances in an IPP

5.343 Transpower submitted that it did not consider that the EDB opex IRIS appropriately treats temporary savings in the base year (year 3 for Transpower) when BST forecasting is used.[707] We agree with Transpower that IRIS needs to align with opex expenditure setting processes, and we have adopted the recommendation to consider and adapt the AER's EBSS for this purpose.[708] To achieve alignment with how we set opex allowances in an IPP, our final decision is for Transpower's opex IRIS to include an additional adjustment term that provides flexibility to adjust the IRIS for non-recurrent amounts in the base year. We outline this further and explain how it achieves our Framework's overarching objectives, as follows.

5.344 Actual opex may include non-recurrent amounts, such as one-off remediation costs.[709] In the context of an IPP, to ensure opex allowances reflect expected efficient spend (s 52A(1)(b)), it would therefore be appropriate to exclude these from the forecast opex allowance.

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706 Differences between the IPP process base year and IRIS base year causes non-constant marginal incentives across the regulatory period. In the case of year 3 being used to set expenditure forecasts and year 4 being used as a base year for IRIS, savings (both permanent and temporary) made in year 4 are overvalued.

707 Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 146.

708 Transpower's two submissions on this matter were substantively the same. Transpower "Email to IM Review providing written submission" (28 June 2023); Transpower "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 145-147.

709 For context, these non-recurrent amounts or atypical one-off costs are referred to as 'non-recurrent efficiency gains and losses' in the AER's EBSS. In its 2013 guidelines, the AER discussed only 'efficiency

5.345 Any such adjustments for non-recurrent amounts made when setting the expenditure allowance also need to be reflected in the IRIS.[710] Not providing flexibility in the IRIS for such adjustments would create misalignment between IRIS and the opex allowances and produce over retention of any temporary over- or underspends in years 3 and 4 (s 52A(1)(c)).[711]

5.346 Aligning IRIS and expenditure setting by introducing the adjustment for non-recurrent amounts better promotes the overarching objectives of the IM Review framework:

5.346.1 More accurate expenditure allowance better promotes s 52A(1)(b); and

5.346.2 Constant marginal incentives help share with consumers the benefits of efficiency gains as per s 52A(1)(c).

Implementation differences between Transpower's opex IRIS and the EDB opex IRIS

5.347 Vector submitted in support of our changes to align the Transpower and EDB IRIS, submitting that they did not see a reason why they should be different.[712] The Transpower and EDB opex IRIS have several similarities. However, we consider the differences between Transpower's IRIS and the EDB IRIS appropriately reflect the differences between IPP regulation and DPP regulation.[713] We note that the IRIS mechanism for EDBs on a CPP also include additional adjustment terms to reflect that CPPs are more customised and further adjustments may be required to link regulatory periods.

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gains', but in later determinations, the AER recognised that the term could also include losses. For further information refer to AER "Explanatory statement, Expenditure forecast assessment guideline" (November 2013), pp. 95–96.

710 The IRIS for EDBs subject to a DPP does not account for non-recurrent costs in the base year. This would require scrutiny and regulation that is not consistent with the relatively low-cost purpose of DPP regulation under s 53K. Instead, we treat actual opex as the base amount for forecast opex. This means that if there are significant non-recurrent amounts the expenditure allowance set may be different than an allowance set where these non-recurrent savings are accounted for. The EDB IRIS aligns with this approach and ensures that businesses do not experience any incentive to inflate or deflate base year expenditure. A profit-satisficing business may spend a different amount than they would have if a more accurate allowance was set.

711 IRIS works in tandem with the expenditure setting process to ensure that suppliers experience constant marginal incentives across a regulatory period. If the expenditure setting process accounts for non-recurrent costs and IRIS does not, then these non-recurrent costs are over-valued in years 3 and 4 when compared to other years in the regulatory period.

712 Vector "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 41.

713 Under s 53ZC(1), if individual price-quality regulation applies to goods or services supplied by a supplier, we may set the price-quality path for that supplier using any process, and in any way, we think fit, using the IMs that apply to the supply of those goods or services. This contrasts with the relatively low-cost purpose of DPP regulation under s 53K.

5.348 As noted above, Transpower's expenditure proposals have typically used year 3 as a base year unlike EDB DPPs which have traditionally used year 4. DPP and IPP regulatory processes differ significantly and it is appropriate for the IRIS base year to be different to accurately reflect established processes.

5.349 The IPP reset process also allows us to apply additional scrutiny when compared to the DPP reset process. This scrutiny is reflected in the different approach to setting expenditure allowances in the IPP. As explained above, for the opex IRIS to provide constant marginal incentives, both the IRIS base year and treatment of non-recurrent costs must align with the expenditure setting approach. We therefore consider the additional flexibility provided for in Transpower's IRIS to be appropriate.

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.[714, 715]

6.2 This chapter sets out our decisions on specific tools for promoting innovation under our regulatory regime, including regulatory sandboxes, the innovation and non-traditional solutions allowance for EDBs, and incentives for opex and capex trade-offs across regulatory periods for EDBs and Transpower. Providing the right incentives are 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 final 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 allowances for these investigations and consider that this continues to be appropriate);[716, 717] and

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714 None of the four outcomes are paramount and, further, the outcomes are not separate and distinct from each other, or from section 52A(1) as a whole. Rather, we must balance them, and must exercise judgement in doing so. When exercising this judgement, we are guided by what best promotes the long-term benefit of consumers. See *Wellington International Airport Ltd and Ors v Commerce Commission* [2013] NZHC 3289, at [684], and [1391]-[1492], as noted in Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022), para 2.7.

715 Note that we may not treat income generated from innovative solutions sold by one supplier to another as regulated income.

716 First Gas Limited "Submission on IM Review Process and issues paper and draft Framework paper" (13 July 2022), pp. 3, 32.

717 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.

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.[718]

6.4 Our main Part 4 tools for promoting innovation 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.[719]

6.4.2 For price-quality (PQ) 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 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;

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718 For example Air New Zealand "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 3.

719 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.

6.6.2 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;

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 are intended to make EDBs indifferent between opex and capex solutions from a regulatory financial perspective (within regulatory periods), reducing barriers for the adoption of 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 innovation project allowance (IPA) is intended to improve incentives to innovate and encourage distributors to try new ways of doing business.[720]

6.7 The IMs and Part 4 regulation are part of wider regulatory system concerned with encouraging innovation and investment. There are also several organisations who provide innovation funding and support.[721]

6.8 We received submissions on our draft decisions that were concerned that the changes proposed did not go far enough in enabling the regime to incentivise innovation. Entrust[722] and solarZero[723] considered that the regime should change further to enable a sufficient level of innovation and investment for the energy transition.

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720 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), para 6.53.

721 For example see the GIDI fund and Callaghan Innovation.

722 Entrust "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 3.

723 solarZero "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 2.

6.9 Mercury (supported by Transpower in cross-submissions) raised concerns with how the application of IMs would handle the dual problem of incentivising investment in network capacity ahead of the expected increase in demand while also incentivising investment in non-traditional solutions that may reduce whole of system costs.[724] Mercury submitted:

> It is unclear how the IMs presently address this dual challenge of maintaining the incentive to invest in network capacity ahead of demand while promoting the incentive to invest in new, innovate flexible, demand-side resources. Commission should give thought to the application of its available tools so that its decisions incentivize regulated suppliers to make decisions that enable the development of flexible, demand-side resources and promote economic efficiency in the long run.

6.10 We consider that the decisions explained in this chapter better promote s 52A(1)(a) than the status quo. The IM changes we have made, when applied under PQ regulation, enable more options in the regulatory toolkit to incentivise innovative or non-traditional solutions and reduce potential barriers in the regime for the adoption of non-network solutions.

6.11 Our decisions will also enable more flexibility for EDBs than the status quo, by ensuring all drawdown criteria for the INSTA are set at a PQ reset. We consider that when we apply the amended IMs in setting PQ paths in the current context of faster change, we will need to be responsive to the context and information available closer to that time. We consider that Transpower's IMs already provide the flexibility needed to allow the price path to be set in a way that promotes the long-term benefit of consumers under s 52A. These changes will be complemented by existing Part 4 regulatory tools (discussed at paragraph 6.6), as well as the wider regulatory system.[725]

6a: Regulatory sandboxes for EDBs

6.12 Feedback from some suppliers before our draft decision suggested 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.

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724 Mercury "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 3; Transpower "Cross-submission on IM Review 2023 Draft Decision" (9 August 2023), p. 2.

725 For example, the Electricity Authority's work programme includes a project to improve distributors' and flexibility traders' access to meter data and visibility of distributed energy resources. Electricity Authority "Delivering key distribution sector reform - Work programme" (16 October 2023)

6.13 Formal regulatory sandboxes have been implemented overseas, and the Electricity Authority[726] is currently developing guidance surrounding exemptions, to increase the flexibility of regulatory regimes to better enable innovation.[727] 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.

6.14 Tools used by these schemes can be broadly broken down into three categories:

6.14.1 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;

6.14.2 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

6.14.3 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.

Final decision

6.15 Our final decision is to not introduce a regulatory sandbox mechanism in the IMs. We consider the IMs generally enable the desired outcomes of regulatory sandboxes

6.16 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. We consider that implementing a formal sandbox in the IMs would not better achieve the overarching objectives of the IM Review.

Problem definition

6.17 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.

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726 Electricity Authority "Delivering key distribution sector reform" (16 October 2023), p. 10.

727 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).

6.18 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.

6.19 PQ-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 also symmetrically limit the downside risk of overspending. Suppliers currently only bear 23 percent of any overspend incurred with consumers bearing the rest.

6.20 However, PQ-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.

6.21 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. We consider that when we apply the IMs in setting PQ paths in the current context of faster change we need to be responsive to the context and information available closer to that time.

Draft decision

6.22 Our draft decision was that we considered the IMs generally enabled the desired outcomes of regulatory sandboxes and did not propose to change them for this purpose.

Draft decision reasons

6.23 In our draft decision we considered the IMs generally enabled the desired outcomes of regulatory sandboxes and did not propose to change them for this purpose. Our view was that the current rules afford a large degree of flexibility for suppliers to innovate, and, we had not been presented with evidence of specific examples where innovation had not occurred that a regulatory sandbox would have enabled.

6.24 The reasons for our draft decision reflected that:

6.24.1 in our view that there is sufficient flexibility between the tools of setting the price path, IRIS and the innovation project allowance to provide EDBs with financial incentives to innovate;

6.24.2 we already have broad scope to set flexibility regarding quality standards at the DPP reset (there are no input methodologies for quality standards); and

6.24.3 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. Suppliers did not provide us with examples of any such projects prior to our draft decision.

6.25 To assess whether there was a need to implement a regulatory sandbox scheme we evaluated the pre-2023 IM Review Part 4 regime's ability to:

6.25.1 provide flexibility to innovate to suppliers regarding expenditure; and

6.25.2 provide flexibility to innovate to suppliers regarding quality.

Existing settings provide flexibility regarding expenditure

6.26 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.

6.27 IRIS provides expenditure-type neutral financial incentives within regulatory periods.[728, 729] It provides innovation incentives in the following ways:

6.27.1 it shares with suppliers savings resulting from innovative approaches that lead to reduced costs within the regulatory period;

6.27.2 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

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728 For more details on the working of IRIS see Attachment B.

729 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 solution are discussed in section 6b.

6.27.3 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).

6.28 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.[730] Our draft decision recognised there are issues with the current IPA mechanism and we have made amendments to improve our ability to provide better financial incentives to innovate, in line with s 52A(1)(a).[731]

Existing settings provide flexibility with quality standards

6.29 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.[732] However, once set, the price-quality path cannot be reopened except under specific circumstances,[733] so any exclusions or carve outs need to be prescribed ex-ante, at the reset.

6.30 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.[734] 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.

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730 Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper” (27 November 2019), para 6.53.

731 For more detailed discussion on the changes to the IPA see topic 6b.

732 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.

733 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 6.34.

734 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.

6.31 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.[735]

Alternatives considered

6.32 For our draft decision, we reviewed formal regulatory sandbox schemes in other jurisdictions and concluded that the benefits of these schemes are best provided for under the current IMs.

6.33 There are some tools commonly seen in regulatory sandboxes that are more difficult to provide for under Part 4 regulation. These are:

6.33.1 temporary rule exemptions such as 'IM/ price-quality exemption mechanisms'; and

6.33.2 temporary rule changes such as 'trial IMs/ price-quality provisions'.

6.34 While we can amend IMs and PQ 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:

6.34.1 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;

6.34.2 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

6.34.3 at the IM level, we cannot make new IMs beyond those we have made under s 52T(1)[736] 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).

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[735] Section 53K of the Act.

[736] Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022), para 2.65-2.74.

6.35 This means that, while we have substantial scope to provide flexibility and to lower risk when setting the PQ path,[737] 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.

6.36 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.[738] 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.

6.37 We considered that understanding if there are specific regulatory rules that are standing in the way of innovation is important for the regime and invited further submissions on this subject.

Stakeholder views on sandboxing prior to our draft decision

6.38 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, and considered these in reaching our draft decision.

6.39 Vector identified sandboxes as a tool used by overseas regulators submitting:[739]

> 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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737 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.

738 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.

739 Vector "Submission on the Process and issues paper" (11 July 2022), para 45.

6.40 Orion submitted that we should investigate regulatory sandboxes:[740]

> 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.

6.41 The ENA submitted supporting investigation into sandboxing stating:[741]

> Introducing regulatory sandboxes is one way the IMs can encourage innovation, and these should be considered by the Commission.

6.42 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.[742]

6.43 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.

6.44 On sandboxing tools Horizon submitted:[743]

> 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.

6.45 Also on sandboxing, Orion submitted:[744]

> 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

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740 Orion "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 35.

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

742 Commerce Commission "IM Review 2023: Forecasting and incentivising efficient expenditure for EDBs - 'Full slide deck'" (7 November 2022).

743 Horizon Energy Group "Submission on Expenditure incentives EDB workshop" (8 December 2022).

744 Orion "Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 15.

• Funding should be up front

• 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

Stakeholder views on the draft decision

6.46 Vector submitted it is not convinced that the flexibility currently provided by the IMs will translate into innovation in practice. It considered that additional impetus, such as formalising the regulatory sandbox would be required to encourage adopting non-traditional solutions. Vector submitted:[745]

> 224. The Commission's draft decision to not introduce a regulatory sandbox is motivated by two factors. First, it considers the current rules already afford significant flexibility for suppliers to innovate. Second, it has not been provided any examples of things EDBs could have done within the confines of a sandbox that they could not be done already. As for the first point, although the IMs may provide scope to innovate in theory that does not mean businesses will be inclined to do so in practice without additional impetus. Traditional solutions may still hold significant appeal for a variety of reasons.
>
> 225. Although we cannot say for certain, that inertia could be why the Commission has not yet been provided with any examples of innovation being hindered through the lack of a sandbox. The lack of examples may merely be symptomatic of the very problems a sandbox might (at least partially) address. Introducing such a mechanism might therefore have a 'kindling' effect and encourage businesses to try new things that could deliver benefits to customers.
>
> 226. Moreover, even if a regulatory sandbox was seldom used, the costs associated with introducing and maintaining such a mechanism would be relatively modest. In other words, the potential upside benefits could well outweigh the downside costs. On balance, having a regulatory sandbox available for those occasions that businesses might want to use it (even recognising that this may not be that often) may therefore be preferable to not having one if/when businesses required it in the future.

6.47 Vector also submitted:[746]

> 229. In Vector's view, the Commission should reconsider introducing a regulatory sandbox. It is increasingly seen as regulatory best practice. Introducing such a mechanism may spur businesses to try new things that may yield benefits. It is also likely to foster collaboration across the energy supply chain. Even if was rarely used, introducing and maintaining such a mechanism would not cost very much. For those reasons, on balance, having a regulatory sandbox available for those times businesses want to use it may therefore be preferable to not having one if/when it is needed at some point in the future.

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745 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 224-226.

746 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 229.

Analysis and final decisions

6.48 Our final decision is to confirm our draft decision and not introduce amendments to the IMs to enable regulatory sandboxing.

6.49 Vector's submission suggests we should introduce regulatory sandboxing to encourage innovation and outside the box thinking. They consider the lack of evidence of projects that could not occur under the current regulatory settings as a symptom of not having a formal regulatory sandbox. Following the EDB workshop held in November 2022, and in our draft decision, we sought evidence from stakeholders regarding innovative projects that did not go ahead but would have been enabled by a regulatory sandbox. We received no evidence of such projects from either consultation.

6.50 As laid out in the reasons for our draft decision, the regime already provides flexibility when setting a PQ path to provide incentives to innovate. We consider that the IMs when applied in the context of CPP/DPP price-quality regulation appropriately incentivise innovation and non-traditional solutions.

6.51 As we explain below, our decision to amend and expand the EDB IMs governing the IPA into the 'innovation and non-traditional solutions allowance' (INTSA) will provide broad flexibility to set innovation incentive schemes at a PQ reset. Rather than specify another scheme in the IMs, we consider that improving the tools we already have available will better achieve our Framework's overarching objectives.

6b: Encouraging innovation and non-traditional solutions

6.52 We added the IPA at the EDB DPP3 reset in 2019 to encourage businesses to try new ways of doing business.[747] 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.[748]

Final decision

6.53 Our final decision is to 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. As part of this decision, we are also removing the 'innovation project' definition from the EDB IMs.

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[747] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), para 6.53.

[748] See for example Vector "Cross-submission on IM Review Process and issues paper, and draft framework paper" (3 August 2022), para 32-37.

Problem definition

6.54 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.[749] Regulatory support for innovation or, more generally, non-traditional solutions that will support the transition to a lower carbon economy may take different forms.

6.55 For EDBs, the current IMs have mostly an enabling role in encouraging innovation, with implementation left to price paths.[750] 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.[751] 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.

6.56 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.

6.57 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.[752, 753]

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749 For example NERA Economic Consulting "Innovation under the DPP - potential barriers and solutions" (report prepared for 'Big six' EDBs, 20 December 2022).

750 We discuss the current role of Part 4 in promoting innovation at paragraph 6.6.

751 Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper” (27 November 2019), para 6.52.

752 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.

753 We note that we have amended the drawdown approval of the IPA specified in the DPP determination within the regulatory period to improve suppliers' ability to access the IPA. See Commerce Commission "Electricity Distribution Services Default Price-Quality Path (Innovation Project Allowance Approval Criteria) Amendment Determination 2023" [2023] NZCC 29, (10 November 2023).

6.58 In our draft decision, we noted that 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.

6.59 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. Since publishing our draft decision, we have seen some developments in this area, with Orion[754] recently announcing a flexibility trial with Ecotricity, due to start on 1 May 2024.

Draft decision

6.60 Our draft decision was to amend and expand the IPA into the 'innovation and non-traditional solutions allowance' (INTSA) 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. We also proposed to remove the 'innovation project' definition found in the EDB IMs.

Draft decision reasons

6.61 Along with changing the IPA to the INTSA, we also proposed to remove the associated definition of 'innovation project'. We describe the allowance in the box below.

Figure 6.1 Draft decision 'innovation and non-traditional solutions allowance'

Under the '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.

754 Orion "Energy Flexibility".

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.

6.62 We explained that the differences between the current arrangements (ie, the 'innovation project allowance' and the 'innovation project' definitions) and the INTSA are:[755]

6.62.1 The IPA does not allow us to set schemes that contain rewards or penalty elements (it just provides a simple allowance for drawdown).

6.62.2 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).

6.63 The draft decision proposed a widened the scope at the DPP reset or in setting a CPP to implement schemes that better promote the Part 4 purpose. We explained that the changes would allow us to:

6.63.1 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 would promote certainty as to the Part 4 rules – ie, the IM purpose in s 52R – more effectively.

6.63.2 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 changes would provide scope for implementing a solution to the problem relating to opex/capex trade-offs across regulatory periods, discussed at paragraph 6.59 when setting a price-path.

755 Both the status quo and the proposal are implemented to apply under price-quality regulation by means of a recoverable cost.

6.63.3 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 would likely limit the number of schemes that could operate concurrently in the DPP context).

6.63.4 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).

6.64 NERA on behalf of the 'Big Six' 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.[756]

6.65 We agreed with submitters that the existing 'innovation project' definition in the IMs is imprecise. We considered 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 draft decision considerations of more specificity of the innovation project definition below.

6.66 We considered that 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).

6.67 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 6.59 and in Attachment C) may encourage suppliers to increase their use of demand side management (including by using non-traditional solutions).

6.68 We considered the draft decision 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.

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756 NERA Economic Consulting "Innovation under the DPP - potential barriers and solutions" (report prepared for 'Big six' EDBs, 20 December 2022), p. 15.

Draft decision alternatives considered

Alternative solution: shift prescription out of the DPP into the IMs

6.69 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.

6.70 Providing for more specificity on what an innovation project is would improve certainty. However, we considered 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 recognised 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 considered 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

6.71 As discussed at paragraph 6.59 we received several submissions in relation to an innovation or non-traditional solutions related problem prior to our draft decision.

6.72 This issue was identified in submissions by Wellington Electricity, Transpower and NERA on behalf of the big six EDBs.

6.73 NERA’s report for the Big Six EDBs states that:[757]

> 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.

[757] 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).

> 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.

6.74 Wellington Electricity submitted that the issue is expected to bias traditional capex wire solutions over non-wire solutions funded by opex.[758] Limiting IRIS opex/capex substitution to a single regulatory period causes bias by not allowing offsetting opex/capex expenditure substitution across regulatory periods.[759]

> … 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.
>
> 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).

6.75 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.

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[758] Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 14.

[759] Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 14.

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.

6.76 Our draft decision was 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.

6.77 Given submissions' focus on this specific problem we considered this problem in some detail for our draft decision and considered alternative solutions. We considered that our draft decision better achieves our Framework's overarching objectives in relation to innovation and non-traditional solutions.

6.78 For further information refer to Attachment C, where we provide tentative examples of schemes that, if appropriate in the context, we could implement under DPPs and CPPs.

Our draft decision was to make no changes to the Transpower IMs

6.79 The potential financial disincentives to make certain opex/capex trade-offs may also be relevant for transmission services. As noted in 6.75, Transpower submitted it may be financially worse off when substituting opex for capex, for example when adopting transmission alternatives (involving opex).

6.80 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 expanded the scope also to other areas with potential trade-offs.

6.81 Our draft decision was to make no changes to the Transpower IMs to provide explicit tools in the IMs to encourage innovative or non-traditional solutions. We considered Transpower's IPP provides for flexibility when setting expenditure allowances, including in relation to innovation and non-traditional solutions.[760]

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760 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).

Stakeholder views on the draft decision

6.82 Several submitters on our draft decision considered that changes proposed in the draft decision were warranted and that they would be an improvement on the IPA.[761] They considered that the changes made would allow us to set an INSTA that would improve incentives to innovate.

6.83 Others submitted that while the INTSA was an improvement on the IPA that the IMs still did not go far enough.[762] For example, Vector submitted that even with the changes the new allowance, similar to the current allowance, would remain low powered and unused.[763] Electra considered that the changes were only tweaks to the status quo and that innovation could not thrive under a regulatory framework that was heavily prescriptive and designed for certainty.[764] We also received a submission from solarZero that considers that the changes made would have no impact on the incentives to innovate.[765]

6.84 Common issues submitters had with the proposed INSTA related to the drawdown criteria of a potential scheme and fall outside of the scope of the IM Review.[766] Issues such as the size or drawdown criteria of a INTSA scheme are considerations for a DPP or CPP determination, not the IMs. Contact considered that the concept of additionality (ie, that the work would not have occurred without the allowance) was so fundamental to the innovation allowance, that it should be prescribed in the IMs.[767] The allocation of risk between suppliers and consumers was also raised as a concern, with Wellington Electricity, for example, submitting the ex-post nature of the current IPA put most of the risk on suppliers.[768]

761 Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 6; Orion "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 22; Major Electricity Users Group (MEUG) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 7; Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para. 11.

762 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 14; Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 227 - 231.

763 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 227 - 231.

764 Electra "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 1.

765 solarZero "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 2.

766 Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 7; Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 26; Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 59; Entrust "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 7.

767 Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 14-15.

768 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 26.

6.85 Submitters such as Vector and Flexforum submitted that moving all the drawdown criteria to the DPP would result in no certainty surrounding the INTSA being provided until the DPP determination in December 2024.[769]

6.86 Our draft decision provided scope for non-traditional solutions (not just innovative solutions) to be subject to incentives.[770] We provided examples, whereby the allowance may be used to set DPP or CPP schemes to improve financial incentives to incur opex to defer capex in future regulatory periods. Submitters[771] supported this change and considered it would help facilitate the uptake of flexibility services. Wellington Electricity[772] considered that the addition was welcome, and helped address the capex deferral issue, but that the amendments represented only a short-term solution to the capex deferral problem.

6.87 Along with the submissions on non-traditional solutions, we received submissions on incentivising the wider flexibility market. Wellington Electricity submitted that submitted that suppliers need to not only procure or develop flexibility services, but the related processes and functions to ensure they can be successfully incorporated into the network.[773] Counties Energy submitted that due to the cost and risk to EDBs that we should ring fence DSO expenditure to encourage EDBs to engage in behaviour that would unlock long-term savings.[774] In contrast, Contact submitted that we should ensure that innovation funding provided by the IMs is not used in a way that provides regulated entities with a 'leg up' over non-regulated entities in potentially competitive service.[775]

Analysis and final decision

6.88 Our final decision is to amend the IPA to become the INTSA and remove the 'innovation project' definition from the EDB IMs.

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769 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 227; Flexforum "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 3.

770 We note that the IMs following the 2023 IM Review will no longer define innovation; they also do not define "non-traditional solutions. We acknowledge the ENA's submission (Electricity Networks Aotearoa (ENA) "Submission on Targeted ID review 2024 draft decision reasons paper for EDBs" (14 September 2023), p. 5) on the TIDR regarding the definition of 'non-traditional solutions' and can consider the need to be consistent between ID and PQ regulation when determining whether and, if so, how to set an INTSA scheme at the DPP reset.

771 Flexforum "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 3; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 6.

772 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 19.

773 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 26.

774 Counties Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 2-3.

775 Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 14-15.

6.89 While many submitters considered that the changes made to the IPA were a step in the right direction, many considered that the changes did not go far enough in enabling the energy transition.

6.90 Vector[776] and Flexforum[777] were concerned that there would be no certainty regarding the INTSA until the DPP4 final decision in December 2024. In response, we consider our final decision promotes the IM purpose under s 52R by providing certainty that a wide range of schemes can be provided for at a reset, and what elements those schemes may contain will depend on what promotes the Part 4 purpose in the specific context - namely, the DPP4 reset. Some examples of schemes that could be implemented under the INTSA are provided in Attachment C, which are unchanged from our draft decision.

6.91 As explained at paragraph 6.70 from our draft decision, we consider that specifying the details of an innovation and non-traditional solutions scheme in the IMs would not better promote the Part 4 purpose. We consider that when we apply the IMs in setting PQ paths in the current context of faster change, we will need to have flexibility and be responsive to the context and information available at the time.

Current scope for capex deferral is modest but expected to increase over time

6.92 Most submitters agreed with our draft decision to expand the innovation allowance to cover non-traditional solutions, so the IMs provide us with the flexibility needed to implement schemes that improve incentives for opex/capex trade-offs across regulatory periods.

6.93 Submissions from Flexforum and Wellington Electricity consider that the changes made to INTSA are a short-term solution to incentivise capex deferral. As discussed from paragraph 5.36, the current scale of these potential savings is modest but is expected to grow. As such, a solution that is adaptable to the changing environment is appropriate. The INTSA provides us with significant flexibility in scheme design, that can adapt as these flexibility services become more mainstream and the size of the long-term problem becomes clearer.

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776 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 227.

777 Flexforum "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 3.

6.94 Wellington Electricity[778] submitted that suppliers need to not only procure or develop flexibility services, but the related processes and functions to ensure they can be successfully incorporated into the network. The current arrangements allow us to provide incentives for demand flexibility adjacent spending (such as expenditure on LV data) at a PQ reset should we consider it appropriate. We consider that further specifying such requirements in the IMs would not better achieve the overarching objectives of the IM Review.

Transpower

6.95 Our final decision is to make no 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. For further discussion refer to Appendix C.

Consideration of submissions that are outside the scope of the IM Review.

6.96 Some submitters were concerned that the draft decisions related to the INSTA did not go far enough in facilitating the innovation and investment required for the energy transition. Several submitters disagreed with current IPA drawdown criteria (eg, Vector,[779] Contact,[780] Chorus[781] and Orion[782]). INTSA (and IPA) design considerations are outside the scope of the IMs but are matters to be considered when setting a PQ path.

6.97 Submitters such as Wellington Electricity suggested that the regime needed to provide more incentives for EDBs to develop LV management to enable the expected increase in use of flexibility services. The INTSA is just one of the tools at a PQ reset that could be utilized to encourage the development of LV management.[783]

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778 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 24.

779 Vector "Incentivising efficient expenditure for EDBs" (6 April 2023), pp. 4-5.

780 Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 14-15.

781 Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 6.

782 Orion "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 10.

783 We note that in the Aurora CPP we provided a step change in expenditure for the purchase of LV data see Commerce Commission "Decision on Aurora Energy's proposal for a customised price-quality path Final Decision" (31 March 2021), para D302-D305.

6.98 The INTSA is only one of the tools available to us to encourage innovation and investment. The INTSA works alongside other tools, such as IRIS, to provide suppliers with incentives to innovate, and to share the risk associated with innovation between suppliers and consumers. When designing a scheme at a PQ reset, we can consider the degree to which a scheme shares risk between suppliers and consumers. We consider that specifying such requirements in the IMs would not better achieve the overarching objectives of the IM Review.

6.99 Counties Energy submitted that we should ringfence DSO expenditure to allow EDBs to undertake the work which they submit contains financial risk and is open to competition but will lead to significant long-term savings.[784] Counties Energy also submitted that DSO structures are unlike EDB fixed network structures and are open to competition.

6.100 Contact submitted that providing a regulated entity with funding to engage in a competitive market is unlikely to be in the long-term best interest of the consumer as it may distort the development of the market.[785]

6.101 In response to Counties Energy and Contact's points, we note the INTSA provides wide scope and flexibility to set innovation schemes under PQ regulation, which could foreseeably include setting a scheme that encourages EDBs to develop DSO capabilities, if we decided doing so would promote s 52A for the long-term benefit of consumers in the relevant context.

[784] Counties Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 2-3.

[785] Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 14-15.

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:[786]

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:

[786] 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.[787]

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.

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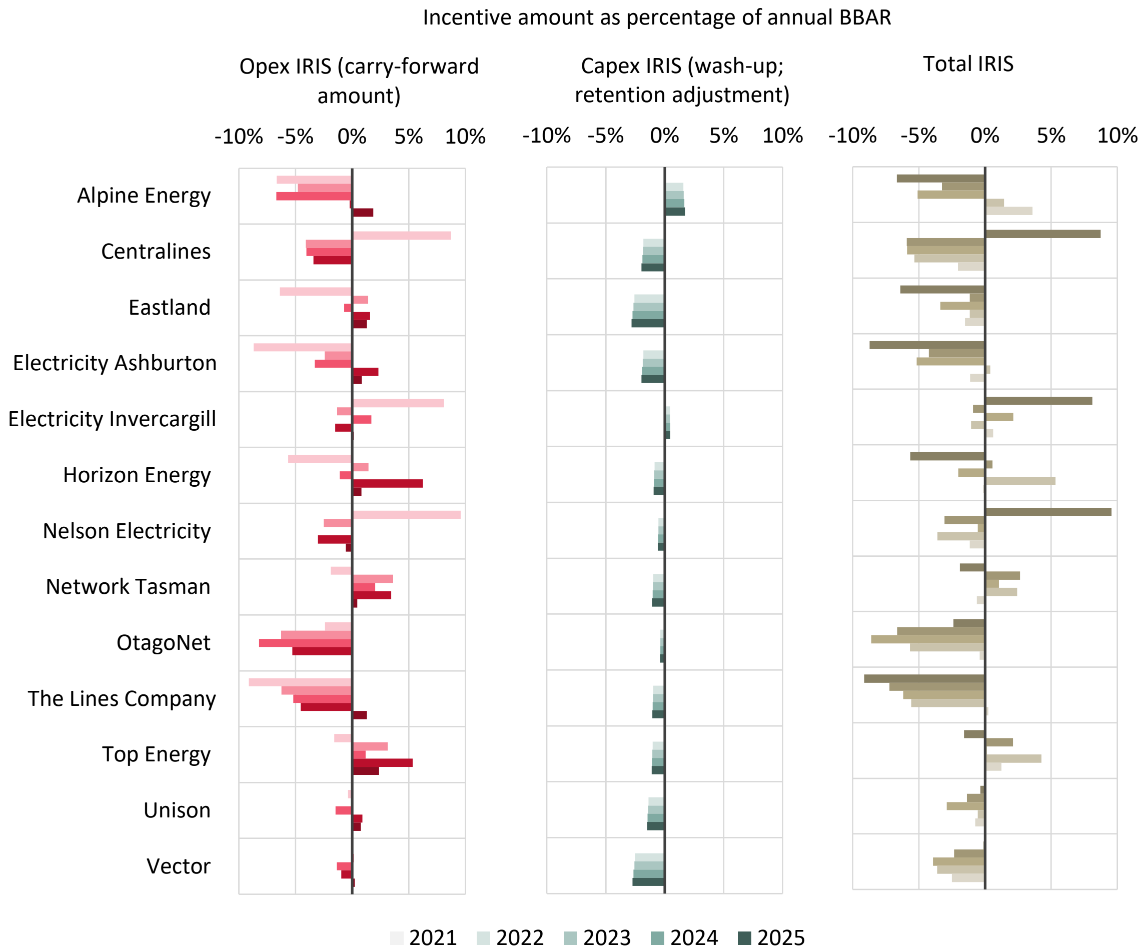
[787] The capex IRIS, is based on total capex spend over the period but is not rolling like the opex IRIS so is more intuitive to understand the cashflow timing implications.

Figure A1 IRIS incentive amounts as a proportion of annual BBAR[788]



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.[789]

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 five years prior, building cumulatively over the regulatory period.

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788 Aurora Energy has not been included in this analysis as it is on a CPP and subject to different incentives under the CPP.

789 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.

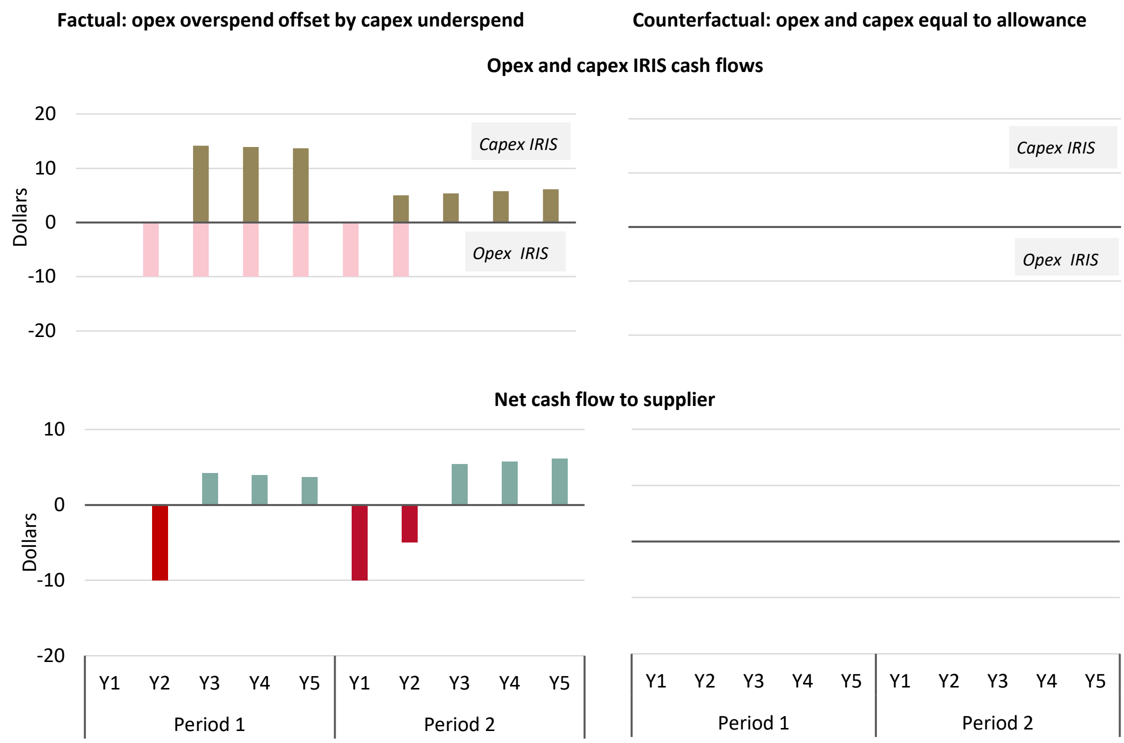
A13 To illustrate opex and capex IRIS cashflow timing differences, we have modelled two NPV equivalent cashflows.

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[790]



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.

790 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 5a (opex and capex substitutability)

B1 In this Attachment we provide further analysis that:

B1.1 supports the problem definition of Topic 5a '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 5.13, 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.[791] 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 This section discusses stakeholder feedback that we received on the consultation related to the staff discussion paper and model on the equivalence between the opex and capex IRIS. We did not receive feedback on the equivalence of opex and capex incentives in response to our draft decisions (see Topic 5a of this paper for a discussion of our approach to mitigating the bias for preferring one type of expenditure over another).

B5 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 solution to this issue is discussed in Chapter 6.

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[791] 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).

B6 Horizon Energy did not consider that there was broadly financial equivalence between opex and capex stating:[792]

> 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.

B7 Vector submits that incentive rates are equalised but that the allowances are not substitutable:[793]

> 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

B8 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.[794]

B9 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.

B10 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:

B10.1 **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

792 Horizon Energy Group “Submission on Expenditure incentives EDB workshop” (8 December 2022), p. 5.

793 Vector “Submission on Expenditure incentives EDB workshop” (6 December 2022), p. 6.

794 Commerce Commission “IM Review 2023: Incremental rolling incentive schemes equivalence model” (22 November 2022).

terms these are equivalent.[795] We discuss IRIS cashflow timing implication in Chapter 3 (Topic 3b) and Attachment A.

B10.2 **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).

B10.3 **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.

B11 In response to Vector's comments at B7 above, this may reflect a misunderstanding of the expenditure incentive mechanism's objective rather than an issue with its operation.

B12 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.

B13 Building on Vector's example at B7, assume:

B13.1 a supplier has a choice between an opex solution and a capex solution that are otherwise financially identical;

B13.2 the supplier has a large headroom in its capex allowance; and

B13.3 the supplier would exceed the opex allowance if it implemented an opex solution.

B14 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:

B14.1 spending capex (which reduces the underspend that would otherwise occur and hence requires forgoing the positive incentive adjustment

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795 We discuss cash flows from IRIS in Chapter 3 (Topic 3b - Implications for IRIS for cashflow timing) above.

associated with the larger capex underspend) and avoid a negative opex IRIS adjustment; and

B14.2 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).

B15 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.

B16 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.

B17 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 IM 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.[796]

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.

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[796] 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.[797]

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.

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797 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 6.73 to 6.75.

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.[798] EDBs indicated that the current scope for deferral is limited but they expect opportunities to grow significantly over time.[799] 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.[800]

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.[801]

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798 Commerce Commission "IM Review 2023: Forecasting and incentivising efficient expenditure for EDBs - 'Full slide deck'" (7 November 2022).

799 Powerco "Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 5.

800 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.

801 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:[802]

> 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 in Chapter 6, we have decided 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.[803] However, eventually, the investment planning horizon would clash with the fixed horizon of the regulatory period and other issues would arise.

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802 Powerco "Submission on Expenditure incentives EDB workshop" (6 December 2022), p. 3.

803 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)).[804] 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 Six' EDBs submitted that:[805]

> 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:[806]

> 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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804 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 - Final decision - Cost of capital topic paper" (13 December 2023).

805 NERA Economic Consulting "Innovation under the DPP - potential barriers and solutions" (report prepared for 'Big six' EDBs, 20 December 2022), p. 22.

806 Vector “Submission on Expenditure incentives EDB workshop” (6 December 2022), para 15.

Transpower

C25 We have not made 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 6.75, Transpower submitted it may be financially worse off when substituting opex for capex, for example when adopting transmission alternatives (involving opex).[807]

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 expanded the scope also to other areas with potential trade-offs.

C28 We have not made any changes to Transpower's IMs to provide explicit tools in the IMs to encourage innovative or non-traditional solutions. We consider Transpower's Part 4 regulatory regime already provides for flexibility to provide desirable longer term planning incentives, including in relation to innovation and non-traditional solutions.[808]

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807 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.

808 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.[809] 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 5.93).

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.

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809 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.[810]

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.[811]

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.[812] 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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[810] 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.

[811] 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.

[812] 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.[813]

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 'innovation and non-traditional solutions' allowance would also allow for schemes such as the demand management incentive scheme introduced by the AER.[814] Under such a scheme if an investment 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 focus on inputs, but also reward 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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813 Wellington Electricity – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), p. 35.

814 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 paragraph C37, we do not consider ex-ante allowances would be appropriate.[815]

[815] 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 changes to the revenue cap and wash-up mechanisms for EDBs and GTBs.

D2 We are making these changes to:

D2.1 give effect to our substantive decisions in 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 making. These are:

D3.1 **improvements to the revenue path to better manage volatility** during the regulatory periods;

D3.2 **improvements to the wash-up mechanism** to implement other policy decisions, and to reduce compliance cost and complexity; and

D3.3 changes to the **treatment of CPI in the revenue path and wash-up**.

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 accurate 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 can 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 has 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 overly burdensome); 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 better manage volatility

Final decisions

D10 We have decided to:

D10.1 replace the limit on the "annual maximum percentage increase" in forecast revenue in the current IMs with a “revenue smoothing limit”,[816] and remove the provision for a "limit on increase in revenue as a function of demand";

D10.2 apply this "revenue smoothing limit" to revenue including recovery of recoverable costs, but excluding recovery of pass-through costs and (for EDBs only) revenue received under large connection contracts;[817]

D10.3 reclassify transmission recoverable costs as pass-through costs (for EDBs only);

816 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.) will be set in the PQ determination.

817 Our reasons for excluding forecast revenue and revenue received under large connection contracts are discussed in Chapter 8 of the CPP and In-Period Adjustment Mechanisms topic paper.

D10.4 clarify in the IMs that the "revenue smoothing limit" does not apply in the first year of a regulatory period.

D11 We have also decided to retain the "voluntary undercharging" lower limit on the revenue path.[818]

D12 In reclassifying transmission recoverable costs as pass-through costs, we have made some minor technical corrections to the drafting of clauses 3.1.2 and 3.1.3 of the EDB IMs.

Problem definition

D13 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. The problems the Commission and stakeholders have identified are with this secondary control.

D14 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:

D14.1 the requirement in the IMs for it to be a "percentage" change is unduly restrictive, and may interfere with our ability to set DPPs or CPPs that respond to circumstances at the time; and

D14.2 expressing it in "forecast revenue from price"[819] terms creates a ratchet effect for EDBs, where a decision to temporarily undercharge lowers the secondary limit for the duration of the period.

Submissions on problem definition

D15 Several EDBs disagreed with the secondary revenue control and raised the following additional concerns:

D15.1 it is expressed in nominal terms, requiring EDBs to temporarily bear additional costs from rising inflation without passing them on;[820] and

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818 The existing EDB IMs include a voluntary undercharging lower limit on the revenue path. We are retaining this and, for consistency, extending it to the GTB IMs.

819 "Forecast revenue from prices" is defined in the IMs as the forecast revenue used by a supplier to set prices, where forecast revenue is the total of each price multiplied by each forecast quantity.

820 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.

D15.2 because it applies to all revenue, it requires EDBs to absorb increases in transmission costs.[821]

D16 They also objected to the limit being set as low as it has been (10 percent).[822]

Draft decision

Secondary revenue control

D17 In our draft decision, we proposed 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 including pass-through costs.

D18 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.

D19 Put another way, the maximum a supplier could charge in any year is the lesser of:

D19.1 the sum of forecast net allowable revenue, recoverable costs, and pass-through costs; or

D19.2 the sum of the revenue smoothing limit and pass-through costs.

D20 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.) will be set in the PQ determination. Compliance with these limits is illustrated in Figures D2 and D3 at the end of this attachment.

D21 For EDBs, we also proposed recategorising 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

D22 We proposed retaining the "voluntary under-charging limit", to avoid the build-up of significant wash-up balances via undercharging. We proposed 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.

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821 Electricity Networks Aotearoa "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.

822 Vector "Submission on the Process and issues paper" (11 July 2022), para 55. Note that this is a matter specified in PQ determinations.

Reasons for our draft decisions

Better promoting the s 52A purpose

D23 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 agreed 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

D24 We considered that our draft decision would continue to promote regulatory certainty to a similar extent to the current IMs. The fundamentals of how compliance 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

D25 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 considered the benefits in terms of promoting the s 52A outcomes justified any transitional cost.

D26 Additionally, the removal of the function of demand limit will reduce the overall complexity of the IMs.

Price stability

D27 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 considered it worthwhile to do so.

Stakeholder views on our draft decisions

Secondary revenue control

D28 A number of submitters supported our modifications to the secondary revenue control, to address the unforeseen circumstances which emerged during DPP3.[823]

D29 Submitters shared our concerns about consumer affordability.[824] We also received support for the objective of achieving revenue and price stability, as best promoting the long-term benefit to consumers.[825]

D30 Submissions reiterated – and strongly highlighted – concerns with the current form of secondary revenue control: the limit on the increase in forecast revenue specified in the current IMs, and the current (nominal) 10% limit applying under DPP3 for EDBs.[826]

D31 Some EDBs expressed disagreement with smoothing mechanisms, on the basis that, if they bind frequently,[827] such mechanisms can lead to a build-up of unrecovered revenue and unsustainable cashflow issues for businesses.[828] For example, Frontier Economics, on behalf of the 'Big 6' EDBs, suggested that:

> The Commission should ensure that any attempt to smooth regulated EDBs' prices does not compromise EDBs' ability to recover their efficient costs or dampen incentives for EDBs to improve efficiency or service quality, because such outcomes would undermine rather than promote the Part 4 purpose.[829]

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823 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 12; PowerNet "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 10-11; Orion "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 20.

824 For example, Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 30.

825 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 14, Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 10-12.

826 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 19(d) and para 145-154; Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), see in particular para 8-24, para 68-72, & section 4 (pp. 15-35); Unison "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 39-47; Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), section 5.5.

827 In this context the revenue smoothing limit "binds" where it prevents a supplier from recovering its full maximum allowable revenue in a given disclosure year, in which case the undercharge required to comply with the revenue smoothing limit would accrue to the wash-up for recovery in the future.

828 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 148; Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 16, see also paras 115-116; Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 30, Orion "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 8.

829 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 12 & para 76.

…

If the price limit binds in several consecutive periods, that could defer the recovery of EDBs' efficient costs over multiple periods. If the accumulated under-recovery of allowed revenues from prior years in the revenue wash-up account becomes sufficiently large and exceed consumers' willingness to pay, then there would be no feasible means of recouping those under-recoveries.[830]

…

Under a binding price limit, an EDB would be prevented from recovering its efficient costs in the years in which the limit binds. If the under-recovery is sufficiently large … the EDB may face a financeability constraint that prevents it from attracting sufficient capital to invest in regulated assets. The Commission should, in our view, perform analysis at each revenue determination to assess whether such a situation is likely to occur over the forthcoming regulatory period.[831]

D32 Frontier Economics also noted that:

D32.1 s 52A of the Act does not specifically identify price smoothing or the insulation of consumers from price shocks/volatility as a means of promoting the Part 4 purpose;[832] and

D32.2 should the revenue smoothing limit bind, "[t]his would seem to create an intergenerational equity problem".[833]

Views on regulatory certainty

D33 Some EDBs commented that our approach does not significantly improve regulatory certainty, and offered the following suggestions to address this:

D33.1 making the approach common to all EDBs subject to a DPP determination;[834] and

830 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 16 and para 255. See also para 115-116.

831 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 126.

832 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 68-72.

833 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 137-138 and para 260.

834 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), section 5.5.

D33.2 providing the criteria that the Commission will use to set the revenue smoothing limit at each PQ determination in the IMs or our final report. [835]

D34 Vector, with reference to Frontier Economics, submitted that the Commission should urgently develop an IM that specifies how it would reset starting prices and that "[t]his would remove a significant source of regulatory uncertainty currently faced by suppliers."[836]

Views on options for specifying the revenue smoothing limit

D35 EDBs also suggested several possible alternative approaches for specifying the revenue smoothing limit:

D35.1 Frontier Economics, supported by some EDBs, proposed alternatives to the nominal 10% limit applying under DPP3, which could mitigate the above concerns, including:

D35.1.1 applying the limit net of inflation, which would: [837]

> … provide EDBs with a greater opportunity to set tariffs by reference to the underlying economic cost of providing network services … because the limit will bind less frequently, it will improve the ability for EDBs to recover their prudent and efficient costs in each regulatory period, and so lead to more efficient decisions about network investment.

D35.1.2 restricting the price limit to a shorter, defined period of time (one or two years), so the period over which cost recovery is deferred may be reduced;[838]

D35.1.3 raising the price limit to a higher level (eg, 15%)[839] to genuinely limit it to annual changes of an outlier nature; [840]

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835 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), section 5.5; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023) p 4.

836 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 150-152; Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), paras 306-312. Supported by Wellington Electricity Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 56.

837 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 290-294; Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 154.

838 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 26(a) and para 315(a).

839 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 26(b) and para 315(b).

840 Powerco "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 2.

D35.1.4 applying a sliding scale to the price limit so that a 10% price limit applies to the first year of a regulatory period but gradually increases over the period, such that the price limit would become progressively 'looser' over the period;[841] and

D35.1.5 specifying in the IMs how the revenue smoothing limit would be increased if inflation differs materially from assumptions.[842]

D35.2 Aurora Energy suggested the revenue smoothing limit include an adjustment mechanism based on the forecast change in connections determined during the annual price-setting process. In support of this approach, it noted that:[843]

> A mechanism focussed on revenue ignores the impact that connection growth has on reducing customer price and has the effect of disadvantaging electricity distributors operating higher growth networks.

Views on the inclusion of IRIS within the revenue smoothing limit

D36 Frontier Economics, Vector, and Unison Networks proposed excluding IRIS and quality incentives from the limit on the basis that, if the limit binds, EDBs may face weakened incentives to deliver cost efficiency improvements and/or improvements in reliability and service quality.[844]

D37 Other submitters:

D37.1 supported our view, in our draft decisions on implications of IRIS for cashflow timing,[845] that volatility in cashflows introduced by IRIS be addressed at the aggregate level as part of revenue smoothing;[846] and

D37.2 recognised that there are other elements of the regulatory environment which encourage investment in efficiencies, aside from IRIS.[847]

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841 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 26(c) and para 315(c).

842 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 26(d) and para 315(d).

843 Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 31-32.

844 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 280-289; Unison "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 46(b); Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 154.

845 See Topic 3b, in Chapter 3 of this paper.

846 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), section 3.1.2.1, p. 11.

847 Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 28.

Views on excluding pass-through costs from the revenue smoothing limit, and reclassifying transmission recoverable costs as pass-through costs

D38 ENA, Powerco, Frontier Economics (on behalf of the 'Big Six' EDBs), Aurora Energy, PowerNet, Orion and Unison supported our draft decision to exclude the recovery of pass-through costs from the revenue smoothing limit, and to reclassify transmission recoverable costs as pass-through costs.[848] Aurora Energy also suggested that this should be further expanded to cover "all reasonable and prudent Transpower costs".[849]

D39 Contact Energy opposed our draft decision, stating that "a more consumer centric approach would be to retain the current obligations on EDBs and put greater obligations on Transpower for smoothing prices".[850]

Views on the application of the revenue smoothing limit between regulatory periods

D40 Several submitters discussed the application of the revenue smoothing limit between regulatory periods:

D40.1 Contact Energy submitted that the smoothing limit should apply to price changes that occur between regulatory periods:[851]

> … it will be particularly important to protect consumers from price shocks during this period … even a 10% limit on revenue increases could result in a much more significant increase for those who can afford it least.

D40.2 Some submitters noted the revenue smoothing limit is not necessary in year 1 of a regulatory period, given the Commission's discretion to set starting prices.[852] They requested that the Commission clarify that the revenue smoothing limit does not apply in the first year of a regulatory period in

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848 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 12; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 4; Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 78; Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para. 29; PowerNet "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 10, 11, 12; Orion "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 20, 21, 22; Aurora Energy "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para 3.1. & 3.4; Electricity Networks Aotearoa (ENA) "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 3; Orion "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), para 16; Unison Networks "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p.3.

849 Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 29.

850 Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 36-38.

851 Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 31.

852 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 18; Powerco "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 2.

order to improve regulatory certainty[853] and avoid exacerbating financeability concerns.[854]

Final decisions and reasons

D41 After taking into account submissions, we have decided to:[855]

D41.1 confirm our draft decisions; and

D41.2 clarify in the IMs that the "revenue smoothing limit" does not apply in the first year of a regulatory period.

Secondary revenue control

D42 Our final decision is to amend the secondary revenue control by replacing the "annual maximum percentage increase" in forecast revenue in the current IMs with a “revenue smoothing limit”.

D43 In making our final decision, we have balanced the importance of enabling suppliers to recover allowable revenues in a timely way, alongside the desirability of managing aggregate volatility in gross allowable revenue and avoiding mid-period price-shocks.

D44 We have carefully considered the concerns raised by submitters that if the limit binds frequently, this could lead to a build-up of unrecovered revenue which may reduce suppliers' ability and incentives to invest.

D45 We agree with submitters that this is a real risk with the "limit on increase in prices" as specified in the current IMs. We consider the amended IMs, together with the improvements to the wash-up mechanism discussed in the following section,[856] will better address this risk, as we explain below.

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853 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 18.

854 Powerco "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 2.

855 See para D10 to D12 above for a summary of our final decisions on this issue.

856 Including our decision to enable the Commission to specify the pace of drawdown, to address any large wash-up balances by returning the wash-up account balance towards zero over time (discussed in para D122 to D126 below).

D46 At the same time, as we discussed in the reasons for our draft decision, features of the regulatory regime such as IRIS and revenue wash-ups lead to additional revenue volatility for regulated suppliers. Providing for an aggregate revenue smoothing mechanism allows us to manage all-cause volatility in gross allowable revenue and to protect customers from mid-period price-shocks.[857]

D47 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, price stability is generally valued by consumers. This view was supported by Alpine Energy and strongly reinforced by Contact Energy.[858]

D48 Therefore, to the extent that we can achieve the framework objectives without creating volatility, we consider it worthwhile to do so.

D49 Frontier Economics suggested that we analyse, at each price-quality reset, whether the revenue smoothing limit is likely to bind frequently (see paragraph D31 above). This suggestion has merit. Any decision about how (or even whether) to apply a smoothing limit is unavoidably context-specific, taking account of what better promotes the Part 4 purpose given the circumstances of suppliers, their networks, and their customers at any given reset.

D50 However, the requirement in the current IMs for a "limit on the increase in forecast revenue" that is expressed as a percentage change is unduly restrictive and limits our ability to do this effectively.

D51 Our decision to replace the current limit on the increase in forecast revenue with a "revenue smoothing limit" will provide more flexibility in how the limit is specified. We consider this approach better promotes the Part 4 purpose, by enabling us to take account of the circumstances affecting regulated suppliers in specifying the revenue smoothing limit (including changes from one regulatory period to the next) when setting price paths.

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857 See Topic 3b in Chapter 3 of this report, and our discussion under "Context for these decisions" in para D5 to D9 above.

858 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para. 14, Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 10-12.

D52 This decision provides the flexibility to address the problems the Commission and submitters have identified with the current limit. For example, by enabling us to specify the 'revenue smoothing limit' in real terms (as suggested by Frontier Economics and Vector),[859] or adopting alternative approaches such as those proposed by submitters.

D53 We consider our final decision to implement a 'revenue smoothing limit' allows us to provide some protection from all-cause volatility in gross allowable revenue and from mid-period price-shocks, while preserving suppliers' ability to recover allowable revenue, consistent with our FCM principle.[860]

D54 Frontier Economics suggested that, when the revenue smoothing limit binds, this "would seem to create an intergenerational equity problem".[861] We consider that, under the amended IMs, this risk is addressed through the way the Commission sets the revenue smoothing limit in PQ determinations, along with provisions (discussed in the following section) to help return the wash-up balance toward zero.[862]

Regulatory certainty: A framework for making decisions on the revenue smoothing limit

D55 We have considered submitters' request that we specify in the IMs the criteria for setting the revenue smoothing limit or for changing it, should outcomes differ materially from assumptions.

D56 We acknowledge submitters' view that it is desirable to develop a set of principles to guide these decisions on setting the revenue smoothing limit. However, as discussed in the previous section, our view is that maintaining flexibility to determine the appropriate approach in the specific context that applies at a PQ reset enables us to better promote the Part 4 purpose.

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859 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 290-294; Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 154.

860 We discussed our FCM principle, and how we apply it, in Commerce Commission "IM Review 2023 - Decision-making Framework paper (13 October 2022), para 4.7 to 4.11.

861 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 138 and para 260.

862 We also discuss "intergenerational equity" in Chapter 3 of this paper (Topic 3a, para 3.116-3.118).

D57 We note the submission from Vector, with reference to Frontier Economics' report,[863] that the Commission should develop an IM that specifies how it would reset starting prices in order to improve regulatory certainty. Our view, as endorsed by the Court of Appeal and subsequently by the Supreme Court, is that we are not required to determine a starting price adjustment input methodology.[864]

D58 While setting fixed criteria or principles in the IMs may provide greater regulatory certainty, this alone is not a sufficient reason for doing so:

D58.1 The s 52R purpose is "conceptually subordinate" to Part 4's overall goal to promote the long-term benefit of consumers.[865]

D58.2 We therefore consider it appropriate to retain a level of flexibility where doing so better promotes the Part 4 purpose.

D59 In this instance, we consider the purpose of Part 4 is better promoted by taking account of changes in the economic environment, and specific circumstances affecting suppliers, from one regulatory period to the next in making decisions about setting or changing the revenue smoothing limit.

D60 While setting fixed criteria or principles in the IM may provide greater regulatory certainty (better promoting the s 52R purpose), we still consider that the IM provides sufficient regulatory certainty as to be consistent with the s 52R purpose.

D61 As we noted in our draft reasons, above, our final decision continues to promote regulatory certainty to a similar extent compared to the current IMs. The fundamentals of how compliance 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.

D62 As part of the next price path reset for EDBs, we intend to develop our approach to revenue smoothing in more detail.

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863 Vector "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 150-152; Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 306-312. Supported by Wellington Electricity Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 56.

864 See: Commerce Commission v Vector Ltd [2012] NZCA 220, [2012] 2 NZLR 525; and Vector Ltd v Commerce Commission [2012] NZSC 99, [2013] 2 NZLR 445.

865 *Wellington International Airport Ltd & Ors v Commerce Commission* [2013] NZHC 3289, para 165.

Options for specifying the revenue smoothing limit

D63 Consistent with our draft decision, we have decided to leave the details of how the "revenue smoothing limit" is specified (dollar vs percentage terms, real or nominal etc.) to the PQ determination.

D64 As noted in the problem definition, the requirement in the current IMs for the limit to be an “annual maximum percentage increase” in forecast revenue is unduly restrictive, preventing us from setting DPPs or CPPs that respond to circumstances at the time.

D65 Any decision about how (or even whether) to apply a smoothing limit is unavoidably context-specific. Leaving the details of the "revenue smoothing limit" to the PQ determination enables us to take account of the circumstance of suppliers, their networks, and their customers at any given reset. We consider that this enables us to make decisions on the revenue smoothing limit that better promote the Part 4 purpose, compared to specifying the details of the revenue smoothing limit in the IMs.

D66 As we noted above, in submissions on our draft decisions EDBs reiterated concerns with the 10% limit on the increase in forecast revenue applying under DPP3. Submitters suggested several possible alternatives.[866]

D67 The current IMs require us to specify the limit on annual increases in forecast revenue in percentage terms. We have discretion to set the level of this percentage increase, taking account of circumstances and available information, at the time we reset the PQ path. While that percentage change is currently set at 10% under the DPP, we have the ability to specify a different percentage at the reset.

D68 Our decision to replace the limit on the annual percentage increase in forecast revenue with a “revenue smoothing limit” means that we are no longer restricted to specifying the limit in percentage terms. This allows us to consider alternative options for specifying the limit that may better promote the Part 4 purpose in the context of the economic/sector environment at the time we are resetting the PQ path. This change enables us to consider the various options put forward in submissions for specifying the limit, as part of the DPP4 process for EDBs.

D69 Our final decision also enables us to consider, in making decisions on DPP4, the merits of alternative approaches suggested by submitters, including:

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[866] See "Views on options for specifying the revenue smoothing limit" above (para D35).

D69.1 making the approach common to all EDBs subject to a DPP determination, as proposed by the ENA;[867] or

D69.2 including adjustments to account for differences in circumstances between EDBs, such as Aurora's proposed adjustment for forecast new connections.[868]

D70 Aurora expressed concern that a smoothing limit that focuses on revenue may disadvantage EDBs operating higher growth networks, and proposed an adjustment mechanism based on the forecast change in connections.

D70.1 We agree Aurora's concern is valid where suppliers are forecasting high growth in new connections. However, if we were to adopt the adjustment mechanism proposed by Aurora for all suppliers, this could disadvantage those suppliers experiencing a reduction in new connections.

D70.2 For those EDBs, it would have the effect of reducing the level of the revenue smoothing limit, causing the limit to 'bind' more frequently and potentially leading to a build-up of unrecovered wash-up balances over the remainder of the regulatory period. This could detrimentally affect the promotion of the Part 4 purpose (specifically s 52A(1)(a)) by impacting on those EDBs' incentives and ability to innovate and invest.

D70.3 This highlights that in some circumstances the Part 4 purpose is better promoted by taking account the specific circumstances of each supplier at the time of resetting PQ determinations.

D70.4 Accordingly, we have not specified in the IMs an adjustment in the revenue smoothing limit for forecast new connections, but may consider Aurora's proposal in the context of decisions on DPP4.

Inclusion of IRIS and quality incentives in the revenue smoothing limit

D71 Our final decision is to confirm our draft decision to include IRIS and incentive payments within the revenue smoothing limit.

D72 We have considered the points raised in favour of excluding IRIS and quality incentives from the revenue smoothing limit. On balance, as we discuss in Chapter 3 (Topic 3b) and Attachment A of this paper, we consider that assessing and smoothing all cashflow-sensitive factors as part of revenue smoothing better promotes the Part 4 purpose, particularly s 52A(1)(a).

[867] Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), section 5.5, p. 12.

[868] Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 32.

D73 Frontier Economics' concerns regarding weakened incentives to deliver cost efficiency or quality improvements only materialise if suppliers do not have a reasonable expectation that they can recover the net present value (NPV) of any deferred revenue over time.

D74 This is not the case here, as the wash-up mechanism is set up such that it is NPV neutral.[869] Further, our final decisions on improvements to the wash-up mechanism (discussed in the following section) mean that, in the future, wash-up balances will be carried forward from one regulatory period to the next, including an adjustment for the time value of money.

D75 Frontier Economics' submission also does not account for the other aspects of the regime that encourage investment in efficiencies. Nor did it address the impacts of greater revenue and price volatility for suppliers and consumers, which could result from excluding IRIS from the revenue smoothing limit.[870]

D76 In our view, the concerns raised by Vector and Frontier Economics are better addressed through the way the Commission sets the revenue smoothing limit in PQ determinations, such that, if the limit binds, suppliers have an expectation that they will be able to recover the NPV of any revenue reduction, including IRIS and incentive payments, in future years.

Exclusion of transmission recoverable costs

D77 Based on the support received in submissions, we have decided to confirm our draft decision to:

D77.1 exclude pass-through costs from the revenue smoothing limit; and

D77.2 for EDBs only, reclassify transmission recoverable costs as pass-through costs.

D78 We have considered Aurora's suggestion that we expand the definition of transmission costs to include all reasonable and prudent Transpower costs.[871] We do not have sufficient evidence that this expanded definition would better achieve the framework objectives, and we have therefore retained the current scope of transmission costs.

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869 The only situations in which the mechanism would not be NPV neutral are: where a supplier voluntarily charges below the undercharging limit (UCL), as discussed in the final section of this Attachment ("Compliance with the revenue path"); or in the case of compulsory revenue foregone (as defined in the EDB and GTB IM Amendment Determinations).

870 See our discussion in Chapter 3, Topic 3b.

871 Aurora Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 29.

D79 In response to Contact Energy's submission that "a more consumer centric approach would be to retain the current obligations on EDBs and put greater obligations on Transpower for smoothing prices",[872] we consider that Transpower is better placed than EDBs to manage volatility in transmission charges. We therefore consider that the appropriate place to manage transmission cost volatility is either via the TPM or in Transpower's IPP setting.

D80 As transmission recoverable costs are outside EDBs' control, we do not consider it appropriate to require that EDBs bear the risk of any remaining volatility. As we noted in our draft decision, for costs over which suppliers have no control - such as transmission recoverable costs for EDBs - we consider that allowing suppliers to directly pass through those costs rather than bearing the risk of any volatility, promotes incentives to invest and improve efficiency consistent with s 52A(1)(a).

D81 On balance, we consider our decision to reclassify transmission charges as passthrough costs for EDBs - and to rely on the TPM or Transpower's IPP to manage volatility in transmission costs - better aligns with our risk allocation principle and better promotes incentives to innovate and invest (s 52A(1)(a)), compared to the proposed alternatives.

Application of the revenue smoothing limit between regulatory periods

D82 Our final decision is to clarify in the IMs that the revenue smoothing limit does not apply in the first year of a regulatory period, ie, it does not apply to price changes that occur between regulatory periods.

D83 In response to Contact's suggestion that the revenue smoothing limit should apply to price changes that occur between regulatory periods, we note that the Commission has the discretion to reset starting prices at the beginning of each regulatory period. Therefore, it is not necessary to apply the revenue smoothing mechanism between regulatory periods.

D84 In addition, fixing a rule in the IMs which applies the revenue smoothing mechanism between regulatory periods would detrimentally affect the promotion of the 52A(1)(a) outcome:

D84.1 This would limit the Commission's ability to reset prices in each regulatory period to reflect changes in the sector/economic environment, which could lead to situations where regulated suppliers are unable to recover their maximum allowable revenue for sustained periods of time.

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872 Contact Energy "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 38.

D84.2 This is inconsistent with promoting incentives to invest and innovate and the Commission's FCM principle.

D85 We consider that making it clear that the revenue smoothing mechanism will not be applied between regulatory periods by specifying this in the IMs will improve regulatory certainty (without detrimentally affecting the promotion of the section 52A purpose). Together with our decision to give the Commission the ability to specify the pace of wash-up drawdown for the purpose of returning the wash-up account balance towards zero over time (discussed in the following section), this addresses the potential risk raised by Frontier Economics of an accumulation of large wash-up balances over time.[873]

"Voluntary undercharging" lower limit and "limit on increase in revenue as a function of demand"

D86 We received no submissions on these points. Our final decision is to confirm our draft decision to:

D86.1 retain the "voluntary undercharging" lower limit on the revenue path;[874] and

D86.2 remove the provision for a "limit on increase in revenue as a function of demand".

Improvements to the wash-up mechanism

Final decisions

D87 Our final decision is to:

D87.1 make a package of changes modelled on the Chorus wash-up and Transpower economic value (EV) account mechanisms. The key features of the wash-up mechanism are:

D87.1.1 a ‘one big bucket’ approach to all mechanisms that true-up for forecast versus actual differences;

D87.1.2 a wash-up account that tracks accruals, balances, time-value-of-money, and drawdowns;

D87.1.3 the ability for the Commission to specify the pace of drawdown over subsequent regulatory periods, for the purpose of returning the wash-up account balance towards zero over time;

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873 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 16 and para 255. See also para 115-116.

874 The existing EDB IMs include a voluntary undercharging lower limit on the revenue path. We are retaining this and, for consistency, extending it to the GTB IMs.

D87.1.4 the ability for suppliers to make early drawdowns of the wash-up balance provided it does not cause price-shocks; and

D87.1.5 an implementation approach that where possible references "re-running" the models used to calculate allowable revenue, to simplify drafting; and

D87.2 provide for a transition to the new wash-up mechanism by linking the wash-up account balance and drawdown for the start of the next regulatory period to the wash-up balances for the last two years of the current regulatory period.

D88 As part of our decision to introduce an optional large connection contract (LCC) mechanism for EDBs, LCC forecast revenue will be included in forecast allowable revenue for EDBs, and actual LCC revenue will be taken into account in the revenue wash-up. Our reasons for making this change are discussed in Chapter 8 of the CPP and In-Period Adjustment Mechanisms topic paper.

D89 In addition, we have made some minor technical improvements to the drafting of the wash-up provisions to improve readability and clarity.

Problem definition

D90 The current revenue path wash-up mechanism for EDBs and GTBs:

D90.1 calculates a number of different wash-up components separately;

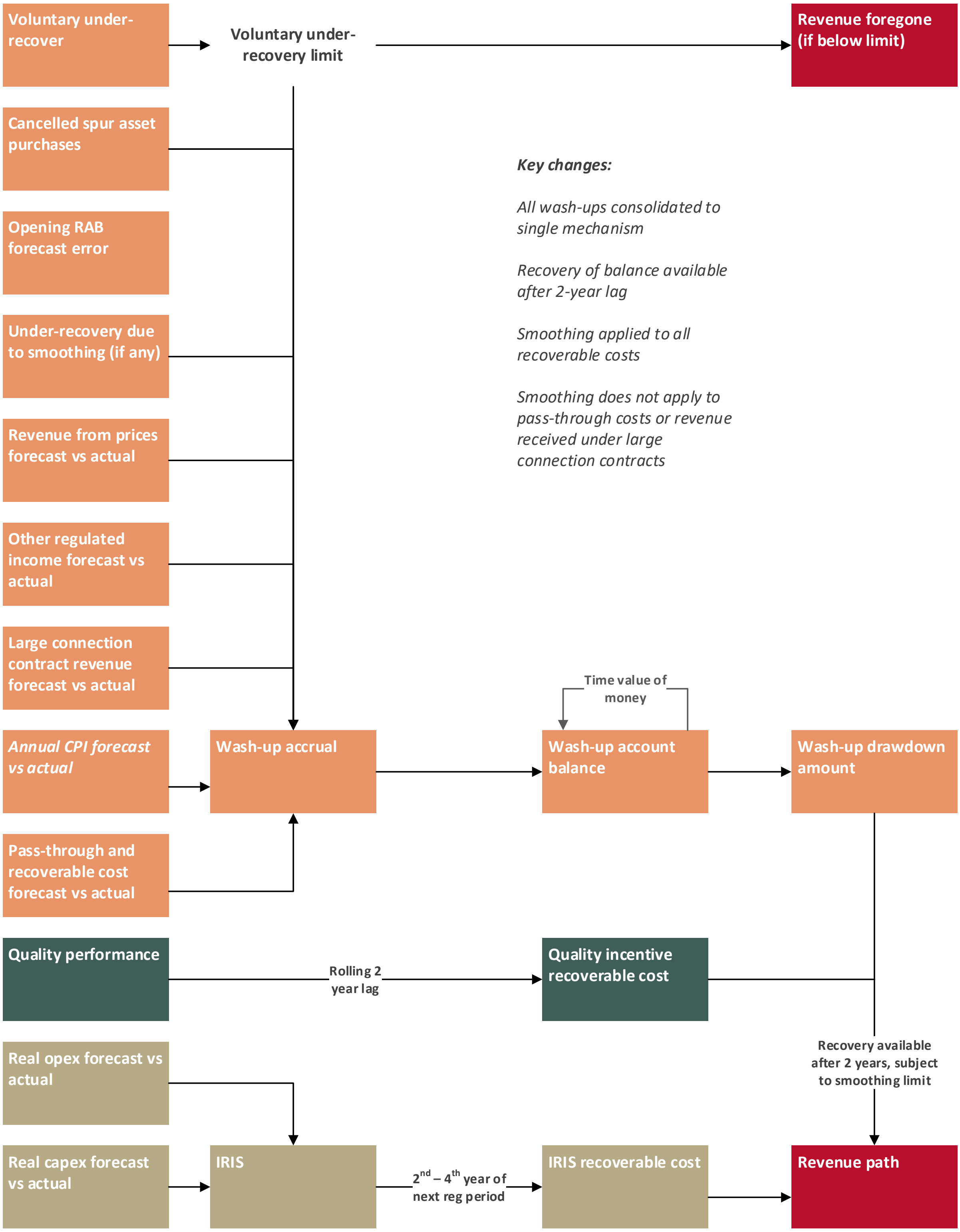
D90.2 requires drawdown over varying timeframes, but for the main wash-up on a two-year lag; and

D90.3 allows no Commission discretion (and only limited supplier discretion) over the rate of drawdown.

D91 Figure D1, below, illustrates these various components and highlights the key changes we are making.

D92 While the current mechanism is workable, these design features 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 New wash-up mechanism



Note: The "Large connection contract revenue actual vs actual" component of the wash-ups applies to EDBs only.

Stakeholder views on problem definition

D93 In its submission on the Process and issues paper, Horizon Energy identified this as a concern:[875]

> 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.

D94 Similar concerns were identified by First Gas.[876] Conversely, Orion noted that the current mechanism was "operating as intended".[877]

Stakeholder views on proposed solutions

D95 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.[878]

Draft decisions

D96 In our draft decisions, we proposed a package of changes modelled on the Chorus wash-up and Transpower economic value (EV) account mechanisms. The key features of our proposed approach were:

D96.1 a 'one big bucket' approach to all mechanisms that true-up for forecast versus actual differences;

D96.2 a wash-up account that tracks accruals, balances, time-value-of-money, and drawdowns;

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875 Horizon Network – "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 26-28.

876 First Gas Limited "Submission on IM Review Process and issues paper and draft Framework paper" (13 July 2022), pp. 20-21.

877 Orion "Submission on IM Review Process and issues paper and draft Framework paper" (11 July 2022), para 85.

878 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), pp. 20-21.

D96.3 the ability for the Commission to specify the pace of drawdown over subsequent regulatory periods;

D96.4 the ability for suppliers to make early drawdowns of the wash-up balance provided it does not cause price-shocks; and

D96.5 an implementation approach that where possible references “re-running” the models used to calculate allowable revenue, to simplify drafting.

D97 We considered but did not propose incorporating the IRIS and quality incentive recoverable costs within the broader wash-up. Instead, we proposed keeping these mechanisms separate. We considered the revenue smoothing limit discussed above was adequate for smoothing the impact of these incentives.

D98 Finally, our draft decisions included a “transitional wash-up accrual” in the first two years after these IMs come into effect. This was to allow ‘wash-up’ amounts accrued under the current wash-up mechanism to be carried forward and recovered or repaid in future.

Reasons for our draft decisions

D99 We considered this package of changes would:

D99.1 directly better promote the s 52A purpose by reducing revenue volatility that can potentially limit incentives (and ability) to invest;

D99.2 indirectly better promote the s 52A purpose by better implementing our risk allocation principle;[879]

D99.3 improve regulatory certainty by giving suppliers and consumers a more predictable revenue path, consistent with s 52A(1); and

D99.4 reduce compliance cost and complexity through referencing DPP/CPP financial models rather than attempting to replicate the relevant calculations within the IM determination itself.

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[879] We discussed our risk allocation principle, and how we apply it, in Commerce Commission “IM Review 2023 - Decision-making Framework paper (13 October 2022), para 4.12-4.19.

Better promoting the s 52A purpose

D100 In terms of direct outcomes from these proposed amendments, we considered 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 suppliers to defer or avoid investment that would otherwise be in consumers' interests. Moving to a combined and smoothed approach will mitigate this.

D101 On the other hand, deferring recovery to the following regulatory period may also lead to cash-flow constraints. To mitigate this, we 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 "revenue smoothing limit").

Better implementing other economic principles that promote the s 52A purpose

D102 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).

D103 We considered our draft decisions would 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 for the long term benefit of consumers

D104 Under this approach, at the start of each DPP or CPP period, suppliers and consumers would 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.

D105 Over the longer term, fixing the carry over to future periods in the IMs (rather than leaving it to the DPP/CPP determination) would give suppliers and consumers certainty that eventually revenues will be recovered or repaid.

Reducing compliance cost and complexity

D106 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.

Stakeholder views on our draft decisions

D107 Submitters generally supported our proposed approach in principle and agreed with our intention to reduce complexity, with some offering suggestions for technical improvements to the implementation.[880]

Submissions on the interaction between the IMs and PQ determinations

D108 The ENA said they found it challenging to respond to our draft decisions as the revenue cap rules are partly specified in the IMs and partly specified in the relevant PQ determination, and noted that:[881]

> It would be useful if the final decision included a numerical worked example of each element of the revenue path limits and wash-up, and the PQ clauses which will give effect, along with the IM clauses, to the revenue cap.

Transitional provisions for the wash-up mechanism

D109 ENA suggested that, instead of the transitional accrual, the wash-up balance drawdown formula for the start of DPP4 simply links to the wash-up balances in years 4 and 5 (ie, t-2) in DPP3. This is consistent with how the mechanism is intended to apply in future transitions between regulatory periods. [882]

D110 ENA and others noted that:

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880 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 12-13 & Appendix C; Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 27; PowerNet "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 10-11; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 3.

881 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 11. This view was supported by Powerco, Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 3.

882 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 13 & Appendix C.

D110.1 as drafted, it appeared EDBs would not be able to draw down any positive wash-up balance in years 1 and 2 of DPP4;[883] and

D110.2 it is essential that the transitional amounts are available for draw down from year 1 of DPP4.[884]

Submissions on ability for the Commission to specify the pace of drawdown over subsequent regulatory periods

D111 ENA, Powerco, and Wellington Electricity did not support the Commission's discretion to specify the pace of drawdown over subsequent regulatory periods, stating that:[885]

D111.1 it is unnecessary given the compliance limit, the revenue smoothing limit, and the cap on the accelerated wash-up;

D111.2 it adds regulatory uncertainty which is contrary to the purpose of the IMs;

D111.3 suppliers are best placed to manage cashflow, and pricing and funding decisions, within regulated revenue limits; and

D111.4 it appears that the mechanisms could conflict with the intent of the accelerated wash-up drawdown mechanism.

D112 These submitters requested that we clarify the purpose for which the Commission will exercise this discretion and what criteria the Commission will apply.[886]

Submissions on technical improvements to the implementation of the wash-up mechanism

D113 In Appendix C of its submission, the ENA provided specific drafting comments on the wash-up and the revenue smoothing limit, suggesting changes to:[887]

D113.1 the sequencing of cl 3.1.4(4) (calculation of actual allowable revenue); and

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883 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 13 & Appendix C; Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 27; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 4.

884 For example, Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 4.

885 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 13; Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 27-28; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 3-4.

886 Wellington Electricity "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 28; Electricity Networks Aotearoa (ENA) "Sub mission on IM Review 2023 Draft Decisions" (19 July 2023), p. 13.

887 Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Appendix C, p. 18.

D113.2 the specification of the "cap and collar" for the accelerated wash-up in cl 3.1.4(5)(b).

D114 ENA also, in Appendix D of its submission, noted that it is unclear what time value of money value to apply when lagging across DPP/CPP periods.[888]

Analysis and final decisions

Interaction between the IMs and PQ determinations

D115 We have considered the ENA's request for a worked numerical example of each element of the revenue path limits and wash-up, applying both the clauses from the IMs and the PQ determination which will give effect to these.

D116 As we are currently in the initial phase of our consultation on DPP4 for EDBs, we do not consider it to be appropriate for us to provide a worked example showing the application of both the IMs and the PQ determination at this stage. To do so would be pre-determining the outcome of the DPP4 consultation and our decision-making process.

Transitional provisions for the wash-up mechanism

D117 We have decided to adopt the ENA's proposed alternative, by linking the wash-up account balance and drawdown for the start of the next regulatory period to the wash-up balances for the last two years of the current regulatory period. This approach carries forward the wash-up for the last two years of the current regulatory period into the new mechanism.

D118 As set out in our reasons for our draft decisions (above) the intent of the proposed transitional provisions was to allow 'wash-up' amounts accrued under the current wash-up mechanism to be carried forward and recovered or repaid in future. However, we agree with submitters that the proposed 'transitional wash-up accrual' did not properly give effect to the policy intent.

D119 We consider that ENA's proposed alternative better gives effect to the policy intent and provides for a smooth transition from the current regulatory period to the next. As noted by the ENA, this is consistent with promoting regulatory certainty and managing revenue and cashflow volatility.

[888] Electricity Networks Aotearoa (ENA) "Appendix D - IM Practicality Issues Log" (19 July 2023), "Cost of Capital".

D120 In implementing ENA's proposed approach, we have ensured that all 'wash-up' amounts accrued under the current wash-up mechanism are carried forward, have the correct time value of money adjustment applied and are available for drawdown in years 1 and 2 of the next regulatory period.

D121 We have done this by removing the 'transitional revenue accrual' proposed in our draft decisions, and instead providing in the EDB and GTB IM Amendment Determinations that the wash-up account balance for the last year of the current regulatory period:

D121.1 is calculated in accordance with the DPP or CPP determination currently applying to the regulated supplier; and

D121.2 includes the 'wash-up amount' for the last year of the current regulatory period, also calculated in accordance with the DPP or CPP determination currently applying, except that the time value of money adjustment applied to this component of the wash-up account will be specified in the next DPP or CPP determination to ensure this amount is correctly carried forward.[889]

Ability for the Commission to specify the pace of drawdown over subsequent regulatory periods

D122 In our final decision we have:

D122.1 confirmed our draft decision to allow the Commission to specify the pace of drawdown over subsequent regulatory periods; and

D122.2 clarified that the Commission will exercise its discretion to specify the pace of drawdown for the purposes of returning the wash-up account balance towards zero over time.

D123 While we acknowledge suppliers' views,[890] as we noted above less certain forecasts (of demand or inflation) mean potentially greater differences between forecast and actual inputs. This creates the potential for large positive or negative wash-up balances to build-up over time, which would be inconsistent with the Part 4 purpose, specifically:

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889 Under the existing DPP and CPP provisions, the 'wash-up amount', consisting of the wash-up amount – voluntary undercharging amount foregone for the previous assessment period, does not enter the wash-up account balance until the following period (i.e. the first year of the next regulatory period). With the transition to the new wash-up mechanism, we have brought this amount forward as if it were included in the closing wash-up balance for the last year of the current regulatory period to ensure that it is captured in the opening balance for the first year of the next regulatory period and is available for drawdown.

890 See para D111-D112, above.

D123.1 section 52A(1)(a) - should a substantial balance of unrecovered revenue build up over time, this could reduce suppliers' incentives and ability to innovate and invest; and

D123.2 section 52A(1)(d) - conversely, allowing a substantial negative wash-up balance to accrue over time would be inconsistent with the outcome of limiting suppliers' ability to extract excessive profits.

D124 We agree with submitters that specifying the purpose for which the Commission will exercise this discretion, as noted above, enhances regulatory certainty (without detrimentally affecting the promotion of the s 52A purpose).

D125 Accordingly, we have amended the EDB and GTB IMs to clarify that the purpose of the discretion for the Commission to specify the pace of drawdown is to address any large wash-up balances (whether positive or negative), by returning the wash-up account balance towards zero over time.

D126 Submitters also noted that this discretion could conflict with the intent of the accelerated wash-up drawdown. We have addressed this by clarifying in the IMs that the cap and collar mechanism for the wash-up drawdown applies to the sum of:

D126.1 any drawdown specified by the Commission; and

D126.2 any accelerated drawdown amount nominated by a supplier.

Technical improvements to the implementation of the wash-up mechanism

D127 We appreciate the attention submitters gave to the technical implementation of the wash-up mechanism, which has helped us make several improvements to the drafting of these provisions.

D128 As we noted above, ENA provided additional specific technical comments, which we address in the table below.

Table D1 Responses to technical points raised by ENA

Topic	Submission point	Our response & decision
Actual allowable revenue	To make this easier to apply, separate the calculation of actual allowable revenue into two sub-clauses: wash-ups which only impact year 1 actual allowable revenue, and those which apply in subsequent years. [891]	We agree the sequencing of this calculation is important. This sequencing is already provided for under our price-quality determinations, in the financial model.
Accelerated wash-up: cap and collar	The cap and collar for the accelerated wash-up was incomplete: "Although there is a cap and collar specified with reference to the t-2 wash-up balance, there is no cap or collar in the other direction, which should be zero." [892]	We agree that the cap and collar should be more clearly specified. In the final amendment determination, we have amended the drafting of the cap and collar for the wash-up drawdown to: (a) ensure the cap and collar is complete; and (b) clarify that the cap and collar applies to total amount of the wash-up draw down for a disclosure year (ie the sum of any amount specified by the Commission and any accelerated drawdown amount nominated by the supplier).
Time value of money across DPP/CPP periods	It is unclear what time value of money value to apply when lagging across DPP/CPP periods. For example, for a revenue wash-up where the wash-up amount is from one regulatory period but it affects forecast allowable revenue in the next regulatory period, it is unclear which WACC value (ie from which regulatory period) should be used.[893]	The WACC used in calculating the wash-up is the WACC that applies for the disclosure year to which the calculation relates.

Treatment of CPI in the revenue path and wash-up

Final decision

D129 Our final decision is to:

D129.1 confirm the change we proposed to our draft decision (in our further consultation) to the EDB and GTB IMs to ensure that the most up-to-date CPI inflation (actual and forecast) is used when determining forecast net allowable revenue at the start of each regulatory year,[894] and

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[891] Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Appendix C.

[892] Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), Appendix C.

[893] Electricity Networks Aotearoa (ENA) "Appendix D - IM Practicality Issues Log" (19 July 2023), "Cost of Capital".

[894] See para 4.79, in Chapter 4 of this topic paper.

D129.2 provide for a residual wash-up for differences between these updated forecasts and actual inflation via the mechanism discussed in the previous section.

D130 As we discuss in Chapter 4 of this paper (Topic 4b), we have also decided to provide a revenue wash-up for inflation for the first year of a regulatory period. We have made some technical amendments to the drafting of the wash-up provisions to implement this decision.

Problem definition

D131 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.

D132 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

D133 Orion and Wellington Electricity highlighted this problem when submitting on possible improvements to the form of control.[895]

Draft decisions

D134 In our draft decisions, we proposed providing for revenue path indexation in two steps:

D134.1 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

D134.2 second, with a residual wash-up for differences between these updated forecasts and actual inflation via the mechanism discussed above.

D135 This is the same as the approach taken for Chorus' revenue path.

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[895] 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.

Reasons for our draft decisions

D136 We noted that our draft decision would help to 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.

D137 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.[896]

D138 We did not consider this change in approach would have a significant impact on regulatory certainty or complexity of the regime.

Stakeholder views on our draft decisions

D139 Our draft decisions received support from Alpine Energy, Chorus, ENA, Orion, Powerco, and Powernet.[897]

D140 Chorus provided comments on the implementation of the CPI wash-up, suggesting that additional clarity is needed as to which forecasts are captured to ensure the proposed wash-up operates as intended:[898]

> Additional clarity could also be added to avoid the uncertainty which is likely to arise given the complexity of the modelling that underpins PQ decisions. For example, whether calculating the MAR on the “same basis as the forecast allowable revenue” extends to recalculating the nominal values of supplier produced forecasts of opex or capex dependent on cost inflators, obtained by the Commission through information requests or from Asset Management Plans (as opposed to those inputs explicitly labelled as reliant on ‘CPI’ in Commission published models).

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896 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.

897 Alpine Energy Ltd "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 13; Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 12; Electricity Networks Aotearoa (ENA) "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 13; Orion "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 20; Powerco "Submission on IM Review 2023 Draft Decisions" (19 July 2023), p. 4; PowerNet "Submission on IM Review 2023 Draft Decisions" (19 July 2023), pp. 10-11.

898 Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 14(c).

D141 Chorus also noted that: [899]

> [T]here is a potential inconsistency between the draft reasons paper (which suggests that the existing wash-up at the revenue level will be extended by a year) whereas the drafting in the IMs would require a re-running of the MAR model and updating the values of building blocks that include inflation assumptions.

D142 We discuss the implementation of the annual update to forecast net allowable revenue for CPI, and of the CPI wash-up, below.

Analysis and final decisions

D143 Based on the support received on the draft decision, our final decision is to confirm our draft decision, with changes to improve implementation (discussed below).

Implementation of the annual update to forecast net allowable revenue

D144 The current approach of setting forecast allowable revenue using one year of forecast inflation ($FNAR_t$ = ($FNAR_{t-1}$) x forecast CPI_t) contributes to a delay in cashflows. This ignores the actual CPI being available for t-1 at the time of setting revenue. The effect of this in the context of a sudden, unforeseen spike in inflation is that the starting point for FNAR for period t (that is $FNAR_{t-1}$) is too low. This in turn means cash compensation is delayed two years by the wash-up account.

D145 Changing the general wash-up mechanism to index the revenue path (ex-ante) using two years of inflation ((Forecast Net Allowable $Revenue_{t-2}$ x (1+actual CPI_{t-1}) x (1+updated forecast CPI_t)) will reduce the delay by making use of as much up-to-date information about inflation as is possible when determining forecast net allowable revenue at the start of each regulatory year.

D146 The amendments will mitigate cashflow and revenue volatility concerns about the revenue wash-up, identified by stakeholders in submissions on our draft decision.[900]

Implementation of the CPI wash-up

D147 Under the new wash-up mechanism, 'actual allowable revenue' is calculated on the same basis as 'forecast allowable revenue', adjusted by substituting actual values for forecast values in the formulas and/or financial model specified in a DPP or CPP determination.

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899 Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 14.

900 See our discussion in para 4.179-4.182 of this topic paper.

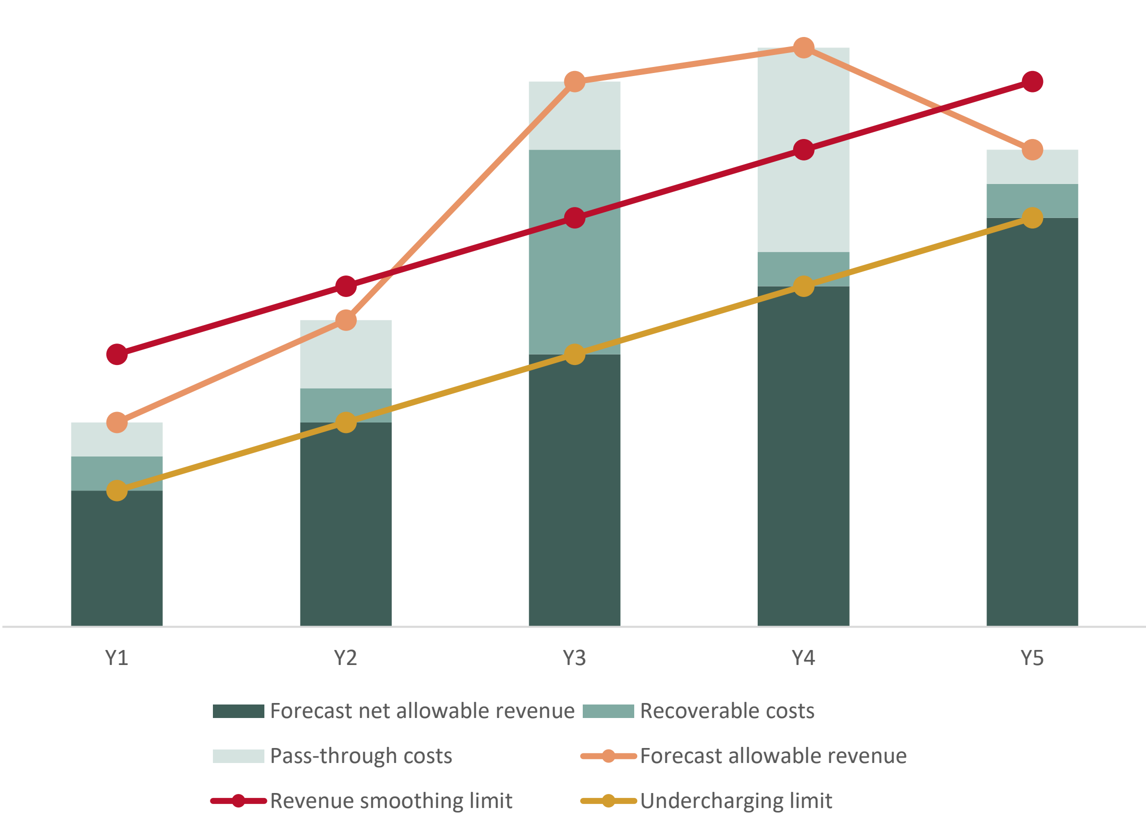
D148 With respect to the substitution of "actual CPI for forecast CPI" in this calculation, as noted above, Chorus suggested additional clarity is needed as to which forecasts are captured to ensure the proposed wash-up operates as intended.[901]

D149 We agree that more specificity is needed. We have amended the drafting proposed in clause 3.1.4(4) of the draft EDB and GTB IM amendment determinations to clarify that the substitution of actual CPI for forecast CPI only applies to the calculation of forecast net allowable revenue for the disclosure year.[902]

D150 We have made this change to ensure that, when re-running the formulas and/or financial model in order to calculate actual allowable revenue, the wash-up calculation works as intended and does not impact other elements of the model.

Compliance with the revenue path

Figure D2 Step 1 - calculating limits on revenue



901 Chorus "Submission on IM Review 2023 Draft Decisions" (19 July 2023), para 14(c).

902 The correct approach for Year 1 differs from subsequent years of a regulatory period, because FNAR for year 1 is not already defined by reference to CPI.

D151 Forecast allowable revenue is the sum of forecast net allowable revenue, recoverable costs, and pass-through costs.

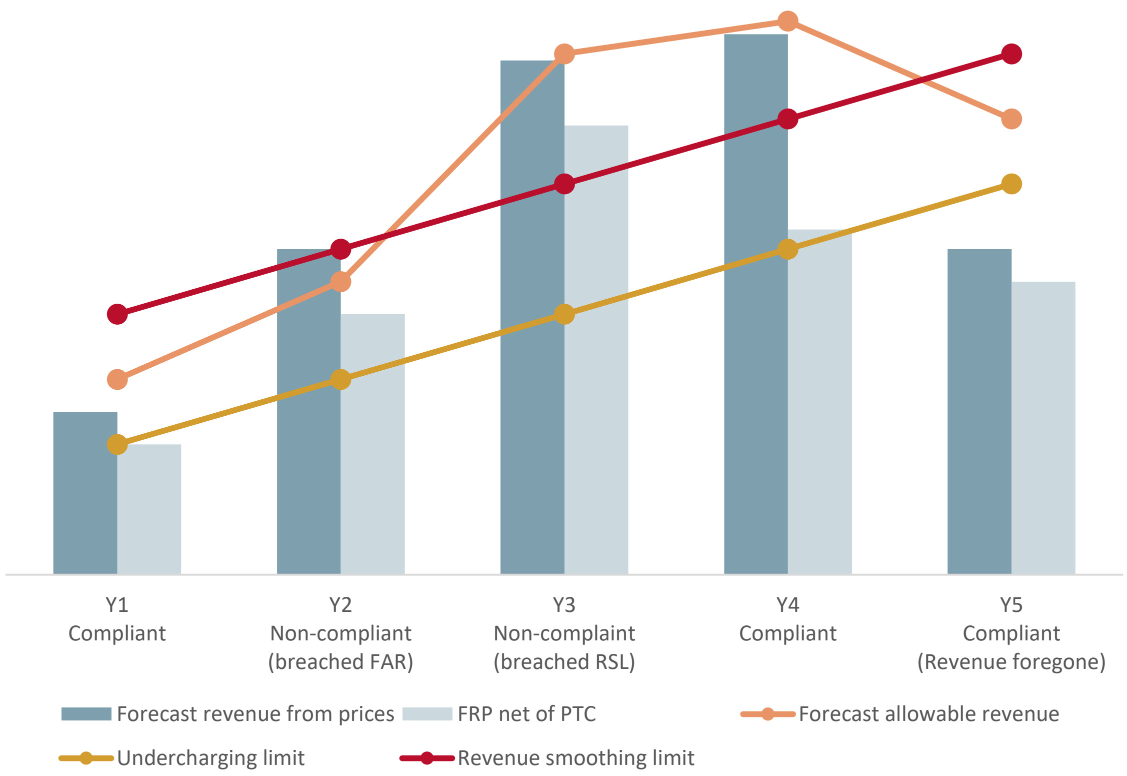
D151.1 Forecast net allowable revenue is defined in the PQ determination and increases at the rate of forecast CPI.

D151.2 Recoverable costs and pass-through costs are defined in the IM and forecast at the start of each year.

D152 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.

D153 The undercharging limit is defined in the PQ determination. As with the revenue smoothing limit, this may be defined in dollar terms or using a formula (such as a percentage).

Figure D3 Step 2 - Assessing compliance with the revenue path



Year one

D154 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

D155 In year two the supplier is non-compliant with the primary revenue cap because FRP is greater than FAR.

Year three

D156 In year three the supplier is non-compliant with the secondary revenue control because FRP net of PTC is greater than the RSL, even though they are compliant with the primary revenue cap.

Year four

D157 As with year one, the supplier is compliant.

Year five

D158 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

D159 To aid stakeholder understanding, we have laid out the revenue path and wash-up mechanisms formulaically, for EDBs and GTBs respectively, in the tables below. These are incorporated into Subpart 3.1 of the EDB and GTB IMs.

Table D2 Illustrative revenue path and wash-up formulae (EDB IMs)

Primary revenue path formulae	
Clause 3.1.1(1)(a)	FRP < FAR FRP means “forecast revenue from prices”, as defined in the IMs FAR means “forecast allowable revenue”, as specified in a PQ determination
Clause 3.1.1(2)	FRP = ∑ (FP × FQ) + FORI FRP means “forecast revenue from prices”, as defined in the IMs FP means forecast “prices”, as defined in the IMs FQ means forecast “quantities”, as defined in the IMs FORI means forecast “other regulated income”, as defined in the IMs
Clause 3.1.1(3)	FAR = FNAR + FPTC + FRC + FRLCC FAR means “forecast allowable revenue”, as specified in a PQ determination 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 FRLCC means revenue forecast to be received under "large connection contracts"

Secondary revenue control formulae	
Clause 3.1.1(1)(b)	FRP - FPTC - FRLCC < RSL FRP means “forecast revenue from prices”, as defined in the IMs FPTC means forecast “pass-through costs”, as defined in the IMs FRLCC means revenue forecast to be received under "large connection contracts" RSL means “revenue smoothing limit”, as specified in a PQ determination
Wash-up formulae	
Clause 3.1.4(1)	$WAB_t = WAB_{t-1} \times (1 + WACC) + WA - WD - RF$ WAB means “wash-up account balance”, as defined in the IMs WACC means mid-point estimate of post-tax WACC, as specified in the WACC determination WA means “wash-up accrual amount”, as defined in the IMs WD means “wash-up drawdown amount”, as defined in the IMs RF means “revenue foregone”, as defined in the IMs Note: the calculation of the WAB in the transition to the new mechanism is provided for in clause 3.1.4(2)
Clause 3.1.4(3)	WA = AAR - AR WA means “wash-up accrual amount”, as defined in the IMs AAR means “actual allowable revenue”, as defined in the IMs AR means “actual revenue”, as defined in the IMs
Clause 3.1.4(9)	$AR = \sum (AP \times AQ) + AORI$ AR means “actual revenue”, as defined in the IMs 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 + AWD If $WAB_{t-2} > 0$: $0 \leq WD \leq WAB_{t-2}$ If $WAB_{t-2} < 0$: $WAB_{t-2} \leq WD \leq 0$ WD means “wash-up drawdown amount”, as defined in the IMs BWD means base washup drawdown. This will be an amount specified by the Commission in a PQ determination AWD means any additional amount to be drawn down, as nominated by the regulated supplier in accordance with clause 3.1.4(5) WAB means “wash-up account balance”, as defined in the IMs
Clause 3.1.4(6)	RF = VRF + CRF RF means “revenue foregone”, as defined in the IMs 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 “undercharging limit”, as specified in a PQ determination VRF means “voluntary revenue foregone”, as defined in the IMs

Table D3 Illustrative revenue path and wash-up formulae (GTB IMs)

Primary revenue path formulae	
Clause 3.1.1(1)(a)	FRP < FAR FRP means “forecast revenue from prices”, as defined in the IMs FAR means “forecast allowable revenue”, as specified in a PQ determination
Clause 3.1.1(2)	FRP = ∑ (FP × FQ) + FORI FRP means “forecast revenue from prices”, as defined in the IMs FP means forecast “prices”, as defined in the IMs FQ means forecast “quantities”, as defined in the IMs FORI means forecast “other regulated income”, as defined in the IMs
Clause 3.1.1(3)	FAR = FNAR + FPTC + FRC FAR means “forecast allowable revenue”, as specified in a PQ determination 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 FRP means “forecast revenue from prices”, as defined in the IMs FPTC means forecast “pass-through costs”, as defined in the IMs RSL means “revenue smoothing limit”, as specified in a PQ determination

Wash-up formulae	
Clause 3.1.4(1)	$WAB_t = WAB_{t-1} \times (1 + WACC) + WA - WD - RF$ WAB means "wash-up account balance", as defined in the IMs WACC means mid-point estimate of post-tax WACC, as specified in the WACC determination WA means "wash-up accrual amount", as defined in the IMs WD means "wash-up drawdown amount", as defined in the IMs RF means "revenue foregone", as defined in the IMs Note: the calculation of the WAB in the transition to the new mechanism is provided for in clause 3.1.4(2)
Clause 3.1.4(3)	$WA = AAR - AR$ WA means "wash-up accrual amount", as defined in the IMs AAR means "actual allowable revenue", as defined in the IMs AR means "actual revenue", as defined in the IMs
Clause 3.1.4(9)	$AR = \sum (AP \times AQ) + AORI$ AR means "actual revenue", as defined in the IMs 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)	$WD = BWD + AWD$ If $WAB_{t-2} > 0$: $0 \leq WD \leq WAB_{t-2}$ If $WAB_{t-2} < 0$: $WAB_{t-2} \leq WD \leq 0$ WD means "wash-up drawdown amount", as defined in the IMs BWD means base washup drawdown. This will be an amount specified by the Commission in a PQ determination AWD means any additional amount to be drawn down, as nominated by the regulated supplier in accordance with clause 3.1.4(5) WAB means "wash-up account balance", as defined in the IMs
Clause 3.1.4(6)	$RF = VRF + CRF$ RF means "revenue foregone", as defined in the IMs 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 "undercharging limit", as specified in a PQ determination VRF means "voluntary revenue foregone", as defined in the IMs