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Input Methodologies (IM) Review 2023 – Response to Draft Decision

Contents

1. Introduction

1. Until recently, Aotearoa New Zealand's energy sector was in a relatively 'steady state.' Almost all electricity flowed in one direction from large power stations, travelling long distances (generally south to north) over high voltage transmission lines to reach end users connected to local distribution networks. Most capital investments by electricity lines companies were consequently in poles, wires, and transformers. There was little innovation or any great need for it because all consumers really wanted or expected was for the lights to stay on – ideally at a reasonable price. It was a simpler time.

2. Life in the gas distribution and transmission sectors was similarly uneventful. Between them, the Maui and Pohokura gas fields were expected to continue providing a reliable and predictable supply of gas – and additional offshore exploration was both permissible and anticipated. Aside from the occasional unexpected disruption, the demand and supply sides of the market remained reasonably constant and undisturbed. There were certainly no reasons to think the sector as a whole could be facing a serious existential threat within a mere matter of years.

> *"When the facts change, I change my mind."*
> -John Maynard Keynes

3. This was the industry context within which the Commission first determined its IMs in 2009-10 and reset them in 2015-16. Those stable, rather tranquil times are now in the rear-view mirror and growing evermore distant. Today, the energy sector is facing the full force of transformational change, driven by swiftly evolving technology, sweeping changes to government policy and fundamental shifts in customer demands. This has profound implications for New Zealand's economy, for the energy sector and, most immediately, for the IM review. The Commission has recognised as much, observing that:[1]

   > *"The environment in which regulated suppliers are operating has changed significantly since our last review of Input Methodologies (IMs) in 2016 and continues to evolve. Government policy on climate change has developed, with a legislated target and high-level supporting policies now in place to facilitate a transition to net-zero carbon emissions by 2050. This is occurring alongside advances in technology and changes in consumer preferences, while inflation is at around a 30-year high and post-Covid supply chain challenges continue. These changes present regulated businesses with new challenges and opportunities."*

4. The great English economist, John Maynard Keynes, once famously said: "when the facts change, I change my mind. What do you do, sir?" This question seems especially fitting as the Commission faces the significant task of revising the IMs to enable businesses to better meet the challenges and opportunities to come. To that end, the draft decision certainly entails some

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[1] Commerce Commission, *Context and summary of Draft decisions, Part 4 Input Methodologies Review 2023,* 14 June 2023, p.5 (hereafter: 'Context and summary paper').

welcome instances of the Commission responding to the 'changing facts' by recommending sensible modifications. For example, many of the proposed revisions to 'reopeners' would improve on the existing, unduly narrow arrangements though we consider that the Commission can still do more in this area[2].

5. However, for the most part, the draft decision is a case study of a regulator not changing its mind despite changing circumstances. The Commission repeatedly proposes to retain IMs that are no longer fit for purpose or, worse, recommends changes that would be retrograde steps. Examples of the former include the insistence on persevering with Regulatory Asset Base (RAB) indexation and the seeming reluctance to embrace changes that would support network investment and foster more innovation. The starkest example of the latter is the proposed reductions to the weighted average cost of capital (WACC) percentiles.

6. This submission is accompanied by a cover letter from our CEO and seven expert reports (three of which were jointly commissioned) covering the key topics we wish to raise. We have provided a list in Appendix E of all these reports. No parts of our submission, cover letter and the expert reports are confidential, the Commission is free to publish them on their website.

A disappointing IM process

7. Given that the Commission only has a requirement to review the IMs every seven years (at a minimum), it is disappointing to have a witnessed a less than robust process to seek stakeholder views over the last year and a half. The Commerce Act requires the Commission to give interested persons a reasonable opportunity to give their views on that draft methodology[3] we are concerned this requirement has not been met.

    a. The draft decision only had a five-week consultation period despite the documents containing more than a thousand pages and introducing some completely new changes / topics[4] (for e.g., the revenue wash-up amendments). Our submission reflects the time that was awarded to us respond to the Commission's draft decision. Our feedback on the draft decision could have been more fulsome and in depth if the Commission had provided more time. The Commission seems to overlook that significant time is needed from a business process perspective to select, engage, and brief experts, to brief directors and stakeholders and to ensure submissions have the appropriate level of governance and oversight. We are not alone and note that important consumer organisations have also struggled to meet the tough deadlines imposed by the Commission and that requests from other interested

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[2] Along with our submission we have sent a report by Complete Strategy providing an overview of the uncertainty mechanisms used by Ofgem in the UK for RIIO-ED2. The report is entitled, '*Uncertainty mechanisms in the UK: an overview*,' March 2023

[3] s52V (2) (b)

[4] One of our experts explained that the amount of work they had to do to respond to the draft decision would usually have taken them a year, yet they had to condense their review in five weeks. Their experience is that regulators in other jurisdictions would drip feed issues for interested parties to comment on rather than land hundreds of pages on interested parties in one go.

parties for an extension of time were denied by the Commission. This IMs review sets the regulatory framework for arguably the most critical stage of New Zealand's drive to decarbonise its economy. The Commission have responded with standard processes, timeframes, and a reduced engagement programme.

b. There were only two issues papers – many important topics were only dealt with in a stakeholder workshop followed by a questionnaire with a two-week deadline. Topics such as 'IRIS', 'in-period adjustments' and 'incentives' needed their own issues paper in order to appropriately cover the topics rather than leave things until the draft decision;

c. On the two issues papers that were published, the Commission invited no cross-submissions which included the cost of capital which is always one of the most material issues for the IM review;

d. Additionally for the cost of capital, the Commission held no WACC conference as has previously been undertaken (e.g. in the 2016 IM review which permitted experts debate and deliberate on issues face to face);

e. When stakeholder workshops were held, they were one-sided with the Commission only sharing material shortly in advance of the workshop, leaving little time for stakeholders to digest and properly participate in them; and

f. We have requested information from the Commission to inform our submission and are still awaiting that information. As such we may amend or add to our submission and/or our cross submission once that information is received. We will do so as soon as practical on receipt of the information requested.

8. Crucially, a weakness of the Commission's draft decision is that very significant choices have been made on the basis of limited, or even no, expert evidence. For example, the Commission has gone for the midpoint WACC for gas pipelines on an intuition that gas pipelines are different to electricity distribution. While this reverses an earlier position, the Commission has done so without actually undertaking any analysis of the difference between gas and electricity or the likely impact of their decision on investment incentives for gas pipelines.

9. This is different from a 'typical' process because we usually do not get this deep into an IMs process with so little actual evidence supporting the Commission's draft decisions. This has placed the onus on suppliers having to backfill the work the Commission ought to have done but has not.

The future is electric

10. For New Zealand to avoid the use of fossil-fuelled backup generation while retaining appropriate reliability standards it will not only need more investment in 'poles and wires,' but also innovations in technology and demand management to deliver the most efficient network

build and more flexibility.[5] Without these investments by lines businesses, the economy cannot decarbonise. The energy sector will also need to move earlier than most, accelerating pathways for other sectors, such as transport.[6] The scale of investment that is required is unprecedented – and it is needed now. As the Boston Consulting Group (BCG) (2022) explained:[7]

> *"Delivering this future will require an unprecedented investment of $42 billion in the 2020s, including … $22 billion in distribution infrastructure to enable electrification in the 2020s and prepare networks for rapid electrification and multi-directional flows of electricity in the 2030s. Total investment need in 2026–2030 is forecast to be 30% higher than 2021–2025."*

11. For gas pipeline businesses (GPBs) this of course means a highly uncertain future characterised by declining demand.[8] Those providers will naturally want any such transition from gas to electricity to be as orderly as possible and free from asset stranding risk. So too will their customers. The last thing anyone wants is for a GPB to abruptly shut-down parts (or even all) of its network before upstream producers and downstream customers have had a chance to adequately prepare.[9] Thus, 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.

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[5] A flexible energy system is one that minimises the amount of generation and network assets that are required to meet peak demand. It gives consumers greater control over their energy bills, through access to smart technologies and services. Flexibility enables the time or location of consumption or generation to be shifted, thereby managing network constraints. This also reduces cost when compared to the counterfactual.

[6] For example, if power grids are unable to accommodate uptake in EVs, or if charging infrastructure is inadequate, then this will have undesirable knock-on effects. This would give rise to costs not only in the form of additional emissions but, potentially, also through foregone reductions in peak demand (which would otherwise have resulted in infrastructure cost savings). EV chargers will typically use the most electricity of any appliance in a household. Consequently, widespread investment in 'smart' and energy-efficient EV chargers could significantly reduce peak demand issues by shifting the demand from charging away from peak periods to times when demand on the network is lower. This could then reduce the need to upgrade the electricity supply and distribution system to the same extent if compared to the counterfactual and therefore results in lower electricity bills for charging.

[7] Boston Consulting Group (2022), *The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector,* p.9 (hereafter: 'BCG (2022)'; available: here).

[8] The Climate Change Commission has recommended phasing out natural gas use in residential, commercial and public buildings. The initial report recommended a 'hard sunset' of 2050. *See:* Climate Change Commission, *Ināia tonu nei: a low emissions future for Aotearoa Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025*, 31 May 2021 (available: here).

[9] For example, when the transition was made from analogue to digital television, people were given *years* of warning. And all they had to do was replace their TVs, which is not a major expense (and an item that is replaced periodically in any case). Switching from gas to electricity is a far more extensive undertaking – especially for large industrial users and is not an insignificant cost for households.

The IMs must also transform

12. The 2020s will be a critical decade for the electricity sector and Aotearoa's transition to net zero carbon. There is a strong public interest in companies making the investments needed to meet expected increases in electricity demand, ensure an orderly transition away from fossil gas, and keep pace with increasingly complex consumer preferences. The potential benefits on offer from getting this right and kick-starting rapid electrification are enormous. BCG (2022) recently concluded that with decisive, prompt action supported by the right policy, regulatory and market settings, the electricity system can:[10]

    a. by 2030, transition to 98% renewables and kick-start electrification, reducing New Zealand emissions by 8.7 Mt CO2-e per year; and

    b. by 2050, enable rapid electrification of transport and heating, reducing New Zealand emissions by 22.2 Mt CO2-e per year.

13. Ofgem also recently explored the potential costs of the United Kingdom's future electricity system under a range of different flexibility assumptions (using a dynamic dispatch model). Its objective was to understand the role and value of additional flexibility in a decarbonised power sector, and to identify the amount and type of flexibility needed in that system. Its modelling showed the following:[11]

    a. Increased flexibility was estimated to provide significant cost savings in a decarbonised power sector. In the scenarios Ofgem tested, increased system flexibility provided system cost reductions of up to £10bn per year (2012 prices, undiscounted) in 2050.

    b. Ofgem also assessed the cumulative value (from 2020 to 2050) of increased flexibility based on illustrative pathways to net zero. It estimated that increased flexibility could reduce system costs between £30-70bn across that period (2012 prices, discounted).

> The IMs that are in place over the next crucial seven-year period will have a huge bearing on whether the substantial benefits of electrification are seized or squandered.

14. The implications are clear. If network owners make the right investments at the right times, enabling the power grid to become smarter and more integrated as we transition away from fossil fuels (including gas), the benefits would be huge. But similarly, the downside costs associated with missing this opportunity would be vast. The IMs that are in place over the next crucial seven-year periods will consequently have a decisive bearing on which of these scenarios comes to pass, i.e., whether the benefits are seized or squandered.

15. In determining its IMs, the Commission must, of course, be guided by the legislative objective. When weighing the outcomes specified in the purpose statement it must do what best promotes

[10] BCG (2022), p.2.

[11] Ofgem, *Transitioning to a net zero energy system Smart Systems and Flexibility Plan 2021*, July 2021 (available: here).

the long-term benefit of consumers. To that end, it is reasonable to anticipate that dynamic efficiency considerations (fostering efficient innovation and investment) will often have a greater bearing on long-term consumer welfare than short-term static efficiency objectives (e.g., avoiding excess profits), especially in the current industry context. As Axiom Economics (2022) has explained:[12]

> *"… although the Commission cannot – and should not – automatically elevate dynamic efficiency considerations in its decision making, those concerns will nevertheless be frequently decisive. Furthermore, the circumstances that currently exist in the energy sector provide even more reason for the Commission to pay heed to long-term dynamic factors as it performs its review. Most notably, the full force of transformational change is in motion across the energy sector, driven by rapidly evolving technology, government policy and changing customer demands."*

16. This conclusion is uncontroversial as a matter of economics, given the strong link that exists between investment and long-term consumer interests in industries characterised by long-lived infrastructure. Consumers almost always derive greater benefits from firms investing in the right things at the right times than they do from lower prices for existing services. And the circumstances that presently prevail in the energy sector provide even more reason for the Commission to pay heed to long-term dynamic factors.

17. Put simply, given what is at stake, the Commission should be doing all it can to ensure its IMs promotes the investment and innovation that almost all agree will be needed to enable rapid electrification and a smooth transition away from fossil fuels. To refer back to Lord Keynes' quote, the 'facts have changed' and so to must the IMs. To remain fit for purpose and serve the long-term interests of consumers, the IMs must transform along with the energy sector itself. Unfortunately, the draft decision largely fails to meet this moment.

The draft decision does not meet the moment – and appears stuck in the status-quo

18. In the very first sentence of its summary and context paper, the Commission acknowledges that the environment in which regulated suppliers are operating has changed significantly since the last IM review – and that it continues to evolve.[13] Yet, despite these 'changing facts', the Commission has not 'changed its mind' – at least, not to a significant extent. It contends instead that the IMs "broadly remain fit for purpose and flexible enough to cope with the changing operating environment."[14] Vector strongly disagrees with this sentiment.

There are many instances where the Commission has proposed to retain IMs that are no longer fit for purpose or recommended changes that would be retrograde steps.

[12] Axiom Economics, *Dynamic Efficiency and the Energy Transition, A report for Vector,* September 2022, p.2.

[13] Context and summary paper, p.5.

[14] *Op cit*, p.6.

19. There are numerous instances throughout the draft decision where the Commission has opted to retain (in totality or with only minor changes) IMs that are no longer the best options available in the wake of the developing circumstances. As Vector and others have highlighted, there are frequently materially better alternatives available yet, the Commission chooses repeatedly to ignore them. Some of the more prominent examples of the Commission opposing worthwhile revisions include its proposals to:

    a. Refuse to add a financeability test into the IMs at a time when it is essential that suppliers have the certainty that the regulatory regime will support the funding requirements that will underpin the investments required to enable our decarbonised future.

    b. Continue indexing the RABs of both electricity distribution businesses (EDBs) and GPBs, despite:

        i. the benefit this would provide EDBs at a time of facing additional financing challenges when seeking to fund the billions of dollars in investment that will be needed to enable electrification;

        ii. that the Commission's track record at forecasting inflation has been extremely poor resulting in, period on period, large under and over recovery of revenues with these impacts being borne by suppliers and consumers unnecessarily;

        iii. the inappropriateness of adopting Reserve Bank of New Zealand's (RBNZ) inflation forecasts and projections despite these being "set and forget" beyond 6 months and wholly unfit for the purpose the Commission utilise them for in reducing networks permitted cash revenue; and

        iv. the additional asset stranding risks that indexation will impose upon GPBs facing an uncertain future characterised by unpredictable diminishing demand.

    c. Resist alternative front-loaded approaches to depreciation under the default price-quality path (DPP).

    d. Refuse to reconsider an arbitrary 10% limit for EDBs' revenue cap, which fails to address a high inflationary environment, artificially constraining allowed revenues for EDBs within a regulatory period.

    e. Retain a weighted average price cap (WAPC) for GPBs, despite the substantial demand forecasting volume risks those businesses will face relative to:

        i. a revenue cap that delinked recovered revenue (which would vary with largely uncontrollable demand risk) from underlying costs (which are largely sunk); or

        ii. a WAPC that could be re-opened if outturn demand differed from the underlying forecasts by certain pre-specified margins.

    f. Refuse to make improvements to WACC settings that are largely used by other regulators such as trail average cost of debt, risk free rate tenor and equity raising costs.

g. Tinker with flexibility mechanisms rather than full embrace a full suite of flexibility mechanisms that have been introduced in other jurisdictions.

h. Recommend against changes that could spur much-needed innovation with few downside costs, including the introduction of regulatory sandboxes.

> The draft decisions to reduce the WACC percentiles for both EDBs and GPBs seem inexplicable in the circumstances and would have broad, highly detrimental impacts.

20. This 'IM inertia' will materially compromise EDBs and GPBs' incentives to make the investment decisions required to unlock electrification benefits throughout the energy supply chain and the wider economy (e.g., the transport sector). It will diminish EDBs' desire to invest either in resilience/reliability or innovation. Retaining unfit IMs will also act as a disincentive for GPBs to continue to invest and maintain their infrastructure to ensure an orderly transition from gas to electricity. They will reduce incentives for preserving option value for the repurposing for biogas or other green-gas opportunities.

21. The draft decision does contain some welcome changes that Vector supports. The change of the revenue limit to be net of pass-through costs is an improvement though how any revenue cap is applied by the Commission at the DPP requires careful consideration given financeability issues if revenues are deferred to future periods. Many of the proposed revisions to 'reopeners' would improve on the existing, unduly narrow arrangements – including when it comes to resilience-related expenditures. But aside from these occasional highlights, the draft decision is largely underwhelming and feels strongly stuck in the status quo. As it stands, the Commission risks forsaking an excellent opportunity to lay the regulatory foundation needed to meet the current moment.

22. In the remainder of this submission, we provide a more detailed assessment of the specific elements of the draft decision. We also set out the changes that the Commission should make between now and its final determination to remedy the many failings in its current draft and better promote the long-term interests of consumers.

2. Summary of Vector's position on the draft decision

23. We have summarised in the table below Vector's position on each of the decisions made by the Commission in its draft decision. Against each one we have also referenced the appendix and section where further information can be found on our position.

24. Our detailed submissions are found by topic in four separate appendices:

    A. Cost of capital;

    B. Financing and incentivising efficient expenditure;

    C. Incentivising efficient expenditure for EDBs; and

    D. Customised price-paths (CPPs) and in-period adjustments.

NZCC draft decision	Vector position/ reference
COST OF CAPITAL	
Cost of debt	
Maintain the current hybrid approach to estimating the cost of debt	Not supportive – see Appendix A, section 2
Maintain the current approach to estimating the risk-free rate	Not supportive – see Appendix A, section 2
Maintain the current approach to estimating the debt premium	Not supportive – see Appendix A, section 2
Maintain the current spread premium of 7.5bps for the TCSD for energy businesses	Not supportive – see Appendix A, section 2
Maintain our current decision of not specifying a TCSD allowance for regulated airports services	Not considered
Maintain the allowance for debt issuance and associated costs at 20bps p.a., but allow debt issuance and associated costs at 25bps for a four-year regulatory period	Not supportive – see Appendix A, section 2
Maintain the current credit rating of BBB+ for EDBs/Transpower and GPBs	Support for EDBs and GPBs neutral for Transpower
Maintain the current credit rating of A- for airports	Not considered
Cost of equity	
Update the equity beta estimate for EDBs/Transpower - from 0.60 to 0.59	Not supportive – see Appendix A, section 3
Update the equity beta estimate for GPBs - from 0.69 to 0.68	Not supportive – see Appendix A, section 3
Maintain the equity beta for airports at 0.74	Not considered
Update the TAMRP for GPBs - from 7.5% to 7.0%	Not supportive – see Appendix A, section 3
Maintain a TAMRP of 7.0% for EDBs/Transpower and Airports	Not supportive for EDBs, not considered for Transpower and Airports– see Appendix A, section 3
Maintain our current decision of not providing an allowance for equity issuance costs	Not supportive – see Appendix A, section 3
Other decisions related to the cost of capital	

Use the 65th WACC percentile for EDBs and Transpower	Not supportive – see Appendix A, section 1
Use the 50th WACC percentile for GPBs	Not supportive – see Appendix A, section 1
Change the leverage estimate for EDBs/Transpower and GPBs - from 42% to 41%	Not supportive – see Appendix A, section 2
Change the leverage estimate for airports - from 19% to 26%	Not considered
Changes to allow for a WACC for a four-year regulatory period for EDBs DPPs and Transpower's IPP	Support
Maintain the current standard error of the WACC as 0.0101 for EDBs and Transpower	Not supportive – see Appendix A, section 3
Maintain the current standard error of the WACC as 0.0105 for GPBs	Not supportive – see Appendix A, section 3
Change the standard error of the WACC for airports - from 0.0146 to 0.0153	Not considered
Maintain the current approach to tax rates	Not supportive – see Appendix A, section 1

NZCC draft decision	Vector position/ reference
FINANCING AND INCENTIVISING EFFICIENT EXPENDITURE	
Financing and incentivising efficient investment	
Maintain RAB indexation to inflation for EDBs and GPBs	Not supportive – see Appendix B, section 2
Introduce RAB indexation to inflation for Transpower	See Vector's Transpower submission due on 26th July
Enable Transpower to apply for an alternative depreciation profile	See Vector's Transpower submission due on 26th July
Not to introduce any tools to alter cashflow timings specifically for IRIS	Not supportive – see Appendix C, section 2
Introduce a new connections volume wash-up mechanism for EDBs on a customised price-quality path (CPP)	Support if also allowed for DPPs – see Appendix D, section 5
Maintain approach to address asset stranding risk in the context of expected declines in gas demand	Not supportive – see Appendix B, section 2
Maintain the form of control for GDBs	Not supportive – see Appendix B, section 4
Not to adopt a financeability test in the IMs	Not supportive – see Appendix B, section 1
Our approach to incentivising efficient expenditure for EDBs and Transpower	
Not adopt a totex regime. Maintain current expenditure incentive schemes as tools to mitigate capex bias	Not supportive – see Appendix C, section 1
Maintain current incentive mechanisms as they best balance effectiveness and understandability	Not supportive – see Appendix C, section 1
Adjust IRIS allowances for inflation	Support – see Appendix C, section 2
Maintain our approach to setting incentive rates	Needs further consideration – see Appendix C, section 2
Not to exclude specific expenditure categories from IRIS	Not supportive – see Appendix C, section 2
Use the midpoint discount rate in the opex IRIS calculation	Not supportive – see Appendix C, section 2
Maintain our current treatment of operating leases	Not supportive – see Appendix C, section 2
Make no change to IRIS for undercharging	Not supportive – see Appendix C, section 2

Remove the Transpower baseline adjustment term	See Vector's Transpower submission due on 26th July
Inflation risk	
Maintain our current method for forecasting inflation	Not supportive – see Appendix B, section 2
Introduce inflation wash-up on revenue for the first year of a regulatory period	Support - see Appendix B, section 5
Adjust annual revenue wash-up to reflect debt servicing costs being fixed in nominal terms	Not supportive/ needs further consideration – see Appendix B, section 5
Innovation incentives for EDBs and Transpower	
IMs generally enable the desired outcomes of regulatory sandboxes – no IM changes for this purpose	Not supportive – see Appendix C, section 3
Amend the innovation project allowance mechanism	Not supportive – see Appendix C, section 3

NZCC draft decision	Vector position/ reference
CPPS AND IN-PERIOD ADJUSTMENTS	
Whether changes to CPP IMs are necessary	
Not amend CPP IMs for the purpose of streamlining CPPs	Not supportive, see Appendix D, section 1
Not allow for a single-issue CPP	Not supportive, see Appendix D, section 1
Improving the price-quality path reopener process	
Introduce the definition of a 'reopener event'	Support
Require suppliers who nominate a reopener event to provide sufficient information	Support
Require the Commission to publish notices after a significant step in the reopener process	Support
Prescribe factors the Commission must have regard to when deciding whether to amend a price-quality path	Support
Introduce a new clause to provide the Commission the option to identify reopener applications that are better suited to CPPs	Not supportive – see Appendix D, section 4
Introduce a new clause on how the Commission will handle confidential information in a reopener application	Support
Introduce a new clause to require the Commission to take into account the expenditure objective when determining extent of price-quality path amendment	Support
Not introduce timeframes for the Commission to evaluate reopener applications	Not supportive – see Appendix D, section 1
Not provide more prescription about the types of information required in reopener applications	Not supportive – see Appendix D, section 1
Not include application windows for reopeners	Not supportive – see Appendix D, section 1
Not prescribe when consultation is required and when it is not	Not supportive – see Appendix D, section 1
Not include a modification or exemption provision for DPP or IPP reopeners	Support
Not include a pre-application stage for the process of reapplying for a reopener	Not supportive – see Appendix D, section 1

Not include a reopener for the purposes of assessing programme financeability	Not supportive – see Appendix D, section 1
Not allow price-quality path reopeners to apply across more than one regulatory period without suppliers having to reapply	Not supportive – see Appendix D, section 1
Not allow a single CPP application to cover multiple parties	Not supportive – see Appendix D, section 1
Not allow a single reopener application to cover multiple parties	Not supportive – see Appendix D, section 1
Whether reopeners will cover future circumstances	
Allow opex solutions for system growth	Support
Allow system growth to include general growth for Foreseeable major capex project (FMCP) reopeners where project is identified in the AMP and is well-evidenced	Support
Not allow system growth to include general growth for Unforeseeable major capex project (UMCP) reopener	Not supportive – see Appendix D, section 2
Allow consequential opex and consequential capex for FMCP, UMCP, Capacity reopeners	Support
Include resilience related expenditure in EDB FMCP and UMCP reopeners and a separate resilience and asset relocation reopener for GPBs	Support
Extend the GDB/GTB risk event reopener to EDBs	Support
Change how the impact of GAAP changes are assessed in the Change event reopener to remove the potential for windfall gains and losses	Support
Not include a reopener to cover Government policy changes, Local Government rule changes and legislation affecting others in the supply chain	Not supportive – see Appendix D, section 2
Not include a general reopener or a general escalating costs reopener	Not supportive – see Appendix D, section 2
Not include a 'contingent projects reopener' for DPPs in the EDB, GDB and GTB IMs	Not supportive – see Appendix D, section 2
Not include a reopener to address digitalisation and data	Support with further consideration needed – see Appendix D, section 2
Not include a reopener to address monitoring of Low Voltage (LV) networks	Support with further consideration needed – see Appendix D, section 2
Not include a reopener to address changes to a system operator's approach to security	Support
Not include a reopener to address software as a service (SaaS)	Support with further consideration needed – see Appendix D, section 2
Not include a reopener to address avoided cost of distribution payments (ACOD)	Neutral
Not include a reopener to address increased insurance premiums	Support with further consideration needed – see Appendix D, section 2
Not include a reopener to address Distribution System Operation (DSO) type services	Support with further consideration needed – see Appendix D, section 2
Reviewing our approach to reopener thresholds	

Change the test and materiality threshold which applies to Catastrophic event and Change event reopeners (non-GAAP changes) for all suppliers	Not supportive – see Appendix D, section 4
Remove the $30 million upper threshold for EDB FMCP and UMCP reopeners	Support – Appendix D, section 4
Raise the existing dollar thresholds which apply to EDB FMCP and UMCP reopeners	Not supportive – see Appendix D, section 4
Retain the percentage of revenue threshold for all EDB reopeners apart from Error event	Support – Appendix D, section 4
Retain existing thresholds which apply to Gas reopeners, apart from Error event	Support
Not implement a lower threshold for high consumer benefit projects	Not supportive
Not implement a change in requirements to specifically allow for cumulative application of lower thresholds	Not supportive – see comments on general growth in Appendix D, section 4
Apply reopener thresholds for new and extended reopeners on a consistent basis with other reopeners	Support
Large Connection Contract Mechanism	
Introduce a 'large connection contract' mechanism for EDBs	Support if changed – see Appendix D, section 3
Whether other in-period adjustment mechanisms are necessary	
Not allow new volume wash-up mechanisms	Not supportive – see Appendix D, section 5
Not allow new pass-through costs or recoverable costs to manage increased forecasting uncertainty	Not supportive – see Appendix D, section 5
Not incorporate new contingent expenditure allowances as recoverable costs	Not supportive – see Appendix D, section 5
Not incorporate new use-it-or-lose-it allowances	Not supportive – see Appendix D, section 5

Appendix A. Cost of capital

25. In collaboration, the six largest EDBs (Vector, Aurora, Orion, PowerCo, Unison and Wellington Electricity) and separately the three largest GPBs (Vector, PowerCo and FirstGas) have commissioned Oxera to assess the Commission's draft decision relating to the Cost of Capital.

26. Oxera's electricity distribution report is entitled '*Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital*[15]' and their gas distribution report '*Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital relating to the gas sector*[16]'. Both are submitted in parallel to this submission on 19th July with associated cover letters. We refer to the two reports throughout this section of our submission.

1. WACC percentile

27. There is tremendous public interest in EDBs investing the huge sums of capital required to meet expected increases in electricity demand, ensure an orderly transition away from fossil fuels and keep pace with increasingly complex consumer preferences. The benefits on offer from getting this right and kick-starting rapid electrification are huge. But those potential gains could be squandered if the IMs compromise business' incentives to invest efficiently.

Myopic focus on reliability

28. The draft decision to reduce the WACC for EDBs from the 67th to the 65th percentile is based on a solitary factor. The Commission thinks the probability of major outages occurring in the electricity sector is lower now than in 2014, and it believes it can rely on other tools to manage these risks (e.g., quality of service regulation). It is difficult to understand why the Commission would think this after the tumultuous year North Island customers have experienced. Any customer who lived through the last four months might rightly query how anyone could reasonably believe the expected costs and/or likelihood of outages have fallen, considering:

    a. Vector has faced two network-threatening events since January. Cyclone Gabrielle and the Auckland floods both did widespread damage and gave a stark reminder of the challenges posed by changing weather patterns. Any suggestion that the probability of outages has decreased seems incongruous in light of these recent disasters (which are likely to become even more frequent in the future with climate change); and

    b. Relatedly, the costs of outages stemming from events such as 'atmospheric rivers' (a phrase that entered the lexicon following the January floods) are only going to escalate further as electrification ramps up. For example, major outages prevent EV owners from

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[15] Oxera, *Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital*, 19th July 2023

[16] Oxera, *Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital relating to the gas sector*, 19th July 2023

recharging. As more New Zealanders transition away from internal combustion vehicles, the flow-on costs of blackouts for EV owners will increase substantially.

29. Moreover, almost all the measures the Commission says it can now harness to mitigate the risk of underinvestment in resilience/reliability were available in 2014. They are not new – nearly all were in in place when it first adopted and justified the 67th percentile. Why then would these tools suddenly prove so much more effective at mitigating the even greater potential costs EDBs are likely to face in years ahead? This draft decision contains few clues. As such, even if one focuses myopically on reliability and ignores all other relevant factors (see below), this still provides no justification for reducing the WACC percentile for EDBs.

Blindness to other factors

30. The Commission's draft decision on the EDB WACC percentile is even more unfathomable once other crucial factors are considered that have been discounted or unheeded. Shielding consumers from the immense costs of major outages, while critically important, is by no means the only reason for providing a WACC uplift. Another vital reason to 'aim up' in the present circumstances is to improve the likelihood of consumers reaping the enormous benefits[17] that would stem from EDBs' investments in electrification. Put simply:

    a. If EDBs are able to upgrade their networks in ways that allow for the timely connection of low carbon technologies, then this will generate substantial benefits throughout the electricity supply chain and the wider economy; but

    b. If the WACC is set too low (e.g., if it is inadvertently set below its true level due to estimation error), then these investments may be delayed or replaced with sub-optimal alternatives, with profound downside costs for consumers.

31. The Commission has inexplicably ignored this obvious reason to 'aim up.' Once it is taken into account there is little justification for decreasing the WACC percentile. Tellingly, Oxera, the architect of the Commission's WACC percentile framework, concluded that the 65th percentile is not appropriate.[18] The urgent need to invest in electrification means there is instead compelling reason for the WACC percentile for EBDs to increase. The Commission's draft decision to recommend the opposite defies common sense.

Inconsistency with government policy on gas and not in consumers' interests

32. The draft decision to reduce the WACC for GPBs from the 67th to the 50th percentile is also based on a singular factor. The Commission believes the probability and cost of major outages

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[17] Frontier Economics, *Regulatory Financeability*, para 31. "A recent detailed assessment of the net benefits to consumers has been conducted by the Australian Energy Market Operator (AEMO) in its Integrated System Plan (ISP). AEMO has computed that every dollar of approved transmission network expenditure is expected to generate $2.20 in customer benefits."

[18] Oxera, *Review of the percentile of the WACC distribution that should be targeted by the NZCC, Prepared for Aurora, Orion, Powerco, Unison, Vector, Wellington Electricity* ,14 October 2022—reviewed on 31 January 2023, *Final*, p.2.

is lower for GPBs than for EDBs. Very little analysis is provided to support this contention but, even if it is true (which we do not accept), several other vital factors have been missed. Most notably, it is hard to fathom why the Commission would want to make gas cheaper at the very time the government wants people to buy less of it and switch to electricity. Reducing the WACC percentile would therefore undermine this objective:

a. Setting the WACC at the 65th percentile for EDBs and at the 50th for GPBs will, naturally, reduce the price of gas relative to electricity and make people less likely to transition to the latter, hindering progress towards electrification; and

b. it is rare to incentivise uptake of a 'new product' (e.g., Sky digital services, fibre, or electricity) by reducing the price of the 'legacy product' (e.g., Sky non-digital services, copper, or gas).

33. The reduction of the WACC percentile is not in the long-term interests of consumers. Consumers need time to transition their business processes and lifestyles away from gas to electricity. While this transition is underway it is essential that GPBs have incentives to continue to invest in their pipelines. Lowering the WACC percentile reduces that incentive and puts an orderly transition at risk. It also incentives parts of networks that are marginal from a cashflow perspective to be discontinued earlier than maybe necessary. There is also option value in preserving pipelines through ongoing maintenance and investment while the uncertainty around a green gas future is being determined. Lowering the returns from these pipelines risks this option value being lost before the future of green gases is known.

Assumptions favoured over factual analysis

34. The scale of investment that EDBs are facing over the next seven years is unprecedented.[19] Many EDBs have said they will encounter real challenges raising the funds needed to undertake those investments unless changes are made to the IMs, e.g., to increase the WACC and/or bring forward cashflows. The Commission expressed scepticism about whether EDBs would, in fact, encounter material financing challenges. It ultimately decided against making any concessions to moderate such concerns in its draft decision and appears to have done so on very limited evidence. In particular, it is impossible to come to any robust conclusions about whether the draft decision would cause financeability problems without first modelling the impacts upon EDBs' cashflows and key financial metrics (net gearing ratios, etc).[20] The

[19] The Boston Consulting Group (BCG) (2022) has estimated that $22 billion of investment will be required in distribution infrastructure alone to enable electrification in the 2020s and prepare networks for rapid electrification and multi-directional flows of electricity in the 2030s. *See:* Boston Consulting Group (2022), *The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector,* p.9 (hereafter: 'BCG (2022)'; available: here).

[20] The Commission appears to have done *some* modelling to this effect for Transpower, yet it is conspicuously absent for EDBs. *See:* Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Draft decision,* 14 June 2023, p.57 (hereafter: 'Financing and incentivising efficient expenditure paper').

Commission has done none of this fact-finding and therefore is in no position to make any informed judgements about financeability risks for EDBs.

Oxera's assessment of the WACC percentile for electricity distribution

35. Oxera has analysed the Commission's reasoning for reducing the WACC percentile for EDBs from the 67th to the 65th percentile and find that the 67th percentile was already at the lower end of the optimal range. The main reasons why Oxera considers the estimates by the Commission to be low are:

    a. The Commission uses an Oxera estimate based on outage costs of NZ$1bn, which represents the lower bound of the range that they considered in their previous report[21]. As this lower bound is then used to form a new range, this might underestimate the impact of Oxera's derived figures. Using the mid-point of the range that they considered (NZ$1.45bn) results in an optimal estimate of between 61% and 78%, which suggests a mid-point above the 67th percentile (even without removing the tax uplift—see the next bullet); and

    b. The Commission's WACC uplift model adjusts the RAB by 1 minus the corporate tax rate. Oxera considers that taxes are redistributed to society, resulting in a welfare benefit. We therefore consider that a full tax uplift is not appropriate. Removing the tax adjustments results in a range of 60% to 77%, i.e., a mid-point above the 67th percentile under the Commission's and Oxera's most conservative cost of outages assumption of $1bn.

36. Oxera identify that a number of additional factors suggest that the 67th percentile is likely to be more appropriate than the 65th percentile. For instance, insufficient investment incentives might risk delaying the energy transition, which would have significant asymmetric effects in terms of social outcomes that are additional to those captured in the loss analysis framework.

37. Overall, Oxera's analysis suggests that the 67th percentile is already conservative, and therefore a reduction to the 65th percentile is not appropriate.

Oxera's assessment of the WACC percentile for gas distribution

38. The Commission's draft proposal is to remove the WACC uplift for GPBs. The reasons for this are that the Commission considers the cost of electricity outages to be higher than that of gas outages, and the likelihood that underinvestment will go undetected and lead to outages to be lower for gas[22]. However, Oxera considers that there is sufficient evidence to warrant a WACC uplift (in line with EDBs) for several reasons.

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[21] https://comcom.govt.nz/__data/assets/pdf_file/0018/308502/27Big-Six27-EDBs-Oxera-report-Review-of-the-NZ-Commission27s-WACC-setting-methodology-Submission-on-IM-Review-CEPA-report-on-cost-of-capital-3-February-2023.pdf

[22] Commerce Commission, *Cost of capital topic paper, Part 4 Input Methodologies Review 2023 – Draft decision,* 14 June 2023, p.66.

39. First, the previous decision to set the WACC at the 67th percentile appears to have resulted in good outcomes for consumers - removing the WACC uplift for GPBs based on this appears to 'punish' networks for good performance, which could lead to unintended consequences.

40. Additionally, there are significant costs associated with gas outages that have not been examined by the Commission as part of its considerations, in relation to reducing the WACC percentile for GPBs in the draft decision.

41. Oxera explains that, while outage costs in the gas sector are indeed lower than in the electricity sector, there is also a much lower RAB for GPBs (NZ$2.1bn compared with NZ$18bn for electricity networks). This is relevant in the context of the Commission's loss analysis framework, which weighs the costs of two opposing effects:

    a. the costs associated with a given WACC percentile (i.e., the impact on consumers measured by RABxWACC)—the higher the WACC percentile, the higher these costs will be; and

    b. the cost of outages that might occur if there is underinvestment, with underinvestment occurring when the regulated WACC at a given percentile is below the true WACC— the higher the WACC percentile, the lower the probability (and therefore the expected cost) will be.

42. Oxera states that:

    > *"When calibrating the NZCC's loss analysis framework for the lower RAB of GPBs, the model finds that at an outage cost of NZ$110m (and when removing the tax uplift), the average optimal WACC percentile would be at the 67th percentile, in line with the previous NZCC decision."*

43. Finally, outages are not the only potential downside of underinvestment in gas networks. Oxera find and indicatively quantify the magnitude of two additional costs that may occur as a result of underinvestment.

    a. Increased leakage and gas escapes, leading to environmental costs associated with the released methane into the atmosphere; and

    b. Decarbonisation costs of delaying the transition to renewable gas.

44. Oxera concludes that these costs are additional to any outage costs that are being considered as part of the loss analysis framework. Overall, this analysis suggests that there can be significant costs if gas networks were to underinvest. Using a percentile above the 50th reduces the risk that the true WACC is below the regulated one, and therefore the risk of underinvestment.

45. Vector recommends that the Commission re-instates the GPB gas WACC uplift back to 67^{th} in line with the above recommendations.

Decarbonisation through an orderly transition

46. Central to the Commission's argument for reducing the WACC percentile for both electricity and for gas is its resistance to taking account of "benefits" to consumers other than reliability-focused investments. The Commission says reliability/outages are particularly relevant to WACC percentile because it is difficult to use ex post mechanisms to ensure adequate reliability investments. Conversely, innovation and demand-driven investments can be dealt with through ex post mechanisms. The Commission suggests that this narrow role for the WACC uplift has been its consistent position.

47. There is no reason in principle why the Commission's asymmetric risk principle should be limited to reliability-focused investments:

   a. The asymmetric risk principle acknowledges that the risks to consumers of over-estimating versus under-estimating the WACC are asymmetric. The benefits to consumers from incentivising investments is greater than the short term disbenefit of higher prices. That principle does not exclude any particular type of investment; rather, the question is: what types of investments might be forgone or deferred if the Commission's midpoint WACC underestimates the true WACC, and do the benefits to consumers of those investments outweigh the costs?

   b. The Commission says that from 2014 it has considered that investments in innovation, economic investments, and investments to meet demand growth are better incentivised by targeted mechanisms that reward businesses for achieving pre-defined targets. However, in the Commission's 2015 final determination of Chorus' UCLL and UBA services, the Commission accepted that an WACC uplift in principle would be prudent if it brought forward technology changes that would benefit consumers. While in that particular case the Commission decided the quantitative evidence was not sufficiently strong to justify the uplift, the principle remains.

48. EDBs are making and will continue to make investments intended to support electrification and decarbonisation of the economy. A number of those investments must be made ahead of demand to enable electrification to occur. The timing of those investments is important to ensure that the country can meet its decarbonisation goals. That is the type of investment scenario that the WACC uplift was intended to address.

49. It is notable that the discussion that begins at para 6.34 of the Commission's reasons paper is headed "The potential impact of decarbonisation" but does not actually talk about decarbonisation. It talks about the four drivers of investment the Commission identified in 2014: quality, demand growth, innovation, and economic investments. Decarbonisation is a discrete driver of investment and needs to be considered as such.

50. The Commission has acknowledged that s 5ZN of the Climate Change Response Act (CCRA) allows it to take into account the Government's 2050 target, emissions reductions budgets and

emissions reductions plans where that does not conflict with achieving the s 52A purpose.[23] The investments that EDBs will make in the future are critical to achieving those climate goals. The adverse impacts on consumers of failing to undertake those investments are by any measure substantially greater than the short term disbenefits of marginally higher prices. Giving proper effect to s 5ZN in the present context therefore requires that the Commission:

a. recognise that decarbonisation is a discrete driver of investment that requires more careful evaluation than the Commission has undertaken to date; and

b. retain the existing WACC uplift given the potentially significant adverse effects to consumers if decarbonisation-related investments are deferred or forgone.

51. Even if one accepts that some types of investments are better incentivised via ex ante mechanisms (percentile) and others via ex post mechanisms, decarbonisation-related investments are more analogous to the Commission's characterisation of reliability investments than the types of investments it says are suitable for ex post mechanisms. Essentially the Commission says that reliability-driven investment is difficult to target with an ex-post mechanism. Given that decarbonisation-related investments: (i) are often 'enabling' in character, and (ii) produce benefits both within and without the electricity market that are difficult to identify and quantify in advance, there is a good argument that an efficient level of decarbonisation investment is also hard to target with an ex-post mechanism. Put another way: if EDBs do not invest to support decarbonisation the Commission will not necessarily know what benefits are forgone; for example, which energy users might have electrified, what network investment might have been avoided, etc.

52. In any event, the Commission is not proposing an ex post incentive mechanism to ensure an efficient level of decarbonisation-related investment.

53. GPBs similarly will have to continue to invest to maintain the regulated service at a level that reflects consumer demands. GPBs will have to invest not just in maintaining the reliability of the service, but in maintaining its reach and those aspects of the quality of the service that go beyond simple reliability measures. GPBs are having to invest in the face of uncertainty regarding the remaining lifespan of the regulated service, which creates a significant deterrent to further investment. Against that background, this is not the time for the Commission to be reducing GPBs' investment incentives.

Unreasonable 'reasonableness' checks

[23] We remain concerned that the Commission is not taking the role of s 5ZN sufficiently seriously. While the clarification to the process and issues paper partially accepted the advice prepared by Chapman Tripp and provided by the Commission, we note that at various points in the draft decisions the Commission continues to downplay the role of s 5ZN. For example, para 6.9 of the Commission's draft decisions on CPPs and in-period adjustments says that the Commission can only take into account s 5ZN to the extent that doing so promotes the purpose of Part 4 of the Commerce Act "more effectively". This is, even on the Commission's narrow construction, incorrect.

54. The Commission claims to have undertaken 'reasonableness checks' to test the appropriateness of its WACC decisions. But these are anything but reasonable.

55. First, the Commission cites three RAB multiples: one observable outcome from the sale of Eastland Network and two estimates provided by brokers (Jarden and UBS) for Vector's regulated businesses.[24] These all valued the businesses above the levels implied by their regulatory asset values. This was said to support the proposition that the 65th percentile (which is not far beneath the 67th) would be sufficient for EDBs to make reasonable returns. This is problematic, because:

    a. Even if the sample was not manifestly inadequate, there are severe limitations on what can be discerned from RAB multiples in any event (for well-documented reasons[25]); and

    b. The analysis cannot possibly reveal anything about the reasonableness of the draft decision on the WACC percentile for GPBs.

56. Second, the Commission rather tenuously claims to have observed 'improved credit ratings' which supports its position. While the Commission uses the plural – 'ratings' –it only provides a single example: S&P's upgrade of Vector to BBB+ in April 2023.[26] However this change was a direct result of Vector's recent divestiture of 50% of its unregulated metering business. S&P noted this transaction would enable Vector to – among other things – use the proceeds to deleverage the business. This is of no relevance to the overall reasonableness of the draft decision.

57. Oxera has also assessed WACC allowance reasonableness checks using RAB multiples and by proposing an alternative one.

    a. RAB multiples: In their report, Oxera explains that many factors need to be accounted for when interpreting RAB multiples, and that conclusions are sensitive to the assumptions. Oxera does not consider RAB multiples to be a reliable check of the reasonableness of the WACC allowance; and

    b. Asset risk premium–debt risk premium (ARP–DRP) framework: Oxera introduces an alternative approach of cross-checking the cost of equity allowance with reference to the cost of debt estimate. The cross-check shows that the risk premium, embedded in the cost of equity, if adjusted for the effect of leverage (ARP), is not sufficiently high relative to the DRP, which suggests that the overall allowance for the cost of equity should be higher.

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[24] Commerce Commission, *Cost of capital topic paper, Part 4 Input Methodologies Review 2023 – Draft decision,* 14 June 2023, p.66.

[25] *See for example:* CEG, *Economic Review of Draft Decision on the WACC Percentile*, *A report for NZ Airports*, August 2014, pp.30-41.

[26] Financing and incentivising efficient expenditure paper, footnote 75, p.42.

2. Cost of debt

Risk free rate

58. Oxera assessed the following three aspects of the Commission's IMs that relate to setting the RFR allowance and came to the following conclusions:

    a. Adding a convenience yield premium to government bond yields: Oxera have assessed Dr Lally's dismissal of the academic evidence, based on which the Commission has provisionally decided not to add a convenience yield premium to the government bond yields when estimating the RFR, and concluded that the theoretical case for the convenience yield remains strong - a convenience yield of any magnitude would imply a higher RFR allowance; and

    b. The term of the government bonds used to estimate the RFR: Oxera have reviewed Dr Lally's modelling and concluded that it does not prove that the term has to match the length of the regulatory period. Oxera recommends considering longer tenors such as 5 to 20 years.

59. Since the inception of the IMs, the Commission has 'term-matched' when setting the risk-free rate, i.e., it has used bid yields on New Zealand government bonds for a term to maturity equal to the length of the regulatory period: five years. Businesses have long complained that this defies reality, since investors often have much longer investment horizons. The Commission has chosen again to disregard what investors are doing and decided to rely instead on a theory posited by its chief WACC advisor, Dr Martin Lally In recent work for the Australian Energy Regulator (AER), Dr Lally explained that:[27]

    a. In his view, a term-matching approach was needed to ensure firms earned a reasonable return on their capital, but no more (the so-called 'NPV=0 rule'); and

    b. This opinion was based on earlier work undertaken by Emeritus Professor Richard Schmalensee of Massachusetts Institute of Technology.

60. Professor Schmalensee has since come forward to clarify that his work had been misapplied by Dr Lally.[28] He explained he had not concluded that 'term-matching' was required, and that Dr Lally had fundamentally misunderstood and misinterpreted his paper. Professor Schmalensee confirmed that the appropriate regulatory task is for the regulator to set the allowed return equal to the return that real-world investors require, i.e., that reflects what they are doing. The AER was consequently unpersuaded by Dr Lally's theory. We urge the Commission to follow suit.

A high-stakes lottery

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[27] Energy Networks Australia, *Rate of Return Instrument Review Response to AER's Draft Instrument and Explanatory Statement,* 2 September 2022, p.4.

[28] *Ibid*.

61. The Commission has proposed to keep its ‘high-stakes lottery’ approach to setting the risk-free rate,[29] whereby businesses’ returns are determined to a large degree by what transpires in a narrow 90-day window this is not regulatory best practice.[30] If interest rates happened to be low during this arbitrary period, then the WACC – and allowed revenues/prices – would be lower, and vice versa. This could cause ongoing volatility in the WACC – and returns – from one period to the next.

62. Businesses (and their customers) would have no choice but to ‘buy a ticket’ for this five-yearly lottery – as reluctant as they may be to do so – because it would be impossible for them to ‘avoid playing’ by refinancing their entire debt portfolios in that 90-day window (i.e., to ‘match-up’ the interest rates). However, this is not a view shared by the Commission who is of the view that a supplier can hedge this risk-free rate. We understand that this would require obtaining a hedge over 1/90th of the actual and forecasted debt[31] for each day during the reference period.

63. The practical implications of this are significant given the combined RABs of Transpower and regulated EDBs of over $16 billion and, even if such large amounts could be hedged simultaneously and within such a narrow time window, would likely lead to suppliers being held to ransom by counterparties who knew exactly what they were attempting. We maintain that the theoretical approach endorsed by the Commission is neither in accordance with good treasury management practice nor efficient; and

64. The methodology would therefore continue to needlessly expose businesses to risks they can neither avoid nor hedge against. This would be inefficient and manifestly unfair. Unsurprisingly, no other regulator sets the risk-free rate in this way. The continued novelty of the Commission’s approach should cause it to pause and reconsider its position.

Debt premium and term credit spread difference (TCSD)

65. Among the topics relating to the cost of debt allowance, Oxera have assessed the case for the trailing average approach to the debt premium and the level of the TCSD.

   a. The trailing average approach to the debt premium: Based on Dr Lally’s assessment, the Commission has provisionally decided not to introduce any mechanisms that address the uncertainty in relation to the level of credit spreads that networks face during the regulatory period. Oxera have evaluated Dr Lally’s assessment and found that bringing the assumptions of his modelling more into line with market conditions makes the case for the trailing average significantly stronger. Oxera also notes that the trailing average is not the

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[29] The risk-free rate is a key input into the costs of debt and equity and, by extension, the WACC. Because EDBs and GDBs are highly capital intensive, small changes in the assumed risk-free rate can therefore result in large changes in returns/profits.

[30] Ever since the Commission first introduced the IMs in 2010 it has estimated the risk-free rate by looking at 5-year bid yields on New Zealand government bonds during the three-months preceding the date of the WACC estimate.

[31] We note that the current RAB of EDBs and Transpower is circa $16bn at 41% leverage this is a significant amount to be hedged

only approach that could be used to address the credit spread uncertainty faced by the networks; and

b. The term credit spread difference: Oxera finds that the Commission's own evidence supports a higher TCSD at 10.2bps instead of 7.5bps if the Commission does not subjectively exclude the COVID-19 period from the estimation window, and if it avoids double-counting a category of the bonds within its sample. In addition, Oxera does not find the ten-year term cap to be well justified.

3. Cost of equity

Tax adjusted market risk premium (TAMRP)

66. Oxera have assessed the evidence that the Commission relied on when it concluded on the TAMRP level of 7.0% and found that some of it is not sufficiently reliable.

a. Dividend growth model (DGM): Oxera have undertaken modelling that demonstrates why they do not find DGM to be a robust approach to estimating the TAMRP. They have also previously explained the limitations of using survey-based evidence to assess the reasonable level of the TAMRP. Therefore, Oxera recommends that the Commission does not put weight on the results from the DGM, and the survey-based results, in its estimation of the TAMRP.

b. The Siegel models: Oxera recommends placing more weight on the evidence from the Siegel II model and less on the evidence from the Siegel I model, due to the former's more reliable assumptions about the relationship between the RFR and the market risk premium. This means that a more reliable TAMRP estimate would be anchored on the evidence from the Ibbotson model and a weighted Siegel model that reduces reliance on the Siegel I specification.

c. Broker estimates: Based on the evidence that Oxera have collated from the public domain, they have found that the TAMRP estimates by investment banks selected by the Commission do not fully represent the view of these institutions. As a result, the data relied upon by the Commission does not appear to be robust.

67. Oxera surmises that the more robust estimation methodologies that underpin the TAMRP range point to an estimate that is closer to 7.5% than to the 7.0% proposed by the Commission. The figure of 7.5% is also consistent with the broker estimates that Oxera have collected.

Asset beta

68. Oxera have commented on two aspects of the Commission's asset beta estimation, as follows.

a. Frequency of returns data: Oxera recommends that the Commission adds daily beta estimates to the set of evidence that it uses to set the allowed asset beta. The key concern typically associated with daily beta estimates is stock illiquidity, which is mitigated in this instance given that the Commission applies liquidity filters. They also show that the average standard errors of individual comparators' asset betas are the lowest for daily asset betas, which shows that from the point of view of statistical significance, there is no reason to exclude daily betas from the Commission's assessment.

b. Treatment of the COVID-19 period: Oxera considers that the beta estimates affected by the COVID-19 pandemic provide valuable information about the companies' risks, in the same way as any other event causing market volatility would. Accordingly, Oxera sees no reason for the COVID-19 pandemic period to be treated differently and for it to lead to the change in the Commission's approach as part of this IM review. Oxera finds the Commission's approach concerning, as it introduces non-justified non-replicable methodological steps and, in so doing, reduces the stability and predictability of the regulatory regime.

69. Oxera states that:

> *"The NZCC's asset beta allowance underfunds the networks and is a deviation from the NZCC's principles-based approach to the review."*

70. Oxera explains that compared with the Commission's preferred asset beta estimate of 0.35 for energy networks, an average of daily, weekly and four-weekly estimates for the last two five-year periods is 0.37, while the 75th percentile of the range (which is consistent with the percentile that the Commission chooses for asset betas in its draft decision within its proposed range) of these estimates is 0.39.

Equity issuance costs

71. In their report, Oxera explains that retained profits may not always be sufficient to finance growth, while not paying dividends for a long period of time is not sustainable, and at times new equity financing may be needed and the allowance for equity issuance costs would be justified. An allowance for equity issuance costs, combined with a regulatory assumption that dividend payments will be made, is aligned with precedent.

Appendix B. Financing and incentivising efficient investment

1. Financeability

72. In its 2010 decision on Transpower's IMs, the Commission plainly concluded that an unindexed RAB is appropriate when a regulated business faces a period of significant capital expenditure. At the time, Transpower was planning to invest over $3 billion in upgrading and renewing the transmission network over the ensuing five years. This was going to more than double the value of its RAB. The Commission observed that this was in excess of what EDBs were investing at the time and that an unindexed approach would allow Transpower to better meet those investment needs:[32]

> *"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."*

73. In other words, the Commission accepted that it was appropriate to 'front-load' the recovery of those investment costs to address financeability concerns. It reached that conclusion even though it would result in higher prices for that new capacity (much of which would not be needed immediately) in the near-term. The longer-term dynamic efficiency benefits associated with ensuring the investments could be adequately funded ultimately trumped the shorter-term static efficiency costs resulting from short-term price rises and any allocative efficiency concerns.

74. Vector sees no reason why precisely the same logic does not apply equally – if not more so – to EDBs today[33].

75. The investment that EDBs will be looking to undertake over the next seven years is unprecedented. As we noted earlier, BCG (2022) has estimated that EDBs will need to invest $22 billion in infrastructure in the 2020s to prepare their networks for rapid electrification and multi-directional flows. It concluded that the total investment across EDBs in 2026-2030 would be 30% higher than for 2021-2025.[34] Like Transpower before them, EDBs have explained to

[32] Commerce Commission, *Input Methodologies (Transpower) Reasons paper,* December 2010, pp.30-31.

[33] Vector has requested more information from the NZCC relating to their 2010 Transpower indexation decision

[34] Boston Consulting Group (2022), *The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector,* p.9 (hereafter: 'BCG (2022)'; available: here).

the Commission that an unindexed RAB approach would help them to fund that expenditure, without jeopardising crucial financial metrics.[35]

76. Yet, despite the undeniable parallels with Transpower's circumstances in 2010, the Commission has refused to change the IM for EDBs. As we noted earlier, one of the reasons it offers is that front-loading recovery via a nominal approach would cause prices to rise at a time that short- and long-run marginal costs of usage would be falling.[36] We accept this would entail some short-run static inefficiencies – just as it did when the Commission decided not to index Transpower's RAB. But, just as in 2010, these short-run considerations would be comfortably outweighed by the long-term benefits of ensuring EDBs can fund their investments.

77. As addressed in our cover letter to the Commission, financeability is of the utmost concern to Vector. We have sought expert advice from Frontier Economics and PWC on the Commission's approach to 'financeability' taken in the draft decision.

78. In their report[37] submitted with this submission, Frontier explains that, in the regulatory context, a project or firm is 'financeable' if the annual regulatory allowance is sufficient to support the benchmark financing parameters (leverage and credit rating) that the Commission has adopted in setting that regulatory allowance. In Frontier's view:

> *"It logically follows that:*
>
> i. *If the Commission's benchmark financing parameters produce an allowed return that best reflects just that level of return that investors require to finance efficient investment; and*
>
> ii. *The annual regulatory allowance is insufficient to support the Commission's benchmark financing parameters; the result would be that*
>
> iii. *Investors would be unwilling to provide the finance that would be required to support efficient investment."*

79. Frontier proposes that a financeability problem should be addressed by accelerating the annual regulatory allowance (in an NPV-neutral way) to the point where it is able to support the Commission's benchmark financing parameters.

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[35] Some of these key metrics include: **Funds from operations (FFO)** interest cover ratio, which provides an indication of the regulated business's ability to make interest payments; **Net debt gearing ratio**, which measures the proportion of regulatory capital structure that is made up by debt and provides an indication of its ability to repay its debt (or increase borrowings in the short term if required); **FFO to net debt ratio**, which provides an indication of the regulated business's ability to repay debt from cash flows**; Retained cash flow to capital expenditure ratio**, which provides an indication of the regulated business's ability to finance a prudent portion of capex after paying dividends and the overall **credit rating**.

[36] Financing and incentivising efficient expenditure paper, p.45.

[37] Frontier Economics, Regulatory financeability, 18 July 2023

80. The regulatory solution to a financeability issue is to accelerate the allowed cash flows in an NPV-neutral manner. The draft decision discusses a number of approaches put forward by stakeholders that can be used to accelerate the allowed cash flows in an NPV-neutral manner.

81. Vector agrees with Frontier that the two most plausible solutions are either removing indexation of the RAB or at least removing indexation of the debt component of the RAB.

82. We also agree with PWC's separate assessment[38]:

> *"The IMs therefore currently do not address the second component of s53P(8)(a) which is to minimise any undue financial hardship for suppliers. Including a financeability test in the IMs would address this omission and would better give effect to s53P(8)(a) by ensuring that both the price shock and financial hardship criteria are addressed in the IMs."*

83. PWC explains that the Commission's decision not to include a financeability test in the IMs is not compelling. The s52R purpose of the IMs is to promote regulatory certainty. One 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.

84. PWC also believe that a financeability test will enhance the s52A purpose to incentivise investment at a time when there is significant amount of investment in electricity network infrastructure needed to meet increased demand and improve resiliency, as New Zealand becomes more reliant on electricity to meet its energy needs.

85. Vector asks the Commission to as part of its final decision categorically set out its views on how it 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 the Commission.

86. It is of the utmost importance to consumers that EDBs invest the billions needed to ensure rapid electrification of the economy, given the potential gains at stake relative to short-term impacts on prices. The Commission does not directly challenge this incontrovertible welfare calculus. Instead, it expresses scepticism about whether EDBs would, in fact, encounter material financing challenges if indexation was kept. It claims to be unaware of any shortage of capital currently willing to invest in the sector, and then points to some RAB multiples above one and improving credit ratings to support its contentions.[39]

87. This justification is profoundly flawed. The Commission cites three RAB multiples: one observable outcome from the sale of Eastland Network and two estimates provided by brokers

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[38] PWC, *Including a financeability test in the Input Methodologies for electricity distribution businesses*, 19th July 2023

[39] Financing and incentivising efficient expenditure paper, p.42.

(Jarden and UBS) for Vector's regulated businesses.[40] This superficial assessment is incapable of supporting the Commission's draft finding. It is fanciful to think anything meaningful about EDBs financing issues can be gleaned from three data-points – two of which have no 'real-world' empirical basis. Even if the sample was not manifestly inadequate (which it is), RAB multiples have only limited explanatory power for such purposes in any event (for well-documented reasons[41]). This analysis should be disregarded in its entirety.

88. The Commission's claim that is has observed 'improved credit ratings' and this somehow supports its position is even more tenuous. The Commission uses the plural – 'ratings' – yet, in its draft decision, only provides a singular example: S&P's upgrade of Vector to BBB+ in April 2023.[42] However, this credit rating change was a direct result of Vector's recent divestiture of 50% of its unregulated metering business. S&P felt this would enable Vector to – among other things – use the proceeds to deleverage the business somewhat over the next few years. This has absolutely no bearing on broader financeability issues facing Vector or other EDBs and, again, ought to be ignored.

89. The Commission's 'reasonableness' checks are therefore manifestly deficient and, ultimately, irrelevant. The Commission cannot arrive at any robust conclusions about whether continued RAB indexation would (or would not) give rise to financeability problems without first modelling the impacts upon EDBs cashflows. Specifically, it would need to investigate the differential effects upon EDBs' key financial metrics (e.g., credit ratings, net gearing ratios, etc.) from retaining/removing indexing. The Commission appears to have done some modelling to this effect for Transpower,[43] yet it is conspicuously absent for EDBs.

2. RAB indexation and depreciation

90. For some time, many EDBs and GPBs – including Vector – have submitted that the Commission should remove RAB indexation and allow alternative forms of depreciation under the DPP.

91. The rationales that underpinned the Commission's original decision to index EDB and GPB asset bases and not to index the asset base of Transpower (and to continue the practice at the 2016 IM reset) have never seemed well reasoned or justifiable do not so today especially given the future large scale investment context. The single most important driver of long-term

[40] Commerce Commission, *Cost of capital topic paper, Part 4 Input Methodologies Review 2023 – Draft decision,* 14 June 2023, p.66.

[41] *See for example:* CEG, *Economic Review of Draft Decision on the WACC Percentile*, *A report for NZ Airports*, August 2014, pp.30-41.

[42] Financing and incentivising efficient expenditure paper, footnote 75, p.42.

[43] *Op cit.,* p.57.

customer interests over the next seven years will be the efficiency of EDBs and GPBs investment programmes.[44] Looking forward, it is of the utmost importance to consumers that:

a. EDBs invest the billions that will be required over the next seven years (and onwards) to ensure rapid electrification of the economy, thereby unlocking significant benefits throughout the electricity supply chain and other sectors; and

b. GPBs invest and operate their networks in ways that ensure the continued safe, reliable delivery of services whilst also allowing for a stable, equitable transition to electricity in line with the Government's climate objectives.

92. Moving to a nominal return framework and/or adopting more front-loaded depreciation methodologies would significantly enhance the likelihood of both of these crucial objectives being achieved. In particular:

a. By front-loading the return profile EDBs would be better placed to finance the unprecedented investment that will be needed in the coming period. This is in fact precisely why the Commission moved Transpower to an unindexed approach when the current regime commenced. 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; and

b. GPBs would have the chance to recoup their sunk costs from the largest possible group of consumers (i.e., before increasing numbers transition to electricity), reducing the significant asset stranding risks they face and allowing for more efficient pricing.

93. Despite this, the draft decision retains RAB indexation both EDBs and GPBs (and introduces it for Transpower). In reaching this draft position the Commission fails to properly investigate the financeability challenges that EDBs would face in the next pricing period and beyond if the status quo is maintained. It also wrongly assumes that GPBs' asset stranding risks could be fully addressed under the current IMs, e.g., by adjusting asset lives. Vector disagrees strongly with the draft decision. We continue to support removing indexation and adopting more front-loaded depreciation.

The draft decision

94. The Commission draft decision is to maintain the status quo of indexing EDBs' and GPBs' RABs to inflation. Under this approach, the higher that inflation is expected to be, the lower the real rates of return and current revenues/prices need to be in order to deliver up the target nominal rate of return. Indexing the RAB to expected inflation therefore reduces near-term prices and cashflows by pushing back the recovery of costs relative to a 'nominal' returns

[44] For a more comprehensive discussion of the trade-offs between dynamic and static efficiency, see: Axiom Economics, *Dynamic Efficiency and the Energy Transition, A report for Vector,* September 2022.

approach.[45] The degree of back-loading is especially pronounced during times of higher inflation, such as we are experiencing at present.

95. In arriving at its draft decision, the Commission stated that the reasons underpinning its original decisions to index remain valid today.[46] The primary motivation for indexing the RAB is to insulate consumers and businesses (and their investors) from inflation risks. In its initial IM determinations, the Commission stated that the greater protection against inflation risk afforded by indexation was sufficient reason in-and-of itself to prefer such an approach – a position it has maintained ever since:[47]

> *"[T]he central purpose of RAB indexation to maintain the regulatory value of the RAB in real terms over time, which provides an expectation of real FCM and delivers an ex-post real return (things other than inflation being equal). In doing so, it protects consumers and suppliers from inflation risk. The frontloading of cashflows achieved by removing RAB indexation could also be achieved through alternative depreciation profiles. However, removing RAB indexation would expose consumers and suppliers to inflation risk."*

96. The Commission was unmoved by EDBs' requests to remove indexation and/or allow for alternative depreciation approaches (under the DPP) to better-allow them to finance their large investment programmes. The Commission considered the resulting front-loading was neither necessary nor desirable. It stated it was not aware of a shortage of capital currently willing to invest in the sector, and that it had observed RAB multiples above one and improving credit ratings.[48] It then expressed concerns about the time-profile of prices that would eventuate for electricity customers if such a change was made:[49]

> *"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 … 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."*

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[45] Provided the Commission's inflation forecasts are unbiased, what is 'taken out' (i.e., for forecast inflation) should equal what is 'put back,' on average over the long run. And, in the meantime, consumers and suppliers will be insulated from inflation risk. At least, that is the *theory*. As we explain subsequently, it has arguably *not* worked this was in *practice*.

[46] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Draft decision,* 14 June 2023, p.36 (hereafter: 'Financing and incentivising efficient expenditure paper').

[47] Commerce Commission, *Part 4 Input Methodologies Review 2023: Process and issues paper*, 20 May 2022, p.83.

[48] Financing and incentivising efficient expenditure paper, p.42.

[49] *Op cit.,* p.45.

97. The Commission was similarly unreceptive to GPBs pleas to dispense with indexation. GDBs – Vector among them – have said that 'tilting' the recovery profile would reduce the significant asset stranding risks they face from declining demand and create more efficient pricing. Their preference is to recover a greater proportion of their sunk costs from the largest possible pool of consumers (i.e., before they transition away) – something an unindexed approach would enable. The Commission resisted those changes as well. For example, it contended that asset stranding risks can be addressed fully by adjusting asset lives and allowing stranded assets to remain in the RAB.[50]

98. Finally, the Commission pointed out that EDBs and GPBs also have the option of applying for a CPP, under which (amongst other things), alternative depreciation approaches are potentially available. In other words, but for a few minor changes (e.g., to inflation forecasting 'wash-ups'), the Commission has proposed to leave these IMs unchanged. In our opinion, the analyses underpinning this draft decision are deficient in numerous respects and are not in accordance with good regulatory practice given the future investment demands on EDBs and the asset stranding risk faced by GPBs. For the reasons set out subsequently, there is an urgent need to revise these elements to allow EDBs and GPBs to meet the significant challenges they are confronting.

Problems with the Commission's analysis

99. The Commission's draft decisions rest on several core claims. Some are highly questionable; some are demonstrably wrong. For example, the Commission has implied that EDBs would not face significant financeability challenges if the status quo is maintained (see the previous section on 'financeability'). Yet, it performs barely any analysis to examine this proposition and what little testing it has done is inadequate and irrelevant. Not undertaking appropriate modelling and then making bold statements on financeability is not what would be considered good regulatory practice. The Commission has also maintained that GPBs' asset stranding risks can be fully addressed by making adjustments to asset lives. That is false. It also underestimates the problems with its inflation forecasting approach and wrongly assumes that applying for a CPP could address any residual issues. Finally, there are issues with the reasoning behind the Commission's decision-making. We elaborate below.

Inflation forecasting risk

100. The approach the Commission has adopted in previous periods for forecasting inflation – and updating for actual inflation (i.e., with no 'wash-ups') – only works if inflation forecasts are unbiased. This occurs when every period of under-recovery (e.g., due to actual inflation being less than expected inflation) is expected to be equally offset by a future period of over-recovery. However, a significant body of evidence has now been amassed that casts substantial doubt on this foundational assumption.[51]

[50] *Op cit.,* p.78.

[51] *See for example:* CEG, *Dealing with negative real risk-free rates,* July 2019.

101. John McDermott from Motu has once again provided his views on inflation forecasting in a memo[52] submitted with our submission. He disagrees with the Commission's view that it is appropriate to use the RBNZ forecasts as a basis for a five-year ahead inflation forecast to index the RAB:

> *"The fundamental problem with using the RBNZ projections is that they are a tool designed for near-term planning and signalling, not for long-term regulation."*

102. He explains 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. The existing long-term inflation risks are influenced by some large and persistent secular forces whose impact on inflation is very uncertain, if not unknowable.

103. The solution he proposes is that 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."*

104. To conclude, the Commission's chief rationale for introducing and maintaining indexation – namely, protecting businesses and consumers from inflation risk – is dubious. The performance of the inflation forecasting framework in previous periods has been demonstrably poor. For the reasons we set out, the materially better approach would be to dispense with indexation altogether.

<u>Asset stranding risks for GDBs</u>

105. GPBs' motivations for seeking the removal of indexation and/or more front-loaded forms of depreciation are quite different. They face a highly uncertain future characterised by declining demand. They want the transition from gas to electricity to be as orderly as possible and free from undue asset stranding risks. So too do their customers. The last thing anyone wants is for a GPB to abruptly shut-down parts (or even all) of its network before upstream producers and downstream customers have had a chance to adequately prepare.[53] Vector is certainly eager to avoid that unwelcome scenario.

106. It is consequently essential that GPBs receive appropriate assurances that they will earn a reasonable return throughout this transitional period. Part of that involves ensuring price paths make appropriate assumptions about asset lives. If an asset has a remaining physical

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[52] Motu, *Response to the Commerce Commission report review on the problem of forecasting inflation*, 13th July 2023

[53] For example, when the transition was made from analogue to digital television, people were given *years* of warning. And all they had to do was replace their TVs, which is not a major expense (and an item that is replaced periodically in any case). Switching from gas to electricity is a far more extensive undertaking – especially for large industrial users and not an insubstantial cost for households.

life of 50 years but there is not expected to be sufficient demand to warrant continuing operating it beyond say, 40 years, then the recovery period should be truncated to mitigate that risk. Furthermore, if the economic life unexpectedly turns out to be even shorter, the asset should be allowed to remain in the RAB, nevertheless.

107. The current IMs enable both things to happen to various degrees. This reduces GPBs' asset stranding risks – that much we accept. What we do not accept is the Commission's contention that removing indexation and/or allowing more front-loaded depreciation approaches under the DPP cannot further reduce stranding risks. Although that may be possible in theory (at least in an NPV sense) under certain stringent assumptions, it is not the case in practice. The Commission appears to be under the misimpression that:

- Stranding risk can be reduced by recalibrating asset lives (i.e., by truncating the period over which costs are recovered) and allowing stranded assets to remain in the RAB; but
- Once that period has been defined (i.e., with 'appropriate' asset lives), the profile of recovery/prices *within that period* has no bearing on the likelihood of asset stranding.

108. More specifically, the Commission seems to be suggesting that once a recovery period has been truncated, there is nothing more to be gained from the IMs allowing the recovery profile within that window to be tilted. That is not correct. First, as the Commission itself has conceded,[54] allowing assets to remain in the RAB once they have been stranded is only a partial measure, since it assumes the remaining customers will be willing and able to fund any shortfall. That may not be the case – especially in a 'death spiral' scenario. Second, tilting the recovery profile does reduce stranding risk in practice:

- If it were possible to forecast the rate of decline in volumes with certainty, then any number of potential recovery profiles within a window could deliver up the same NPV of revenues – the choice would simply affect the timing of cashflows, not the overall quantum. This is what the Commission seems to be implicitly assuming; *but*
- In practice, there is *substantial uncertainty* surrounding future volumes. Recovery profiles that appear to yield the same NPV of cashflows *on paper* may not *in practice*. Tilting the return profile and seeking to recover *more sooner* while there are additional customers connected to the network *undoubtedly* increases the odds of recouping costs.

109. Contrary to the Commission's contention, removing indexation and allowing more front-loaded forms of deprecation would therefore significantly reduce the asset stranding risks GPBs currently face. Put simply, it makes sense to recover a greater proportion of costs now, while there are more customers. These measures can therefore be expected to promote dynamic efficiency. For example, they will better-enable GPBs to invest in and operate their networks in ways that ensure the continued safe, reliable delivery of services whilst also

[54] Financing and incentivising efficient expenditure paper, p.73.

allowing for a stable, equitable transition to electricity in line with the Government's climate goals.

110. For the reasons we laid out above, 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.

111. 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.

<u>Availability of CPPs</u>

112. The final pillar of this component of the Commission's draft decision is its contention that businesses always have the option of applying for a CPP. In other words, a business facing financeability problems or asset stranding risks could apply for a CPP and, say, seek an 'alternative depreciation profile' (which is available under a CPP but not the DPP). In Vector's view, the availability of a CPP provides little solace. Applying for a CPP remains an extremely costly and impractical option. There is also no guarantee a CPP would ultimately address the underlying issues that might prompt a business to seek one in the first place.

113. 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. It therefore makes sense that these matters should be dealt with under the default price path.

114. Furthermore, applying for a CPP is an expensive, resource-intensive endeavour. If businesses perceive there is a significant probability the Commission will ultimately not allow them to, say, shift to an alternative depreciation schedule under a CPP, then they will not be willing to endure that cost. At that point, the ostensible availability of a CPP becomes moot – it does not represent a viable solution. To that end, if the Commission maintains its current stances in the final decision (despite the many shortcomings described above), then businesses may perceive the chance of securing a front-loaded CPP as being slim at best.

115. Finally, if businesses did believe, for some reason, that they could secure more front-loaded recovery via a CPP, then the Commission would expect to receive a flood of CPP applications. Given the commonality of the issues across businesses most or all of them would want to have them solved via a CPP. This would create all manner of administrative problems for an already resource-stretched regulator. In other words, the only two logical possibilities are: a) applying for a CPP would not be a solution and so nobody would do it; or b) it would be a viable option, in which case everyone would probably do it. Neither scenario is desirable; the ostensible availability of a CPP is irrelevant.

<u>The Commission's reasoning</u>

116. The Commission's reasoning for retaining indexation for EDBs and GPBs relies heavily on the argument that indexation is more likely to result in constant prices in real terms, which is allocatively efficient, and therefore consistent with s 52A(1)(b). Conversely, removing indexation increases prices in the short term, which the Commission says deters demand growth, which is allocatively inefficient. The Commission essentially makes this point repeatedly in different ways.

The Commission is overstating the extent to which indexation follows from the s 52A purpose

117. The Commission says that its draft decision to retain indexation for EDBs and GPBs best achieves the s 52A purpose in several ways:

a. it maintains the regulatory value of suppliers' investments in real terms, which is consistent with achieving real FCM and thus maintaining incentives to invest pursuant to s 52A(1)(a);

b. the expectation of normal returns over time is also consistent with suppliers being limited in their ability to extract excessive profits, as required by s 52A(1)(d); and

c. an indexed RAB is more likely to result in constant real pries, which is likely closer to an allocatively efficient pricing profile. Conversely, unindexing the RAB results in short term price increases that could cause allocative efficiency losses to consumers, contrary to s 52A(1)(b).

118. The Commission provides a number of other reasons why it considers indexation is preferable, but (in briefest summary), the points set out above.

119. As regards the various limbs of the purpose statement the Commission relies on:

a. While protection from inflation maintains regulatory values in real terms, the Commission acknowledges that this does not necessarily incentivise investment in all circumstances because it also results in deferral of cashflows, which may disincentivise investment. The Commission's response is that it does not see strong evidence that financeability is a concern, and that there are other tools available to address financeability. We think a reasonable summary of the Commission's analysis is that indexation does not necessarily detract from investment incentives, but the argument that indexation incentivises investment (and therefore promotes s 52A(1)(a)) is, at the least, not straightforward as we discuss further below;

b. Both an indexed and unindexed RAB are NPV neutral and therefore the choice whether or not to index has no implications either way for s 52A(1)(d). On either approach, suppliers earn a normal return; and

c. In contrast to the Commission's discussion of indexation in the 2010 IMs and the 2016 IM Review, the draft decision relies heavily on the argument that an indexed RAB results in allocatively efficient prices and therefore best achieves the s 52A(1)(b) purpose.

120. We agree that the Commission can have regard to allocative efficiency, but in our view allocative efficiency is principally a function of s 52A(1)(d) rather than (b). 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:

a. productive efficiency, as suppliers can be incentivised to reduce costs, thus increasing productivity (which gains are then passed through to consumers per paragraph (c)); and

b. dynamic efficiency, in that investing to meet consumers' quality demands represents a dynamic efficiency gain.

121. 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).

122. Allocative efficiency is certainly a feature of s 52A(1)(d), in that prices above the competitive level will result in allocative efficiency losses. But s 52A(1)(d) is achieved whether the RAB is indexed or not because, on either approach, NPV neutrality is maintained.

123. 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.

124. 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.

The Commission's reasoning in the draft decision does not align with the views it has expressed to date

125. While the Commission does refer to other arguments in favour of indexation, the Commission's draft decision appears to rely principally on its view that indexation best achieves s 52A(1)(b). That is a material departure from the reasoning the Commission has offered in its prior discussions of indexation.

126. The 2010 and 2016 reasons papers do say that all else being equal, the efficient prices for a regulated monopolist will be constant prices in real terms. But this is not the principal justification offered for indexation. Rather, in 2010 and 2016, indexation was principally justified by the desirability of protecting suppliers from inflation risk by delivering real returns, which the Commission explains as an out-working on real FCM (and therefore s 52A(1)(a)). The Commission's reasons in support of its draft decision overstates the extent to which it has relied on allocative efficiency as a justification in the past.

The Commission is overstating the allocative inefficiency impacts of non-indexation and understating the potential dynamic efficiency losses

127. The suggestion that increasing prices in the near-term results in a loss of allocative efficiency assumes that output will actually be affected, which is in turn a product of the price elasticity of demand.

128. 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 actually result in a misallocation of resources, to the disbenefit of consumers.

129. 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.

130. The Commission recognises that timing of cashflows is relevant to financeability and investment incentives, and so there is a trade-off here between its desire to achieve allocative

efficiency through indexation and the need to support future investment[55]. But the Commission's argument is that:

a. it doesn't see any evidence of a financing problem; and

b. there are other tools available to address cashflow issues.

131. However, when there is a potential trade-off between incentivising investment and allocative efficiency impacts from short term price increases, the Commission has indicated that it will favour dynamic efficiency gains. For example, in its 2010 EDB-GPB Reasons Paper, the Commission said (in relation to WACC percentile)[56]:

> *"…the Commission is acknowledging that where there is potentially a trade-off between dynamic efficiency (i.e. incentives to invest) and static allocative efficiency (i.e. higher short-term pricing), the Commission will always favour outcomes that promote dynamic efficiency. The reason is that dynamic efficiency promotes investment over time and ensures the longer-term supply of the service, which thereby promotes the long-term benefit of consumers (consistent with outcomes in workably competitive markets)."*

132. That approach was endorsed by the Court in *Wellington International Airport Limited v Commerce Commission*[57].

133. In the 2016 IM Review the Commission observed that if suppliers are already at or past the optimal level of investment there is no benefit from incentivising increased investment. Consequently, in its 2014 WACC percentile decision the Commission did not reiterate its earlier view that it would always favour dynamic efficiency considerations over allocative efficiency[58].

134. 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.

The Commission's original reasoning not to index Transpower's RAB applies equally to EDBs today

135. A number of submitters have pointed out that the same reasoning that supported not indexing Transpower's RAB applies equally to EDBs today, given the significant investments they will be required to make now and in the future.

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[55] Para 3.30.

[56] Para H1.31.

[57] Paras [243] to [244].

[58] Framework for the IM Review (December 2016) paras 141-142.

136. The Commission's response, in part, is to argue that the original reasoning supporting Transpower's unindexed RAB no longer applies. That argument is not persuasive.

137. The Commission refers at para 3.69 to its 2010 Reasons Paper, where the Commission said:

> *"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. … 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…*
>
> *…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."*

138. The Commission is now arguing that the decision not to index Transpower's RAB originally was because Transpower's post-glide path capex was "catch-up" investment, whereas now Transpower is investing in future capacity, and therefore indexation is appropriate. As we understand it, the Commission's argument is that because Transpower's investment was serving current demand, it was appropriate to require present day consumers to pay a larger share of the cost of those assets. Whereas if a supplier is investing to support future demand, future consumers should pay the greater share of those costs. The Commission says that "its reading of the evidence" is that Transpower was at that time investing to catch up with demand. The implication for EDBs, presumably, is that indexation remains appropriate if they are investing to serve future demand.

139. However, regardless of whether it is reasonable to characterise Transpower as undertaking "catch-up" investment in 2010, that is not the reasoning that supported the original decision not to index Transpower's RAB. As is made very clear in the paragraphs cited above, the decision not to index Transpower's RAB was driven by Transpower's investment needs and the benefits of bringing forward cashflows to finance that investment.

140. That was also the reasoning that supported the Commission's decision in 2008 not to index Transpower's RAB, which was then carried through into the reformed Part 4 regime in

2010. In the Commission's May 2008 final decision paper on Transpower's administrative settlement, the Commission said[59]:

> *"…because the application of un-indexed historic cost results in a pricing profile that provides greater cashflows in the first few years following an investment, 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."*

141. There is nothing in the Commission's reasoning in 2008 or 2010 that refers to Transpower undertaking "catch-up" investment. To the contrary, it is very clear that the Commission's decision reflected a view that bringing forward cash would better support Transpower's investment needs. A supplier's investment needs are indifferent to whether capex is serving current demand or future demand.

142. We conclude, therefore, that:

a. the Commission's reasoning for indexing Transpower's RAB is not persuasive; and

b. its original reasoning in 2008 and 2010 supports giving EDBs the option not to index their RABs today.

<u>Materially better alternatives</u>

143. The Commission's draft decision to maintain the status quo of indexing EDBs' and GDBs' RABs to inflation in combination with straight line depreciation is flawed. It is analytically weak, out-of-step with orthodox regulatory principles, internally inconsistent in several respects and irreconcilable with previous determinations for Transpower.

144. It follows that the Commission would appear to have no sound basis to be confident its draft decision would promote the long-term interests of consumers. Vector continues to support the removal of indexation and adoption of more front-loaded depreciation under the DPP. In our view, these alternatives would be a materially better way to meet the Commission's statutory objectives.

3. Form of control for EDBs

145. EDBs are currently on a revenue cap with its existing price limit applied on a nominal basis and to all allowable revenue, including EDBs' recoverable costs and any pass-through costs and transmission charges from Transpower.

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[59] Commerce Commission, *Decision and Reasons for Not Declaring Control of Transpower New Zealand Limited* (13 May 2008) ata para 289.

146. The draft IM decision proposes to exclude from the calculation of the annual price limit any pass-through costs and to reclassify transmission charges as a pass-through cost.

147. Transpower is currently forecasting a significant increase in its revenue requirement over its next regulatory period (RCP4), which corresponds to DPP4 for the EDBs. These costs are entirely beyond the control of EDBs. It would be unreasonable to require EDBs to effectively bear these costs in a given regulatory period rather than to recover them in full as a consequence of the annual price limit imposed by the Commission. For that reason we agree with the Commission's draft decision but believe they could go further.

148. The application of the current revenue cap even with the Commission's proposed changes poses significant financeability issues for EDBs. The current regulatory regime as it is currently designed provides suppliers with an allowed amount of revenue. Revenue caps effectively prevent the receipt of cash by suppliers for revenues that are legitimately able to be earned under the regime. This effectively starves suppliers of cash inflows pushing cash inflows out for possibly significant time periods.

149. In collaboration with the 6 largest EDBs in Aotearoa, we commissioned Frontier Economics to review the limitations of the 10% revenue cap limit as it applies to EDBs.

150. In their report entitled '*A review of the limit on EDB price increases*[60],' submitted as part of this draft decision consultation, they make the following points:

a. The purpose of the price limit was to mitigate potential price shocks for consumers, but the report argues that it should not come at the expense of efficiency. Any attempt to smooth regulated EDBs' prices should not compromise EDBs' ability to recover their efficient costs or dampen incentives for EDBs to improve efficiency or service quality;

b. Frontier believe that the current price limit does not align with the Part 4 purpose of promoting consumer benefits and efficient outcomes. They highlight several concerns, including the deferral of EDBs' recovery of efficient costs over multiple periods, insufficient regulated cash flows, disincentives for EDBs to make necessary capital investments for the country's energy transition, and the shifting of cost burdens to future consumers:

> *"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. This would result in EDBs' costs effectively becoming stranded. If EDBs cannot expect to*

[60] Frontier Economics, '*A review of the limit on EDB price increases*,' 13th July 2023

recover all of their efficient costs over the lifetime of the regulated assets, then investors in the EDBs are unlikely to supply the capital required to invest in regulated assets. This would not promote the Part 4 purpose."

c. The report suggests that removing or amending the price limit would lead to more efficient outcomes and better serve the Part 4 purpose which will be better promoted by removing or amending the price limit - for e.g. increasing it; or applying it net of incentive payments under the IRIS mechanism and the quality standards, and net of inflation; and

d. The Commission should urgently develop an IM that specifies how it would reset starting prices. This would remove a significant source of regulatory uncertainty currently faced by suppliers. This, in turn, would improve incentives for suppliers to invest prudently and efficiently at a time when significant amounts of network investment by EDBs is necessary to support a smooth energy transition for New Zealand:

> *"[…] the absence of an IM explaining how the Commission would approach a task as fundamental as resetting starting prices for each regulatory period fails to provide the level of regulatory certainty that was intended when the Act was amended to create the current regulatory framework."*

151. On the latter point, Frontier describes in summary that the Commission has recently introduced a cap on starting price adjustments for some suppliers (i.e., GPBs) that:

a. "Was not foreshadowed at the time the Court of Appeal and the Supreme Court handed down judgments in relation to Vector's application for judicial review of the Commissions' decision not to publish an IM that specified how starting prices would be reset.

b. Was not supported using any testable evidence or analysis. Rather, the Commission has simply noted that the cap is a matter of judgement.

c. May result in suppliers being unable to recover their efficient costs over a regulatory period because the imposition of the cap may require prices in subsequent years to increase in real terms, but those price increases may also be limited by the Commission.

d. Cannot be subjected to merits review by suppliers, consumers or any other party because the Commission has not developed an IM that specifies how it will reset starting prices, and only IMs may be subjected to merits review under the current regulatory framework.

e. It may or may not decide to extend to other suppliers (e.g., EDBs) in future. Given that the limit on starting price adjustments imposed by the Commission on GPBs was based only on its judgment, there is no way to anticipate what circumstances the Commission may deem it appropriate to extend the cap to other suppliers. It was this sort of uncertainty that the IMs framework was intended to resolve."

152. Frontier continues by explaining:

"As there is no IM that details how starting prices will be reset, no stakeholder (i.e., suppliers, consumers or other affected parties) can challenge the Commission's cap on the adjustment to starting prices through a merits review process.

In our view, a key reason why an IM that explains how the Commission would reset starting prices is necessary is because the scope for that IM to be subjected to a merits review would likely compel the Commission to justify more convincingly than it has done to date any cap it may seek to impose on the starting price adjustment. If the Commission is confident that it can justify convincingly any cap it decides to adopt, it should have no reasonable objection to publishing such an IM."

153. Vector believes that there are significant cash-flow implications of keeping the arbitrary 10% limit on price increases through the regulatory period, and leaving it at the Commission's discretion on any caps for the first year of the reset.

154. Vector recommends in line with Frontier's reporting that the price cap be removed altogether. Failing that it should be increased and applied net of incentive payments and inflation. Vector urges the Commission to develop an IM that specifies how it would set prices at a price-quality reset.

4. Form of control for GDBs

155. Vector – and many others – have suggested the existing weighted average price cap (WAPC) is no longer the best form of control for GDBs. In our opinion, the expected reduction in demand for natural gas over the longer term and the great uncertainty surrounding the pace of this decline renders this form of regulation unfit for purpose. We have proposed instead that GDBs be regulated via a revenue cap. The Commission rejects those overtures in its draft decision. It proposes instead to keep the WAPC which, in its preliminary view, would best promote the Part 4 purpose[61].

156. We disagree with that conclusion. For the reasons we set out below, the Commission's draft decision is out-of-step with orthodox regulatory principles, a growing body of international precedent and the reasoning it provided in its previous IM determination. We continue to support the adoption of a pure revenue cap for GDBs which would better meet the relevant statutory objectives. If the Commission is unwilling to switch to a revenue cap (despite the many reasons to do so) it should at a minimum change the existing WAPC to mitigate GDBs' exposure to volume risk via a new reopener.

The draft decision

[61] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Draft decision*, 14 June 2023, p.92 (hereafter: 'Financing and incentivising efficient expenditure paper').

157. The Government has signalled it wants to phase out the use of fossil fuels such as natural gas, while ensuring energy is accessible, affordable, secure and supports economic development. This forms a key part of New Zealand's transition towards a net zero emissions economy by 2050 under s.5Q of the CCRA. It also wants to ensure a fair transition. No end date has been indicated for this phase out, but demand for natural gas is likely to decline and eventually be phased out.

158. Consequently, GDBs know that they will lose customers in years to come and may one day be forced to decommission their assets (unless they can be repurposed, e.g., to transport green gases and/or blends). But crucially, they do not know how quickly this will happen. The uncertainty surrounding the rate of reduction in demand for gas makes it extremely difficult to arrive at robust demand forecasts[62]. Under a WAPC, GDBs would assume 100% of the associated – and considerable – demand forecasting risk:

- If demand exceeded the level forecast in the revenue requirement and the WAPC, then they would earn higher revenues than expected – at the expense of customers.
- Conversely, if demand fell short of expectations, businesses would earn lower revenues, and customers would pay less for the regulated services, in aggregate.

159. A revenue cap would reduce (without eliminating entirely[63]) this forecasting risk for GDBs by locking-in the revenue they would earn, irrespective of outturn demand (most likely in conjunction with conventional 'unders' and 'overs' accounts). We consider this to be materially better given the uncertainty currently faced by GDBs. This means that at the outset of a regulatory period a GDB would have a much better idea how much revenue it will earn from supplying regulated services, providing it with far more certainty when it comes to making key network maintenance and renewal decisions.

160. In its draft decision, the Commission contends that it would be a good thing for GDBs to be exposed to unpredictable demand forecasting risk. It suggests that if businesses find themselves on the wrong side of a demand forecast, then they will have strong incentives to

[62] The Commission appears to have accepted both the existence and extent of this uncertainty (*see:* Financing and incentivising efficient expenditure paper, p.92).

[63] A regulated business is not completely immune from demand risks under a pure revenue cap. For example, if demand turns out to be higher than expected and the regulated entity's costs are not *completely* fixed (i.e., increase as volume goes up and vice versa) then it will be unable to recoup the costs of meeting that additional demand. Specifically, the higher-than-expected demand will lead to it *over-recovering* relative to its revenue cap, prompting a downward 'overs' adjustment. That adjustment would not account for the fact that the revenue cap had *underestimated* the costs that the business incurred during the prior period, i.e., that the unexpectedly high volume led to costs that were above the level expected. The opposite occurs when demand is lower than expected throughout the regulatory period, i.e., it will result in the business *under-recovering* relative to its revenue cap, precipitating an upward 'unders' adjustment for the next period. However, that adjustment would over-look the fact that the business' costs were also lower than anticipated.

reduce their costs. The Commission appears to assume that the businesses will also have the ability to materially cut costs and reconfigure their operations to mitigate the impacts of any unanticipated reductions in demand. For example, it states that[64]:

> *"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 … Under the WAPC, suppliers are exposed to manageable risk that is likely to provide stronger incentives to invest and operate efficiently than a revenue cap. Under a WAPC GDBs can, to some extent, manage the demand risk by adjusting spending on opex and capex."*

161. In arriving at its draft decision, the Commission also notes that a WAPC provides consumers with more price stability within period, on average, but a higher likelihood of between-period instability if large revenue corrections are needed. In contrast, a change to a revenue cap would shift some demand risk (i.e., price volatility) to consumers within each regulatory period and would likely reduce between-period price stability. For the reasons we set out subsequently, Vector does not support the Commission's proposed approach.

Problems with the Commission's analysis

162. The Commission's draft decision hinges crucially on the assumption that, under a WAPC, GDBs would have both the incentive and the ability to recalibrate their expenditure and investment programs if demand turns out to be lower than forecast. That assumption is not correct. It overlooks one of the most fundamental economic characteristics of gas pipelines. Namely, the vast majority of the costs associated with supplying regulated pipeline services are fixed and sunk, i.e., they do not vary with volumes.

163. The sunk costs of the existing network do not simply vanish if outturn demand is less than forecast. Those fixed outlays must instead be recovered over a smaller customer base than envisaged when the WAPC was set. To be sure, GDBs may be able to reduce their expenditure to some extent. But only at the margin. Almost by definition, GDBs are highly unlikely to be able to fully offset the reduction in their revenues. Rather, the predominantly 'sunk' nature of the underlying cost bases means that if demand is, say:

- 10% below forecast, then a GDB's total revenue will drop by 10% but its total costs will decline by significantly less than this margin; and
- 10% above forecast, then the GDB's total revenue will increase by 10% but the increase in its total costs will be significantly below this level.

164. When costs are largely fixed and unrelated to demand, it generally makes sense for revenue recovery to be largely fixed and unrelated to demand as well, i.e., for the two metrics (revenues and demand) to be 'decoupled' from one another. Good regulatory practice would

[64] Financing and incentivising efficient expenditure paper, pp.94 and 96.

therefore in our view result in the form of control being a revenue cap. This form of best practice regulation significantly reduces the risk of a business recovering materially less revenue than it requires to operate and invest efficiently due to factors largely beyond its control. This can be both efficient and equitable.

165. In a world in which demand for gas is expanding and GDBs have an incentive and the ability to grow connections, a WAPC may still be a worthwhile form of regulation. For example, a WAPC can theoretically incentivise a business to set efficient tariffs that will spur additional connections and consumption, e.g., by setting prices that reflect customers' elasticities of demand, consistent with 'Ramsey-pricing' principles. However, that is not the world in which we find ourselves right now. The Government has in fact signalled it wants to phase out the use of natural gas – and so it would arguably be inconsistent with this objective for GDBs to be trying to stimulate additional gas connections/demand;

166. Consequently, the choice of price control here boils down primarily to the appropriateness or otherwise of allocating to GDBs all the risks associated with a phenomenon they cannot control; the downside costs of which they cannot avoid. In Vector's view, this would not be fair nor efficient or in any way good regulatory practice. As Frontier Economics (2023) has explained[65], keeping a WAPC would cause GDBs to under- or over-recover their efficient costs and may create financeability challenges – none of which would advance long-term consumer interests.

167. Retaining the current WAPC in the current circumstances would therefore risk violating one of the most basic tenets of regulatory economics. Regulated businesses must be afforded a reasonable opportunity to recover their efficient costs, including an adequate return on historic sunk investments. Under the status quo, there would be an intolerably elevated risk of this not occurring. Successful cost recovery would hinge to an untenable degree on demand outcomes that would be exceedingly difficult to forecast with any degree of accuracy.

168. These problems are not unique to New Zealand. Other jurisdictions are facing analogous challenges as their gas markets also enter uncertain futures characterised by declining demand. As Frontier Economics (2023) highlighted, regulators have responded by making changes to insulate GDBs from the attendant demand forecasting risks – citing precisely the factors described above. For example[66]:

- In the UK, Ofgem switched from a WAPC to a pure revenue cap for GDBs in 2007 and has maintained that approach ever since. Ofgem acknowledged that nearly all of GDBs' costs are fixed and allowing GDBs' revenues to vary with volumes simply introduced unnecessary and unmanageable volatility into the recovery of efficient costs.

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[65] Frontier Economics, *The merits of introduced a revenue cap for gas distribution businesses, A report prepared for Vector,* 6 April 2023, p.2.

[66] Op cit., pp2-3.

- In Australia, the AER has introduced a demand re-opener that would allow GDBs to propose a variation to its price cap if there is a material divergence between the actual demand and the demand forecasts used to set the original price cap. It is also actively considering moving to a revenue cap form of regulation[67].

169. It is also difficult to reconcile the draft decision with the Commission's choice to switch EDBs to a pure revenue cap at the previous IM reset. One 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[68].' Those forecasting risk considerations are even more acute in the present circumstances. It is consequently far from clear why the Commission has not reached the same conclusion as it did seven years ago.

Materially better alternatives

170. The Commission's draft decision is out-of-step with orthodox regulatory principles, international precedent and the reasoning it provided in its previous IM determination. Consequently, persevering with the WAPC in its current form would not be in the long-term interests of consumers. Vector supports moving away from a WAPC to a pure revenue cap – in combination with a standard 'unders and overs' account. This form of control would be a materially better way of meeting the overarching statutory objectives because it would:

a. Provide a greater degree of assurance to GDBs that they will recover their prudent and efficient costs (promoting 'criterion (a)' of the purpose statement), but no more (advancing 'criterion (d)'). Relatedly, it would:

   - promote the Commission's ex-ante FCM principle by providing GDBs with greater assurance of earning their risk-adjusted cost of capital; and
   - result in a superior allocation of risk, by insulating GDBs from demand forecasting uncertainty that is largely outside their control given emerging market conditions.

b. Be simpler to implement and enforce than a WAPC, thereby reducing ongoing regulatory costs for both the Commission and GDBs. Implementation costs would also be modest since there are already revenue caps in place for EDBs and GTBs.

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[67] The AER is also actively considering switching to a pure revenue cap. It recently published an Information Paper explaining that there are many sound reasons to regulate GDBs using revenue caps, given the increasing difficulty associated with forecasting demand accurately during the transition to a decarbonised energy system. It has not made a regulatory determination for a GDB since it published that Information Paper, and so it remains to be seen whether/how soon it will adopt a revenue cap form of control. *See:* Frontier Economics, *The merits of introduced a revenue cap for gas distribution businesses, A report prepared for Vector,* 6 April 2023, p.2.

[68] Commerce Commission, *Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower,* 20 December 2016, p.2.

171. If the Commission remains disinclined to introduce a revenue cap (despite the compelling reasons to do so) then, at a minimum, it should modify the existing WAPC to mitigate GDBs' exposure to volume risk. One means of doing so would be to introduce an additional re-opener that would allow a price-quality path to be revisited if actual demand turned out to be below or above the underlying forecast by a pre-specified margin (e.g., 10%). This is the approach currently employed by the AER in Australia.

5. Revenue wash-up changes

Introduce inflation wash-up on revenue for the first year of a regulatory period

172. Vector welcomes this change as we believe it solves the issue identified by Incenta for Chorus in their report 'Options to address the gap in CPI inflation correction[69]' responding to the IMs Process and Issues paper in July 2022.

173. Incenta outlined that the Commission's "within-period" correction for inflation is incomplete for the first year of the regulatory period. The Commission's draft decision change now corrects the calculation to include the difference between forecast and actual inflation for all of the quarters for which inflation is required to be forecast.

174. We also note the consistency with the recently released Fibre IMs published of 28 June 2023.

Adjust annual revenue wash-up to reflect debt servicing costs being fixed in nominal terms

175. Vector welcomes the Commission's recognition of the debt compensation issue conceding that the debt compensation issue only arises when inflation is less than expected. Their draft decision considers that their proposed change to the annual revenue wash-up deals with the debt compensation issue better than removing indexation from EDBs' RABs or keeping only the equity portion indexed for inflation.

176. The EDB IMs currently have an annual wash-up to revenue for the difference between actual and forecast inflation. The Commission is proposing two changes to resolve this issue:

a. Adjust revenue for the first year of a regulatory period by the difference between forecast CPI and actual CPI; and

b. Subtract from annual revenue the revenue debt adjustment.

[69] https://comcom.govt.nz/__data/assets/pdf_file/0035/287990/Chorus-Options-to-address-the-gap-in-CPI-inflation-correction-11-July-2022.pdf

177. We are disappointed at the short time available to assess the debt cost wash-up mechanism. We asked experts for a view on the implications of the proposed mechanism, but none were able to reach a conclusion in the time afforded by the Commission.

178. We are concerned that the Commission may have misrepresented the issues raised by EDBs in regard to debt compensation. However, with the limited time to consider the changes proposed by the Commission we have not been able to reach a firm conclusion on this matter.

179. Our initial review, however, has raised the following concerns for the Commission to consider:

a. The wash-up approach to addressing the issue as proposed by the Commission is in our view unique and complex - we are not aware of another regulator that has solved this issue in the way that the Commission is suggesting;

b. We consider that the Commission has provided insufficient material to show the impact on suppliers of the introduction of this wash up as is required by s52T;

c. The inclusion of a demonstration model does not enable the suppliers to assess if there are any material impacts for them (to adequately assess impacts a real model is required and therefore it is difficult to submit conclusive views on the wash-up changes); and

d. This is a significant change and therefore the Commission has been remiss in not providing an issues paper on it prior to including it in their draft decision.

Appendix C. Incentivising efficient expenditure for EDBs

1. Expenditure incentives

180. The Commission has proposed to keep the current suite of expenditure incentive schemes for EDBs and Transpower as tools for mitigating capex bias due to financial regulatory incentives. In doing so they have considered but not adopted a totex approach.

181. In our submission to the Commission entitled '2023 Expenditure Incentives[70]' dated 6th April 2023, we outlined that there is still a lot to learn from other regimes in their adoption of a totex approach. We should not abandon the idea of improving our current incentive schemes and believe the discussion should continue around finding better ways to tackle the substitution of opex and capex in the best interest of consumers.

182. For example one aspect of the totex approach that could be looked at for the next EDB reset is 'totex assessment/forecasting' where the regulator does not distinguish between capex and opex when assessing efficient allowances. Instead, the regulator reviews total costs (or expenditure). This could address the more procedural aspect of any potential bias whereby it is easier to ask for capex. The Commission could also then consider applying IRIS against a totex view rather than by splitting the mechanism between opex and capex.

183. The Commission has also stated in its draft decision that it would maintain the current incentive mechanisms as they best balance considerations of effectiveness and understandability.

184. 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. Currently only reliability and efficiency are rewarded - even through the IPA those are the only two criteria that are said to make a project 'innovative.' EDBs are playing a central role in the electrification of the economy therefore how they are rewarded should take a wider lens on decarbonisation objectives.

185. For example we propose that the Commission considers a performance-based incentive for avoided peak increase/managed load similar to the Demand Management Incentive Scheme (DIMS)[71] adopted by the Australian Energy Regulator (AER). DIMS encourages distribution businesses to find lower cost solutions to investing in network solutions. The incentive scheme achieves this by providing distribution businesses with financial incentives to undertake efficient expenditure on non-network solutions to manage peak electricity demand.

[70] https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/vector-submission-2023-expenditure-incentives.pdf

[71] https://www.aer.gov.au/taxonomy/term/1203

2. IRIS changes

Adjust IRIS allowances for inflation

186. The Commission has decided, for the purposes of calculating opex and capex incentive amounts, to change their approach to set inflation-adjusted IRIS allowances (based on actual CPI).

187. Vector agrees with this change as it will remove the impact of economy-wide inflation on incentive amounts for opex & capex and correct for situations where inflation has caused operating costs to be higher than expected, but not where PPI, LCI or CGPI have been higher than expected.

Implications for IRIS for cashflow timing

188. In the draft decision the Commission proposes no IM changes to change the cashflow timing of IRIS.

189. 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.

190. The Commission notes that smoothing all cash flow-sensitive factors (in aggregate) is more effective than an IRIS specific mechanism.

191. 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.

192. 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.

Maintain approach to setting incentive rates

193. Currently, the opex incentive rate is a function of the length of the retention period (defined in the IMs as five years) and the WACC (as the discount rate). The means the opex incentive rate changes between periods with the WACC. The capex incentive rate is currently determined at the price-quality reset.

194. In discussing the alternative option of fixing opex and capex incentive rates, the Commission only considers this can be done varying the carry-forward period at each reset – which it considers to be problematic.

195. However, an alternative may be the approach IPART has recently flagged for the water businesses it regulates in New South Wales. 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.

Not to exclude specific expenditure categories from IRIS

196. 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.

197. 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.

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.

199. We recommend once again that the Commission excludes 'consumer connections' from IRIS.

Use the midpoint discount rate in the opex IRIS calculation

200. The Commission has changed their approach to use the midpoint vanilla WACC as the discount rate for estimating the opex incentive rate (rather than using the 67th percentile vanilla WACC).

201. Though we do not estimate that this change is particularly material for EDBs, we believe that the Commission should be consistent and use the same WACC percentile for the opex IRIS calculation as they do in setting the return on capital allowance (i.e. 65th per the draft decision).

202. The change to the discount rate will affect suppliers' share of efficiency gains/losses. The discount rate may distort decision-making if it differs from a supplier's WACC.

203. 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.

Maintain current treatment of operating leases

204. 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.

205. For incentive purposes, the Commission decided that it made more sense that cash flows align with opex treatment (as was the case before the introduction of NZ IFRS 16).

206. Vector believes that the requirement to maintain separate accounting and regulatory treatment adds to the disclosure burden and creates greater risk of error.

207. 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.

208. Similarly software as a service (SaaS) costs were impacted by an accounting rule change. This was reflected in the gas DPP3 reset where the Commission changed its treatment to opex in its final decision[72].

209. In order to solve this issue we suggest removing 'operating leases' and 'SaaS' expenditure from the IRIS calculation.

Make no change to IRIS for undercharging

210. We understand that undercharging occurs when a supplier does not charge up to its maximum allowable revenue (MAR). By voluntarily undercharging, an EDB is lowering prices for consumers sooner than through the IRIS mechanism and receiving a lower portion of the overall saving compared with IRIS.

211. We agree with the Commission that no changes are required in this area.

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[72] https://comcom.govt.nz/__data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf para. A4.2

3. Innovation incentives for EDBs

212. One of the four outcomes of workably competitive markets that the Commission must promote is that regulated suppliers have incentives to invest and *innovate*, including in replacement, upgraded, and new assets.

213. The draft decision suggests there may be some elements forthcoming that will help to incentivise further innovation. The trouble is we *would not know this for certain* until the next DPP reset under the proposed approach. Disappointingly, the Commission has refused to entertain other measures that might spur more innovation (and its attendant benefits) with relatively little downside cost. For example, it does not support any form of regulatory sandbox or, indeed, any mechanism beyond its Innovative Project Allowance (IPA). In our opinion, the draft decision therefore does not go far enough in such a critical and enabling area.

Background

214. Innovative solutions often have a number of less desirable attributes that may diminish EDBs' incentives to pursue them, all other things being equal.

215. Certain specific elements of the regulatory framework itself may serve to further reduce EDBs' appetites for investing in innovation. NERA (2022) set these out in detail in a recent report.[73] Some of the key barriers to innovation it identified included the following:

- Innovative solutions involving opex as opposed to capex may run afoul of the fact that the benchmarking approach for the former inadvertently punishes any expenditure that does not translate into increases in certain metrics (customer numbers, line lengths, etc.) – such initiatives may instead result in improvements in 'uncompensated outputs;'[74]

- In workably competitive markets there is a usually a distinct advantage enjoyed by those firms that are first to invest successfully in innovation, i.e., they may capture a substantial upside and perhaps enjoy it exclusively for extended periods (e.g., through intellectual property rights). The innovation investment calculus is quite different for EDBs:

  - the revenue cap arrangements serve to cap any potential upside;
  - EDBs are also prevented from extracting any of the benefits accruing to other parties (e.g., they receive no advantages from any broader welfare enhancements accruing throughout other parts of the supply chain); and

[73] NERA, *Innovation under the DPP: potential barriers and solutions, 'Big Six' EDBs: Aurora, Orion, Powerco, Unison, Vector, and Wellington Electricity*, 20 December 2022 (hereafter: 'NERA innovation report').

[74] For a more comprehensive description of 'uncompensated outputs,' *see:* NERA Innovation report, p.7.

- on the flip side, EDBs face all the down-side consequences if an innovation does not 'pay off', i.e., the up-side is capped but the downside is not.

216. The historical design of the IPA (e.g., the modest amounts it offers in additional funding, its narrow scope, the contributions businesses themselves must make and its ex-post nature) does very little – if anything – to incentivise investment, as evidenced by the fact it has never been successfully utilised.

217. Vector prides itself for being on the leading edge of innovation, but we find ourselves there largely in spite of the regulatory framework, not because of it. In our opinion, there has arguably been a sub-optimal level of investment in innovation across the sector in recent years.

218. This represents a significant problem with the status quo, given the potential benefits offered by innovation – especially during the next IM period. For example, a recent study undertaken by Ofgem revealed that increased flexibility could deliver system cost reductions of up to £10bn per year in the UK (2012 prices, undiscounted) by 2050.[75] Unfortunately, the proposed revisions to the IM may not do enough to foster efficient levels innovation. In our opinion, there is more that could be done, at relatively little downside cost.

The draft decision

219. In its draft decision, the Commission expressed its view that the current rules afford a large degree of flexibility for suppliers to innovate. It noted that it sets fungible expenditure allowances whereby suppliers can spend as they see fit, i.e., the IMs do not govern how it sets capex and opex envelopes.[76] Businesses are therefore theoretically free to pursue any innovative opex or capex solutions they think might result in outperformance relative to benchmarks, compared with alternative options at their disposal (e.g., 'poles and wires'). The Commission saw little benefit in introducing a regulatory sandbox. It stated that the IMs:[77]

> *"[G]enerally enable the desired outcomes of regulatory sandboxes and do not propose to change them for this purpose. Our view is that the current rules afford a large degree of flexibility for suppliers to innovate, and, we have not been presented with evidence of specific examples where innovation has not occurred that a regulatory sandbox would have enabled."*

220. The Commission did, however, concede that the IPA it introduced at the DPP reset in 2019 has not worked as intended and it recommended some modifications. Indeed, no EDB

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[75] Ofgem, *Transitioning to a net zero energy system Smart Systems and Flexibility Plan 2021*, July 2021 (available here).

[76] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Draft decision,* 14 June 2023, p.184 (hereafter: 'Financing and incentivising efficient expenditure paper').

[77] *Op cit.,* p.183.

has been able to successfully navigate the IPA process and draw down from the allowance. Several parties – including Vector – have highlighted the many problems with the way the IPA has functioned hitherto, including:

- Its restrictive interpretation of what constitutes an 'innovative project';
- The quantum of funding on offer, which is significantly lower than the sums available under similar overseas mechanisms (such as Ofgem's Network Innovation Allowance (NIA)[78]) and the contributions that businesses must themselves make, which are significantly higher than the levels seen elsewhere;[79]
- Relatedly, the IPA is arguably not suitable for larger-scale transformational projects, the likes of which bigger EDBs like Vector might consider. In the UK, Ofgem has a separate fund called the Strategic Innovation Fund (SIF) that caters for these types of projects, i.e., it has double the budget of the NIA. There is no equivalent of the NIA here; and
- The ex-post nature of the mechanism. Namely, businesses can only apply for funding for projects that they have already undertaken. They must spend the money first, and then hope to obtain funding from the IPA after-the-fact. In contrast, the UK's NIA is and ex-ante 'use it or lose it' arrangement.

221. The Commission accepted some of these criticisms in its draft decision. For example, it agreed that the 'innovation project' definition contained in the IMs was imprecise and had caused some confusion.[80] It also conceded that the current definition may limit the implementation of schemes that encourage innovative or non-traditional solutions but are outside the definition's scope (even when encouraging those solutions would better promotes the long-term interest of consumers).[81]

222. However, instead of clarifying the definition in the IM with, presumably, some significant broadening to expand its application, the Commission opted to remove it altogether. Specifically, the Commission has proposed to delete the definition of 'innovation project' and rebrand the IPA as the 'innovation and non-traditional solutions allowance' ('INSA').[82] Under the proposed INSA, at the DPP reset or in setting a CPP the Commission would specify:[83]

- the amount or amounts EDBs could recover with its approval; and
- 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.

223. Under the Commission's proposed approach, there would not be any additional clarity about these matters until the next DPP reset decision in November next year – nearly a year

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[78] NERA Innovation report, p.28.

[79] *Ibid.*

[80] Financing and incentivising efficient expenditure paper, p.193.

[81] *Op cit.,* p.191.

[82] *Op cit.,* p.190.

[83] *Op cit.,* p.191.

after the final IM decision. In other words, the idea is to leave the IM relatively 'high-level' and to specify the detail at DPP resets. As we elaborate below, that would leave businesses in a rather uncomfortable state of flux in the meantime. We elaborate on this and other potential problems with the draft decision below.

Assessment of the draft decision

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.

227. Vector is pleased that the Commission has acknowledged that the current IPA arrangement is flawed. We welcome the broadening of scope and flexibility of the mechanism. What is lacking is detail. The Commission has opted to defer consideration of the substantive elements of the proposed INSA until next year. Those crucial details would not be finalised until November 2024 at the earliest when the DPP reset decision is made. In the meantime, EDBs would be left to speculate over:

- What sums will be available – recognising that those on offer under the current mechanism are lower than those offered in some other jurisdictions, e.g., Ofgem's NIA budget is 5x-7x as large as the current IPA;
- What contributions businesses will themselves be expected to make – noting again that these are much higher in New Zealand than in other places, e.g., Ofgem's NIA requires EDBs to contribute 1/5th as much as the existing IPA;
- Whether funding will be limited to 'electricity lines services' and, if not, what would be permissible under the revised arrangement;

- What potential incentives/rewards might entail, e.g., the AER's Demand Management Incentive Scheme (DMIS), applies a 50% uplift factor. This means that an EDB receives $150 of allowance for every $100 spent on approved opex; and
- Whether the INSA would be an ex-post arrangement (like the IPA), whereby EDBs would first need to spend the money before seeking compensation after the fact (giving rise to the risk the Commission may not provide compensation).

228. This uncertainty is undesirable and contrary to the purpose of the IMs which is to promote certainty – especially at such a crucial juncture in the energy transition. Businesses need to be making crucial investment planning decisions now – and uncertainty is the moral enemy of dynamic efficiency. If the Commission is unwilling to provide additional specificity in the IMs themselves then it should at least endeavour to provide more guidance in its final decision (or elsewhere) on these key matters. Moreover, for the DPP, all the Commission has provided so far is a solitary example of what it would likely not approve.[84]

Materially better alternatives

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.

230. As for the IPA, it is pleasing to see the Commission recognising the flaws in the current arrangement. We welcome its desired objective of broadening the scope and flexibility of the mechanism. What is missing is the details. What initiatives will be eligible? What sums will be available? What contributions will EDBs be required to make? All this and more remains unclear. Rather than waiting until November next year, we would urge the Commission to provide more guidance in its final decision (or elsewhere) on these key matters.

231. In particular, we would welcome examples of what might be permissible under the INSA. To that end, unless the Commission is contemplating very substantial increases to the funds available (which we would certainly support), there would still be no mechanism to incentivise larger projects. Vector would therefore support the Commission introducing a parallel scheme to sit alongside the INSA – something more akin to the SIF used to promote such projects by Ofgem in the UK.

[84] Specifically, the Commission indicates that it would not approve an in-period adjustment mechanism that provided EDBs additional opex allowances for demand management solutions that efficiently defer capex. *See:* Financing and incentivising efficient expenditure paper, p.214.

4. Other matters to consider

Legal costs removed from operating costs

232. Vector is concerned about the Commission's decision to remove legal costs from operating costs in the context of appeals against IMs. We would argue that this amendment fails to consider the transformative and uncertain nature of the energy market, disincentivises suppliers from initiating merits appeals, and overlooks the importance of context in evaluating the appropriateness of the decision. It also highlights accountability concerns, the complexity of regulatory decisions, and the financial burden on suppliers.

233. Removing recoverability of legal costs from consumers is not suitable as it may hinder the ability of suppliers to act in the long-term interest of consumers. We suggest that the Commission should ensure a robust IMs process is maintained, which instils confidence among suppliers and stakeholders before making such amendments.

Appendix D. CPPs and in-period adjustments

1. Improving the price-quality path reopener processes

Not allow for a single-issue CPP

234. We do not agree with the Commission's draft decision to not allow for a single-issue CPP.

235. Single issue CPPs could pick up instances where an IM changed is required for an EDB that has a material impact on an its revenue. An IM change would not be picked up by a DPP reopener. They could also offer several benefits:

- Targeted Focus: A single-issue CPP allows regulators to specifically address and evaluate a particular aspect or issue within the regulatory framework. This targeted approach enables a more in-depth analysis of the specific concern at hand, ensuring a comprehensive understanding of its impact and potential solutions;

- Efficiency: By concentrating on a single issue, the regulatory process can be streamlined and expedited. This can lead to quicker decision-making and implementation, reducing administrative burdens for both regulators and EDBs;

- Flexibility: A single-issue CPP provides the flexibility to address emerging challenges or changes in the industry. It allows regulators to respond to specific circumstances or developments promptly and efficiently, without the need for a comprehensive review of the entire regulatory framework; and

- Cost-Effectiveness: By narrowing the scope to a single issue, the resources required for analysis, consultation, and decision-making can be optimised. This can result in cost savings for both regulators and EDBs while still effectively addressing the identified concern.

236. Whilst we think that the Commission is moving in the right direction with removing the $30m upper threshold on the unforeseen and foreseen project reopeners (see section 4 of this appendix) – there is still merit is ensuring these is coverage for a single issue CPP in the IMs. We also note that the Commission has already effectively undertaken a single issue CPP with the granting of Wellington Electricity's CPP in March 2018.

Process improvements

237. We welcome the Commission's proposed amendments to align the DPP reopener processes to that of the Fibre IMs and subsequently improve the mechanics sitting behind a reopener application. However, we do believe the Commission is missing out on some easy additions to the regime. For example, the draft decision to:

- Not introduce timeframes for the Commission to evaluate reopener applications: this would hold the Commission to account and where consumers are involved – set their expectations. It would also enable the Commission to publicly report against the required timeframes which should improve process performance through time;

- Not provide more prescription about the types of information required in reopener applications: for an efficient process why not provide guidelines so that suppliers can be certain of what level of detail the Commission is seeking. We understand the Commission's reluctance to provide guidelines as exampled by the non-provision by the Commission of regulatory enforcement guidelines despite various assertions that these would be provided. However, we do not consider this to be good regulatory practice. Guidelines are a useful tool for best practice regulatory agencies to issue to assist and help guide regulatory processes;

- Not prescribe when consultation is required and when it is not: again for an efficient process, a supplier could avoid cost intensive consultation when in fact it is not required;

- Not include a pre-application stage for the process of reapplying for a reopener: again for an efficient process, a supplier could avoid a costly application when in fact the Commission could decline it at an early stage;

- Not include a reopener for the purposes of assessing programme financeability: we believe a re-opener to support project financing (for example, through proposing a different cashflow profile or rate of return) if the existing regulatory settings did not enable the project to be funded resulting in suboptimal outcomes for consumers. This would support the long-term benefit of consumers by providing a mechanism to support project financing when engaging in a CPP application would be inappropriate (for example, for specific projects where the scale of expenditure would not justify a CPP application);

- Not allow price-quality path reopeners to apply across more than one regulatory period without suppliers having to reapply. Reopeners in their current form are limited in their value because they have to be approved, the investment designed and built, and the final assets commissioned within the same regulatory period. Practically, this limits the use of reopeners to smaller projects that can be started early in the regulatory period so that they can be completed before the regulatory period ends. Increasing equipment lead times, resource shortages and reopener application consideration timeframes will all reduce the time periods available within a regulatory period for a supplier to complete works funded by a reopener. Vector recommends that a contingent project reopener be introduced and be designed to be regulatory period agnostic. If the project starts in one regulatory period, any remaining investment needed to complete the works could be automatically rolled into the next regulatory. This could be similar to the High Value Project (HVP) reopener[85] adopted in Ofgem's RIIO-ED2 price control;

- Not allow a single CPP application to cover multiple parties nor allow a single reopener application to cover multiple parties. We believe this is a missed opportunity to streamline the CPP or reopener process when multiple suppliers face the same issue but are unable to apply together (for e.g. the legal or expect advice required for an application would only need be sought once); and

- Not include a reopener for general growth – see our section 'other uncertainty mechanisms' below for our views of general or incremental growth.

238. In addition to the above we encourage the Commission to review Vector's submission[86] on in-period adjustments dated 6 April 2023. In that letter we outlined several process improvements that could be made at very low cost to the Commission. Please refer to the 'process and administration' and 'better guidelines' sections in particular.

2. Whether reopeners will cover future circumstances

Government policy changes, Local Government rule changes or legislation affecting others in the supply chain

239. The Commission's draft decision is not to amend the EDB, GDB and GTB IMs to include DPP reopeners to cover Government policy changes, Local Government rule changes or legislation affecting others in the supply chain, unless otherwise covered by the Change event reopener.

240. In our view, an appropriately qualified re-opener for government policy changes would be appropriate. Executive action (e.g. Ministers exercising statutory powers of decision) can have a significant impact on the cost of delivering regulated services and therefore in principle a re-opener should be available.

241. But our more significant concern is that the Commission currently construes the change event re-opener so narrowly it has no real effect. We were disappointed, for example, with the Commission's response to our health & safety re-opener request. The HSWA created a new legislative framework for health & safety and was intended to change the way suppliers approached their health and safety obligations. The introduction of that legislation prompted a

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[85] HVPs are large, one-off projects that are typically more bespoke in nature due to their size and being delivered less frequently than many of the other day-to-day activities undertaken (see Chapter 6 of Ofgem's RIIO-ED2 Core Methodology here: https://www.ofgem.gov.uk/sites/default/files/2022-11/RIIO-ED2%20Final%20Determinations%20Core%20Methodology.pdf)

[86] https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/vector-submission-2023-in-period-adjustments.pdf

sector-wide change in approach to working on live lines. The costs were immediate, significant and quantifiable. Nonetheless the Commission declined to re-open the price-quality path.

242. If the Commission is not going to extend the change event re-opener, it is important that the Commission at least:

a. clarify what it understands to be the scope of the re-opener;

b. confirm that any amendments to, or new, primary or secondary legislation (including, for example, the Electricity Industry Participation Code) constitute a “change in or a new” legislative requirement for which a re-opener is in principle available (subject to meeting the remaining criteria); and

c. explain in more detail what the Commission considers are qualifying “regulatory” changes that trigger a re-opener.

Contingent project reopener

243. The Commission’s draft decision is not to amend the EDB, GDB and GTB IMs to include a new DPP contingent project reopener.

244. However, Vector supports the introduction of a contingent project re-opener. Expenditure with less certainty around cost and timeframes would be right for a contingent project re-opener. For example, the Auckland network may see a number of data centres connect over the next DPP. This would avoid the need for costs to be included in supplier allowances and would ensure consumers only fund these costs if the need actually arises in-period.

245. We note Transpower proposed a ‘use it or lose it’ funding mechanism in its RCP4 proposal which it described as ring-fencing funding for its resilience programme where there was less certainty around scope and cost. We consider a contingent project re-opener should also apply to projects that are high impact and value for consumers but may not reach a 1% of revenue threshold.

246. Please also see our comments around Ofgem’s ‘HVPs’ in the section above on ‘process improvements.’

Categories of expenditure

247. The Commission’s draft decision is not to amend the price-quality path DPP reopener IMs to specifically address changes in the following specific categories of costs:

1. digitalisation and data;
2. monitoring of Low Voltage (LV) networks;
3. changes to a system operator’s approach to security;

4. software as a service (SaaS);
5. avoided cost of distribution payments (ACOD);
6. increased insurance premiums; and
7. Distribution System Operation (DSO) type services.

248. Vector agrees with the Commission's assessment here but would like to draw attention to categories 1, 2, 4 and 6 specifically. If digitalisation and data, the monitoring of LV networks and increased insurance premiums are not considered as reopener worthy expenditure types, then then Commission must ensure that these costs are accepted in EDBs' opex allowances for the next reset DPP4.

249. To illustrate, Vector was denied opex expenditure in relation to visibility of LV networks for DPP3. It has become apparent that this activity is essential going forward with the penetration of EVs on the LV network.

250. Enabling distribution system operation services through better data and digitalisation of networks will also be crucial as the LV network becomes even more important to manage growing capacity. The Commission must ensure the DPP4 reset is amenable to those costs being accepted as essential and enabling expenditure items.

3. Large Connection Contract (LCC)

251. Vector supports the introduction of the LCC mechanism similar to Transpower's 'new investment contract' (NIC). This approach would support the long-term benefit of consumers by mitigating forecast uncertainty; allowing negotiation of contracts on commercial terms supplying more consumer options for new large connects, avoiding costs attributable to an individual connecting party being recovered from consumers through lines charges. It will also avoid the need for reopeners thus ensuring a quicker turnaround of project acceptance.

252. We disagree with the Commission on the requirement that the mechanism would be available only for contracts for which the maximum capacity of the connection under the contract is at least 10 MW.

253. Transpower's NIC mechanism does not have a minimum capacity requirement so we do not believe that EDBs' LCC should either.

254. Projects with capacity of 10 MW or more are very significant. To illustrate this point, early last year, Vector sought Registrations of Interest (ROI) from suitably qualified suppliers who were interested in delivering non-wires alternatives (NWAs) in the wider Warkworth region. We determined a need for a total of 3-5 MW to alleviate the network constraint for periods of 2-5 years and were seeking to purchase this in 1 MW blocks.

255. To further illustrate in our 2023 Asset Management Plan[87] we explained that over the last two years, several large tech and data centre providers have announced to build data centres in Auckland due to the exponential rise in cloud-based services, demand to store data in New Zealand for governance reasons and excellent connectivity of Auckland to global fibre backbone. Early and continuous customer engagement means that Auckland now already has 20 MW of new data centres connected in aggregate and much larger connection pipeline.

256. The 10 MW capacity minimum threshold is too high. If it stays at that level, it will very rarely be used. In order to reap the benefits of the new mechanism the threshold must be removed completely. Vector believes that this new requirement should be based on the principle of a new network agreement negotiated between the parties as if there were workably competitive market forces at play without size being a factor.

4. Materiality thresholds

Remove the $30 million upper threshold for Foreseeable and Unforeseeable large project reopeners

257. Vector agrees with the removal of the $30m threshold for Foreseeable and Unforeseeable large project reopeners. The Commission has stated that removing the upper limit provides an alternative solution for EDBs proposing the introduction a single issue CPP. We believe this is a step in the right direction but remain concerned with the discretion the Commission has with regard to deciding when a reopener is more appropriate as a CPP.

Consideration of whether an application is better suited to a CPP

258. The Commission has proposed to amend the IMs to include a new clause to allow the Commission to identify reopeners better suited to CPPs. This new provision excludes error events, major transactions, and false or misleading information reopener events.

259. We oppose this change. The reopener mechanisms must offer certainty of process. This amendment gives the Commission too much discretion not to consider a reopener application and to force an EDB to make a CPP application.

Raise the thresholds for Foreseeable and Unforeseeable large project reopeners, Change events, Catastrophic events and Risk events

260. The Commission has raised the existing dollar thresholds to $5 million for Vector Limited and PowerCo Limited or $2.5 million for all other EDBs ($2.5m for all EDBs for Risk events) for above reopeners.

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[87] https://blob-static.vector.co.nz/blob/vector/media/vector-2023/vec246-vector-amp-2023-2033_120523_1.pdf

261. Vector does not agree that us and PowerCo should have a higher threshold than others. Size of reopeners should not be a factor due to the size of the network. Reopeners of any size are in place to assist in efficient investment for the benefit of consumers. We recommend that the $2.5m threshold applies to all EDBs.

Change the minimum threshold to $100,000 for Error events

262. Vector agrees that 1% of forecast net allowable revenue (FNAR) was too high a threshold to be appropriate for an Error event and that $100,000 is an appropriate hurdle for this type of reopener.

5. Whether other in-period adjustment mechanisms are necessary

New connections volume wash-up mechanism for EDBs on a CPP

263. In its draft decision the Commission has introduced a new connections volume wash-up mechanism in the EDB IMs for CPPs, but not DPPs.

264. The Commission states that there is no wash-up in the IMs to mitigate forecast connection volume error (i.e., for those not included in existing reopeners or proposed large connection mechanism) – e.g., system growth from EV uptake.

265. They also explain that the mechanism is not appropriate for a DPP due to lack of sufficiently reliable and verifiable data on connection unit costs.

266. Vector believes that the Commission's proposed solution does not solve the problems it identifies. The current DPP reopener provisions cover large connection driven projects (being the lesser of 1% revenue or $2 million). This means that uncertainty related to other connections under the DPP would remain unaddressed.

267. The extent and pace of future demand growth is uncertain and with most EDBs under a DPP at any one time they may be penalised for costs outside of their control. Further, the energy transition will occur across multiple regulatory periods and repeated CPPs is not a proportionate tool to mitigate uncertainty under Part 4.

268. We recommend that the Commission (under a S53ZD notice) requests unit cost data for new and existing connections from non-exempt EDBs shortly after this consultation closes. It can then assess whether the data is reliable enough to apply the new wash-up mechanism to DPPs.

Other uncertainty mechanisms

269. On 6th April 2023, Vector sent the Commission our views[88] on in-period adjustments which included four proposals we would like considered. In particular we would like to draw the Commission towards the four proposed uncertainty mechanisms to be considered and developed into the IMs:

- Use-it-or-lose-it (UIOLI) allowance for Resilience;
- UIOLI allowance for Worst Served Feeders;
- Pass-through costs for Storm Response; and
- Volume driver for incremental demand.

270. As explained in that submission, the Commission weighs heavily on the use of reopeners to provide flexibility in the price paths. Yet there are other uncertainty mechanisms[89] which could work well or better than reopeners which are resource intensive for both EDBs or GDBs and the Commission.

[88] https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/vector-submission-2023-in-period-adjustments.pdf

[89] Complete Strategy – Uncertainty mechanisms in the UK: an overview, March 2023

Appendix E. List of expert reports

Vector commissioned:

- Motu – July 2023 memorandum on inflation forecasting
- Frontier – Regulatory financeability
- PWC - Including a financeability test in the Input Methodologies for electricity distribution businesses
- Complete Strategy – Uncertainty mechanisms in the UK: an overview

In collaboration with the 6 largest EDBs:

- Oxera – Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital
- Frontier – A review of the limit on EDB price increases

In collaboration with the 3 GPBs:

- Oxera – Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital relating to the gas sector

Kind regards

Richard Sharp
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