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Input Methodologies (IM) Review 2023 – Vector's cross-submission to Draft Decision

1. This is Vector's ('our', 'we', 'us') cross-submission on responses to the Commerce Commission's (Commission) draft decision on the IMs. No parts of this submission are confidential, and it can be published on the Commission's website.

A. Executive summary

2. The energy sector in Aotearoa New Zealand is undergoing significant transformation due to evolving technology, changes in government policy, and shifting customer demands. The Commission's IMs for the sector were last reviewed in 2016, but the current industry context calls for a comprehensive reassessment. The energy sector's shift toward renewable energy and electrification requires substantial investment and innovation to meet climate change targets.

3. Across submissions to the Commission's draft decision there were references to the Boston Consulting Group's (BCG) report *The Future is Electric*[1]. The report presents a decarbonisation roadmap for Aotearoa New Zealand's electricity sector. It highlights the need for substantial investment in distribution infrastructure. This amounts to $22 billion in the 2020s, to support electrification and prepare for increased electricity flows in the 2030s. The report also emphasises the importance of supportive policy and regulatory settings to facilitate the transition.

4. Frustratingly, the Commission's draft decision largely retains outdated IMs that are no longer suitable for the changing circumstances. The draft decision lacks dynamic

[1] Boston Consulting Group (BCG), *The Future is Electric*, Oct 2022 available here.

efficiency considerations that could foster efficient investment and innovation. It also overlooks essential elements like a financeability test, depreciation adjustments, and improvements to flexibility mechanisms. This cross-submission calls for the Commission to embrace changes in the IMs to support the energy sector's transition and the achievement of decarbonisation goals.

Issue	Vector recommendation
Process	The Commission needs to take on board the criticism it has received from almost all stakeholders on the IM process so it can learn for the Default Price-Quality Path (DPP) reset. It can achieve this by implementing longer consultation periods, better engagement with stakeholders, and decision-making backed by evidence.
Financeability	The Commission should add a financeability test to the IMs. This test would ensure that regulated suppliers have certainty that the regulatory regime will support the funding requirements so critical to support investment in the energy sector. With the significant investments needed for decarbonisation, having such a test would provide clarity to companies and facilitate the transition to a low-carbon future.
Cost of capital	The Commission should maintain regulatory certainty and keep the Weighted Average Cost of Capital (WACC) percentile for electricity distribution businesses (EDBs) and gas pipeline businesses (GPBs) at 67th.
Limit on price increases	The Commission should reconsider the arbitrary 10% limit for EDBs' revenue cap. A more flexible approach to revenue caps would better address the high inflationary environment and allow for better alignment with investment needs.
Indexation	The Commission should reconsider the practice of indexing the Regulatory Asset Bases (RABs) of both EDBs and GDBs. This indexing has resulted in large under and over-recovery of revenues due to the inherent difficulties in forecasting inflation 5-6 years out. Removing RAB indexation would provide more stable and predictable revenue streams for companies and remove substantial forecast errors bringing cash-flows forward at a time when investment in decarbonisation is critically required.
Uncertainty mechanisms	The Commission should embrace a full suite of flexibility mechanisms, similar to those used in other jurisdictions. This would support innovation and efficient investment decisions in the rapidly changing energy landscape.

B. Process and timescales

Vector information request

5. In July 2023, Vector requested information from the Commission on matters pertinent to the draft decision. As of the date of this cross submission we have only received part of the information requested. The information received was not provided in time for us to consider as part of our cross submission. Given some of the information is still to be received and the timing of the information already provided, Vector reserves the right to make supplementary submissions once we have had adequate time to consider the information from the Commission.

Extensions declined

6. When Electricity Networks Aotearoa (ENA), representing 27 electricity distribution businesses (EDBs), the Major Electricity User Group (MEUG), representing 14 large electricity users, and the Major Gas User Group (MGUG), representing 7[2] large gas users, all state to the Commission that the consultation period is not long enough – it is hugely disappointing that no extension was granted.

7. In response to the ENA's extension request the Commission stated that no new topics had been raised in the draft decision and that the issues were known to stakeholders. We challenge this statement as many key draft decisions were not consulted on or even forewarned. For example, reducing the WACC percentile (for GDBs in particular) and introducing a new and complex debt wash-up mechanism.

Lack of engagement

8. Upon reading the correspondence between the Commission and MGUG[3] we were shocked to see that the Commission had declined to meet with the consumer group because "it would not be consistent with a fair process" for them to meet with a particular interested person (such as MGUG) to discuss their draft decisions.

9. This does not seem reasonable given the purpose of the meeting for MGUG was not to discuss the draft decisions, instead understanding the process behind the Commission's decision-making:

   a. *"To have a better understanding of Comcom's internal reasoning and decision-making processes under IM and DPP reviews; and*

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[2] Latest figure available from Google search

[3] Commerce Commission, *IM Review letter to Major Gas Users Group (MGUG),* 16 June 2023, p2

b. *How to build more effective dialogue."*[4]

10. Further to the lack of engagement in this process, there was a distinct lack of evidence also.

Inadequacies in the Commission's process

11. We are very concerned about the inadequacies in the Commission's IM review processes. The Commission is proposing to make very significant changes to the IMs, which will affect the ability of regulated suppliers to attract capital and deliver future investments, on the basis of limited evidence, analysis, and discussion.

12. There are several examples of this, principally:

    a. the Commission introducing a complex debt cost wash-up mechanism which could result in significant revenue and price volatility without any previous papers or discussions proposing such a mechanism and no consideration / evaluation of alternative approaches to what the Commission was proposing;

    b. the Commission's draft decision to adopt an asset beta for airports based on a comparator sample that excludes most of the listed airport stocks used to estimate the asset beta in 2010 and 2016;

    c. the Commission's draft decision to adopt a midpoint WACC for gas pipeline businesses; and

    d. the Commission's draft decision not to allow EDBs the option for an un-indexed RAB.

13. In summary, we are concerned that:

    a. the Commission has failed to apply its own decision-making framework;

    b. the draft decisions are unsupported, or minimally supported, by expert advice;

    c. the Commission's reasoning and justification for its draft decisions is inadequate; and

    d. the Commission's emerging views phase did not offer a meaningful opportunity to engage.

14. We elaborate on these concerns below.

Commission has failed to apply its own decision-making framework

[4] Major Gas Users Group (MGUG) Email attachment, *Meeting our new chair*, 16 June 2023 p.1

15. In late 2022 the Commission published a paper outlining the decision-making framework it proposed to apply in the IM review. We have relied on a legitimate expectation that the Commission would apply its decision-making framework in conducting the IM review and have approached our submissions on that basis.

16. The Commission explained that, in identifying which IMs to consider changing, and in reaching decisions on changing IMs, it would be guided by three overarching objectives: (i) to promote the s 52A purpose more effectively, (ii) to promote the s 52R purpose more effectively, and (iii) to significantly reduce compliance costs, regulatory costs or complexity. In deciding whether or not to review and change an IM, the Commission said it would consider:[5]

    a. whether the policy intent behind the IM remains relevant and appropriate, having regard to, for example, the objective of the IM, the relevance of the policy intent, evidence suggesting the original policy decision is no longer appropriate, or changes in external circumstances;

    b. whether the current IM is still achieving the policy intent, having regard to any changes in external circumstances, challenges to the effectiveness of the IM, or new evidence;

    c. whether the current IM could be improved to better achieve the policy intent, with regarding to changes identified by stakeholders, a court or the Commission, changes in external circumstances or new evidence; and

    d. whether the current IM could be improved to better achieve certainty under s 52R or reduce complexity or compliance costs.

17. As Wellington International Airport Limited discusses in its submission on the draft decisions:[6]

    "The key point that emerges from that description is that the Commission does not change an IM simply because it now prefers a different choice amongst the several options that were reasonably available to it when it made its original decision. In order to change the IMs, the Commission must be satisfied that the change is justified with reference to a shift in policy, effectiveness, evidence, or external circumstances."

18. We agree with that characterisation. When the Commission changes an IM, it should be able to point to some new evidence, change in circumstances, or other justification that justifies taking a different approach. Otherwise, the IMs lack the predictability and stability

[5] Page 39 and following.

[6] Wellington International Airport Limited, *Submission on 2023 Input Methodologies Review Draft Decisions* (19 July 2023) at paragraph 32.

over multiple regulatory periods that suppliers and investors require in order to confidently invest.[7]

19. In a number of instances, the Commission appears to have simply reversed a long-held position without reference to any new evidence or change in circumstances. The most glaring example is the Commission's decision to adopt a midpoint WACC for gas pipelines, which is not justified with reference to any new evidence (a fact the Commission itself acknowledges in its draft reasons). The Commission explains that its original decision to adopt the 67th percentile for gas was based on the loss analysis it undertook for electricity distribution and transmission. The Commission now says that evidence does not provide a sufficient basis for an uplift for gas pipelines. But the Commission has not undertaken any specific analysis of the case for an uplift for gas pipelines. Rather, it has simply reversed its earlier position without undertaking any further analysis.

20. The choice of WACC percentile is highly influential in investor's decision-making. By simply changing its mind, the Commission signals to investors that critical regulatory settings are subject to the individual views of Commission personnel from time to time, rather than updated economic theory, new evidence or changed circumstances.

Draft decisions are unsupported by expert evidence

21. The original IMs decisions in 2010 were extensively supported by expert evidence provided by independent experts instructed by both the Commission and submitters. The draft decisions in the 2023 IM review are notable for the absence of expert support. The draft decisions lack both a sound theoretical underpinning and any serious empirical analysis.

22. Regulated suppliers have had to fill that gap through the submission process. Vector has provided extensive expert evidence setting out the flaws in the Commission's reasoning. A number of other submitters have also provided expert evidence. The net result is an emerging consensus that the Commission's draft decisions are, in many respects, poorly justified with reference to accepted economic theory and lacking in empirical support.

23. For example, in response to the Commission's draft decision to narrow the comparator sample used to determine airport betas and exclude the Covid-19 affected period from the sample, airlines have provided extensive expert evidence from CEG, HoustonKemp and Incenta. In response to the Commission's draft decision on WACC percentile for gas pipelines (which is not supported by any evidence or analysis), we have instructed Oxera to provide expert evidence.

24. The Commission appears to have deliberately eschewed any opportunity to obtain independent expert advice in relation to its draft decisions. For example, it instructed CEPA to update its asset beta estimates using its existing methodology, but specifically instructed CEPA not to advise on the methodology itself. The Commission instead relied on three

[7] A proposition acknowledged by the Commission in its decision-making framework paper at paragraph 2.24.

paragraphs of discussion from TDB suggesting alternative approaches to asset beta to support a radical shift in the Commission's approach. As CEG's report shows, not only is the Commission's reasoning flawed, but its implementation is also inconsistent.

25. The Commission appears not to have approached its long-time expert Dr Martin Lally to assist with its revisions to the cost of capital methodology. Notwithstanding, Dr Lally has made a submission – unsolicited – which explains the errors in the Commission's approach to accounting for the impact of Covid-19 on asset beta.

26. FirstGas dedicated a whole section of their submission to "no new evidence justifying a change to approach[8]." This was in relation to the Commission reducing the WACC percentile to midpoint for GDBs.

> *"The Commission's decision-making framework explains that the Commission will only change an IM where a change is justified. It follows that the Commission should not change an IM – particularly an IM as critical to investor expectations as the WACC IM – simply because it has reviewed the evidence that was available to it in 2010 and 2014 and has now formed a different view. That undermines the predictability and stability that is essential to the maintenance of investment incentives."*

27. In a similar vein, Transpower[9] (and others) describe the same lack of evidence for the reduction of the EDB and Transpower percentile to 65th.

> *"We do not consider the Commission has presented compelling evidence as to why the 65th percentile better promotes the Part 4 objective when compared to the status quo (the 67th percentile), especially alongside the second overarching objective for the IM Review being promotion of the IM purpose in section 52R more effectively."*

28. In relation to the draft decision of Asset Beta for New Zealand airports, Competition Economists Group (CEG)[10] have given a scathing description of the Commission's engagement with expert evidence:

> *"The draft decision implements the following departures from regulatory precedent without any expert evidence in support and, often, in conflict with the expert evidence it has received (including from its own experts)."*

Commission's reasoning and justification is inadequate

29. The Commission is proposing major shifts in key elements of the IMs on the basis of minimal and often unpersuasive reasoning. For example, the Commission's discussion for adopting a midpoint percentile WACC for gas pipelines occupies three and a half pages in a topic

[8] FirstGas Ltd, *Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.13-14

[9] Transpower Ltd, *Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.34

[10] NZ Airports Association, *CEG Critique of 2023 IM Draft Decision on Asset Beta for NZ Airports*, 19 July 2023

paper of 179 pages. The reasoning offered is not persuasive. The Commission says that its decision to use a midpoint WACC for gas is primarily based on:[11]

a. the expected differences in the costs of outages; and

b. the differences in reliability.

30. However, the Commission also acknowledges that it has "no empirical basis for estimating a magnitude" and merely "expects" that the cost of outages will be lower for gas users than for electricity users.[12] FirstGas' submission explains in detail why this is an unsafe assumption.

31. The Commission's analysis of the differences in reliability is based on comparative SAIDI and SAIFI figures, which the Commission says "point to engineering differences that were not accounted for in our previous decisions".[13] However, again, the Commission has neither investigated these differences, nor has it considered whether comparative SAIDI and SAIFI results are a reasonable measure of differences in reliability or the effects of outages. As FirstGas has explained, the Commission's conclusion does not follow from its brief overview of SAIDI and SAIFI outcomes.

32. The Commission appears to have justified its draft decision to index Transpower's RAB, and not to allow an unindexed RAB for EDBs, by reframing its original reasons not to index Transpower's RAB. The Commission's 2010 reasons paper explained that "the level of Transpower's investments will result in it having, relative to other lines businesses, high investment programme funding requirements" and that not indexing Transpower's RAB would result in a "level of revenue…likely to be better matched to Transpower's investment needs".[14] We explained that this rationale now applies to EDBs, which face significantly increased investment needs in the future, which can be more readily financed with an unindexed RAB that does not defer cashflows into the future.

33. However, the Commission now argues that its original decision not to index Transpower's RAB was because Transpower's post-glide path capex was "catch-up" investment, as opposed to investment to meet future demand. We cannot see any reference to that rationale in the Commission's 2010 decision. Moreover, a supplier's investment needs are indifferent to whether capex is serving current demand or future demand.

34. The inadequacy of the Commission's reasons in support of its draft decisions is particularly relevant because the Commission is proposing to reverse its own decisions and reasoning from prior determinations. Those decisions and reasoning were more extensively supported

[11] Para 6.113.

[12] Para 6.106.

[13] Para 6.112.

[14] 2010 Reasons Paper at para 3.69.

with evidence and analysis, and so cannot be reversed based on such minimal discussion and justification.

New matters of substance

35. Given the lack of evidence provided for key decisions the Commission may be minded to now procure expert analysis and evidence post its draft decision. We stress the importance of any new evidence procured by the Commission between its draft and final decisions be made available to stakeholders and consulted on.

36. Vector cautions against a repeat of what occurred in the 2010 IMs process, where we understand that the Commission instructed experts to provide advice to them after the draft decision but that these reports were only published at the same time as final decisions were made public. These reports contained expert advice on a range of matters and reviewed submissions which had been made to the Commission on its draft IM determinations. We are also aware that stakeholders in 2010 subsequent to the final decision provided reports on the Commission's new expert reports, which the Commission declined to consider. We are strongly of the view that all parties will want to avoid such a situation occurring again in 2023.

Emerging views phase did not offer a meaningful opportunity to engage

37. The Commission allowed five weeks for submissions and two weeks for cross-submissions. This might have been an acceptable period of time had the Commission engaged with submitters on key aspects of its draft decisions during the emerging views and workshop phase of the review, but it chose not to. We were surprised that the draft decisions proposed such significant changes to fundamental elements of the regulatory framework without more engagement earlier in the process. For example, the Commission could have conducted workshops on the significant changes it is proposing to the WACC IM and the introduction of a brand-new debt cost wash-up mechanism. Instead, suppliers' only opportunity to engage with the Commission's proposals in any detail is in response to the draft decisions.

38. Moreover, because the Commission has offered minimal supporting evidence, and in many places has not clearly explained its reasons, it has been challenging for suppliers to meaningfully engage with the Commission's draft decisions in the limited time available.

Unison's section 54q reasoning

39. Vector places strong support behind Unison's[15] interpretation of s 54q below.

> *"The Commission has not read s 54Q and s 52A consistently, nor has it demonstrated why the sections conflict such that s 54Q must be subordinated. In our opinion, the correct interpretation accepts that the regulatory mechanisms under Part 4 must both:*

[15] Unison, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023 p.11

a) protect the s 52A outcomes (including limiting excessive profits); and

b) ensure there are no disincentives to invest in energy efficiency, demand-side solutions and reducing energy losses (as a subcomponent of s 52A(a) and (b) incentivising efficiency and innovation), as well as promote incentives in those s 54Q matters.

To meet the s 52A purpose and appropriately balance the listed outcomes, the Draft IM Decisions need to ensure there are genuine incentives to invest and resolve the disincentives to invest, in accordance with s 54Q."

40. To conclude on process, we urge the Commission to learn from the IM process and make concerted improvements ahead of the DPP reset:

    a. Longer consultation periods for Issues Papers and Draft Decisions (if that means starting the consultations earlier to fit the Commission's timeline then it should do that);

    b. Better engagement with stakeholders – it is refreshing to see this has started in the DPP process via the Asset Management Plan (AMP) meetings already held in 2023;

    c. That when proposing changes, the Commission shows the alternatives it has considered and why it considers its proposal is preferred;

    d. Robust evidence for decision-making – we need to see decisions are backed up by data and/ or independent expert advice; and

    e. Ensure there are genuine incentives to invest and resolve the disincentives to invest, in accordance with s 54Q.

C. Cost of capital

WACC percentile for GDBs

41. The arguments brought forward by stakeholders agreeing with the Commission lowering the WACC percentile for gas pipeline businesses (GPBs) are inadequate. None of these stakeholders bring any new evidence to support the proposal.

42. MGUG[16] makes a list of all the decisions it "variously supports" which includes applying the midpoint WACC i.e. 50th percentile. But as described by MGUG themselves, it does

[16] Major Gas Users Group, *MGUG Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.2

not further comment on those matters because it is “not confident that it fully understands all the reasoning or their materiality in application.”

43. Meanwhile Methanex[17] states that it:

“[…] supports reducing the WACC percentile for GDPs from the 67th percentile to the 50th percentile as there is no compelling reason to use a WACC for gas distribution businesses that is anything other than the Commission’s best estimate of the true cost of capital.”

44. We are not alone in disagreeing with Methanex’s viewpoint and instead agree with PowerCo[18]:

“*The draft decision for using the midpoint percentile of WACC for gas is not well evidenced, with no empirical evidence and reasoning for what has changed since the 2014/2016 decisions.”*

45. Methanex has provided its reasoning below:[19]

“[…] that deviating from the mean WACC percentile to address a perceived investment asymmetry is of dubious merit in general, as measuring the degree of asymmetry and determining the appropriate response is difficult. The primary drivers of asset integrity spend should be the quality standards and the consequent penalties for breaching these. For GPBs, the case for a percentile uplift is particularly weak, given it is based on analysis done for electricity distribution.”

46. In response to Methanex, we refer to Oxera’s report[20] which provides new reasoning why the materially better WACC uplift should be maintained including:

    a. The costs associated with gas outages (not examined by the Commission in consideration of this change);

    b. The fact that GPBs have lower regulatory asset bases (RABs) than EDBs (relevant in the context of the Commission’s loss analysis framework); and

    c. The other potential downsides of underinvestment in gas:

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

[17] Methanex, *Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.2

[18] PowerCo, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023 p.10

[19] Methanex, *Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.3

[20] Oxera, *Response to Commission’s draft decision for IM Review 2023 on the cost of capital relating to gas sector,* 19 July 2023 p.2-4

- Decarbonisation costs of delaying the transition to renewable gases; and

- Preventing an orderly transition: a successful transition to a low-carbon system requires a coordinated approach among different parties.

47. We reiterate a point made by FirstGas[21] on evidence and regulatory stability with reference to the s 52A purpose which we support.

> *"[…] the Commission should only amend the WACC IM with adequate justification and evidence supporting the need for change. The predictability that is needed to maintain investment incentives requires the Commission to properly explain, justify and support with evidence a proposed change in the WACC IM. Conversely, the Commission undermines investment incentives if it simply changes its mind on a matter on which it has previously opined without reference to a change in policy, evidence, or circumstances."*

WACC percentile for EDBs

48. Both Contact and MEUG call upon the Commission to reduce the WACC percentile for EDBs by even more than the draft decision proposed. Contact advocates for the application of the 60th percentile[22]. MEUG goes further and proposes the selection of the mid-point[23]. The analysis the parties rely upon to support these positions is either superficial or, in some cases, plainly wrong. MEUG's submission begins with a bewildering statement that: "By maintaining WACC above the true cost of capital, consumers will continue to pay more for electricity than we consider is reasonable."[24] Whilst technically true, this declaration is nonetheless nonsensical since nobody knows the true cost of capital.

49. Obviously, if we knew the true cost of capital, it would not need to be estimated. The uncertainty surrounding the true value of the WACC is what prompted the Commission to introduce an uplift in the first place. Because the adverse costs of inadvertently underestimating the true cost of capital substantially exceed those of overestimation it is in consumers' long-term interests to have an uplift – even if it means paying more than they would at a lower percentile. MEUG seems to be conflating the mid-point estimate with the true WACC. That is clearly incorrect as a matter of finance theory.

50. Other arguments offered by Contact[25] and MEUG[26] are equally unpersuasive:

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[21] FirstGas Ltd, *Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.2

[22] Contact Energy, *2023 Input Methodologies Review – Draft Decision, Contact Energy Submission*, 19 July 2023, p.13.

[23] Major Electricity Users Group, *Draft decisions: Part 4 Input Methodologies Review 2023*, 19 July 2023, p.2.

[24] *Ibid*.

[25] Contact Energy, *2023 Input Methodologies Review – Draft Decision, Contact Energy Submission*, 19 July 2023, pp.12-13.

[26] Major Electricity Users Group, *Draft decisions: Part 4 Input Methodologies Review 2023*, 19 July 2023, pp.2-4.

- MEUG's claim that the Commission has assembled a considerable body of evidence from independent experts ignores the fact that this analysis has been comprehensively rebuked by an even larger body of evidence prepared by experts commissioned by lines businesses. Among them is the architect of the WACC percentile framework, Oxera, which has advised explicitly against reducing the percentile and explained in exacting detail why the Commission's experts (and its draft decision) are erroneous.

- The contention by MEUG and Contact that the Commission now has 'better tools' at its disposal to guard against underinvestment is similarly misplaced. All the measures they identify were available in 2014. They are not new – they were in situ when the Commission first shifted to the 67th percentile. Why then would these old tools suddenly prove so much more effective at mitigating the even greater potential costs EDBs are likely to face in years ahead? Neither MEUG nor Contact explains.

- Contact states that the lower bound of the loss model has shifted from the 60th percentile in the 2014 calculation to the 55th in the updated calculations and suggests this supports adoption of a yet lower percentile. Both Oxera and CEG explain in their reports why this is wrong. Oxera also highlights the obvious downward bias that is introduced into the Commission's approach through the coupling of the lower bound of the cost estimate ($1 billion) with an estimate below the mid-point of the range.

- Contact's assertion that New Zealand's experience applying the 50th percentile in other contexts should give the Commission comfort that underinvestment would not occur is equally mysterious. The conditions in which the midpoint has been applied in regulatory settings previously in New Zealand bear no resemblance whatsoever to the circumstances currently facing EDBs. There is therefore nothing useful to be gleaned from examining outcomes in those other sectors; namely:

    a. The three monitored airports operate under dual till arrangements that serve to maintain their incentives to invest even though the 'information disclosure' WACC for regulated aeronautical services is set at the midpoint[27]. There are no equivalent complementarities between regulated and unregulated services for EDBs; and

    b. Chorus' circumstances are similarly distinguishable. EDBs must maintain their ageing assets and are facing the prospects of spending billions more of new investment that have not yet happened. Chorus fibre network is brand new and

[27] For example, consider a terminal expansion. If the information disclosure WACC is set at the mid-point, this may reduce the revenues that a monitored airport may be able to report under the regime relative to a higher percentile. However, investing in a terminal may give rise to other sources of *unregulated* revenue, e.g., from carparking, retail concessions, etc. Those additional revenues from the 'unregulated till' may reduce or eliminate entirely any incentives airports might otherwise have to underinvest. There is no parallel here whatsoever to the electricity distribution sector.

completed. It is precisely because of these differences a lower percentile was applied to Chorus.

- It is not obvious why the Commission undertaking enforcement action to enforce quality breaches would have a material bearing on the selection of the WACC percentile, in the manner implied by Contact. The threat of enforcement action has been present ever since the IMs were first introduced and EDBs have been well-aware of the potential for it to be exercised. It is unclear why businesses would suddenly change their conduct significantly simply because those provisions have been enforced.

- MEUG's contention that the Commission's "reasonableness checks" point to no problems under the status quo overlooks their manifest unreasonableness. Three RAB multiples – only one of which is based on an actual market transaction – cannot reveal anything meaningful about the WACC percentile. The superficial analysis of Vector's recent credit rating upgrade is also completely irrelevant. Oxera has proposed an alternative approach to assessing reasonableness that is infinitely preferable.

51. More fundamentally, neither Contact nor MEUG explain how consumers would benefit from a reduced WACC percentile (and, in turn, diminished incentives to invest) when EDBs are facing profound resilience challenges and unprecedented levels of capital expenditure. Vector has faced two network-threatening events since the beginning of the year and these types of disruptions could well be the 'new normal.' This hardly seems like the appropriate time to risk EDBs skimping on reliability and resilience spending. Contact and MEUG also ignore completely the profound asymmetric consequences associated with investments in electrification. This factor alone warrants a sizeable uplift in the WACC percentile and provides a materially better outcome for EDBs to transition towards net zero while facing these resilience challenges.

RFR period

52. EDBs and Transpower[28] continue to support a "trailing average approach" for the risk-free rate.

> *"We continue to advocate for the "trailing average approach" noting that the Commission agrees that "the efficient debt financing strategy of a supplier is to issue debt with staggered maturity dates to minimise the potentially significant refinancing risk associated with having to refinance a large portion of debt at any one point in time"."*

[28] Transpower, *Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.35

53. Vector has submitted a memo by Dr Schmalensee[29] in response to Dr Lally's commentary on the appropriate tenor to be used to estimate the risk-free rate and got Oxera[30] to comment on its implications.

54. Oxera concludes that:

> *"Dr Schmalensee agrees that there is no academic evidence that the tenor to be used for the risk-free rate (RFR) estimation needs to match the length of the price control."*

55. Vector therefore maintains our recommendation for longer tenors (this is a materially better outcome because it is supported by regulatory precedent, and takes into account the indefinite maturity of equity financing within the context of long-lived network asset investments).

Asset beta

56. MGUG[31] insists that the beta uplift for GPBs is not warranted:

> *"The current evidence provided in the CEPA report doesn't justify asset beta uplift for GPBs. It combines the already weak case for the current uplift decided in 2016, with the two other pieces of information from CEPA's work showing that no uplift is needed (i.e., high degree of confidence interval overlap, and Vector's asset beta being considerably lower than the recommended energy asset beta)."*

57. However, Oxera[32] points towards the Commission's own estimates which support an uplift above 0.05 and nearer to 0.10.

> *"These [the Commission's] estimates are closer to the 0.1 that the NZCC applied in the 2010 IMs, than to the 0.05 uplift that the NZCC applied in the 2016 IMs and proposed for the 2023 IMs.*
>
> *We do not find the NZCC's evidence supportive of an uplift of 0.05, as both estimates of the differences between gas-specific and energy asset betas that the NZCC considers are higher than 0.05.*
>
> *Therefore, we find the NZCC's considerations inconsistent, and consider that the evidence it provides supports an uplift that is closer to 0.1 rather than 0.05."*

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[29] Dr Schmalensee, *Memorandum* 31st July 2023

[30] Oxera, *Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital (cross-submissions stage),* 8 August 2023

[31] Major Gas Users Group, *MGUG Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.4

[32] Oxera, *Response to Commission's draft decision for IM Review 2023 on the cost of capital relating to gas sector,* 19 July 2023 p.13

58. To explain this further FirstGas[33] points to CEPA's analysis and concludes:

"CEPA notes that the difference between the asset betas for the electricity and gas samples is generally greater than 0.05 and recommends that the beta for gas should be higher than that for electricity, with a difference greater than 0.05 between the two betas. The Commission highlights that the average asset beta value of the gas subsample for the most recent two five-year periods is 0.12 higher than the energy beta. However, when excluding the firm ONEOK from the sample, the difference reduces to 0.08."

59. Given that the Commission, CEPA and Oxera all assume a beta greater than 0.05, Vector supports an uplift between 0.05 and 0.10.

60. Dr Lally[34] has published a follow-up paper on the treatment of the Covid-19 period for the estimation of asset beta. Specifically, this follow-up paper describes and compares two alternative adjustments for data during the Covid-19 period.

61. The first approach, as adopted by the Commission in the draft decision, estimates conditional betas for Covid-19 and non-Covid-19 periods separately and arrives at a single beta using probability-based weights for the two periods.

62. The second approach, as preferred by Flint (2021) and TDB (2023), applies probability-based weights to the share price data during Covid-19 and non-Covid-19 periods to generate a single beta estimate.

63. Vector asked Oxera[35] to review Dr Lally's additional paper. While they do not comment specifically on Dr Lally's conclusion, Oxera's report (provided alongside this submission) points out that he does not address the issues raised by Oxera's response[36] to the draft decision. We summarise their concerns below:

- *"Although the NZCC follows regulatory precedent from the UK aviation sector (i.e. Flint (2021)) in its approach to the Covid-19 returns treatment, this approach is currently under appeal, and it is against many other regulatory precedents;*

- *the NZCC's estimate is sensitive to the assumptions about the length and frequency of the pandemic-like events; the NZCC has not evidenced what the length and frequency of the modelled pandemic period should be;*

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[33] FirstGas Ltd, *Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.32-33

[34] M. Lally (2023), *The impact of future Covid scenarios on beta*, 22 June 2023

[35] Oxera, *Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital (cross-submissions stage),* 8 August 2023

[36] Big 6 EDBs, *Oxera's Response to Commission's draft decision for IM Review 2023 on cost of capital*, 19 July 2023

- *while being sensitive to the assumptions on the length and frequency of the pandemic-like events, the NZCC's estimate is even more sensitive to the choice of the assumptions on representative pandemic and non-pandemic periods;*
- *the NZCC double-counts the impact of the pre-pandemic asset beta estimate;*
- *the NZCC does not explain its choice of the point estimate within the range;*
- *as a result of the approach it has taken in its DD, the NZCC introduces a large degree of subjectivity that undermines the robustness of the analysis and introduces regulatory risk;*
- *using the NZCC's standard approach (i.e. the approach used prior to this DD) would apply the same treatment to the observations during the* Covid*-19 pandemic, which is a common approach to allowing for outliers that contain important information about market risk."*

Debt premium

64. In its report for the ENA on cost of capital, CEG[37] suggests adopting "a longer benchmark tenor assumption (e.g., 10 years) to reduce the magnitude of the bias".

65. In their latest report reviewing submissions, Oxera concurs with CEG's assessment, they state:

> *"We have not examined the issue of debt betas in relation to the NZCC regime but we agree that the market data for the New Zealand energy networks supports a debt tenor assumption of longer than five years, with the weighted average debt tenor at issuance being 7.25 years across the industry, as per the NZCC's assessment."*

66. Vector insists that the Commission follows CEG's recommendation for longer-term debt to be used to estimate the allowed debt premium.

Equity raising costs

67. CEG[38] criticises the Commission for calling for more submissions on how to accurately model equity raising costs in the fact of potentially high RAB growth due to electrification.

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[37] ENA, *CEG Response to 2023 IM draft decision on cost of capital*, 19 July 2023, p.21

[38] ENA, *CEG Response to 2023 IM draft decision on cost of capital*, 19 July 2023, p.2

"We gave the NZCC a fully functioning model of how we thought equity raising costs should be estimated. The draft decision was the correct time for the NZCC to explain why it did not agree with any aspects of that model and to propose an alternative."

68. Vector suggests that the Commission reviews and adopts the CEG model or at least suggests an alternative for consultation ahead of the final decisions.

Tax-adjusted market risk premium (TAMRP)

69. Oxera[39] also derived some conclusions around its method for estimating TAMRP, based on Chorus's[40] submission on this subject.

"In the context of estimating the allowed tax-adjusted market risk premium (TAMRP), the Chorus submission reinforces our recommendation of putting more weight on the Siegel II model."

TCSD

70. Although CEG[41] and Oxera[42] take different approaches to examining the Commission's approach, both CEG's and Oxera's analysis of the TCSD support higher estimates. Different approaches by different experts demonstrate that the Commission's TCSD estimate is too low with reference to the market data.

D. RAB indexation and financeability

71. Contact and MEUG each support the Commissions' draft decision to continue with RAB indexation for EDBs. Contact's submission is devoid of any analysis; it simply agrees with the draft decision and urges the Commission to: "hold firm against the likely mountain of pages that EDBs will write on the topic in their submissions."[43] This plea is highly irregular. As it happens, the Commission did receive a "mountain of evidence" on this topic, including detailed reports from multiple independent experts. We have the utmost confidence the Commission will engage fulsomely with that material with an open mind and ignore Contact's (quite extraordinary) request for it to predetermine an outcome.

72. For its part, MEUG includes a token analysis of the points usually proffered in support of indexation: safeguarding against inflation risk and promoting more efficient price profiles. These matters were dealt with comprehensively in our initial submission. In summary, the

[39] Oxera, *Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital (cross-submissions stage),* 8 August 2023, p.3

[40] Chorus, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.3

[41] ENA, *CEG Response to 2023 IM draft decision on cost of capital,* 19 July 2023

[42] Big 6 EDBs, *Oxera's Response to Commission's draft decision for IM Review 2023 on cost of capital*, 19 July 2023

[43] Contact Energy, *2023 Input Methodologies Review – Draft Decision, Contact Energy Submission*, 19 July 2023, p.13.

Commission's inflation forecasting approach has been poor and nothing in the draft decision would improve it. Indexation has simply replaced one source of risk (inflation) with another (inflation forecasting). And as we explained earlier, any allocative inefficiencies arising from near-term price increases must be weighed against the vast benefits associated with the materially better outcome of ensuring EBDs are able to fund investments enabling rapid electrification.

73. While PowerCo[44] has lent its support to un-indexation of GDBs RAB, it favours indexation of EDBs' RAB.

"Electricity: Support the decision as it shifts cost recovery to the future when the consensus is that electricity demand will be higher. For example, scenario modelling by the Business Energy Council indicates electricity generation/consumption will almost double by 2060 as part of the economy's transition to net-zero in 2050."

74. Vector refutes this; the investment requirement comes before the consumption increase and will require funding. Un-indexation will help to meet the funding requirement.

75. Frontier Economics[45]' analysis on behalf of Transpower on this issue has reviewed the Commission's rationale behind its 2010 decision for not indexing Transpower's RAB. They outline two key points behind their reasoning:

   a. *"A very significant amount of capital expenditure is required, relative to the existing RAB; and*

   b. *Expenditure is required in advance of commissioning."*

76. Transpower[46] explains as follows:

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

77. Frontier, Transpower and Vector argue that Transpower and EDBs are in precisely the same situation now and therefore we remain adamant that un-indexation of our RABs is the better option.

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[44] PowerCo, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.7

[45] Transpower Ltd, Frontier Economics, *RAB Indexation Submission on IM Review 2023 Draft Decisions*, 19 July 2023

[46] Transpower, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.2

78. However, if the Commission is reluctant then Vector advocates a hybrid approach for EDBs in the same vein as Transpower[47] have called for:

"Notwithstanding our strong preference for the status quo, if the Commission's final decision is to index our RAB, we consider a hybrid approach, where only the equity component of the RAB is indexed, better promotes the section 52A purpose of Part 4. This is because it better matches our revenue to the nominal interest payments we need to make on our debt. A hybrid approach also better resolves for the debt compensation issue identified by the Commission."

79. This leads to the question of financeability. It is made apparent from submissions that network companies are concerned with levels of investment required for decarbonisation.

80. Moving to a nominal return framework and/or adopting more front-loaded depreciation methodologies would significantly enhance the likelihood our net zero objectives being achieved.

81. 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.

82. Meanwhile 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.

83. Vector disagrees strongly with the submissions supporting the status quo on indexation for EDBs and GDBs. We continue to support removing indexation and adopting more frontloaded depreciation.

84. Additionally, the six largest EDBs all support a financeability test being introduced. We are discouraged at the Commission's refusal 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 enable the funding requirements to underpin the investments required to enable our decarbonised future. The reality is that the Commission's ability to forecast inflation has been extremely poor. It is not appropriate for consumers and suppliers to bear the risk brought about by the Commission's inaccurate inflation forecasts. The obvious answer is as recommended by Motu[48] in removing the forecasting inflation risk from the equation.

85. Vector reiterates to the Commission that it must set out its views on how it would:

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[47] Ibid, p.2-3

[48] Motu, *Response to the Commerce Commission report review on the problem of forecasting inflation*, 13 July 2023, p.3

a. assess whether a financeability problem exists; and

b. how it would remedy any such problem.

86. Vector considers that materially better 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.

E. Inflation risk

Debt wash-up mechanism

87. The Commission states that they are proposing the debt wash-up mechanism to deal with the debt compensation issue. Many submitters expressed concern that this had not been forewarned previously in the Commission's IM review process and many suppliers were concerned they had not been given adequate time to consider its implications.

88. These concerns would appear warranted as what the Commission is proposing will lead to revenue volatility for suppliers and price volatility for consumers / retailers. Furthermore, the proposed mechanism exacerbates the financeability issues raised in the previous section (and at length by Vector and other EDBs in previous submissions). Also, the Commission's proposed mechanism is heroically assuming that suppliers can fully hedge their debt costs.

89. Vector asked both Oxera[49] and CEG[50] to review the Commission's new debt wash-up mechanism in particular to assess whether or not it solved the 'debt compensation issue'.

90. Oxera make a number of conclusions about the proposed mechanism:

> *"We have reviewed the NZCC's proposed cost of debt wash-up adjustment and observe that stakeholders have used the term 'debt compensation issue' to define two different phenomena. One is about cash flows being backloaded as part of the NZCC's price–quality path regulation model. The other is about the deviation of the actual inflation rate from the forecast inflation rate as expected at the start of the regulatory period, and the impact of this deviation on the cost of debt compensation. The cost of debt wash-up adjustment is focused on addressing the latter, but not the former definition of the 'debt compensation issue'."*

91. They also find inconsistencies between:

[49] Oxera, *Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital (cross-submissions stage),* 8 August 2023, p.1

[50] CEG, *NZCC proposed approach to targeting a nominal return on debt*, 9 August 2023

a. the cost of debt wash-up adjustment formula and the Commission's allowed revenue financial modelling; and

b. the Commission's stylised demonstration model does not show NPV-neutrality in a baseline scenario. This observation implies that the NPV-neutrality test has not been calibrated appropriately.

92. Finally, they observe that:

"[…] the cost of debt wash-up adjustment may be introduced at a point in time where this is unfavourable for the networks. Examined over a longer period, the adjustment may be net present value (NPV)-negative for networks because they have previously been disadvantaged in environments with lower-than-expected inflation, and may not gain countervailing upside from future periods of potential higher-than-expected inflation, such that the losses and gains could balance out over time."

93. Meanwhile Tom Hird from CEG[51] has derived the same conclusions over the NPV neutrality of the mechanism.

"I do not consider that the draft decision's proposed approach to compensating for the nominal cost of debt will have an NPV=0 result. In order to ensure that this is the case, I consider that the NZCC should:

- *Clearly state the underlying debt management strategy that the EDB us assumed to be undertaking; and*

- *Include direct modelling of the cost of that strategy and derive the adjustment to revenues from that modelling."*

94. And the unanticipated swings in debt raising/ repayment:

"I note that by forcing the entire adjustment for inflation forecast error into revenues the NZCC proposed adjustment will mean that:

- *Unexpectedly low inflation can result in compensation for interest costs that materially exceed the actual interest costs paid by the EDB (with the surplus proceeds needing to be used by the EDB to retire debt in order to maintain target leverage).*

[51] CEG, *NZCC proposed approach to targeting a nominal return on debt*, 9 August 2023, p.11

- *Unexpectedly high inflation can result in negative compensation for interest costs – which is a corollary of the fact that the EDBs are expected to fund large (nominal) increases in their RAB."*

95. Dr Tom Hird warns the Commission that EDBs could face huge volatility in revenues and subsequently price changes for consumers:

*"I further note that these swings in return on capital can be expected to result in large, unexpected swings in revenues and prices paid by customers/retailers. Again, taking the example of a 7.3% inflation increase. If that reduces the cash return capital by 40% and the cash return on capital is 40% of total revenues then this implies a 16% reduction in revenues. The other 60% of building block costs (opex and return of capital) will rise by 5% more than expected (=1.073/1.02-1). Consequently, total revenues will fall by 13% (=16%-5%*60%)."*

96. He also notes that:

"[…] it is important to note that the NZCC's adjustment mechanism forces the supplier to raise high (low) levels of debt when there is unexpectedly high (low) inflation precisely because the NZCC adjustment reduces (raises) revenues in anticipation of unexpectedly high (low) compensation in the form of RAB growth."

97. Vector is unsure that the Commission is fully aware of the consequences of the proposed mechanism. We are also unsure if the Commission has considered how the mechanism would work with other mechanisms such as the revenue cap. We note that the Commission did not obtain input from experts in coming up with the proposed mechanism. This proposal put forward by the Commission is a perfect example of a topic that could have benefitted from a workshop of stakeholders, experts and the Commission. It could have at least warranted its own issues paper. Neither of these transpired.

98. The Commission must not rush into introducing it until all implications of it have been considered, all stakeholders are fully aware of its impacts, and the Commission shows that its proposal is materially better than the alternatives.

99. CEG proposes two materially better solutions to the Commission's approach:

- *Solution A. To roll-forward the RAB to the beginning of the next regulatory period using DPP forecast inflation applied to the debt portion of the RAB (while still using actual inflation applied to the equity portion of the RAB). This preserves the same expected profile of return of capital as the current regime; or*

- *Solution B. To simply do not index the debt portion of the RAB for inflation at all (i.e., neither for forecast inflation in the financial model nor actual inflation in the RAB roll-forward from one DPP to the next). This is the simplest solution to model but it does bring forward the profile of return of capital relative to the current regime.*

100. CEG points out that:

- *"Solutions A and B have the advantage to consumers and EDBs of providing much more stable revenues/prices.*

- *This is likely to be particularly important for EDB's facing the challenges of investing to achieve decarbonisation objectives. An EDB with an already challenging debt and equity raising profile would likely incur considerably higher costs (and be viewed by investors as riskier) under the NZCC's proposed solution.*

- *By way of illustration, an unexpected drop in revenues equal to circa 5.3% of the debt portfolio (associated with an inflation rate of 5.3% above forecast) would cause an equivalent and unexpected increase in required debt funding – precisely at a time when interest rates are likely to be high (due to unexpectedly high inflation)."*

101. Vector urges the Commission to reverse its decision to introduce the new debt wash-up mechanism and instead solves the debt compensation issue by removing indexation to EDBs' RABs (or at the least the debt funded portion of the RAB) i.e. CEG's Solution B. As Vector has previously submitted and expressed in this cross submission the best way to remove the inflation forecast risk is to remove the requirement to forecast inflation. History shows that the ability to forecast inflation accurately is not possible. Therefore, rather than burden consumers and suppliers with this forecast risk or try and incorporate mechanisms to correct the forecasting error, a simple solution is to no longer require inflation to be forecasted by moving to an unindexed RAB approach.

102. We disagree with Transpower's[52] acceptance of the exclusion of the return on debt from the annual revenue wash-up.

"This decision follows the underlying assumption that suppliers can hedge the risk-free component of the cost of debt for the duration of a regulatory period. Assuming a supplier can behave in this manner, then Transpower agrees that washing up the return on debt for actual inflation could produce windfall gains and losses to the extent that actual inflation does not follow forecast inflation. We consider the 'hybrid approach' better manages the debt compensation issue. It also provides the cashflows at a more appropriate time (i.e. when the debt needs to be serviced)."

103. Vector reiterates that the Commission failed to raise this new mechanism through proper consultation channels ahead of draft decisions (i.e. workshop or issues paper). The Commission also failed to share actual models to help demonstrate to stakeholders the workability of the wash-up changes.

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[52] Transpower, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.33

Inflation forecasting

104. Vector is not alone in criticising the Commission's decision to maintain its current approach to inflation forecasting.

105. GasNet[53] puts forward that there is "an argument for the NZCC to revise how it deals with inflation." They explain that:

"Regulation needs to be predictable and provide certainty, which may require the NZCC to be more flexible to ensure long term outcomes for consumers."

106. We concur with GasNet and also subscribe to the point made by Wellington Electricity[54]:

"We believe that more work needs to be done on exploring better forecast methods or methods of removing the need to forecast inflation. We don't think this issue should be left to the next IM review – it's a known issue that still needs to be resolved. We would support a residual work programme that follows on from the final IM decision."

107. Some submitters go a next step further and provide alternative methods for example GasNet suggests looking at the AER approach. Alpine Energy[55] proposes the following:

"We suggest the Commission further explores and tests various alternative approaches in forecasting CPI, especially the glide-path and survey approaches in estimating long term inflation projections. There are various alternatives that the Commission can consider as applied by regulators overseas."

108. And Electricity Networks Aotearoa[56] (ENA):

"As highlighted in ENA's submission on the cost of capital from March 202312, this single-point forecast risk can easily be mitigated by averaging the RBNZ forecast with a second forecast of inflation derived from the market expectation of inflation. ENA submits that the Commission should reassess its draft decision on the inflation forecasting method."

109. 15. Although Vector appreciates the intent behind these alternatives, we remain convinced with our previous submitted solution to this issue; rather than use the Reserve Bank forecasts, a materially better regulatory approach would be to remove the inflation uncertainty altogether and stop indexing EDBs and GDBs' RABs.

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[53] GasNet Ltd, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.8

[54] Wellington Electricity, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.23

[55] Alpine Energy Ltd, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.6

[56] Electricity Networks Aotearoa, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.14

F. Form of control

Revenue smoothing and limits to price increases for EDBs

110. The Major Electricity Users Group (MEUG) and several generator-retailers have resisted virtually any change to the IMs that might result in higher network prices. For example, there has been opposition to full pass-through of transmission charges, calls for even larger reductions to the WACC percentile and pleas to maintain indexation. Although it is no surprise to see generator-retailers and a user group for large industrial companies lobbying intensely in their submissions for measures that would constrain prices, the analysis relied upon to support those positions leaves a lot to be desired. Without exception, it is overly narrow, near-sighted and oblivious to electricity customers' long-term interests.

111. The reality is that suppliers must have sufficient cashflows to finance the investments required to enable rapid electrification and those critical upgrades will not happen (or will be delayed). If the Commission wants New Zealand to meet its decarbonisation goals, then someone ultimately has to pay for it. Some submitters seem to be labouring under the misimpression that EDBs should simply fund these investments out of their own pockets and be paid later (or not at all). Contact Energy claims that: "lines companies will be better placed to manage price volatility than will end customers" – a statement that has no evidential or rule basis.

112. It is in fact a euphemistic way of saying: "lines businesses should fund billions of dollars in new investments without prices increasing significantly". It would be nice if that were possible. But, of course, it is not. Like all commercial enterprises, EDBs are subject to the basic laws of economics. If costs go up; so too must revenues (if profit levels are to be maintained- noting that EDB profits are effectively regulated). If new investments are required; those outlays will need to be funded. If customers want more right now; then they must pay more right now. The submissions of MEUG and certain generator-retailers seem predicated on the misplaced belief that these immutable realities of commerce somehow do not apply to EDBs. But they do.

113. It is worth also remembering that the Part 4 purpose statement directs the Commission to promote outcomes consistent with those seen in workably competitive markets. In such markets, if the cost of supplying a service increases, then 100% of that uplift will be passed through to final prices. That is trite economics. There is no cap on the amount by which prices can increase, as anyone who has purchased a block of cheese recently could readily attest. We also cannot recall hearing any similar requests to manage the extent of any price reductions when interest rates were plummeting to unprecedented levels in prior periods. It would seem rather asymmetric and unprincipled to cap the upside but not the downside.

114. Furthermore, the regulated parts of the supply chain should not do all the heavy lifting on price impacts to consumers. Distributors charge retailers and therefore retailers can

mitigate costs on their consumers by not passing on those costs to their customers. Retailers could look to self-impose caps on end bill impacts in the interests of mitigating the consumer price shocks. Generator – retailers are possibly even better placed to do this as they have profited from the wholesale market spot prices being well above their investment and operating costs in recent times[57]. We note below that the Commission have stated that EDBs have not earned excessive profits[58]. Can the same be said of generator – retailers such as Contact Energy.[59]

115. Contact[60] also goes out of their way to relay their interpretation of gas network price increases:

> *"The price shock mechanisms the Commission has put in place are not having the desired effect. We have recently seen a price increase from First Gas for 2023/24 of over 30%, despite the 10% price shock limit. Similarly last year Vector gas had an almost 20% price increase for the 2022/23 year, significantly higher than the 7.7% revenue increase allowed by the Commission. Not only have these increases resulted in substantial price rises for end customers, but notification about them has also often come through so late that it has been a shock in every sense of the word."*

116. We can only comment for Vector but our increase for 2022/23 was due to the decision made by the Commission on accelerated depreciation[61], which meant that the timing of our revenues changed resulting in a price increase. We note that the acceleration of depreciation is neutral (NPV=0) to consumers in the long term.

117. Vector consulted with retailers on this change and offered to meet with Contact and others, but Contact declined to engage with us at the time. It is disappointing that they did not accept the opportunity of constructive engagement with us back then and instead have opted to criticise our price change in a formal submission.

118. It is worth reminding stakeholders at this stage that the Commission stated back in May's IM review process and issues paper[62] that "profitability across EDBs has been below our estimates of reasonable returns. EDBs have not been making excessive profits."

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[57] Noting that non-integrated retailers do not run capital-intensive businesses and may tend not to have the ability to absorb the cashflow implications, but integrated gen-tailers would be better placed

[58] Commerce Commission, *IM Review Process and Issues Paper*, 20 May 2022, para. 5.18, p.51

[59] The EPR final report included a recommendation to "Make generator-retailers release information about the profitability of their retailing activities" - https://www.mbie.govt.nz/assets/electricity-price-review-final-report.pdf

[60] Contact Energy, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.10

[61] Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2022*, 31 May 2022, p.12

[62] Commerce Commission, *IM Review Process and Issues Paper*, 20 May 2022, para. 5.18, p.51

119. In their submission, Meridian[63] have called on the Commission to take a greater role in communicating price increases to consumers.

> *"Where any step change in prices from 2025 is driven by regulatory decisions in respect of network companies, it seems reasonable to expect assistance in explaining the changes and the reasons for them. We hope to see more on the topic of consumer communication in the DPP and IPP reset processes."*

120. Vector would like to point out that in our annual letters to retailers on price changes for our electricity and gas distribution businesses, we have offered to help retailers communicate our price changes to their customers. To date no retailers have taken up our offer.

121. Affordability is a real issue considering the investment that will be required in the energy sector through to 2050. Quite possibly now is the time for regulators such as the Electricity Authority to look at retailer and generator pricing and to consider retailer and generator price caps like those that exist in other jurisdictions.

122. In other jurisdictions, retailers (not distributors) have a price cap. In Great Britain, the first energy price cap for default energy tariffs was introduced by Ofgem in 2019[64]. It was first introduced in response to rising concerns over fuel poverty and in order to protect consumers from volatile and in recent times - skyrocketing wholesale energy prices.

123. Ofgem's price cap protects over 11 million household energy customers, providing stability and ensuring they pay a fair price for their energy bills.

124. It prevents energy suppliers from charging whatever they want per kWh of energy used, while at the same time taking into account the real wholesale price, to prevent suppliers from purchasing energy at a higher price than they are selling.

125. As a reminder, Vector is 75% owned by Entrust, whose beneficiaries are electricity customers in the Entrust district, which comprises Auckland, Manukau, northern Papakura and eastern Franklin. Last year, 351,000 households and businesses received just over $300 each from Entrust. This injected $95.8 million into the Auckland economy.[65]

Revenue cap for GDBs

126. Gas distribution businesses (GDBs) are united in demanding the move away from a weighted average price cap (WAPC) to a materially better revenue cap mechanism.

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[63] Meridian, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023 p.2

[64] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/default-tariff-cap

[65] https://www.entrustnz.co.nz/news/news-and-media-releases/entrust-dividend-to-provide-some-relief-amid-high-cost-of-living/

127. PowerCo[66] recommends:

"[…] the Commission reconsider a revenue cap for gas networks for the reasons we and gas pipeline businesses have previously submitted on during the gas DPP reset."

128. GasNet[67] is of the view:

"[…] that incentives to grow connections under WAPC is no longer relevant, given climate change policies to phase out natural gas. A move to a revenue cap may therefore be more appropriate. However, GasNet is also of the view that irrespective of the form of control, given expectations of declining consumer demand, there is likely to be an inability to recover costs where there are insufficient end-users to generate required revenue."

129. FirstGas[68] supports the points made by Vector and PowerCo in our submissions to the draft decision.

130. Disappointingly, the Commission did not take the Frontier Economics report[69] into account in make its draft decision on form of control (despite it being submitted only four working days after an earlier stage in the Commission's process). However, we are now confident that the Commission will consider the important points made in this report and reconsider moving GDBs to a revenue cap, notably:

a. Uncertainty in New Zealand's energy transition makes accurate gas demand forecasting difficult, reducing the effectiveness of a WAPC in promoting consumer welfare;

b. The conventional rationale for a WAPC weakens due to new government policies aiming to reduce fossil gas consumption to meet net-zero targets;

c. WAPCs provide price stability, but with uncertain demand, it introduces volatility in cost recovery, negatively affecting consumers;

d. A revenue cap is preferred as it aligns with consumer benefit, ensures recovery of efficient costs, and simplifies regulation; and

e. Regulators like AER and Ofgem are considering or have switched to revenue caps for gas distribution businesses to address forecasting challenges and fixed costs.

[66] PowerCo, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023 p.6

[67] GasNet Ltd, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.8

[68] FirstGas Ltd, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.35

[69] Frontier Economics, *The merits of introduced a revenue cap for gas distribution businesses*, 6 April 2023, p.2

G. Large connection contracts

131. Vector continues to support the introduction of a large connection contract (LCC) mechanism. Nothing that has been presented in stakeholders' submission has caused us to question the wisdom of this proposal. It was also pleasing to see the initiative being supported by the Major Electricity Users Group (MEUG),[70] which considered the mechanism would be beneficial for both EDBs and consumers alike. In its draft decision, the Commission identified a significant deficiency in the existing IMs that could cause material harm to long-term consumer interests if left unaddressed. To briefly recap:

a. EDBs face the prospect of large new customers (data centres, embedded wind and solar farms, etc.) connecting at times and in places that are difficult to predict (recall that this mechanism would not affect the replacement of existing connection assets);

b. Under the status quo, this may necessitate reopening an EDB's price-quality path – a costly and time-consuming process that will delay connection considerably and, potentially, the delivery of benefits from electrification/decarbonisation; and

c. This also has the undesirable consequence of 'smearing' connection costs being caused by one party across others through lines charges, i.e., connection charges cease to be 'cost-reflective,' thereby departing from one of the defining principles of efficient pricing.

132. In Vector's opinion, uplifting a mechanism that has been working well for many years in the transmission sector represents a materially better, pragmatic solution. We disagree with Contact Energy's hyperbolic claim – echoed by some other 'gentailers' – that the proposal would "unleash a fully unregulated monopoly."[71] We also dispute Contact's allegations that existing connection charges are excessive. These contentions are meritless. We consequently believe the proposal should proceed, but with one important modification: without the 10MW threshold to ensure the purpose of the mechanism is not inadvertently undermined.

No evidence that connection charges are excessive

133. Contact insinuates that EDBs are already charging too much for connections and supposedly using capital contributions to circumvent the application of the IRIS scheme. It contends that it is "very common for an EDB to bundle connection costs and wider network upgrades, and charge all these costs to the connecting customer."[72] It then lays out four stylised scenarios that it says are the "most common issues" it sees "when customers are

[70] Major Electricity Users Group, *Draft decisions: Part 4 Input Methodologies Review 2023*, 19 July 2023, p.5.

[71] Contact Energy, *2023 Input Methodologies Review – Draft Decision, Contact Energy Submission*, 19 July 2023, p.4.

[72] *Op cit.,* p.5.

charged for wider network upgrades."[73] Vector certainly does not require customers to make contributions to investment projects that greatly exceed their own requirements. Quite the contrary:

a. we guard against precisely this scenario through the application of a standard $/kVA charge to deal with system growth;[74]

b. we also allow customers to do their own trenching, civil works, reinstatement and laying of duct, i.e., if they believe they can undertake a project more cheaply themselves;[75] and

c. as a more general point, many of the most significant costs of connection (traffic management, etc.) are imposed by others (local councils) and beyond our control.

134. We obviously cannot attest to what other EDBs are doing in this space, but we have not seen any credible evidence of EDBs levying excessive connection charges on individual parties for investments that benefit others. However we do see the opposite from some parties: namely, the costs arising from one party connecting being smeared across other network users via lines charges. It is quite telling that Contact appears to have no qualms whatsoever with this obvious source of existing inefficiency, and yet is apparently deeply troubled by another source of supposed problems for which there seems to be little or no empirical evidence.

135. Indeed, it will not have escaped the Commission's attention that Contact provides no real-world examples of these supposedly 'common' scenarios. Not one. The only case study Contact presents involves a completely different scenario, in which a customer by-passed the grid after receiving an initial quote from an EDB. The customer sought a connection, received an initial quote and then found a cheaper alternative that it ultimately pursued without going back to negotiate with the EDB (e.g., to present it with the cost of the other option). We fail to see how this example elucidates any problem with the current regime, much less a significant one warranting intervention.

136. Capital contributions also have one vital broader implication that bears mentioning: they reduce EDBs' financing requirements. Without those contributions from connecting customers, EDBs would need to finance those works themselves (for recovery via price-quality paths). That additional burden would come at a time EDBs are already facing profound financing challenges from the substantial investments required to enable electrification. As we stressed throughout our initial submission, the draft decision could

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[73] *Op cit.,* p.16.

[74] Vector, *Policy for determining capital contributions on Vector's electricity distribution networks, From 1 December 2021, Pursuant to: Electricity Distribution Information Disclosure Determination 2012*, p.6.

[75] *Op cit.,* p.8.

compromise our ability to maintain satisfactory credit metrics and any move to limit capital contributions would only make those problems worse.[76]

Customers would not be powerless

137. The introduction of a LCC mechanism would not leave customers at the mercy of an 'unregulated monopoly.' For one thing, customers may often have other feasible locations in which they can connect, e.g., in a distribution footprint elsewhere in New Zealand. This may create the potential for some element of competition between the 29 EDBs when it came to connections – something that is not possible under the NIC framework, where Transpower is the only possible counterparty. Larger customers (e.g., large data centres) may even have the option of taking their business offshore if the returns on offer in New Zealand are unduly compromised by the terms offered by EDBs. The likes of Microsoft and Google have enormous countervailing power in this respect.

138. Even if a customer did have a strong preference for connecting in a particular location and could not easily relocate an EDB still could not simply dictate terms in the manner implied by Contact. The proposed IM would place obligations on EDBs to consult adequately and to respond with appropriate supporting material. EDBs would need to demonstrate beyond a reasonable doubt that the terms and conditions of a contract were arrived at following a process that provided opportunities for the customers to make or approve reasonable price-quality trade-offs. If a customer believed an EDB was proposing to build assets that were either overbuilt or unduly expensive, then:

   a. the IM would afford it the right to question those elements of the EBD's proposal – perhaps even by supplying alternative estimates sourced from other suppliers; and

   b. the IM would require the EDB to provide the customer with opportunities for competitive provision by parties other than itself – something Vector already does under its capital contributions policy (see earlier discussion).

139. It is consequently wrong to suggest that customers would be forced to 'take it or leave it' by an unassailable monopoly. The draft IM guards explicitly against that possibility. Instead, customers would be active, ongoing participants in negotiations and EDBs would be subject to clear requirements. Furthermore, even if EDBs could feasibly extract monopoly rents, it is fanciful to think that customers would sit back and meekly allow it. The Commission – and likely also the Electricity Authority – would be inundated with complaints. This conduct would also become evident through EDBs' information

[76] Contact is also asking the Commission to reduce the WACC for EDBs to the 60th percentile. In other words, it appears to want greater proportion of costs in the RAB and a reduced rate of return. And all at a time when it is universally accepted – including by Contact – that lines businesses will need to invest considerable sums to strengthen their networks to support decarbonisation. We cannot understand how Contact's prescription could possibly be in consumers' long-term interests.

disclosures, as MEUG highlighted in its submission.[77] In other words, even if rent seeking were feasible, it would be short-lived.

Relevant precedent

140. Even if Contact's rather histrionic claims were not flawed in principle for the reasons set out above, they would still face a rather confounding practical consideration. Namely, if the proposed LCC mechanism is as unsound as Contact maintains, why has almost exactly the same arrangement worked so well for Transpower for so long – a company that, coincidentally, does have a national monopoly? Indeed, every single criticism levelled at the LCC mechanism by Contact and other gentailers would, if valid, seem to apply equally if not more so to Transpower's NICs as well.

141. Under the NICs, Transpower charges customers 100% of connection costs up-front and, in theory at least, all the 'common scenarios' identified by Contact in its submission would apply. Yet, NICs have been a consistent feature of the transmission pricing regime for years and have survived multiple regulatory reviews unscathed – barely rating a mention. Put simply, they work. Neither Contact nor anyone else has explained why this demonstrably successful element of the transmission regime would not function just as well, if not better, in a sector populated by 29 suppliers.[78]

142. We find it impossible to fathom why the factors outlined in Contact's submission are apparently so troublesome in a distribution context yet seemingly not problematic in the least at the transmission level. This strikes us as an irreconcilable contradiction. Indeed, one could be forgiven for thinking that Contact's chief motivation may not in fact be to avoid paying too much for a connection, as it claims. It may instead simply find it advantageous for connection costs to continue being 'smeared' across all users in a distortionary, non-cost-reflective fashion and for it to advocate for such, despite the obvious inconsistencies.

Other proposals

143. The material set out hitherto demonstrates why the concerns expressed by Contact and other gentailers about the LCC mechanism are unwarranted. Contact's proposal to initiate a separate joint project between the Commission and the Electricity Authority is consequently moot – there is no need for such a workstream. Moreover, a joint project of this kind would serve only to impose needless additional costs on the sector and delay the

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[77] Major Electricity Users Group, *Draft decisions: Part 4 Input Methodologies Review 2023*, 19 July 2023, pp.5-6.

[78] In a similar vein, airlines and the three major monitored airports (Auckland, Wellington and Christchurch) have been engaging in periodic commercial negotiations over charges and major capital investments in a reasonably successful fashion. Those airports theoretically have the right to set whatever airport charges they see fit. But they know that if they attempted to do so, this would quickly become evident through their information disclosures and the Commission would likely respond swiftly and decisively.

implementation of a change that would benefit EDBs and consumers alike – as MEUG has rightly acknowledged.[79] It would also cause mass confusion and uncertainty heading into the final IM determination and the DPP reset.

144. Meridian's suggestion that the LCC mechanism be an optional arrangement that both customer and EDB must opt into is similarly misguided.[80] If customers have the fall-back option of requiring the connection costs to be included in the RAB, where they might then be spread across other customers then, understandably, this may frequently be their preferred option. Indeed, when faced with the prospect of paying less than 100% of the relevant costs the prospect of waiting a bit longer to be connected may constitute only a minor inconvenience. Hence, providing customers with such a choice would be likely to create an untenable "heads you win; tails I lose" scenario for EDBs.

145. Meridian also suggests that aspects of Transpower's NIC process be included to mitigate the risk of market power being exercised by EDBs and provides some recommended wording to that effect.[81] Had Meridian reviewed the specifics of the LCC mechanism before lodging its submission it would have been pleased to discover that the draft IM already includes the very provisions it proposes.[82] If Meridian had been aware of those details, it would presumably have agreed that the safeguards included within the recommended mechanism (which we described earlier) will serve to mitigate any concerns regarding any supposed imbalance in negotiating power.

The 10MW threshold should be removed

146. Our one concern with the proposed LCC mechanism is the 10MW threshold. Transpower's NIC framework does not include a capacity limit – and with good reason. New connections with a capacity of 10MW are very significant. If a 'floor' is set at this level the mechanism would seldom be used, defeating the purpose of introducing it in the first place. There is no reason to limit the mechanism's application in this way. The factors outlined above mitigating against the exercise of market power would also apply to customers seeking smaller connections. We therefore remain of the view that a LCC mechanism without a minimum threshold would be a materially better option.

Additional information

147. EDBs do the heavy lifting on annually connecting tens of thousands of consumers. This involves managing a variety of third parties, complex and varied sites to work on (greenfields and brownfields each having their own complications), and high consumer/

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[79] Major Electricity Users Group, *Draft decisions: Part 4 Input Methodologies Review 2023*, 19 July 2023, p.5.

[80] Meridian, *Input Methodologies review 2023: Draft decisions*, 19 July 2023, p.3.

[81] *Ibid.*

[82] *See:* Commerce Commission, *[Draft] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC [XX]*, p.39.

developer expectations. This is done with nearly no complaints from connecting parties as can be seen by the small number of Utility Disputes Limited (UDL) complaints[83].

148. At Vector we pride ourselves in the work we do to connect customers safely, quickly and cost efficiently and we are of the view that the majority of connecting parties value the connection services provided.

149. Contact[84] are clearly missing a huge part of the puzzle when it comes to connections costs. They claim that:

"The current connection cost settings frequently result in excessive costs being charged to customers, which is creating a significant barrier to process heat conversions."

150. Unfortunately for consumers, EDBs' pass-through costs have increased across all segments (notwithstanding the high inflationary environment we currently face). These costs reflect third-party pass-through costs that Vector and others cannot absorb. Examples include traffic management, civil works, and reinstatement.

151. To mitigate these costs, Vector issues multiple civil quotes for each connection, strives to continuously improve processes, and implements efficient network designs for long-term resilience. Vector provides options to large customers like data centres and allows them to arrange civil works themselves. From our discussions with international consumers, this practice is common to other parts of the world.

152. Regarding traffic management, it is important to note we are actively working with Auckland Transport and Waka Kotahi to move it from a rules-based approach to risk-based approach. A more pragmatic approach will assist in reducing costs.

153. Contact's assertion that customers have limited bargaining power is false. They presume the following:

"The Commission justifies this on the basis that large customers have 'significant bargaining power.' There is no evidence to support this assertion. The reality is that it will give substantially more power to EDBs in an already lop-sided relationship."

154. We agree with the Commission; large customers engage in robust discussions with Vector and have strong negotiation abilities due to their scale. These customers seek

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[83] In the past 5 years UDL has recorded 102 complaints about delays in setting up new connections, 69 are about retailers (0.7% of retailer total), 33 are about EDBs (2.6% of EDB total). In these cases, delays can be confusing and costly to the consumer. See UDL submission to the EDB Targeted ID Review Process and Issues Paper, 20th April 2022, p.3 available here https://comcom.govt.nz/__data/assets/pdf_file/0016/282121/Utilities-Disputes-Limited-Submission-on-EDB-targeted-ID-review-process-and-issues-paper-20-April-2022.pdf

[84] Contact Energy, *2023 Input Methodologies Review – Draft Decision, Contact Energy Submission*, 19 July 2023, p.3

more commercial options outside the standard regime, considering various security of supply requirements and capital considerations. Pricing options for these types of developments can be subsequently refined.

155. Contact continues by saying:

> *"Sorting a connection is usually the last issue to consider, and at that point a customer will have little bargaining power. In most cases the only choice a customer has is to take or leave the connection price offered by the EDB."*

156. The claim that the only choice for customers is to accept the offered connection price is flawed, as a large part of the costs are outside of Vector's control. For example, Solar sites assess multiple locations and clearly consider Vector's costs when making decisions. Offering the large connection contract as an option for both parties to agree also avoids having to rely on a reopener where the agreement of special terms would not be negotiable by both parties in such a way because suppliers and customers will have greater control over the timing of a decision.

157. Finally, we refute Contact's point of view that "connection costs often include wider network upgrades not related to the connecting customer."

158. Vector's disclosed capital contribution's policy adheres to the Electricity Authority's pricing principles. There are also no incentives to inflate costs because assuming the contribution paid is equal to the costs no asset is added to the EDB's RAB.

159. Furthermore, we have received feedback from large data centres wanting to connect that Vector's methodology is consistent with international norms.

H. Uncertainty mechanisms (UMs)

Process and guidelines

160. Several EDB submissions have raised concerns that the Commission has declined to add prescriptions around timelines and guidance to the IM reopener process.

161. We support the views provided by Alpine Energy, Aurora and Wellington Electricity below.

162. Alpine Energy[85] outline the following:

> *We encourage the Commission to establish clearer details on the reopener process and process timelines, outlining possible guidelines on required information and application evaluation periods.*

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[85] Alpine Energy Ltd, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.11

We further encourage the Commission to consider the implementation of a templated 'fast-tracked' reopener for those events likely to impact all EDBs equally regardless of size, for example a change event from legislative change.

163. Aurora Energy[86] describe their dissatisfaction below:

"[…] we are disappointed that the Commission has not provided more prescription about the information required to support a reopener process, or commit to evaluation timeframes."

164. And Wellington Electricity[87] propose these points:

- *"Support the reopener IMs with guidelines and example assessments to assist suppliers to provide applications that can quickly and efficient assessed and to provide customers and suppliers with a high degree of confidence of whether a reopener will be approved.*
- *Removing reopener assessment criteria that are subjective and create uncertainty about whether a reopener application will be approved."*

165. PowerCo[88] has proposed that the Commission could implement these prescriptions (timeframes, staging) outside of the IMs in a similar way to how generation connections have time requirements under Part 6.

166. Like PowerCo, we are concerned with the resourcing issues the Commission could face if multiple reopener applications with time pressures for consumers were sent to them at once.

167. Through this process it has become apparent that this is also something consumers want the Commission to address. MEUG[89] has pitched to the Commission:

"While we recognise the difficulties the Commission may face, we are concerned that the Commission has not set timeframes for the DPP reopener process."

168. If we take a look at two recent applications made to the Commission to reconsider costs within the price-path, it is Vector's view that we should be genuinely concerned. It took the Commission 10 months to respond to Unison's capex reopener application; and 7 months

[86] Aurora Energy, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.3

[87] Wellington Electricity, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.9

[88] PowerCo, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.13

[89] Major Electricity Users Group, *Draft decisions: Part 4 Input Methodologies Review 2023*, 19 July 2023, p.4

to respond to Orion's IPA application[90]. And this was during a period with a low number of consultations for the Commission on electricity distribution.

Unison's capex reopener application timeline:

- *Unison applied in June 2021*
- *The Commission made its draft decision in December 2021,*
- *The Commission made its final decision in March 2022*

Orion's Innovation Project Allowance application timeline:

- *Orion applied in June 2021*
- *The Commission's final decision was made in December 2021*

169. For Vector, whether it be through the IMs or through an alternative method, the Commission must set expectations for EDBs, their stakeholders and consumers. To that end, we urge the Commission to reverse its decisions to:

a. Not introduce timeframes for the Commission to evaluate reopener applications;

b. Not provide more prescription about the types of information required in reopener applications;

c. Not prescribe when consultation is required and when it is not;

d. Not include a pre-application stage for the process of reapplying for a reopener;

e. Not allow price-quality path reopeners to apply across more than one regulatory period without suppliers having to reapply; and

f. Not allow a single CPP application to cover multiple parties nor allow a single reopener application to cover multiple parties.

170. The IMs are supposed to provide certainty to suppliers. Adding set timeframes for the Commission to consider reopener applications will help with that certainty. If the Commission decides against providing timeframes, then it should articulate why it is not prepared to hold itself to the same standards it requires of suppliers. The Commission's current regime is littered with deadlines that are required to be met by suppliers. It would be positive if the Commission were prepared to subject themselves to time driven requirements regarding the delivery of outputs.

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[90] https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-price-quality-paths/electricity-lines-default-price-quality-path/2020-2025-electricity-default-price-quality-path

Reliance on reopeners

171. Transpower[91] joined Vector in calling out the Commission's reliance on reopeners to deal with regulatory flexibility.

> *"The Commission's view is that rather than adding new uncertainty mechanisms, the existing ones may be used for the identified areas of uncertainty. We have considered this for RCP4, however we have identified areas of where the existing uncertainty mechanisms are not appropriate, for future transmission investments based on following reasons:*
>
> *• The existing reopeners are linked to specific expenditure or triggers, these are not applicable to all of the areas of uncertain expenditure we are proposing for RCP4*
>
> *• The reopeners are typically administratively burdensome*
>
> *• The E&D reopener is a once-only application, does not provide certainty that expenditure already incurred or for unforeseen costs towards the end of the period, can be recovered."*

172. ENA[92] proposed new UMs including a connections volume driver to allow connections capex to adjust with actual rather than forecast connections; and use-it-or-lose-it allowances to capture necessary but uncertain opex that crystallises during the period.

173. Vector supports the ENA's proposals which, along with Vector's suggestions[93], add to the list of new flexibility tools the Commission should consider ahead of its final decision.

174. Another option for the Commission will be to set up a work programme in parallel to the DPP reset which reviews possible new UMs to implement at the time of the reset.

Connections wash-up mechanism

175. A number of EDBs (Vector included) have called on the Commission to consider the connections wash-up mechanism to extend to DPPs as well as CPPs.

176. Vector concurs with the explanation provided by the ENA[94]:

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[91] Transpower Ltd, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.38

[92] Electricity Networks Aotearoa (ENA), *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.4

[93] Vector, *In-period adjustments*, 6 April 2023, p.5-6

[94] Electricity Networks Aotearoa (ENA), *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.11

"It is proposed that this mechanism will apply only to CPPs because the basis of the connection forecasts is better understood at the time the CPP is determined than the DPP. However, as the same level of uncertainty applies at the beginning of DPPs and CPPs, we submit that the wash-up mechanism should also apply to DPPs."

177. We also believe that PowerCo[95] and ENA are correct in suggesting that if the demand volume wash-up is not included in DPPs, then connection capex must be excluded from the capex IRIS to address the concerns raised above.

"If a DPP connection wash-up for general connections is not adopted, an alternative is to exclude it from the capex IRIS calculations. We do not believe that it is appropriate for financial penalties or rewards to be included in prices due to forecasting error for this category of capex. Historical levels of spend will not be a good predictor of future demand during the energy transition."

178. Finally we note that both MEUG and Drive Electric are supportive of the new mechanism which gives great comfort given they see the benefits from a consumer's perspective.

Coverage of reopeners

179. In terms of coverage, submitters are concerned primarily with 'general growth' and 'government policy changes' not being picked up by the current suite of reopeners.

180. Several EDBs did not agree with the Commission's proposal to not include a reopener for 'general growth.'

181. Horizon Energy[96] recommends that:

"The Commerce Commission retain the ability to consider growth based unforeseeable major capex reopeners.

[…] For example, it is possible a future government may introduce incentive schemes for residential generation that causes significant demand for generation capacity that has not been forecast in the AMPs. This could be considered a growth-based reopener, as it is not related to a single large connection, and residential generation is neither a new nor emerging technology."

182. Meanwhile, Wellington Electricity[97] has also voiced its concerns around this decision.

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[95] PowerCo, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.5

[96] Horizon Energy *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.2

[97] Wellington Electricity, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.5

"Restricting reopeners for general growth (from EV uptake or the electrification of gas appliances) to foreseen projects is unnecessarily restrictive. The government still hasn't settled on its gas strategy, the outcome of which could change a networks network growth capex requirements."

183. Vector believes that Horizon and Wellington Electricity have provided concrete examples illustrating why general growth should be in scope for the unforeseen capex reopener. Once again, we recommend the Commission takes note ahead of final decisions.

184. Whilst there was acceptance of the inclusion of resilience expenditure in scope of reopeners, Vector shares Transpower's[98] position below:

"We are concerned with the Commission's decision to not make explicit provision within the IMs for resilience expenditure. We consider that this draft decision is unlikely to demonstrably better promote the section 52A purpose of Part 4, for long-term benefits of consumers."

185. The Commission's draft decisions have left a gaping void in response to the recent storm events across Aotearoa to put resilience front and centre of the IM review and provide an IM for resilience expenditure and meet requirements under the National Adaptation Plan, the resilience work associated with climate change (for example the consultation from the Department of Prime Minister and Cabinet (DPMC) and the changes proposed for emergency management legislation.

186. Alpine Energy[99] has urged the Commission to reconsider its draft decision to not extend the DPP reopeners to capture central government policy and local government rule changes. They provide useful examples where there is ambiguity whether the change event would provide cover or not: National Policy Statements (such as Wellington Electricity's move to a customised price-quality path (CPP) granted in March 2018[100]) and Resource Management Reform. As a solution Alpine Energy says:

"We request that the Commission considers amending clause 4.5.5 (2) of the draft IMs as follows: "a change in a regulatory or legislative requirement that applies to an EDB as a result of new or amended legislation and government or local government policy or plan"."

187. Vector endorses this change – to not be cautious and pro-active around capturing these uncertain costs within the coverage of reopeners would be a missed opportunity.

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[98] Transpower, *Submission on IM Review 2023 Draft Decisions*, 19 July 2023 p.4

[99] Ibid, p.10-11

[100] The application followed a Government Policy Statement issued in light of the 2016 Kaikoura earthquakes, which increased the risk of a major earthquake occurring in Wellington and highlighted the capital city's vulnerability to seismic activity. The statement outlined the Government's expectation that the Commission consider options to allow Wellington Electricity to recover resilience-related expenditure that was not anticipated when its price limits were set in 2014.

I. Innovation and incentives

Innovation project allowance

188. There is a general consensus from submitters that the changes to the innovation project allowance (IPA) to now include 'non-traditional solutions' is welcomed but do not go far enough. The ENA[101] summarises this sentiment well.

> *"While ENA supports the Commission's proposed changes to the innovation allowance, these changes do not go far enough to remove the barriers to the uptake of it or to strongly signal and support innovation in our sector through available funding. As a result, the innovation allowance will likely remain a tool of limited use to EDBs."*

189. MEUG[102] and others note the IPA's limited use. So far none of the allowance available to EDBs has been rewarded which promotes a stagnated regulatory environment for innovation in Aotearoa New Zealand.

190. Consequently, it is hard to disagree with SolarZero's[103] assessment:

> *"In the paper we don't see any change in the incentives that the Commerce Commission is putting in place to encourage innovation. Therefore we can expect the same outcome: Limited innovation. We can only assume, therefore, that the Commerce Commission:*
>
> *1. Is not interested in encouraging innovation or*
> *2. Needs to revisit the proposals in the paper.*
>
> *It is inconceivable that the Commerce Commission can truly believe that maintaining the status quo will deliver an optimal level of innovation in the electricity industry. Given that the paper focuses on the transition and the need for innovation the mis-match between the analysis and solution is puzzling to the point of inexplicable. Clearly, something has gone wrong during the analysis process."*

Incentives

191. On IRIS, Transpower[104] does not agree that an "opex IRIS approach [like that] applied in the EDB DPP" is appropriate for them. Vector does not understand why Transpower should be treated differently to EDBs. We therefore agree that the Commission is right to apply this rule to Transpower.

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[101] Electricity Networks Aotearoa (ENA), *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.14

[102] Major Electricity Users Group, *Draft decisions: Part 4 Input Methodologies Review 2023*, 19 July 2023, p.7

[103] SolarZero, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.2

[104] Transpower, *Submission on the IM Review 2023 Draft Decisions*, 19 July 2023, p.29

J. Accelerated depreciation

192. The three GPBs FirstGas, PowerCo and Vector commissioned Frontier Economics to review MGUG's response to the draft decisions. In particular we asked them to assess MGUG's assertion that the Australian Energy Regulator's (AER) has a better approach to accelerated depreciation; and whether their so-called 'new evidence' supports a change to the Commission's methodology.

193. On the AER approach, the Frontier memorandum concludes that both the Commission and its Australian counterpart adopt very similar approaches and importantly:

> *"In our view, the key point here is that both regulators adopt the principle of ex ante FCM. If ex ante FCM is to be maintained, and if expected economic lives are shorter, it is axiomatic that regulatory depreciation allowances must be increased."*

194. Frontier[105] does not believe a change in approach is suitable at this time:

> *"In our view, it would be logical for the Commission's approach to regulatory depreciation to evolve with changes in government policy that may affect the economic life of gas network assets."*
>
> *"Moreover, it would be counterproductive, in terms of regulatory stability and predictability, for the Commission to change its approach to regulatory depreciation in the absence of evidence with clear implications for the Commission's estimates of the likely economic life of gas network assets."*

195. Frontier also looked at MGUG's 92-page appendix that restates and adds further explanation and commentary to past submissions and updates the data that underpins some of the tables and figures in those earlier submissions.

196. However Frontier surmises that:

> *"The MGUG submission does not identify the implications that this updated evidence might have for the economic life of gas network assets, nor suggest what amendments the Commission should make to the scenarios or the relative probabilities that underpin its assessment of the economic life of gas network assets."*

197. Vector agrees with Frontier's assessment and suggests that the Commission's current approach to accelerated depreciation should be maintained.

[105] Frontier Economics, *Response to MGUG submission*, 9 August 2023, p.10

Kind regards

Richard Sharp
GM Economic Regulation and Pricing