Vector Limited
110 Carlton Gore Road
PO Box 99882
Newmarket
Auckland 1149
[redacted]/ vector.co.nz

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Ben Woodham
Electricity Distribution Manager
Commerce Commission
44 The Terrace
Wellington 6140
By email: infrastructure.regulation@comcom.govt.nz

Vector cross-submission on DPP4 Draft Decision

1. This is Vector's ('our,' 'we,' 'us') cross-submission on the Commerce Commission's (Commission) draft decision for the default price-quality path (DPP) reset. No part of this submission is confidential, and it can be published on the Commission's website. All quotations, unless referenced, are from submitters' responses to the Commission's DPP4 draft decision, as published on the Commission's website.

2. Vector acknowledges the Commission's engagement so far in the DPP reset process, especially the engagement from Commissioners.

Policy matters raised

3. We observed that many submitters raised policy matters in their submissions, on topics such as affordability, the promotion of a whole system's approach, and individualised price paths (IPPs). These are important topics but in our view fall outside of the Commission's DPP reset remit. We encourage the Commission to proactively share the policy matters raised with the appropriate officials and government agencies.

Revenue smoothing/ price impact

4. Submissions were generally supportive of the Commission's draft decision to smooth revenues over the regulatory period to manage price shocks, although we note ETNZ's submission that this is "dangerous territory for the Commission to move into" due to the risk of disincentivising investment.

5. We agree with Orion's submission that:

> "*For the first time, the Commission is currently proposing to smooth the necessary revenue increases across the regulatory period to manage consumer price shocks. While we acknowledge what the Commission is attempting to do, we consider that customers should face more of the cost in the first half of the period (and consequently smaller increases in the latter years).*
>
> *With a higher P0 and lower X-factors, customers will face a bigger initial shock, but lower shocks in subsequent years. This would also avoid the higher allowance revenue in the final years, reducing the risk of needing a more significant step change in revenues between DPP4 and DPP5.*
>
> *Such an approach is supported by economic research by Nobel Prize winning economist, Richard Thaler, who found that where possible, customers would prefer to integrate their losses into a singular payment. This research shows that when faced with a large cost increase, customers will have temporarily inelastic demand for additional costs. Smoothing more of the cost to latter years, when the customers demand elasticity has been restored creates increased perceived pain for customers, even when the total cost impact does not change."*

6. We do not agree with MEUG's submission that it:

> *"[…] would prefer a smoothing profile that weighted a higher proportion of funding to be recovered in the later years enabling EDBs to address deliverability concerns and demand uncertainty first, while acknowledging the compounding cost pressures facing electricity consumers"*

7. We consider a front-loaded revenue profile would better address these concerns as EDBs have better certainty around their work programme and demand forecasts early in the period.

8. We also consider the long-term benefit of consumers is better supported by front loading the revenue profile for the reasons set out in Orion's submission. Consumer price shock may be increased where they face continuous price increases over a period rather than a more significant upfront increase but lower subsequent increases. We would encourage the Commission to consider economic theory as highlighted by Orion.

9. We also agree with the ENA's submission that:

> *"ENA's firm view is that the Commission's draft decision to mitigate P0 changes for DPP4 sets a precedent that should be applied symmetrically to future determinations regardless of whether they result in revenue increases or decreases."*

Capital contributions

10. Vector's submission to the draft decision set out our concerns on the potential for the Electricity Authority (Authority) to regulate connection pricing which could in turn impact capital contributions and disrupt the DPP for suppliers. The significant and fundamental impact on the price-path for all EDBs should be acknowledged by the Commission in its final decision.

11. A number of submitters also discussed capital contributions, for example, the ENA noted that "*The Authority's decision to regulate connection pricing and contributions may have perverse consequences for EDBs' incentives to support electrification.*"

12. Capital contributions play a significant role in terms of financeability and incentives to invest. This could be severely undermined if the Authority removes EDB flexibility to determine upfront contributions, particularly at a time when investment needs are high. The potential impact on financeability is heightened by the back-ended cashflow profile created by RAB indexation.

13. Fonterra submitted that:

> *"[…] most large industry electrification capital requirements for distribution network upgrades will be funded by capital contribution agreements. The Commission should be actively encouraging these agreements as they are in line with the Transpower TPM design whereby the beneficiary pays for capital upgrades. Notably, under the current Commission methodology, EDBs can receive more than what has been accounted for in the DPP4 via capital contribution requirements and can therefore generate windfall profits. Fonterra supports the Commission's additional disclosure obligations to enhance visibility of this."*

14. In line with Fonterra's submission that the Commission should be actively encouraging capital contributions for electrification, we note Vector's capital contribution policy has mitigated DPP4 price increases for our customers by reducing our forecast capex and keeping our RAB lower than it otherwise would have been.

15. We do not consider any additional disclosure obligations are needed to provide visibility around windfall profits. During the recent IM review, the Commission found:

> *"Profitability across EDBs has been below our estimates of reasonable returns. EDBs have not been making excessive profits:"*[1]

16. We do not expect additional reporting around capital contributions would provide sufficient benefit to outweigh the additional regulatory burden given EDBs are already required to disclose their current capital contributions policy (and any changes to the policy).

17. MEUG's submitted that:

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[1] https://comcom.govt.nz/__data/assets/pdf_file/0031/283864/Part-4-Input-Methodologies-Review-2023-Process-and-Issues-paper-20-May-2022.pdf

> "*MEUG welcomes discussion of how capital contribution will be treated through DPP4, and how these are expected to help support the connection or expansion of many business and industrial loads on the distribution network. We support the Commission reviewing the DPP4 decisions following the Electricity Authority's work on mandating efficient connection pricing (paragraph B147) and the Commission looking at additional reporting around capital contribution policies by EDBs (paragraph B252). The capital contribution process is used by many MEUG members when connecting or increasing capacity to their sites*."

18. As set out in our submission, we agree the Commission will likely need to review their DPP4 final decisions if the Authority's regulation of connection pricing impacts capital contributions.

19. We consider the market needs more clear direction from the Commission on how it will address any regulation of capital contributions by the Authority. This regulation could significantly undermine the price paths set by the Commission so it is crucial stakeholders have confidence around how the Commission will handle the impacts and that both regulators appreciate how disruptive the changes could be.

20. In our view s54V of the Commerce Act would be the appropriate mechanism to re-open the price-path. This will need to be done urgently and involve re-running the financeability test to ensure the amended price-path does not compromise EDBs ability to invest.

21. We note we are concerned around the timing of the Authority's review as it should have commenced well ahead of the Commission's DPP review process to ensure the price-path set accounted for any changes. This has undermined confidence about the two regulators communicating and collaborating with each other.

Capex

22. Vector endorses the view that the cap on capex allowances needs an uplift compared to what has been used historically. We are no longer in a steady state, and the regulations must reflect the fact that the energy transition is underway and will ramp up during DPP4.

23. We believe that the Commission should listen to the recommendations from other EDBs suggesting that a small increase on consumers' bills could avoid a great number of reopeners and potential CPPs which are costly and time consuming for both the Commission and the EDBs involved.

24. We therefore agree with the ENA's recommendations:

> *"[…] that the cap be raised to at least 130%. This impact will be felt especially hard by small EDBs driven to apply for a CPP. For these EDBs, the cost and resources consumed by CPP applications may ultimately not be in the long-term interest of consumers."*

25. We refute Fonterra's comments:

"We believe EDB capex allowance requests in AMPs should be held at historic levels and only inflated by CGPI, as the previous two DPPs (2 & 3) have shown no significant increase and end consumers have not suffered any corresponding decline in SAIDI or SAIFI quality measures."

26. Ensuring there is no decline in SAIDI or SAIFI requires both capex and opex investment in asset renewals and replacement, maintenance and responding to faults. The next price path will need to both maintain good reliability performance but also combine a growing number of connections, increased load from existing connections and ensuring capacity is available for the uptake of DERs including EVs. This means that the primary reason for increased investment in DPP4 will be witnessed in the categories of system growth and consumer connections.

27. Also, DPP2 and DPP3 are no reflection of what DPP4 will bring. The industry has been pre-warned by the requirement for increased expenditure by the BCG report The Future is Electric[2] and now EDBs' latest AMPs demonstrate the levels of this increase.

Forecasting and peak demand

28. We note NZIER's report for MEUG discussed EDB demand forecasting. In particular NZIER stated that:

    "*The most recent Transpower regional forecasts for peak demand are included in its latest Transmission Planning Report (TPR 2023). The regions used in TPR 2023 are reasonably similar to the regions covered by the EDBs (except for Aurora Energy).*

    Transpower peak demand growth rate assumptions to the EDB assumptions for Orion and Aurora but the Transpower forecasts are much lower than those for Vector and Wellington lines."

29. We have considered the difference between Vector and Transpower's peak demand forecast for the Auckland region:

    - As acknowledged in NZIER's report, Vector's network and Transpower Auckland region forecast cover slightly different areas (Transpower's report captures Glenbrook and Bombay GXPs – Vector's does not);
    - The divergence in growth rates appears to be driven by the Transpower and Vector forecasts using different starting points for their RY23 numbers. Vector's uses actual figures, as disclosed, for RY23. The growth rate would be more similar without the different starting point;
    - There are areas of significant uncertainty where Transpower's forecast may have taken a different approach. In particular, estimates of EV uptake and point loads.

[2] https://web-assets.bcg.com/b3/79/19665b7f40c8ba52d5b372cf7e6c/the-future-is-electric-full-report-october-2022.pdf

30. Vector's planning team meets with Transpower's planning team regularly to discuss areas such as demand growth. We also provide Transpower our forecast each year. In addition, we are working with Transpower on its Auckland Strategy.

31. We also note the recent IAEngg 2023 review into AMPs scored Vector's system growth forecast as 'excellent.'[3]

32. For completeness, Vector's capital contribution policy funds capex related to peak demand growth, so the peak demand forecast does not impact our capex allowance under the DPP.

Opex

33. The Commission has maintained the base step trend (BST) approach for DPP4 opex allowance setting. Vector acknowledges that coupled with the granted opex step changes, the BST approach is satisfactory. However, we agree with PowerCo:

> *"If EDBs can't make efficient investment in opex solutions at the right time due to the full allocation of allowances going to core functions (e.g., maintenance) to meet quality standards, they may be incentivised to prioritise less efficient capex investment to support electrification."*

34. And Wellington Electricity:

> *"If opex allowances cannot fund its maintenance programme and emergency response function, a network will have to reduce the volume of maintenance tasks […], which will increase the number and length of power outages, worsening network quality further."*

35. For these reasons, Vector's preference remains that EDBs' AMP forecasts should be used for opex allowance setting. The Commission has relied on AMPs for capex allowances as a key input into the DPP, we believe there is no reason why EDBs' own forecasts should not be utilised for opex. Relying on a base year in the past will not reflect the future of opex. For example, service interruptions and emergencies and insurance could see increased expenditure because of climate change (see our original submission for further details); and digitalisation and cyber security will need to reflect the growing electrification of the sector and the introduction of new technologies on EDBs' networks. These types of expenditure are not captured by simple trend setting. The use of EDBs' AMPs would still qualify under a low-cost DPP model.

Opex step ups

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[3] https://comcom.govt.nz/__data/assets/pdf_file/0016/343411/IAEngg-NZ-EDB-2023-AMP-Review-Forecasting-and-Planning-Assesment-Report-29-January-2024.pdf p.96

36. A number of EDBs have criticised the 5% cap on step up increases. For example, EA Networks explains:

> *"Finally, the 5% limit that the Commission has proposed to apply to the combined step changes inefficiently binds those EDBs that face more of the increases than others. An EDB that faces just one of the five approved step changes (excluding CPP specific costs) is allowed a full 5% step change for that increase, whereas an EDB that faces all five cost increases is only allowed an average of 1% for each cost increase. For perspective, we observe that the highest combined request across the five approved step changes amounts to 9.8% of total opex, which does not appear to us to be out-of-step with the 25% step change that is being allowed for capex."*

37. FlexForum also notes that:

> *"However, we are concerned that capping the aggregated step change increase in investment will lead to inadequate or inefficient investment in new capabilities. LV monitoring and analytics, and orchestration are core capabilities. Distributors should be able to invest to obtain these capabilities without being inefficiently constrained by a cap on investment. The cap threshold should be reality tested to ensure it does not drive inadequate and inefficient investment in orchestration capability."*

38. Vector notes Orion's position as sensible:

> *"Given that the step changes are, by definition, able to be justified, are significant and outside the control of the EDB, such a cap seems to be counter to the intent of this mechanism. If the Commission does consider that an aggregate cap is necessary, we would encourage the Commission to increase it to 10% which remains within what the Commission has considered to be a price shock historically, rather than the 5% that is currently proposed. Alternatively, a discrete 5% cap by each step change could be applied."*

39. We would once again argue though, that to avoid arbitrary caps on step changes EDBs' opex forecasts should be used. Network companies already forecast and justify their own operating practices in their AMPs.

Insurance

40. There was a particular interest in how the Commission has proposed to deal with insurance costs in DPP4. For example, MEUG submits:

> *"We recommend that the Commission, EDBs and its supporting body, ENA investigate other options for insurance for electricity infrastructure to provide more cost-effective cover."*

41. Vector joins the chorus of EDBs via the ENA to request that the Commission considers categorising insurance costs as a pass-through item:

"[…] the Commission has issued a notice of intent to amend the IMs to alter the treatment of insurance proceeds. This provides a prime opportunity for the Commission to amend the IMs to categorise insurance costs as a pass-through."

42. Vector agrees with Wellington Electricity's assessment:

"We disagree with the Draft decision that keeping insurance in the allowances rewards suppliers who take active steps to reduce their insurance costs. Insurance costs are outside of the control of networks. Networks cannot materially influence global prices. Any IRIS reward or penalty is simply a reflection of the fluctuation of market insurance prices. Wellington Electricity has access to global experts and can pool our buying power with other electricity networks in Australia (South Australian Power Networks, United Energy, CitiPower and Powercor), the United Kingdom (UKPN), and Hong Kong (Hong Kong Electric). Even with this buying power, we cannot meaningfully influence the price.

The Draft Decision also said it is not practical or low-cost to treat insurance as a pass-through. Again, we disagree. Networks could provide an annual, director-certified if necessary, expert report confirming coverage levels are prudent. They could also disclose their procurement process to ensure they are procuring insurance at market rates. This could be done with little additional effort from the Commission and for a modest cost increase from networks for the expert report, meeting the low-cost principle."

43. We suggest that the annual price compliance statement, which is audited, and director certified could easily incorporate a new section on pass-through insurance costs.

Productivity

44. Vector continues to support the Commission's draft decision to implement a 0% productivity factor to opex expenditure.

45. We agree with the ENA that:

"Any productivity outcomes from EDBs' investment in the energy transition will not manifest until the investment and transition phase is complete. During periods of transition, uncertainty, and growth, it is unreasonable to expect productivity growth. This shows further evidence that the 0% opex partial productivity factor is appropriate for DPP4."

46. MEUG has outlined that:

"[…] the Commission is still left with a position where NZ EDB productivity has declined over the measurement period while the same measures applied to EDB in the UK and Australia show either long term improvement or stabilisation of productivity. We believe that further work is required in this space to get greater insight and the ability to benchmark EDB performance could assist with this."

47. Vector suggests that this work is already underway with the Commission's 'productivity and efficiency study of electricity distributors[4]':

- Phase 1 – Total factor and partial productivity analysis of the EDB sector.
- Phase 2 – Proof of concept for EDB comparative efficiency study.
- Phase 3 – Apply analytical technique(s) and methodology(ies) to produce EDB comparative efficiency analysis and performance assessment.

48. Phase one was completed through CEPA's EDB Productivity Study, and phases two and three are expected later this year.

Deliverability

49. Despite the concerns raised by stakeholders, Vector remains of the view that deliverability falls out of scope of a low-cost regulatory regime. Deliverability would have to be assessed at project and programme level, yet the DPP is forecast and set at a relatively high level (capex and opex expenditure categories). CPPs and IPPs lend themselves well to deliverability assessments due to the more granular way these price paths are set.

50. MEUG has suggested additional reporting could solve deliverability concerns:

> *"Given concerns with deliverability, MEUG strongly support the introduction of an annual deliverability report (ADR), or similar mechanism, for DPP4. If designed well, this would provide interested consumers with a clear understanding of how work on the network is progressing, the achievements made, and the reasoning for any delays."*

51. We note again that ADRs might work for EDBs on a CPP, but we understand that they are both costly and time consuming which is contrary to section 53K of the Act:

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

52. If the Commission is minded introducing ADRs, they must be an ultra-simplified version of the ADRs used in Aurora's CPP. Furthermore, any additional reporting must be accompanied by a review of the reporting already in place. There cannot continue to be the imposition of endless new disclosures and reporting in a regime which already imposes significant and growing compliance burdens and costs on companies. We have not witnessed a single significant reporting obligation being removed in recent years.

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[4] https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/productivity-and-efficiency-study-of-electricity-distributors

53. For this reason, we repeat our call for the frequency of AMP disclosures to be reviewed and suggest again that only the AMPs used to set the DPP reset (years 3 and 4) are full disclosures. The remaining three years should be updates only and not require director sign off.

54. This view is shared by the Commission's independent review of EDBs' 2023 AMPs. Indeed, IAENGG's review[5] of information disclosure requirements for AMPs suggests a review of the frequency of AMP disclosures – improvement #7 describes the following:

> *"Understanding that information disclosures are on an annual cycle, some information perceivably doesn't require updating at such frequency (notably for multi-year projections). It is assumed that changes within some existing asset / network Information Disclosure Schedules (including AMMAT) are rarely of material significance to require annual updating. It is acknowledged that monitoring of such likely happens at least annually within respective EDBs, however external reporting is deemed of minimal value add. Whilst the value provided by these Schedules is not being questioned, their frequency of disclosure should be reviewed and preferably aligned to changes that are of greater materiality."*

55. Another Vector suggestion to mitigate deliverability concerns is provided by Fonterra:

> *"Deliverability is another important issue. As the Commission has identified in the Transpower RCP4, there is a high probability that EDBs will not be able to secure the equipment and/or labour to align to their capital spend requests. This aspect should be managed through a separate use it or lose it mechanism."*

56. Use it or lose it (UIOLI) mechanisms avoid rewarding EDBs for underspending their capex allowances which they could under IRIS. The Commission could in future resets recognise categories of forecasts with low confidence and introduce UIOLI allowances, such as Transpower has proposed for resilience expenditure in RCP4.

57. Finally, we fully agree with Alpine Energy's statement that deliverability depends on the portfolio of work rather than the total cost:

> *"Like all other EDBs, we are aware of the challenges we face in both attracting and retaining talent and are working across our business, and with industry partners to resolve this, build capacity, and identify delivery efficiencies.*
>
> *We are confident we can deliver our planned work programme as set out in our 2024 AMP. Our delivery capacity has grown significantly over DPP3, delivering our increased capex work programme year-on-year.*

[5] https://comcom.govt.nz/__data/assets/pdf_file/0020/350741/IAEngg-NZ-EDB-2023-AMP-Review-Information-Disclosure-Requirements-Review-22-Feb-2024.pdf

One of the reasons for our confidence is that the relationship between capex growth and work is not linear, particularly across different expenditure categories. A 40% increase in capex does not require a 40% increase in work for an EDB or electrical contracting services."

58. Vector therefore also recommends that the Commission acknowledge the non-linear relationship between forecast system growth capex and capacity requirements and ensure any impacts about deliverability on DPP4 settings are evidence-based.

Flexibility mechanisms

59. There appeared to be widespread acknowledgement from submitters that re-openers would be a feature of DPP and that, accordingly, the process needs to be fit for purpose.

60. For example, MEUG submitted:

"We are comfortable with the introduction of more re-opener provisions, on the provision that the reopener process is well resourced, is robust and consumers get transparency of both the application and decision."

61. Similarly, BEC submitted:

"We recommend providing assurance to EDBs that reopener applications will be streamlined but the overall process remains robust and transparent to stakeholders, ensuring any amendments to revenue allowances are validated on accurate and tested evidence."

62. A number of submitters highlighted the need for opex re-openers. We recommend the Commission ensure all re-openers also allow for efficient opex solutions.

63. Submitters described a number of circumstances where opex re-openers would be needed.

64. For example, PowerCo submitted:

"[…] we recommend the Commission expands the reopeners to include more drivers for opex (e.g., re-tendering field services), or allow for a single issue CPP. This addresses the Commission's concerns that customers bear the risk that EDBs are overfunded upfront but mitigates against the asymmetric risk of under investment as EDBs can apply for more funding when the cost arises mid-period."

65. In addition, Fonterra submitted:

"Fonterra supports the use of reopeners to cover the potential operational costs for Non-traditional solutions (NTS) and we recommend that the Commission makes these as simple

and low cost as possible as they do not need the level of scrutiny that a capital cost driven reopener requires."

66. Horizon submitted:

"No reopener mechanism exists to allow Horizon Networks to apply to reopen the price path due to additional vegetation management costs, even if those costs are realistic and quantifiable."

67. Horizon's point is particularly poignant given MBIE's ongoing and everchanging amendments to the Tree Regulations, which could have major impacts on vegetation management opex.

68. In fact, MBIE's most recent consultation states explicitly that EDBs should bear the costs of their proposed changes including their preferred risk-based approach that captures those trees that actually pose the most risk, without promoting deforestation or unreasonably increasing costs for tree owners:

"We propose that lines owners meet the cost of removing trees under our proposals, including the costs of undertaking the risk assessment, and associated costs such as removing debris. The cost would have to be reasonable if the removal work was undertaken by the tree owner. Broadly speaking, the regulatory regime under Part 4 of the Commerce Act 1986 should allow lines owners to meet the cost of avoiding significant unplanned outages."[6]

69. The Commission cannot leave this statement from MBIE unaddressed. The Commission should proactively signal its intent to provide a re-opener to ensure EDBs can recover any additional opex associated with changes to vegetation management practices when MBIE amends the Tree Regulations under both Phase 1 and Phase 2 changes anticipated during DPP4.

70. We would welcome clarification from the Commission if the change event re-opener is available for changes to vegetation management practices following the proposed amendments to the Tree Regulations. If it is not, the Commission should amend the IMs to ensure EDBs can recover these costs. EDBs would be subject to the disincentive of being penalised under IRIS for delivering changes associated with Government policy with EDBs being locked into allowances until 2030. This would prove openly frustrating to the Government's policy intent, by possibly delaying better customer outcomes in this space.

71. It is also critical the Commission amends the IMs to make the unforeseeable/ foreseeable large project/ resilience re-opener opex/capex neutral. Particularly to anticipate the Tree Regulations being amended now credibly on the Government's work-programme, vegetation management

[6] MBIE Proposal to amend the Electricity (Hazards from Trees) Regulations 2003 to address 'out-of-zone' tree risks, July 2024

approaches could be used to address high impact low probability events. However, the unforeseeable/ foreseeable large project/ resilience re-opener would not be available if it remains limited to capex.

72. Other examples which need opex reopener coverage are:

   a. Digitalisation: EDBs could require system changes for e.g., to their enterprise reporting system (ERP), these costs involve a full programme of work; and
   b. Field service contract renewals (as raised by PowerCo): these can/ will happen in DPP4, and rates could mean opex could significantly exceed allowances.

73. Another solution the Commission could consider is an IRIS reopener. Where EDBs incur costs exceeding their allowances (either opex or capex) but those costs are justified to be in the long-term benefit of consumers, the EDB would not incur the IRIS penalty from overspending their allowance.

74. In terms of consumer consultation, we disagree with MEUG's suggestion that:

> *"[…] we encourage the Commission to require the EDBs to demonstrate how they have consulted with impacted stakeholders as part of the reopener application process. This would go some way in addressing concerns about whether the long-term interest of consumers has been duly considered*."

75. While consumer consultation will be relevant for some re-openers, for others it would add a disproportionate regulatory burden and costs for little consumer benefit. We recommend the Commission follow the approach suggested in PwC's guidelines submitted by the Big Six EDBs.

Innovation and non-traditional solutions allowance (INTSA)

76. There is overwhelming support from submissions for an increase of the INTSA fund to higher than the proposed 0.6% of maximum allowable revenue (MAR). Both EDBs and non-EDBs have recognised the scale of innovation required in the sector. This suggests a strong need for the Commission to pause for thought and recheck even on its own assumptions, perception of scale, even ambition, of what is truly required within its DPP4 decision to enable the fundamental change, innovation and transformation that is painted by submitters. We believe it is unprecedented in feedback to a Commission's decision for there to be such clear and categoric demand for more meaningful change. We would encourage the Commission to listen, and even play catch up to the under-shooting on innovation within DPP3.

77. SolaZero explains that the fund should be increased:

> *"The INTSA is a very important initiative and is essentially the only lever the Commerce Commission is proposing to use to shift the industry from being an inefficient user of capital to a more efficient user. The INTSA must be of a meaningful size in relation to the huge*

change in the power system; 0.6% is not huge and INTSA must be increased substantially, e.g., 5%."

78. EECA believes the proposed cap is too small:

    "[…] we are concerned that the innovation allowance cap of 0.6% is small and will be insufficient to address the significant need for innovative solutions. We recommend increasing the INSTA cap."

79. FlexForum has pushed for "a big carrot allowance":

    "At a minimum, the Commission needs to add the additional innovation incentive mechanism that provides a bigger carrot and clearly signals and rewards ambition and investment in learning-by-doing - the highly ambitious option must be a part of the next DPP."

80. Consumer NZ also agrees that the allowance needs to grow to 5% of MAR demonstrating a desire for more fast-paced change in this sector for consumers to benefit from:

    "We agree this more ambitious option would strongly incentivise EDBs to undertake larger scale energy efficiency initiatives. EDBs having an innovation and non-traditional solution allowance (INTSA) of 5% of MAR allows them to undertake larger and more innovative energy efficiency and demand-side initiatives."

81. And MEUG concedes that:

    "The proposed INTSA is set at a very low rate (0.6%) and may not be material enough to drive the change that is needed. An INTSA up to a rate of 5% may be needed to drive the change that is needed."

82. With this overwhelming support, Vector also agrees that the greater the incentives are for innovation, the more benefits to consumers in the long run (noting that one of the criteria is that the INTSA projects need to promote the Part 4 purpose).

83. However, we share Unison concerns around the eligibility of flexibility services for the INTSA.

    "Unison remains concerned that procuring flexibility services (which may optimise demand-side management in DPP4) may be available once only per EDB under the current proposed INTSA criteria."

84. The Commission needs to allay these concerns and clarify that a non-traditional solution or non-wire alternative does not automatically become "traditional" if it forms part of a successful INTSA project. Similarly, if a non-traditional solution is "riskier than BAU" for one project does it automatically become "BAU" if used (albeit differently) on a subsequent INTSA project.

85. In order to circumvent this issue, Vector suggests, as we did in our response to the DPP Issues Paper, that flexibility services be picked up by a separate, dedicated innovation fund (i.e., separate to the proposed INTSA).

86. On the other hand, there are a decent number of suggestions that a portion or full allocation of the INTSA be specifically allocated for energy efficiency schemes. While we fully agree that energy efficiency (and demand side management) should be in scope for the INTSA, we would not want it restricted in this way.

87. We agree with Energy Trusts New Zealand (ETNZ):

> *"[…] we believe strongly that energy efficiency projects should be eligible for funding under this mechanism. Our members have a long history of supporting these projects for the betterment of their customers and communities and have seen firsthand the benefits such initiatives deliver. They are an effective means of providing relief for families experiencing hardship."*

88. We are interested to hear from the Commission and other stakeholders what type of energy efficiency projects would qualify under the INTSA and would welcome this discussion to be part of the innovation workshop on 15 August 2024. Limiting the workshop to merely to simply discussing application, assessment, and approval process is a missed opportunity. Scope (including project eligibility) and purpose of the INTSA must be on the agenda.

Demand side management and distributed energy resources (DERs)

89. There are suggestions from certain submissions that demand side management and non-traditional solutions are underutilised by EDBs.

90. CAC explains:

> *"Our concern therefore remains that consumers will end up bearing the risks and costs of deficiencies in EDBs' planning and the industry's slow progress in recognising the important role of demand management and distributed energy resources in meeting electricity needs."*

91. And SolarZero says:

> *"The electricity industry is going through a once-ever change. Asset management plans are not yet reflecting the uptake of the new technology and approaches, such as flex and efficiency. Yet the Commerce Commission bases its DPP4 decisions on the published AMPs. The approach is therefore circular and could result in poor outcomes: AMPs do not reflect the new way the power system could work, the Commerce Commission bases its decisions on the AMPs, the power system does not evolve, the AMPs do not reflect flex and efficiency, the Commerce Commission bases its decisions on AMPs, the power system does not evolve and so it goes."*

92. Yet IAEngg found that:

> *"[…] the EDBs' AMPs are of generally high standard. The purpose of the AMP is broad and is not required to provide full and detailed justification for expenditure. The lack of data listed above should not be seen as a deficiency of the AMPs. Rather, supplementary information is required to justify expenditure arising from new drivers where there is no historic data."*[7]

93. This comment by IAEngg hints that AMPs, though of good quality, may need to provide more details on the integration of "new drivers" such as DERs on our networks. Since the review took place, the targeted information disclosure review has introduced new requirements to include more of these non-traditional drivers into EDBs' AMPs.

94. As we explained in our submission to the Authority on 'The future operation of New Zealand's power system',[8] third-party management of distributed resources on EDBs' networks is relatively nascent in New Zealand, but operating protocols must be put in place before scale increases. Done well, management of distributed flexibility can save investment and operating costs across the entire system, delivering significant consumer benefits. However, this must be done in a way that keeps networks and consumer supply safe and stable. Parties offering portfolios of resources into the wholesale market, or in response to other market signals, must be aware of the physical and power quality limitations of the networks relative to the individual resources in their portfolios. There must be clear protocols in place specifying how operating limits are to be respected and local and national emergency events managed.[9]

95. Coordination of system operation on, and between, distribution networks will be at least as critical in future as vertical coordination across the value chain. The role of the EDB is changing significantly, in New Zealand and globally. There is significant collaborative effort underway to develop systems and processes in this space, including by ENA's Future Networks Forum.

96. Some of the topics included in these engagements include future system operation, regulatory settings for distribution (including operating protocols, Part 6A requirements and commercial access to data), distribution pricing, streamlining network connections, financeability of new investment, evolving service quality metrics (for a world in which third-party DER management is prevalent), and flexibility in funding allowances (opex versus capex).

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[7] https://comcom.govt.nz/__data/assets/pdf_file/0016/343411/IAEngg-NZ-EDB-2023-AMP-Review-Forecasting-and-Planning-Assesment-Report-29-January-2024.pdf

[8] https://blob-static.vector.co.nz/blob/vector/media/vector-2024/vector-submission-on-the-future-operation-of-new-zealand-s-power-system.pdf

[9] Vector explored this in detail with the help of NERA Consulting in respect to EVs, by preparing a report 'Promoting Efficient and Affordable Infrastructure to Enable Electrified Transport', https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/nera-report-for-vector-20230228-v1-0.pdf

97. The flexibility market in New Zealand is fertile ground for the INTSA to play a huge role in driving the sector towards a future energy system, however, as previously raised we are not sure of its workability surrounding flexibility solutions. The Electricity Authority has clearly indicated the potential for EDBs to participate in this nascent market, we now believe the Commission needs to enable the ambition through a higher INTSA fund or otherwise perpetuate a "chicken and egg" delay to better customer outcomes.

Quality

98. Submitters appeared in favour of continuing the current quality standards. Our submission recommended the Commission revert to the 'two-out-of-three' rule for assessing quality. Aurora similarly submitted that:

> "*We encourage the Commission to reconsider its decision in DPP3 to move away from the two out-of-three rule because we consider that rule to be more appropriate as it allows for one-off poor performing years, which alone may not constitute an underlying material deterioration of reliability*."

99. We strongly agree with Unison's recommendations to ensure the DPP incentivises 'safety first' outcomes around fire risk:

> *"Unison adopts Fire Emergency New Zealand's (FENZ) procedure to shut off auto-reclose during-risk fire periods. We are prepared for more drought conditions caused by climate change. However, safety first is not the outcome currently incentivised by the DPP. The risk increases as adverse weather conditions worsen that are out of EDBs' control.*
>
> ***The existing regulation risks creating an unnecessary risk of harm** (for example, incentivising EDBs not to turn off auto-reclose in high fire risk conditions which includes high wind). Unison had modelled the impact of shutting off auto-reclose on its SAIDI and SAIFI and it is significant.*
>
> *The existing disincentive affects groups of networks differently as it is highly dependent on vulnerability to vegetation risks. There are a large group of non-exempt EDBs who are vulnerable to vegetation risks, and particularly fall distance zone risks based on topology of their regions and network type (overhead or underground). The Information Disclosure confirms the substantial portion of outages caused by vegetation across exempt and non-exempt EDBs*
>
> *Statutory obligations require EDBs to manage vegetation consistent with the Electricity (Hazards from Trees) Regulations. EDBs ability to manage vegetation risk in the Tree Regulations is limited to the growth limit zone and does not extend to the fall distance zone.*
>
> ***It is inequitable to penalise EDBs through economic regulation for a risk they mostly cannot legally or cost efficiently minimise***

Unison's vegetation outage data validates that fall distance zone trees cause most vegetation related outages. This directly correlates to the impact of shutting of auto-reclose. Auto-reclose systems automatically restore power after a transient fault, such as those caused by fallen branches, animals or lightning strikes (it turns the power on and off in short bursts to test whether the object or fault remains). The SAIDI and SAIFI impact of shutting off auto-reclose is highly dependent on the surrounding vegetation conditions

Provide an incentive of SAFETY FIRST given the specific risks relating to electricity and fire. This can be implemented by*:*

• excluding interruptions in the Compliance Statement where there is an evidenced link to FENZ's high fire-risk rating during the time of the outage, procedures or an instruction – as we understand is consistent with what is proposed for INTSA projects; and / or

• providing a distinct class of outage to attribute to FENZ procedures or instructions and excluding that class from calculations for breach.

***Consumer interests are not supported by EDBs trading-off an imprudent fire risk against maintaining quality**.*"

100. Fire risk is increasing due to more frequent severe weather and higher temperatures, so this is likely to become a more significant issue. Overseas jurisdictions have seen significant fire events. Accordingly, we consider the Commission should clarify up front how this should be treated under the quality standards. Currently fire risk is a gap in the regime.

101. As always please feel free to get in touch to discuss any of the above.

Yours sincerely

[redacted]

Richard Sharp
GM Economic Regulation and Pricing