12 July 2024

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Tēnā koe Ben,

Powerco's submission on EDB DPP4 Draft Decision

Powerco Limited (**Powerco**) welcomes the opportunity to respond to the Commerce Commission's (**Commission**) draft decision on the default price-quality path commencing 1st April 2025 (**DPP4**). We acknowledge how challenging and different this DPP reset has been compared to previous DPP resets and appreciate the amount of work that has gone into producing a pragmatic decision.

This reset has real consequences for meeting Aotearoa's electrification needs where EDBs play a key role in fostering emerging markets in flexibility while ensuring security of supply as an investor of last resort. We are concerned the Commission's draft decision may slow down the energy transition and result in costly trade-offs, because:

- Inadequate funding risks security of supply as New Zealand's reliance on electricity significantly increases. The impact of this draft decision indicates we won't be able to invest and respond to the energy transition at the right time, which may end up costing consumers more in the medium-to-long-term if EDBs are forced to trade-off investing in the transition against maintaining their networks. For an additional ~$2.50 increase in a household's monthly electricity bill, the Commission could safeguard against the asymmetric risk of under investment and protect against higher future increases if this investment is deferred until DPP5.

- There is a potential for an unintentional capex bias, if opex allowances are insufficient or reopener mechanisms inadequately support uncertain opex. EDBs will be trading off investing early against the least cost solution. For example, flex solutions might be disincentivised if individual projects can't be grouped into programmes to meet reopener thresholds. It is possible that individually, flex opportunities fail to meet the threshold.

- We are exposed to a significant funding risk through the retendering of field service contacts. We strongly encourage the Commission to consider a mechanism, such as additional opex reopeners or a single issue CPP to accommodate uncertain opex. Field service contracts must be retendered periodically to ensure they represent market-tested rates for efficient delivery, but that introduces the risk of cost increases exceeding normal cost inflators, that will likely result in less work being undertaken by our field service providers.

Our response to the DPP4 draft decision is provided in the following document submitted alongside this letter. If you have any questions about this submission, please contact Emma Wilson (Emma.Wilson@powerco.co.nz).

Yours sincerely,

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POWERCO

Powerco response to DPP4 draft decision

Commerce Commission

12 July 2024

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1. Executive summary

1.1 The Commission has delivered a pragmatic draft decision under challenging circumstances

1. Powerco acknowledges the Commerce Commission's (**Commission**) draft decision on the default price-quality path commencing 1st April 2025 (DPP4). We recognise the amount of work that has gone into producing a pragmatic decision endeavouring to address and reconcile the perspective of submitters raised in the issues paper and through the Input Methodologies (**IM**) review process. The Commission's final decision due in November 2024 comes at a critical time for ensuring electricity distribution businesses (**EDBs**) have the right incentives and funding to deliver the growth and change required to meet evolving customer preferences and Aotearoa's electrification needs.

2. The Commission's decision is taking place in a period of significant change and uncertainty for the sector, where EDBs play a key role in enabling the electrification of New Zealand. To meet customers' additional demand and to adapt to changes in the way the network will be utilised and the climate conditions in which it will need to perform, a material uplift in investment is needed in both network and non-network solutions. That investment needs to include resourcing EDBs to enable them to foster emerging markets in flexibility while ensuring security of supply as an investor of last resort.

3. Changes in demand and increasing resilience needs are difficult to forecast perfectly, but the one thing we can be sure of is that they will not be linear. Electrification becomes viable / desirable for customers with similar use cases within a similar window and uptake will therefore likely move in step-changes. Climate related impacts will occur in unpredictable and sudden moments. EDB performance and the Commission's enablement of it, as experienced by customers in each of those circumstances will be judged with hindsight. EDBs and the Commission are tasked with charting a path through this.

4. In this context, we appreciate how challenging and different this default price quality path (**DPP**) reset has been compared to the first three DPPs. The Commission's decision must balance price shocks to customers with ensuring adequate levels of investment to efficiently meet the demands of consumers, all within a high inflationary and interest rate environment.

5. The Commission's draft decision takes an evidenced and principled based approach to developing Powerco's allowances for the five-year period beginning 1 April 2025. We agree that the primary purpose of the decision is to promote the long-term benefit to consumers and deliver section 53K of the Act by setting price-quality paths for suppliers in a "relatively low-cost" way. Additionally, we:

   - Accept there is a role for flexibility mechanisms to deal with uncertainty, however we encourage the Commission to widen the scope available to accommodate more categories of uncertain opex (e.g. field service contract renewals)
   - Accept that a CPP is an option if it's not possible to meet customers' needs under a DPP with flexibility mechanisms
   - Commit to working with the Commission to ensure the success of DPP4.

6. While we appreciate the suite of flexibility mechanisms and other instruments the Commission is bringing over from Transpower to EDBs, we want to reinforce differences between the two. These differences not only relate to operational aspects but also include differences in the regulatory regimes, which may mean there are areas where the flexibility mechanisms aren't as effective, or the incentives aren't quite right. These points are discussed throughout this submission and summarised as follows:

- Large customer contracts (LCCs) – incentives to use these are different for EDBs (compared with Transpower) given the variation in the types of customers which gives rise to an increased risk of stranding.
- Reporting requirements – EDBs work programmes change frequently, so any ADR / list of priorities is only going to be a snapshot in time. Compared with Transpower, whose work programme is more predictable.
- Fungibility of the DPP vs IPP and needing to make the DPP work in a low-cost way limits the read across from Transpower.

7. Our key messages below are targeted to areas where changes to the final decision would better support us to deliver the Commission's statutory purpose and better achieve the long-term benefit of consumers. In the main body of this submission, we then outline our key messages and responses. Appendix A details modelling errors we have identified, and Appendix B sets out other comments which are not the main focus of this submission.

1.2 Incentives of the whole DPP4 package need to align

8. The majority of the DPP4 revenue increase results from exogenous factors (~70%), with opex and capex allowances not significantly altering the price path for DPP4. We are concerned that the increase in WACC / CPI has caused the Commission to take a conservative approach to allowances. The risk of inadequate funding is detrimental to consumers over the longer term, potentially resulting in a slower transition for the sector and more substantial shocks in DPP5 if we end up in a period of catch-up.

9. If opex isn't funded appropriately, there is risk that EDBs can't make efficient investment at the right time, and/or they will be incentivised to make capex investment to support electrification as opex is prioritized for core functions (e.g. maintenance) to stay within allowances and meet quality standards. As the Commission notes in its paper,[1] opex allowances provide resources for EDBs to fund recurring activities that are not capex, including activities essential to the network operation such as maintenance and planning. This does not recognise the key role of opex in preparing for and delivering non-network solutions. It also does not capture the increase in recurring activities due to network growth and decarbonisation.

10. Using the Commission's models[2] we have tested the materiality of the impact on customers if the Commission approved the full 2024 AMP for Powerco (both capex and opex). This results in an average increase in a household's monthly electricity bill of only $2.52 compared to the draft decision. Allowing this modest increase in monthly charges safeguards against the asymmetric risk of under investment, which is in the long-term interest of consumers. Additionally, it protects against higher future increases if this investment is deferred until DPP5.

11. There is potential for unintentional capex bias, if opex allowances are insufficient. EDBs will be trading off investing early against the least cost solution. There is a critical role for opex solutions to deliver benefits to customers at least cost compared with traditional capex solutions, however, if funding is only sufficient to cover BAU it's either going to delay EDBs investing in opex solutions (i.e. won't occur at the efficient time), or it will force EDBs to favour alternative capex options.

[1] Commerce Commission, *Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision*, at 2.72

[2] Commerce Commission, *Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision*, consumer bills impact model – Powerco.

12. While the IRIS mechanism goes some of the way to equalize incentives between capex and opex, there are a lot more flexibility mechanisms available for capex than opex. This disparity could put real pressure on opex allowances, which are already starting from a low base. EDBs' opex spending in DPP3 has been constrained by allowances that were in hindsight, too low given the level of inflation and therefore do not accurately reflect the escalating costs over the DPP3 period.

13. As MEUG states[3]

> *...strongly focus on how we can better encourage EDBs...to fully optimize the use of...distribution network and develop non-traditional solutions before seeking to build additional infrastructure*.

We agree with MEUG, and Powerco is up for the challenge, the funding and incentive settings need to be able to support this.

14. The capex bias is potentially stronger due to limited flexibility mechanisms for opex. Increasing the availability of flexibility mechanisms to support uncertain opex would help mitigate potential capex bias resulting from the greater number of capex flexibility mechanisms.

15. While there are opex reopeners for costs associated to the energy transition (e.g. flexibility services), there isn't anything available for base opex. As Aurora has acknowledged[4] we are bound by the timings of resets and if spend isn't known with enough certainty to meet the step change criteria at the time of the reset, we are forced to make costly trade-offs. This is evident in the Commission's recent trends study mentioned below.

16. In light of the above, 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. This solution is aligned with the Commission's decision-making framework because it:

    - Is consistent with low-cost principle – by making the most of existing mechanisms already familiar to the Commission (i.e. as opposed to introducing more).
    - Allows for proportionate security – as EDBs must meet the higher burden of proof required for reopeners compared to step changes.

17. The asymmetric consequences of under investment will end up costing customers more in the long-term. Underfunding will force EDBs to trade-off investing in the transition against maintaining performance**.** If investment is too late, and we are too slow to respond to the energy transition or resilience investments, it puts at risk security of supply. As New Zealand's reliance on electricity significantly increases, customers may face more frequent outages and will be unable to connect their EV charging points, their distributed energy resources (**DER**) or electric vehicles when required if EDBs can't keep pace. A recent report by the Commission on Trends across local lines company highlights that EDBs have been historically underfunded: [5]

    - Reliability performance indicators across all networks has decreased, with the long-term trend between 2013 and 2023 illustrating that there have been more outages in total and each outage

[3] Major_Electricity_Users_Group_YBXNDMR.pdf (ea.govt.nz)
[4] Aurora Energy, *DPP4 Issues Paper Submission*, 19 December 2023, pg 11.
[5] Commerce Commission, Trends in local lines company performance, 25 June 2025, pg 5

lasts longer. If funding levels continue to be limiting (e.g. improvements in fault responses will require opex), the existing decline in reliability performance is likely to continue across the sector.

- Profitability has been generally lower than the Commission's estimate of a reasonable return on investment, which is likely to be amplified by the recent change to depreciation. EDBs must have the expectation of real FCM to ensure there are incentives to invest in the network.

18. The base-step-trend (BST) forecasting approach is suitable for forecasting recurring and predictable opex in a stable operating environment. However, the future opex requirements are not recurring and predictable and need to be appropriately accounted for.

19. Given the Commission has retained the BST approach, it's critical they accurately account for step changes. Suggesting that scale growth trends based off historical expenditure will capture any step ups in workforce requirements in system growth and decarbonisation,[6] to name a few, is incorrect. These changes are the result of the energy transition, which is unrelated to historical relationships, and we encourage the Commission to acknowledge and address the limitations of BST.

20. As the Commission has noted recently in their draft decision for Chorus PQP2 proposal, the BST has limited application, and the Commission should be consistent in its views:

> "*…transitional nature of Chorus' business creates issues for the application of a BST approach for forecasting opex. For BST to be effective it generally requires a relatively stable operating environment…*"[7]

21. Just as the Commission is concerned with ensuring EDBs aren't remunerated twice for the same cost, the Commission needs to be equally confident they are not precluding any efficient costs. EDBs are in a period of transition where the next five years are relatively unstable and uncertain, and as previous submitters[8] have stated, historical expenditure is not going to sufficiently forecast expenditure requirements facing EDBs.

22. The Commission needs to be confident that all the caps they are applying (e.g. cap on opex step changes, capex cap and price shock caps) don't contradict and result in EDBs being underfunded or impact on incentives. As mentioned above, there is a risk the caps may result in the Commission precluding costs.

23. We disagree with the Commission that a cap on step changes is required. Imposing an arbitrary threshold undermines the purpose of the decision-making factors and increases the risk of underfunding EDBs. The step change decision-making framework allows the Commission to apply proportionate scrutiny and if the Commission is satisfied that step changes meet the decision-making factors, there is no justification for a cap on step changes.

1.3 Flexibility mechanisms need tighter definitions, less ambiguity and the right incentives

24. We anticipate a heavy reliance on flexibility mechanisms to make the DPP4 work effectively, allowing us to deliver the necessary investments and connections for consumers. However, we have identified several areas where the incentives aren't quite right, or where ambiguity remains about their practical application due to

[6] Commerce Commission*, Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision*, pg 201-202
[7] CC chorus draft decision at 7.7
[8] Powerco, Solar Zero, Wellington Electricity

challenges, such as how we interpret key criteria like "risker than BAU". We offer some pragmatic solutions below.

25. Mechanics of flexibility mechanisms need to work efficiently with ambiguity removed. We are concerned with the mechanics of the flexibility mechanisms and how they will work in practice to deliver investment that consumers want, at the right time at the least cost.

26. There is a real risk sixteen EDBs get caught in regulatory processes which will only slow down the energy transition and will ultimately come at a cost to consumers. Considering this, the industry has worked with PwC to develop reopener guidance, which we encourage the Commission to adopt. This will speed up processes, reduce uncertainty and lessen the burden on the Commission.

27. Incentives of large customer contracts (LCC) aren't right to encourage their use. Without an ex-ante allowance, EDBs are likely to favour reopeners. Under the LCC EDBs are allocated the full risk of investment, which exposes EDBs to asset stranding in the event a customer can't fund the connection for the life of the asset or technology change displaces investment. The EA's plans to regulate connection pricing may also impact how EDBs can manage this risk.

28. While LCCs work particularly well for Transpower, their risk profile is quite different compared with EDBs. Transpower's customers are usually large established businesses, such as large generators, EDBs, or large industrial customers, with a lower risk of default. In contrast, EDBs' customers tend to be smaller commercial and industrial businesses, including new entities, with a higher default risk.

29. It's right that EDBs should manage most of the risk, as they can manage a degree of it through contracts, however, unless some of the risk is shared with consumers, it's unlikely that LCCs will be used, and EDBs are likely to favour reopeners.

30. This preference for reopeners may conflict with the Commissions low-cost decision-making principles, which aim to limit circumstances to reopen or amend a DPP during the period.[9] To address this, the Commission could utilise its framework for Type II asymmetric risks, as demonstrated with Chorus, where ex ante compensation was provided through a 10 basis point allowance applied to cash-flows.[10]

31. With an appropriate cap, the innovation and non-traditional solutions allowance (INTSA) could support EDBs to take bigger steps in a range of services, and reduce the need to implement additional mechanisms (e.g. use-it-or-lose-it). A **higher INTSA cap of 2.5% of MAR** is recommended, reflecting that DPP4 is the start of a sustained increased need for testing, progressing, and investing in more future focused types of electricity services, and the application process enables proportionate scrutiny by the Commission.

1.4 The Commission doesn't need to be concerned about deliverability given the primary incentives of the DPP to avoid reputational consequences and penalties

32. The Commission has raised deliverability concerns with EDBs and reduced allowances accordingly. We disagree with this as it moves against some of the primary incentives of the DPP. The Commission's starting point needs to be that DPP4 allowances must be assumed to be deliverable to avoid quality and reputational penalties for EDBs.

[9] Commerce Commission, *default price quality path for electricity distribution businesses from 1 April 2025 Draft reasons paper*, 29 May 2024, at B22.
[10] [6.1163] – [6.1217] of the fibre IMs

33. We are well rehearsed at delivering on large capex programmes and just like we did in our CPP, EDBs will plan for and implement step changes in organisational capacity and capability to be able to deliver on their commitments. This will also help New Zealand to 'grow to zero'[11], by supporting the economy (creation of jobs) on the road to net zero. Powerco has already taken steps to address deliverability, as highlighted in our response to the Issues Paper.[12]

34. The Commission needs to look at its DPP4 package as a whole. It is inconsistent to reduce capex allowances due to deliverability concerns while not approving opex step changes for workforce expansion and initiatives like graduate programmes aimed at upskilling the workforce and improving EDB deliverability. EDBs are being prudent by forward planning to get ahead and address any potential workforce shortage, but insufficient funding threatens the energy transition's deliverability. Achieving deliverability lies not only in EDBs management of capex delivery programmes but in the amount of capex and opex funding approved.

35. Workforce planning across EDBs is in progress through the ENA. We are also enthusiastic about the opportunity for the sector and government's work on the Government and Sector Energy Transition Framework which aims to agree sector-wide priorities in transforming and decarbonising New Zealand's energy system, including workforce. Workstreams underway include workforce capacity is a key enabler, and we will need the necessary opex step changes for an uplift in workforce capacity. There is a horse and cart situation here. We therefore encourage the Commission to enable the workforce uplift that will support deliverability.

36. An opex reopener could play some role here to provide a means of making workforce increase requests, although reliance on reopeners will likely heighten deliverability issues as it impedes medium-long term planning. EDBs won't have certainty their work programmes will go ahead until they go through reopener processes, which is likely to slow down our ability to build up capability.

37. We support the additional reporting requirements proposed by the Commission, in particular annual delivery reports (**ADR**), which should give comfort on how EDBs are delivering against priorities and keep EDBs accountable. The Commission should first monitor before prematurely taking a view that EDBs aren't going to deliver their work programmes and reduce capex allowances.

2. Price Path

Summary of price path positions:

- We support the Commission's decision not to defer any revenue into DPP5.
- We support the Commission's increasing their threshold for price shocks however, assessing price shocks per ICPs ignores the fact that consumers are using more electricity and should include MWh changes as well.
- We support the Commission's consideration of financeability when determining the price path.
- We have identified a number of modelling errors which has impacted the Commission's analysis of Powerco's price path, these are described in Appendix A.

38. We appreciate the delicate balance the Commission has had to juggle to ensure EDBs have incentives to invest while managing customer impacts. The uplift in revenue over the DPP4 period is largely due to

[11] Powerco promotes 'Grow to Zero' to illustrate that New Zealand has the opportunity to grow the economy as we work towards the 2050 net zero targets.
[12] Powerco, *DPP4 issues paper submission*, 19 December 2023, pg 10-12.

exogenous factors, CPI and WACC updates account for ~70% of the increase. This makes for a challenging decision-making environment, at a critical time of investment for the sector. We support the Commissions decisions to:

- Allow full recovery of DPP4 revenues in period with no deferral into DPP5. This ensures EDBs can maintain real FCM which is fundamental to ensure continued investment in the sector.

- Apply a financeability test as a practical sense check and we welcome the Commission using a BBB+ rating as these reflect credit metrics that rating agencies widely apply. While not a statutory obligation, financeability is a critical consideration.

- Smooth revenues to mitigate price shocks to customers, however, the revenue smoothing limit should also include MWh changes to better reflect New Zealand's energy transition and the significant uplift in electricity consumption i.e. it's not just prices driving up costs, it's the increased reliance on electricity and that needs to be reflected in the Commissions assessment.

39. End consumers won't necessarily be exposed to price changes immediately. EDBs bill retailers, who control how and when changes in EDB distribution charges are passed onto end consumers. Retailers can smooth out price change through hedging and bundling. Consequently, there can be a delay before end consumers actually see the increase in EDB lines charges.

40. We have identified several modelling errors in the Commissions modelling as a result of Powerco's transition from CPP to DPP which impact the Commission's analysis of Powerco's starting prices and application of the X-factor. Details of the modelling corrections are set out in Appendix A.

3. Capital expenditure (capex)

Summary of capex positions:

- We support the Commission's approach to setting a base level of capex with the opportunity to apply for reopeners where there is uncertainty.
- However, relying on past expenditure as a baseline does risk potential slowdown in the energy transition, and increase uncertainty.
- We support maintaining CGPI index in combination with the 0.8% uplift to reflect increasing input costs.

We recommend the Commission:

- changes the 45-year life assumption for new assets, to align with existing asset depreciation changes.
- compliments its depreciation change by allowing for a wash-up between forecast and actual depreciation.

41. EDBs are required to make significant investments in network capacity and capability over the next decade, and beyond, to support New Zealand's transition to a low carbon economy. If New Zealand is to meet its 2050 emissions reductions targets, investment needs to start now. The regulatory settings need to adapt to accommodate this additional investment, otherwise the legislated targets will not be meet.

42. While we are still of the view that our asset management plan (**AMP**) is the best forecast of our expenditure requirements to meet the above targets. Increasing the percentage cap to 125% goes some of the way to addressing the concerns of EDBs, but it's unlikely to be enough and may see an increase in the number of CPP applications as a result.

43. We support the Commission's approach to setting a base level of capex with the opportunity to apply for flexibility mechanisms for areas where there is uncertainty around the timing and cost of the project, as we expect our investment needs will exceed what has been allowed for under the 125% cap.

44. Increasing the capex cap slightly to 130% will ensure we are able to more efficiently keep pace with the energy transition while limiting the extent we need to reopen the price path within the period. This will have limited impact on consumers, an extra $0.57 change in monthly bill per ICP[13] or $6.80 per year, when compared to the draft decision. As mentioned above in paragraph 32, it's not appropriate for the Commission to make assumptions about our ability to deliver on our capex programmes.

45. Specific points regarding flexibility mechanisms are set out further below.

3.1 Adjustments for input price growth

46. We support the Commission maintaining the Capital Goods Price Index (**CGPI**) with an additional adjustment for input price growth for EDBs beyond the all-groups CGPI to reflect ongoing input price pressures. We appreciate the work and evidence the Commission has considered in arriving at this decision.

3.2 Depreciation and asset life assumption on newly commissioned assets

47. The 2023 IM review changed how depreciation is forecasted over the DPP period for the purpose of estimating the return on capital and depreciation building blocks of allowable revenue. This change involves using a forecast of actual depreciation of existing assets, calculated on an asset-by-asset basis over the DPP period, rather than the simplified assumptions previously used in DPP3.

48. We recognise this change better reflects our actual depreciation and have systems capable of forecasting future depreciation on an individual-asset basis. We are aware however that EDBs encountered some implementation issues during the 53ZD process prior to the draft decision:

- Inconsistencies in the responses – some EDBs responses had no change as a result of the new methodology, while others had depreciation on existing assets increasing over time.
- Confusion about how to calculate it – while we are aware the Commission plans to hold a workshop / issue guidance, it's unclear how the Commission can be confident all EDBs can calculate depreciation values correctly in a low-cost way.
- Systems challenges – it's possible that not all EDBs have systems available to be able to calculate depreciation to this level of disaggregation.
- Concerns about audit / certification implications for the forecast depreciation.
- It has a material impact and comes as a surprise to EDBs – we would have welcomed early guidance from the Commission on the expected impacts so we could have understood and prepared for the implications of the change.

49. We understand the ENA submission is proposing a transitional arrangement to enable EDBs some time to be able to comply with the new regime and we think that has merit to achieve a consistent approach. We also

[13] Calculated using the DPP4 draft decision models and updating the capex cap input from 125% to 130%.

recommend that the Commission[14] complements its approach by using the wash-up mechanism to correct for differences between forecast and actual depreciation given the materiality of the depreciation change, the inconsistencies across EDBs, and the complications with forecasting at this level of detail. The Commission could also incorporate a wash-up for disposals as part of this change, given it's difficult to forecast disposals into the future.

50. We also recommend the Commission changes it's 45-year assumption for the remaining life of newly commissioned assets and adopt a weighted average asset life that more closely reflects the actual depreciation and useful lives of these assets. The Capex Wash-up portion of the Capex IRIS mechanism washes up for this depreciation difference, however the recovery is delayed until the next DPP. EDBs will need to calculate the weighted average asset life of newly commissioned assets as an input to the Capex IRIS calculations, therefore the average of the historical DPP3 years could be used to calculate a more accurate assumption to be used in the Commission's financial model.

51. This is to align it with the Commission's change to depreciation of existing assets, which reflects actual depreciation. The mix of assets we commission will change as electrification increases, with more of these assets having shorter useful lives[15], making the 45-year assumption outdated.

4. Operating expenditure (opex)

Summary of opex positions:

- BST can only be relied on for recurring and predictive opex, it is less suitable for unstable operating environments such as the one the energy sector is currently in. Given the Commission has maintained BST to forecast, it is critical the Commission allows for appropriate step changes or widens the availability of reopeners for all types of uncertain opex.
- If opex is underfunded, there is a potential for a perverse capex incentive at a time when EDBs should be readying to increasingly embrace opex solutions.
- We support maintaining LCI/PPI index in combination with the 0.3% uplift to reflect increasing input costs, however we note a generic uplift does make demonstrating what costs are included/excluded in the opex trend challenging.
- We support the Commission's decision to apply a 0% opex partial productivity adjustment.

52. We acknowledge that there are limited forecasting techniques that, consistent with section 53K of the Act, provide a "relatively low-cost" method for setting DPP4 opex allowances for all 16 non-exempt EDBs. However, there is a real risk of an unintentional capex bias and asymmetric consequences of under investment if opex isn't funded appropriately.

53. 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.

54. The BST approach is only sufficient if the Commission appropriately considers the full amount and breadth of the necessary step changes to enable EDBs to play their role in the energy transition. Otherwise, the better alternative is to use EDBs AMPs for opex forecasts. The BST, as currently designed, fails to capture certain

[14] Part-4-IM-Review-2023-Draft-decision-Report-on-the-Input-methodologies-review-2023-paper-14-June-2023.pdf (comcom.govt.nz), at 4.12-4.14

[15] For example, the assumed useful life of a BESS could be ~20 years.

new opex requirements despite the changes made to the framework, such as scale trends and tweaks to the decision-making framework for step changes. These modifications do not account for changing customer preferences, emerging technology, and new regulatory requirements as these are unrelated to historical expenditure. Moreover, the BST will not capture significant step changes if the evidence is inadequately available at the time of reset.

55. Just as the Commission has the responsibility to safeguard that there is no double counting of costs, it has equal responsibility to ensure that it does not preclude efficient costs. Ensuring that opex is adequately funded upfront is consistent with its decision-making framework to limit circumstances to reopen or amend a DPP during the period and ensuring EDBs are incentivised to make efficient investment decisions.

56. We acknowledge the Commission's challenge of balancing incentives for EDBs to invest while minimising customer impacts. Nevertheless, we are concerned that the increases in WACC and CPI, which are exogenous factors driving the majority of the uplift in revenue, have caused the Commission to take an overly conservative approach in setting EDBs expenditure allowances. Unlike WACC and CPI updates, capex and opex allowances have a limited impact on the price path.[16] We are worried that underfunding expenditure in DPP4 will be detrimental to customers over the longer term, as it will result in a slower transition for the sector and inefficient allocation of resources through both DPP4 and DPP5.

4.1 Methodology elements

57. This section outlines our views on key elements of the opex forecasting methodology:

- Selection of 2024 as the base year
- Scale trends
- Step changes.

4.1.1 Selection of the base year

58. Using 2024 as the base year provides the most recent available full-year record of actual audited expenditure but needs to be truly representative of an EDB's efficient and sustainable ongoing level of opex. Because the base year is fundamental to ensuring opex allowances are correct and that IRIS is effective, we encourage the Commission to conduct some form of base year assessment and adjusting it (up or down) to reflect each EDBs efficient and sustainable ongoing level of opex. Failing to make this adjustment risks perpetuating a recurring pattern of insufficient allowances.

59. This was evident for Powerco during DPP3, where we had insufficient funding to support activities in a high inflationary environment (salary and wage cost increases above inflation, insurance increases) as well as incurring additional IT costs such as SaaS and cyber security. Consequently, we constrained expenditure in areas where some additional short-term risks could be managed, which has resulted in an unrepresentative 2024 base year that is $2 million too low, as illustrated in our 53ZD response.[17] This needs to be corrected to ensure sustainable network operations.

4.1.2 Scale trends

[16] Only 33% of the increase in allowable revenue is due to expenditure (opex 20% and capex 13%).
[17] Powerco, 53ZD response – information to support our draft 2024 AMP expenditure forecasts, 21 December 2023, pg 13.

60. We generally agree and support the Commissions approach to scale trends, however, we encourage the Commission to consider the limitations of this approach. As noted above, it is unlikely to accurately capture any steep increases in workforce requirements due to system growth and decarbonisation (for example, opex costs incurred in supporting the connection of distributed generation during the early planning and concept phase which are not part of historical trends). Scale trends, based solely on historical relationships will fail to accurately account for the future operating environment. The Commission has noted recently in their draft decision for Chorus PQP2 proposal that the:

> *"…transitional nature of Chorus' business creates issues for the application of a BST approach for forecasting opex. For BST to be effective it generally requires a relatively stable operating environment…"* [18]

While Chorus is transitioning from network growth to a steady state, similarly, EDBs, are also in an unstable and transitional operating environment, moving from a steady state to a period of growth. The Commission should be consistent it is view and apply the same perspective to the EDB DPP4 reset, recognising that the BST has limited application in these circumstances.

61. While we welcome the refinements made to scale trends, in particular the addition of capex as a driver of non-network expenditure, the Commission's attention needs to be on ensuring step changes are sufficient.

Cost escalation

62. We support the Commission's decision to apply the same cost escalators to all opex along with the application of a 0.3% uplift to reflect historical higher inflation in the electricity, gas, water and waste sector.

63. It's a pragmatic and evidenced decision which balances the Commission's low-cost principles with industry concerns that using a general index will miss structural supply and demand effects EDBs and their supply chains are exposed to.

64. While we have previously advocated for the use of a customised EDB index,[19] we appreciate the amount of work the Commission has done to explore alternative options and we consider this to be a reasonable solution given the lack of information about the breakdown of EDB-specific cost drivers which is required should a more targeted approach be used.

Partial productivity factor

65. We support a 0% opex partial productivity adjustment, as EDBs are in a period of transition and it's not practical to enforce productivity targets that would not otherwise occur. Without a productivity adjustment, incentives remain for EDBs to reduce cost and pass benefit onto consumers.

66. Productivity growth occurs when the aggregate quantity of outputs grows at a faster rate than the aggregate quantity of inputs. Forecasting changes in productivity is inherently complicated and uncertain. Relying on past data is not reliable for predicting future productivity achievements due to variations in operating environment, and changes in input and outputs, among other factors.

[18] Commerce Commission, Chorus' expenditure allowances for the second regulatory period (2025 – 2028), Draft decision – Reasons paper, 18 April 2024, Paragraph 7.7 page 139.
[19] Powerco, Submission on EDB DPP4 issues paper, 19 December 2023, pg 15.

67. The Commission already accounts for some changes in productivity through the application of elasticities as part of the scale trend, which implicitly accounts for realisation of economies of scale and scope. This captures the assumption that opex will grow more slowly than output growth.[20]

68. The Commission's method applies a cost elasticity assumption as a first step and then separately consider whether there are further factors that justify any additional productivity assumptions. Elasticities already account for roughly $421m (7.4%) reduction in opex across all EDBs for DPP4.

69. Given the above, we support the Commission's decision to retain a 0% opex partial productivity factor. Measuring productivity is complicated, and there is no evidence to support the application of a partial productivity factor over and above what's already been accounted for. [21] In addition, it's not principled to apply a productivity adjustment in anticipation of discovery – to enforce productivity targets that would not otherwise be realised.

4.1.3 Step changes

70. We generally support the Commissions amended step change decision making framework and consider it appropriately balances the benefits and risks. However, we are disappointed with the DPP's inability to accommodate the retendering of field service contracts that occur near or after the final DPP decision. We encourage the Commission to consider a mechanism (such as wider scope for opex reopeners) to accommodate uncertain opex. The decision-making framework is still too stringent to allow spend that doesn't fall within the timings of the DPP reset, an issue also highlighted by Aurora.[22] The impact of rising costs that we aren't funded for is that less work will be completed.

71. We welcome the Commission's approval of three step changes for Powerco: insurance, customer engagement and LV monitoring (for purchasing and storage of data). In addition, we appreciate the opportunity to provide further evidence for step changes and we have submitted a separate document setting out our application for step changes assessed against the Commissions draft decision-making framework. The step changes we are submitting / resubmitting are:

    - Additional resource for LV monitoring
    - Graduate programme
    - Additional resource to address a future focused network

72. As mentioned above, for the BST to be a suitable forecasting methodology, it's critical that the Commission ensures step changes are correctly accounted for and they aren't precluding any necessary and efficient costs. In line with this perspective, we challenge the rationale for applying a cap to step changes, because:

    - The Commission can't be confident that all proposed caps, such as those on opex step changes, capex increases, and price changes don't conflict with each other and thereby risk leaving EDBs underfunded.

    - If step changes meet the decision-making factors and have been scrutinised through this assessment process, there is no justification for an additional safeguard. Imposing a cap undermines the purpose

[20] This point is illustrated by Incenta's work for Chorus' PQP2 proposal – I*ncluding a productivity assumption in opex forecasts,* 16 May 2024

[21] ENA, *Submission on CEPA EDB productivity study*, 24 April 2024. Powerco, *Submission on CEPA EDB productivity Study,* 24 April 2024.

[22] Aurora, *DPP4 issues paper submission, 19 December 2023*, pg 11.

of the decision-making factors, which is to apply proportionate scrutiny to mitigate the risk of funding opex that does not eventuate. The Commission's application of a cap calls into question the very role of the step changes decision-making factors and constitutes a duplication of scrutiny which is contrary to the Commission's low-cost principles.

- Limiting a step change solely because it exceeds an arbitrary threshold heightens the risk of underfunding EDBs. The Commission must be cognisant of the asymmetric consequence that under investment can bring about.

73. There is a direct correlation between our step change requests and deliverability. We have addressed this in the Executive Summary comments on deliverability above.

5. Flexibility mechanisms and innovation

Summary of flexibility mechanisms and innovation positions:
We generally support the Commission's approach with recommended improvements:

- Widening the scope of foreseeable and unforeseeable reopeners to include more general opex to reduce the potential capex bias, this actively balances the risk EDBs are underfunded and mitigates against consumers paying for opex that is not used.
- Adopt industry agreed reopener guidelines to assist with a more certain and streamlined application process.
- Increase the INTSA allowance cap to 2.5% MAR and replace the INTSA 'risker than BAU' criteria with 'an activity that has uncertain benefits.'

It is our view that:

- It's unlikely INTSA will support the Commission's 54Q objectives as the more certain the energy loss reduction benefits, the less likely it will meet the INTSA criteria.
- The full allocation of risk to suppliers for LCC is unlikely to warrant their use over the reopeners unless there is some mechanism for dealing with asset stranding risk.

74. The Commission's draft decision is to approve a suite of flexibility mechanisms to deal with uncertainty facing EDBs over the DPP4 period. We appreciate the work the Commission has undertaken throughout the IM review process, including reconciling views of respondents, to arrive at a well-developed and evidenced package of flexibility mechanisms.

75. We anticipate relying heavily on flexibility mechanisms to secure the allowances necessary for our DPP4 investment requirements. We are committed to working with the Commission to ensure DPP4's success by effectively utilising these mechanisms. However, we recognise that if DPP4, including its flexibility mechanisms, proves too restrictive to meet customer needs, we have the option of pursuing a CPP.

76. For flexibility mechanisms to be effective, the Commission must streamline the process and remove ambiguity from the criteria and definitions. Clear rules and processes will expedite the process and improve the quality of applications from EDBs, preventing the Commission and EDBs from getting tied up in burdensome and lengthy regulatory processes.

77. In the following sections we set out our views on the following uncertainty mechanisms and accountability:

- Foreseeable and unforeseeable reopeners
- Innovation and Non-traditional Solutions Allowance (INTSA)

- Large customer contract mechanism (LCC)
- Reporting requirements.

5.1 Reopeners process and definitions need clarity

78. The reopener criteria and process contain inherent ambiguities. Robust guidelines and examples will reduce uncertainty, application timelines and costs. The Big Six EDBs in partnership with PwC, have developed industry agreed guidelines that we recommend the Commission adopts to speed up flexibility applications and to reduce uncertainty regarding the interpretation of certain criteria and process. There is precedent to suggest that industry guidelines can deliver benefits. For instance, in the UK, Ofgem has produced re-opener guidance and application requirements that have proven beneficial for the sector.[23]

79. In addition to the above, we anticipate a practical issue with the ability to rely on reopeners for flexibility services. In our latest AMP, [24] we have identified the opportunity to deploy opex solutions to reduce capex, but we cannot accurately determine the cost or size of the projects until we go to the market for solutions. It is possible that we end up with several small flex opportunities that fail to meet the reopener threshold individually, our only option would be to group into annual programmes. Should the Commission not accept that approach then we may be disincentivised to seek flex solutions.

80. As mentioned previously, as there are more flexibility mechanisms available for capex projects compared to opex, there is risk a capex bias prevails should opex not be funded appropriately. While there are opex reopeners for some opex costs associated with the energy transition (e.g. flex services), there are no mechanisms available for base opex. Which means, spend needs to be known or arise at the right time prior to the resetting process, otherwise it won't be funded, and EDBs must make trade-offs in the next regulatory period.

81. To overcome this issue, we recommend the Commission widens the scope of reopeners to include more drivers of opex such as maintenance**.** This is mutually beneficial because:

    - It reduces the risk to customers that EDBs are over funded at the start of the regulatory period, as EDBs will only receive the opex allowance once they have sufficient evidence demonstrating the cost will arise.

    - It aligns with the Commissions low-cost principles by utilising existing mechanisms already familiar to the Commission and avoids the need to introduce additional mechanisms such as the use-it-or-lose-it allowance.

    - It helps address the potential capex bias caused by insufficient opex funding by allowing access to additional allowances with appropriate scrutiny at the right time, thereby mitigating the risk of under investment.

    - It can assist EDBs who were underfunded in the previous DPP to catch-up on deferred expenditure. The Commission doesn't assess base year opex to determine whether it's an efficient level i.e. it can't distinguish between genuine efficiencies and cuts (i.e. expenditure that was deferred due to underfunding), and therefore can't say with confidence that the base year opex is sufficient. This is

[23] Ofgem, *Re-opener Guidance and Application Requirements Document*, 17 February 2023.

[24] Powerco, Asset Management Plan 2024 update, 21March 2024, schedule 11b

highlighted in Nera's analysis, EDBs have historically been overspending their opex allowances (despite financial penalty), suggesting that opex allowances are frequently set too low.[25]

82. Without a solution, these groups of costs may force EDBs to incur the costs to apply for a CPP where a reopener offers a better solution.

5.2 The innovation and non-traditional solutions allowance could support EDBs to take bigger steps in a range of services, and reduce implementing additional mechanisms

83. We support some key changes introduced to the INTSA which will improve accessibility and drivers for innovative solutions, particularly:

- Increase in scale of allowance
- Moving to ex-ante approval
- Wider scope to include non-standard solutions.

84. However, we do have suggestions which we consider will improve the effectiveness of the INTSA mechanism.

85. While 0.6% of MAR is a welcomed step up from DPP3, we recommend a higher INTSA cap of 2.5% of MAR because DPP4 is a critical period for testing, progressing, and investing in new, more future focused types of electricity services on the path to New Zealand's 2030 and 2050 targets. This is a good outcome because:

- There is no clear rationale provided for a cap of 0.6% of MAR.

- The application process provides for proportionate scrutiny, eg the Commission could include additional criteria such as a requirement for verified business plan for projects over a certain threshold.

- The higher cap will incentivise large projects which might not otherwise be progressed. For example, our project to trial intelligent satellite vegetation management is awaiting approval under the innovation project allowance for FY24. If the pilot proceeds to the first implementation phase, it is forecast to have a cost of over $7m. Should 75% or 100% INTSA be successful for a project like this, it could use a significant proportion of Powerco's $15.2m allowance, leaving limited scope for other large projects.

86. We understand the Commission is trying to capture the idea that innovation projects are typically a 'risker' activity, however we believe the criteria 'risker than BAU' is ambiguous and suggest the Commission changes this criterion to reflect 'uncertain' activities instead.

87. We also consider the following adjustments will improve the process and provide certainty to EDBs to progress projects:

- Specifying a timeframe of 20 working days for the Commission to decide whether to approve an INTSA proposal. As an ex-ante process, having certainty on process timing is critical for project planning.

- Enabling a project to be split into individual phases and outputs to allow for the spread of funding (not just limited to full completion). Innovative or non-traditional projects typically go through

[25] Nera, *On Behalf of Big 6 EDBs Submission on CEPA Productivity Study*, 24 April 2024, at 64.

several phases to assess and trial the project, potentially spanning multiple financial years. This can be enabled through the application requirements which include information on delivery dates, outputs, and costs per disclosure year.

- We agree that the close out reporting and sharing of learnings is a critical aspect of the INTSA however to enable full post-project analysis and write up we recommend a longer close out date of 70 working days post project completion**.**

88. We are also concerned about the effectiveness of the INTSA to fulfil the objectives of Section 54Q as demand side management and energy efficiency initiatives are unlikely to meet the criteria of the INTSA, because the more certain the energy loss reduction benefits, the less likely the INTSA is available. We suggest the Commission considers the scope of the INTSA and whether the criteria are broad enough to meet Section 54Q objectives.

5.3 Allocation of risk needs rebalancing to make LCC's work

89. We support the use of LCC's, they are a useful mechanism to allow the Commission to meet its core principles:

    - Limit the extent the price path is reopened or amended, by allowing for compensation directly from the customer contracted.
    - Low cost, as it removes the need for Commission scrutiny because both supplier and customer agree.

90. However, in practice we are unsure how effectively they can be used. By design, LCCs allocate all of the risk to the supplier, as they sit outside regulatory framework, with the supplier recovering costs directly from the customer. For LCCs to be utilised by EDBs, they need to be supplemented with compensation that accounts for the risk of asset stranding. Without this compensation, it is likely that EDBs will favour reopeners.

91. While LCCs work particularly well for Transpower, their customers have less risk of defaulting as they are usually large established businesses, such as large generators, EDBs, or large industrial customers. EDBs customers on the other hand, tend to be smaller and often new businesses, resulting in higher default risk.

92. It's appropriate for EDBs to manage most of the risk, as they can manage a degree of it through contracts and through upfront capital contributions. However, unless some of the risk is shared with consumers, it's unlikely that LCCs will be used, and EDBs are likely to favour reopeners. We also note that the EAs work on EDB connection pricing, which will likely result in changes to EDBs' capital contribution policies, could limit tools available to EDBs' for managing stranding risk.

93. This preference for reopeners may be inconsistent with the Commission's low-cost decision-making principles to limit circumstances to reopen or amend a DPP during the period.[26] To address this, the Commission could utilise its framework for Type II asymmetric risks, where Chorus receives ex ante compensation through a 10-basis point adjustment to reflect the risk of asset stranding.[27]

[26] Commerce Commission, *default price quality path for electricity distribution businesses from 1 April 2025 Draft reasons paper,* 29 May 2024
[27] [6.1163] – [6.1217] of the fibre IMs

5.4 Additional reporting requirements are a great way to improve visibility and accountability

94. The Commission is considering additional reporting to give effect to DPP4 decisions, including flexibility mechanisms which require EDBs to demonstrate, either implicitly or explicitly, that costs are excluded from DPP4 allowances. We support additional reporting to improve the operation of the regulatory regime and consider it to be a great step towards improving visibility. Below, we provided suggested improvements to enhance the effectiveness of this reporting.

Annual delivery report

95. As mentioned earlier, we are aware of the Commission concerns regarding deliverability. While we believe these concerns are unwarranted and it's inappropriate for the Commission to form a view on EDBs ability to deliver their work programmes without evidence, ADRs are a great tool to give the Commission comfort on how EDBs are delivering against priorities and to hold them to account.

96. The Commission should first monitor EDB's deliverability using ADRs, before prematurely taking a view that EDBs can't deliver their work programmes and reducing capex allowances because of this. Only after gathering sufficient evidence should the Commission consider deliverability when setting capex allowances. To improve the effectiveness of the ADR:

    - The Commission needs to be clear on stakeholders i.e. customer or technical audience? It's difficult to write something that meets both. Should the ADR be technical metrics, these could simply be included in ID requirements. We found it challenging to meet the needs of both customers and technical audiences during the CPP reporting.
    - Given the differences across the EDBs it's more practical for ADRs to be less prescriptive, allowing EDBs to tailor their ADRs to their specific needs and existing reporting systems. For example, the level of granularity can vary, but EDBs could agree to what 'good' looks like.
    - We welcome more discussion, workshops, guidance and clarity around the objective and purposes of the ADR, including the level of scrutiny applied and the level of assurance required.
    - The additional reporting could be implemented in a phased approach, providing EDBs the necessary time to set up the appropriate processes and systems to comply with the new requirements.

6. Quality

Summary of quality positions:

- We support the principle of no material deterioration.
- We support shortening the reference period for planned interruptions to 5 years to reflect modern safety standards (reduced live line work). Failing that, if you retain 7 years we suggest you exclude 2017 data to better reflect planned interruption practices.
- We encourage the Commission to prioritise the development of disaggregated measures of network reliability to ensure they can be implemented in DPP5
- We support excluding outages directly associated with an INTSA project from quality standards and incentives up to the limit.
- The Commission must closely monitor upcoming amendments to the Electricity (Hazards from Trees) Regulations 2003 to ensure appropriate adjustments to EDBs' planned interruption standards

97. We generally support the Commission's draft decision on quality standards including the principle of no material deterioration, as it has delivered a level of service customers value, and their decision to retain the three quality standards set for DPP4, focused on the reliability of supply:

   - SAIDI and SAIFI limits for unplanned outages assessed on an annual basis
   - SAIDI and SAIFI limits for planned outages assessed across the regulatory period
   - An extreme event standard for high impact and low probability events.

6.1 Disaggregated information in order to reflect variances in service quality across the network

98. We appreciate that major changes to the quality standards will take time, effort, and investment which is not feasible for DPP4, however we remain of the view that the current quality standards require change as they are limited in how well they capture the experience of our customers and fall short in driving appropriate incentives for network performance. SAIDI and SAIFI as currently applied (broad averages) do not reflect variances in service quality across different parts of the networks and impact our ability to effectively manage or target investment for service quality reasons.

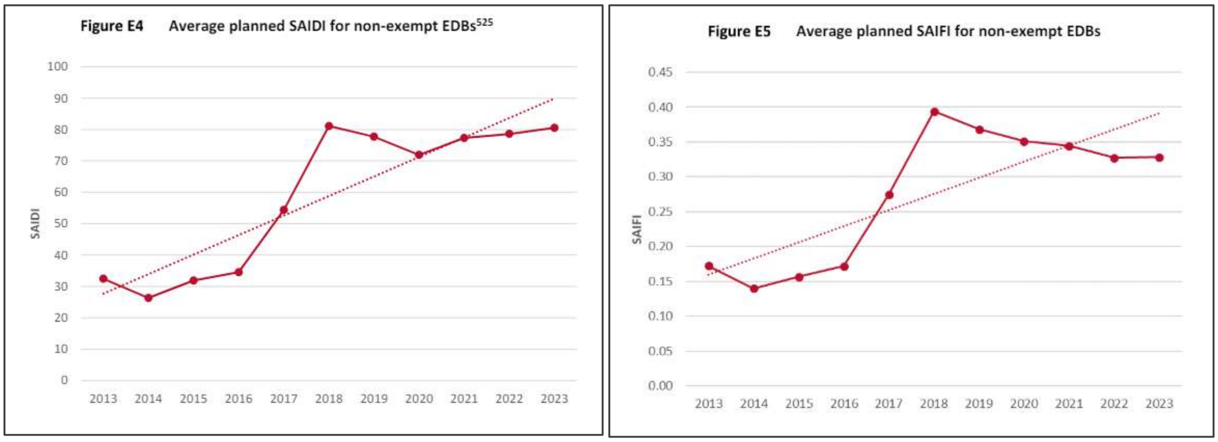
99. With electricity becoming increasingly important as a primary energy source, quality standard shortcomings will become acute in low voltage networks but are excluded from quality measures. There is justification to move towards more granular reliability reporting and load-at-risk measures. With the work required to refresh the approach to quality standards, we recommend the Commission prioritise work on quality standards well in advance of, and to be implemented by, DPP5. To realise this, we would like to see preparatory work such as the collection of better disaggregated information.

6.2 We encourage a shorter five-year reference period for planned interruptions

100. We support the draft decision to shorten the reference period for planned interruptions to better reflect modern safety standards (reduced live line work) and the increase in total work over that period. A five-year reference period aligns it to the reference period for capex to better account for the growth in volume of planned work that is expected, in which the corresponding planned SAIDI will also follow this upward trend. A historical average will always lag, which is not fit for purpose.
101. Failing that, should the Commission maintain the seven-year reference period, we recommend excluding data from 2017 for the final decision, resulting in a 7-year reference period of 1 April 2018 – 31 March 2024.

The 2017 data does not accurately reflect planned interruption practices employed by EDBs, which coincides with safety led (WorkSafe) move away from live line work. This is illustrated in figure 1 and 2 below, where 2017 data is significantly below the average planned SAIDI and SAIFI for EDBs since 2018.[28]

Figure 1 & 2 - Average planned SAIDI and SAIFI for non-exempt EDBs



6.3 MBIE amendments to the electricity (Hazards from Trees) Regulations 2003 need monitoring

102. MBIE is currently working on proposed amendments to the Electricity (Hazards from Trees) Regulations 2003. These changes will likely necessitate increased work to ensure compliance with the new standards, impacting EDBs' planned interruptions and opex expenditures. The Commission must closely monitor these regulatory changes to ensure appropriate adjustments to EDBs' planned interruption standards and opex allowances.

[28] Average planned SAIDI and SAIFI charts copied from page 378 and 379 of the Draft Decision Reasons Paper.

Appendix A: Modelling corrections we have identified

103. We have identified several modelling errors which require correction ahead of the final decision in November 2024. The majority of the errors relate to Powerco's transition from our CPP to the DPP where our DPP3 starting point in FY2024 has not been accounted for. We step through the modelling corrections required for the following areas:

- Wash-up
- IRIS
- Disposals
- Calculation of step changes.

Washup Modelling

104. This correction relates to the Actual Net Allowable Revenue (ANAR) amount used in 2024.

a) Powerco transitioned from our CPP to DPP3 in 2024 and a new starting price was determined in our transition determination[29] of $321,696 ($000) - Schedule 1.1 (3)
b) The wash-up indicative model[30] from the DPP4 draft decision has used 2023 ANAR plus an escalation by CPI to determine the 2024 ANAR amount.
c) We believe that (a), as per the determination, is the correct amount to be modelled.
d) Details of changes to the wash-up indicative model are below:
   (i) TAB: AAR – cell E108 - amount replaced with 2024 Starting MAR
   - Changed from $285,685 to $321,696
   (ii) This changes the output TAB: OWAB – cell H40
   - Draft: ($40,639) – Modified: ($758)

If the actual wash-up amount from Powerco's 2024 Electricity Annual Compliance Statement is used in the final decision this would negate the need to correct this 2024 modelled amount.

IRIS Modelling

105. This correction relates to the modelled Opex IRIS31 amounts included in pricing for 2026.

a) Powerco's transition from our CPP to DPP3 in 2023 means that the start and end of the regulatory periods for Opex IRIS are different to those EDBs on the full DPP3 from 2021 to 2025.
b) 2021 has been modelled for Powerco as a starting year, however, this is the 2nd year of our CPP, therefore the calculation of the amount carried forward should be per the "years 2-4" method, not the "year 1" method.
c) 2023 is the last year of our CPP regulatory period, therefore no opex incentive should be calculated for this year.
d) 2024 is the first year of our DPP3 regulatory period, therefore the calculation should follow the "year 1" method.

[29] Electricity Distribution Services Default Price-Quality Path (Powerco transition) Amendments Determination 2022
[30] Wash-up indicative amounts model_EDB DPP4 draft determination_29 May 2024.xlsx
[31] IRIS Recoverable costs indicative_EDB DPP4 draft determination_29 May 2024.xlsx

e) Details of changes to the IRIS model are below:
   (i) TAB: opex incentives – cell E34,G35,H35 changed to match 2021 Powerco amount per compliance statement workings.
   - E34 Changed from $8,714 to $867
   - G35 changed from ($8,182) to $0 - (no incentive last period of CPP)
   - H35 changed from $11,820 to ($1,372) – 1st period of DPP change treatment.
   - This changes the opex IRIS amount for 2026 from ($1,372) to ($14,230)

Disposals Modelling

106. This correction relates to the modelled disposals[32] amounts included as an input into the draft financial model[33].

a) The disposals model details the forecasting approach as using a 5-year average for EDBs from 2020 to 2024, except Vector who have an outlier in 2020, resulting in a 4-year average being used from 2021 to 2024.

b) Due to the 2024 actual disposals value being unavailable for the draft decision, the data range has been adjusted to end in 2023, resulting in a 4-year average for most EDBs and a 3-year average for Vector.

c) To calculate these differentiated approaches for Vector versus other EDBs, formulas have been included in the model to calculate a 3-year average if Vector is the selected EDB and a 4-year average if a non-Vector EDB is selected. This results in differing results on the "Outputs" tab depending on if Vector is the selected EDB or not.

d) The numbers copied into the financial model as an input, are the numbers on the Output tab with Vector as the selected EDB, therefore a 3-year average has been used for all EDBs which does not appear to be the intention.
   (ii) For Powerco this changes the total output for value of disposed assets for 2024 to 2026.
   - 3-year average total is $161,096 ($000) used in the financial model
   - 4-year average total is $137,501 ($000) intended amount.

Opex Step Change Calculations

107. We have identified an issue with the Commission's calculation of our approved opex step changes, which may be specific to Powerco.

a) The Commission has mistakenly assumed that our non-network opex AMP forecasts include appropriate growth assumptions. However, our methodology for non-network opex forecasts in AMPs does not apply a scale growth rate. Instead, we use a base and steps approach, meaning our baseline does not increase year-over-year except for step changes.

b) We believe this misunderstanding has led to an error in the Commission's opex step changes calculations. To calculate the 'total net step change' in its opex step change model, the Commission deducted our base year opex, and trended it forward by the non-network opex scale growth factor,

32 Disposals model_EDB DPP4 draft determination_29 May 2024.xlsx
33 Financial model_EDB DPP4 draft determination_29 May 2024.xlsx

from our 'Total Gross Step Change. This 'Total Gross Step Change' comprises our base year opex (not trended forward by a scale growth factor) and our forecast step change. Given that we do not apply a scale growth rate to non-network opex forecasts in our AMPs/base year opex in our requested step changes, the Commission's decision to trend forward our base year opex by the scale growth factor results in inconsistent treatment and valuations of our base year opex within the Commission's 'total net step change' calculation.

c) Our negative 'net step change' of -$175,000 for Consumer Engagement in 2026 illustrates this issue – an outcome that should not occur with a positive step change approval. Our 'net step change' is negative in 2026 because:

   1. A step change for Consumer Engagement doesn't occur until 2027; and

   2. The Commission deducted the trended forward base year value of $5.89 million (the 2024 opex of $5.68 million trended forward to 2026 by the scale factor) from the base year component of $5.68 million (which was not trended forward by a growth factor) in our 'Total Gross Step Change'.

d) Our concern is that the Commission's erroneous assumption and inconsistent treatment and valuations of our base year opex have unjustly reduced our approved opex step changes.

Appendix B: Commission submission template

Request for feedback on DPP4 draft decisions

Capital expenditure (capex)

1. Capex

C1	Use EDB 2024 AMP forecasts as the starting point for setting capex allowances.
C2	Set the capex allowance in constant dollars based on the lower of an EDB's total forecast capex or 125% of its historical reference period capex, with an adjustment for forecast capital contributions.
C3	Use a five-year historical reference period for setting capex allowances [2019 to 2023 for the draft and 2020 to 2024 for the final determination] with an additional cost escalation adjustment.
C4	Include an allowance for the cost of financing, scaled in proportion to the capex allowance.
C5	Include an allowance for the value of considerations for vested assets and spur assets equal to 2024 AMP forecasts.
C6	Use the All-Groups CGPI forecast with an additional adjustment to escalate the constant price capex allowance to a nominal allowance.

Views/Response:

C1	Support – EDB AMPs provide the best available forecasts for DPP4 investment needs.
C2	Historical expenditure is not a good predictor of future investment requirements. Our investment needs are far greater than what has been allowed for under the 125% cap and we plan to apply for additional allowances through the flexibility mechanisms for areas where there is uncertainty around the timing and cost of the project. We recommend the Commission increases the cap to 130%
C3	We believe the 2024 AMP provides the most accurate information for forecasting DPP4 investment requirements. However, if the Commission insists on maintaining a cap based on historical spending, a five-year reference period is acceptable.
C4	Support
C5	Support – however not all vested assets / spur assets were known at the time 2024 AMP forecasts were made and suggest these are able to be included as a recoverable cost or be applied for as a reopener.
C6	Support

Operating expenditure (opex)

2. Opex

O1.1	Apply a base-step-trend approach to forecasting opex.
O1.2	Use 2024 as the base year. [2024 AMP forecasts used for the draft decision]

Views/Response:

O1.1	The base-step-trend approach is effective at forecasting recurring opex in a stable operating environment. However, the Commission must acknowledge its limitations when the future differs significantly from the past. For instance, scale growth will not account for a dynamic sector with growing customer needs and evolving preferences, nor will it capture the increasing use of opex solutions. Given the Commission's decision to retain the BST approach, it is critical to accurately account for step changes. The limitations of the BST and options to mitigate these limitations are discussed further in the body of our submission.
O1.2	Using 2024 as the base year offers the most recent full-year record of actual audited expenditure. However, it is only appropriate if it truly represents an EDB's efficient and sustainable ongoing level of opex. The base year is fundamental to ensuring that opex allowances are accurate and that the IRIS is effective. Therefore, it must be adjusted (up or down) to ensure it accurately reflects the EDB's efficient and sustainable ongoing level of opex.

3. Opex step changes

O2.1	Consider proposed step-changes against a defined set of factors, incorporating judgement.
O2.2	Step-changes should be significant.
O2.3	Step-changes should be adequately justified with reasonable evidence in the circumstances.
O2.4	Step-changes must not be included elsewhere in expenditure allowances.
O2.5	Step-changes should have a driver outside the control of a prudent and efficient supplier.
O2.6	Step-changes should be widely applicable.
O3.1	Include a step-change to reflect increasing insurance costs.
O3.2	Include a step-change for greater consumer engagement.
O3.3	Include a step-change for low voltage (LV) monitoring and smart meter data.
O3.4	Include a step-change for increasing cyber-security costs.
O3.5	Include a step-change for the costs of software-as-a-service (SaaS).
O3.6	Include a negative step-change in Aurora's indicative forecasts to capture the end of its CPP spend.
O3.7	Cap aggregate step-changes (in real terms) at 5% of trended opex excluding step-changes.

Views/Response:

O2.1 Support.
O2.2 We support the use of this decision-making factor.
O2.3 We support the use of this decision-making factor.
O2.4 We support the use of this decision-making factor.
O2.5 We support the use of this decision-making factor.
O2.6 We support the use of this decision-making factor. However, the absence of similar step change applications from other EDBs, and the possibility that an EDB is at the forefront of an initiative, does not undermine its necessity or validity for DPP4. As noted in paragraph C120 of the Reasons paper, a step change should be permissible if it has the potential to be generally applicable across all EDBs, even if it currently applies to only a few.
O3.1 Support.
O3.2 Support.
O3.3 Support.
O3.4 Support.
O3.5 Support.
O3.6 No comment.
O3.7 We disagree with the Commission's draft decision to cap aggregate step-changes (in real terms) at 5% of trended opex excluding step-changes. If a step change meets the decision-making factors, it should be fully awarded. Imposing an arbitrary threshold undermines the purpose of the decision-making factors and increases the risk of underfunding EDBs.

4. Opex trend factors

O4.1	Escalate all opex costs using the same cost escalator.
O4.2	Escalate opex using the all-industries labour cost (60% weighting) and a producers' price (40%) indices, plus a 0.3% uplift to reflect EDB-specific inflation.
O5.1	Scale growth forecast separately for network and non-network opex.
O5.2	Use 2018-2024 as the reference period for scale elasticities and driver projections [2024 data available post-draft].
O5.3	Forecast network opex scale growth with line length (elasticity 0.52) and ICPs (0.45).
O5.4	Forecast non-network opex scale growth with line length (elasticity 0.35), ICPs (0.22), capex (0.30).
O5.5	Forecast lines length extrapolated using recent growth rate trend, and irregular data adjusted.
O5.6	Forecast ICP count extrapolated using recent growth rate trend, and irregular data adjusted.
O5.7	Forecast capex based on a constant growth.
O6.1	Apply an opex partial productivity factor of 0%.

Views/Response

O4.1	Support
O4.2	Support
O5.1	Support
O5.2	Support
O5.3	Support, note response to O5.4 below.
O5.4	We support including capex as a driver of non-network opex; however, we urge the Commission to consider the limitations of this historically based approach. Historical relationships are unlikely to accurately capture the significant and unprecedented increases in workforce requirements driven by technological advancements, evolving customer preferences, and the energy transition. This method will only reflect past relationships between capex spending and non-network opex, addressing recurring and predictable changes, rather than accounting for new and significant shifts in EDBs operational needs.
O5.5	Support
O5.6	Support
O5.7	Support
O6.1	Support

Innovation and section 54Q incentives

5. Innovation, energy efficiency and demand-side management

U1	Introduce an Innovation and Non-traditional Solutions Allowance (INTSA), capped at 0.6%.
U2	Incentivise energy efficiency and demand-side management incentives through the INTSA.
U3	Do not introduce a reduction of energy losses incentive.

Views/Response:

U1	A higher INSTA cap such as 2.5% of MAR should be used as DPP4 is a critical period for testing, progressing, and investing in new and more future focused types of electricity services on the path to New Zealand's 2030 and 2050 targets. To allow for a higher cap, projects over a certain threshold could include additional criteria such as a requirement for verified business plan.
U2	We note that 'non-traditional' is not defined, and that energy efficiency and demand-side management are not 'non-traditional' and are unlikely to be 'riskier than BAU' as they are generally well understood technology. It will be important for the guidance to have a broad view on the types of projects that could fit within this INTSA mechanism, and the 'riskier than BAU' criterion to be reviewed to ensure all types of projects are enabled, and Section 54Q obligations therefore achieved.
U3	Support – incentivise reduction of energy losses through the INTSA

Quality

6. Quality standards

QS1	Maintain separate standards for planned and unplanned SAIDI and SAIFI.
QS2	Retain annual unplanned reliability standards for SAIDI and SAIFI.
QS3	Retain the 2.0 standard deviation buffer for setting the unplanned interruptions reliability standards.
QS4	Maintain regulatory period length standard for planned SAIDI and SAIFI.
QS5	Change the planned reliability buffer for the planned interruptions reliability standard to be a 100% uplift on the historic average, capped at a +/- 10% movement from the current standard.
QS6	De-weight the impact of notified planned interruptions by 50% in the assessment of compliance with planned interruption standards.
QS7	Retain SAIDI extreme event standard set at 120 SAIDI minutes or 6,000,000 customer minutes where specified.
QS8	Retain enhanced automatic reporting following a breach of a quality standard.
QS9	No new quality measures are introduced as part of the quality standards applying in DPP4.
QS10	Set interruptions quality standards and incentives for Aurora transitioning from a CPP to the DPP on the same basis as for other EDBs on the DPP.
QS11	Retain the requirement for reasonable reallocation of SAIDI and SAIFI following an asset transfer between EDBs.

Views/Response

QS1	Support.
QS2	Support.
QS3	Support.
QS4	Support.
QS5	Support decision to adjust the buffer for the planned interruptions reliability standard to a 100% uplift on the historic average, it's reasonable given decision to shorten the reference period for planned interruptions to better reflect current network practices. We support the decision to maintain the de-weighting of notified interruptions only being applied to the assessment period and not the reference period dataset.
QS6	Support.
QS7	Support
QS8	Support.
QS9	With electricity's growing importance as a primary energy source and the increasing integration of distributed energy resources on the low voltage network, there is a strong justification for transitioning to more granular reliability reporting and load-at-risk measures. Given the extensive work required to update the approach to quality standards, we recommend that the Commission prioritises this effort well in advance, ensuring implementation by DPP5.
QS10	Support.
QS11	Support.

7. Quality incentives

QIS1	Retain the revenue-linked quality incentive scheme for planned and unplanned SAIDI. SAIFI is excluded.
QIS2	Unplanned incentive rates are informed by the value of lost load (VOLL), discounted by (1-IRIS retention factor) to reflect expenditure incentives, and a further 10% to reflect quality standard incentives, with VOLL set at $35,374r/MWh.
QIS3	Planned incentive rates are reduced by 35% relative to the unplanned incentive rate.
QIS4	Planned 'notified' interruptions are reduced by 75% relative to the unplanned incentive rate to reflect less inconvenience to consumers.
QIS5	Incentives are revenue-neutral at the average of the reference period, also known as the target.
QIS6	The SAIDI caps (which determine maximum losses) are set equal to the SAIDI limits for planned and unplanned SAIDI.
QIS7	The SAIDI collars (which determine maximum gains) are set at 0 for unplanned and planned SAIDI.
QIS8	Cap revenue at risk at 2% of actual net allowable revenue.
QIS9	Do not implement any new incentive schemes.
QIS10	Do not make an explicit adjustment to match the duration of retention benefits between EDBs and consumers.

Views/Response:

QIS1	Support.
QIS2	Support.
QIS3	Support.
QIS4	Support.
QIS5	Support.
QIS6	Support.
QIS7	Support.
QIS8	Support.
QIS9	Support.
QIS10	Support.

8. Normalisation

N1	Normalisation only applies to unplanned interruptions, which are the only initiators of a major event day.
N2	Retain the normalisation approach used in DPP3, being: - define a major event as 24-hour rolling periods (assessed in 30-minute blocks) - the major event boundary value has been identified as the 1104th highest rolling 24-hour period for SAIDI and SAIFI over the 10-year reference period - normalisation is applied on half-hour blocks, within a major event, where the SAIDI figure exceeds 1/48th of the boundary value, and - treat major events by replacing any half-hour that is greater than 1/48th of the boundary value with 1/48th of the boundary value if that half-hour is part of the major event (can exceed 24 hours in duration).
N3	SAIDI and SAIFI major events are triggered independently.
N4	Set a higher boundary for very small EDBs.
N5	Retain additional reporting by EDBs for each unplanned major event in its compliance statement consistent with DPP3.

Views/Response:

N1	Support
N2	Support
N3	Support
N4	Support
N5	Support

9. Reference period

RP1	Use a 10-year reference period from 1 April 2013 to 31 March 2023 to inform the parameters for unplanned interruptions reliability standards and incentives, with the period adjusted to 1 April 2014 to 31 March 2024 for the final determination.
RP2	Apply a reference period for planned interruptions of 2017 – 2023 for the draft decision, extended to 2017 – 2024 for the final decision.
RP3	Retain the cap on inter-period movement, ±5% for unplanned interruptions for both the SAIDI and SAIFI unplanned target and also apply this to the SAIDI and SAIFI unplanned limits.
RP4	Make no explicit step changes to reliability targets or incentives.
RP5	Make no explicit adjustments for instances of non-compliance contained within the unplanned interruption reference period dataset.
RP6	EDBs must record successive interruptions on the same basis they employed in responding to the s 53ZD notice.
RP7	Interruptions directly associated with an approved INTSA project are excluded for calculation of SAIDI and SAIFI values up to a cap of 0.5% of the respective SAIDI and SAIFI limit.

Views/ Response:

RP1	Support.
RP2	We support shortening the reference period for planned interruptions from 10 years to 7 years. However, we strongly recommend this should be shortened further to five years to align with the capex reference period.
RP3	Support.
RP4	Support.
RP5	Support.
RP6	Support.
RP7	Support.

Revenue path

10. Price path

P1	Set starting prices based on the current and projected profitability of each supplier using a building blocks allowable revenue (BBAR) model.
P2	Set a default rate of change relative to CPI (X-factor) of 0%.
P3	Set alternative X-factors such that, in most cases, initial price shock is limited to 20% in real per ICP. terms, and the change between years within the regulatory period to 10% (based on the price shock and notional financeability assessments).
P4	Assess price shocks on a real revenue per ICP basis, incorporating wash-ups and IRIS.
P5	Assess notional financeability using FFO/Debt and Debt/EBITDA ratios.

Views/Response:

P1	Support
P2	Support
P3	Support – change between years is 10% + CPI + x-factor as drafted in determination
P4	Support
P5	Support

11. IRIS

I1	IRIS retention rate for capex is equivalent to the opex rate.
I2	Determine IRIS opex and capex forecasts in real terms (inflated by CPI).

Views/Response:

I1	Support
I2	Support

12. Revenue Path

R1.1	Apply a revenue cap with wash-up as the form of control.
R1.2	Forecast CPI based on the four-quarter average change in CPI between the first year of the regulatory period and the current year.
R1.3	Apply a 90% "voluntary undercharging" limit (or an alternative in some cases).
R1.4	Include a large connection contract (LCC) wash-up term in the wash-up accrual formula, to avoid recovery of LCC revenue from other customers.
R1.5	Allow distributors to agree a reasonable reallocation of revenue following an asset transfer.
R2.1	Apply the revenue smoothing limit based on forecast net allowable revenue for the current year and CPI-adjusted recoverable costs from the prior year.
R2.2	Apply a revenue smoothing limit of 10%.
R3.1	Implement the revenue wash-up by specifying a re-run of the DPP4 financial model.
R3.2	Calculate the Y1 inflation wash-up based on the four-quarter average change in inflation between Y0 and Y1.
R3.3	Do not specify base revenue wash-up draw down amounts for DPP4.
R3.4	Calculate the time-value of money of the opening wash-up balance using one year of the DPP3 WACC and one year of a blended DPP3/DPP4 WACC (for a value of 5.25%). [This will be updated for the final decision.]

Views/ Response:

R1.1 We support the retention of the revenue cap with wash-up as the form of control.
R1.2 Support
R1.3 Support
R1.4 Support
R1.5 support
R2.1 Support
R2.2 Assuming this is annual smoothing limit, we support.
R3.1 Support
R3.2 Support
R3.3 Support – allow full drawdown of DPP3 washup amounts.
R3.4 Support

13. Other Matters

X1	Retain the current five-year regulatory period length.
X2	Include Aurora in the DPP4 expenditure and revenue setting process.
X3	Retain the CPP application timings set for DPP3.

Views/Response:

X1. We support the retention of the five-year regulatory period length, and we don't see any reason for a shorter period.
X2 Support
X3 Support

14. Other inputs to the financial model

M1	Weighted average cost of capital (WACC) of 7.37%. [This will be updated for the final decision.]
M2	Include an allowance for disposed assets, based on historical levels.
M3	Forecast depreciation on existing assets based on information provided by each EDB.
M4	Use base year data from 2024 Information Disclosures in our final decisions, and data from 2023 Information Disclosures for our draft decisions.
M5	For CPI forecasts, use the most recently available RBNZ MPS forecasts from when the WACC was determined.

Views/Response:

M1	Support
M2	Support – although there should be a wash-up of actual and forecast
M3	Support – however, we strongly recommend the Commission supports depreciation methodology by including a wash-up between forecast and actual depreciation given the implementation issues. Please refer to our main submission for more details.
M4	Support
M5	Support

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