Major Electricity Users' Group

Promoting a robust electricity market

12 July 2024

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Sent via email: infrastructure.regulation@comcom.govt.nz

Dear Ben

Electricity Distribution Businesses DPP4 – Draft decision

1. This is a submission from the Major Electricity Users' Group (MEUG) on the Commerce Commission's draft decision paper "*Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision*"[1] and supporting material published for consultation on 29 May 2024.

2. MEUG members have been consulted on the approach to this submission. Members may lodge separate submissions. This submission does not contain any confidential information and can be published on the Commission's website unaltered.

Summary of MEUG's points

3. The Commerce Commission's decisions for the 16 regulated electricity distribution businesses (EDBs) for the next regulatory period (DPP4) from 2025 to 2030, alongside decisions for Transpower's RCP4,[2] will have a significant impact on electricity consumers across New Zealand. These draft decisions are being made during a cost-of-living crisis and slowing economy, alongside the need to decarbonise, and increasingly electrify, our economy. The decisions also come at a time when electricity wholesale prices are remaining stubbornly elevated, with no sign of decreasing in the short term, despite the push for greater renewable energy.

4. MEUG has reviewed the draft decision at a high-level, with our comments focused on the areas of greatest impact to our members. We have not provided comments on technical matters, where we expect the Commission will need to balance its view of consumers interests against the detailed analysis and technical matters that will be raised by the regulated EDBs during the consultation period.

[1] https://comcom.govt.nz/__data/assets/pdf_file/0031/353983/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2025-Draft-reasons-paper-29-May-2024.pdf
[2] https://comcom.govt.nz/__data/assets/pdf_file/0025/353860/Draft-Decision-for-Transpowers-IPP-commencing-1-April-2025-29-May-2024.pdf

5. MEUG appreciates the trade-offs that the Commission has had to make during this DPP reset, balancing the need for increased investment in the distribution networks, against the uncertainty facing the energy sector and the price shocks facing all consumers. In summary, MEUG states that:

- The financial impact of this draft decision will put pressure on all electricity consumers, particularly when considered alongside forecast increases in transmission charges and the wholesale electricity spot price. It is essential that government consider the total forecast price consumers are facing, not just the components in isolation, and whether this supports the long-term interests of consumers, as required by the Commerce Act.

- We support the Commission's draft decision to reduce the level of capital expenditure (CAPEX) approved, below that sought by EDBs in their Asset Management Plans (AMPs). However, we do not support the use of the 125% limit for setting CAPEX allowances and believe that the low-cost approach of a DPP regime does not provide sufficient scrutiny of expenditure sought for the next regulatory period. We recognise that many EDBs may seek reopeners to deal with the increased need for investment – it is important that this process is robust and incorporates proper consumer engagement.

- We are reasonably comfortable with the approach taken to forecasting operational expenditure (OPEX), with the use of a 5% limit. However, we still have concerns with the use of the base-step-trend approach, which relies on the assumption that historic expenditure is efficient and prudent.

- We support continuation of a five-year regulatory period and smoothing the revenue across the period. However, as noted in our submission on Transpower's draft decision,[3] we 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.

- We support the introduction of the Innovation and Non-Traditional Solutions Allowance (INTSA) scheme. It is important that EDBs are incentivised to innovate, pursue demand-side management and energy efficiency initiatives. We recommend that the process for INTSA applications is streamlined and does not disincentivise use of these options over Business as Usual (BAU) approaches.

- We support the continuation of the existing measures for quality standards. We recommend that the Commission look at introducing a quality standard or reporting requirement around network capacity. It is important that EDBs are incentivised to optimise use of the existing network, ahead of new investments.

- There are several broader issues, that while out of the exact scope of the DPP4 process, have impacted and will continue to impact on the regulatory framework for EDBs and the magnitude of distribution charges that consumers will face. We outline these concerns and call for greater effort from Government to address issues.

6. To support this submission, MEUG has commissioned NZIER to prepare a short report that considers the suitability of the low-cost light-handed approach to DPP regulation and the combined impact of the DPP decisions on the total cost of energy and how those increases along with wholesale market price pressures and supply constraints could affect the pace of electrification. A copy of NZIER's report is provided in **Attachment 1**.

[3] http://www.meug.co.nz/node/1373

Context facing MEUG members and affordability issues

7. MEUG's members connect to the electricity system in a variety of ways – some businesses connect directly to the transmission system, some directly connect to the distribution network, while other members connect through a retailer, like many consumers across New Zealand. Our members collectively engage with many of New Zealand's 27 electricity distribution businesses (EDBs); therefore, the Commission's decisions for the 16 regulated EDBs are of great interest and relevance.

8. It is important to understand that the financial impact on our members from these decisions will be of a scale much greater than that quoted for the average household – in the order of millions. This will increase the input costs for businesses, impacting profitability, particularly those exposed to international commodity markets – it should not be assumed that these increases can simply be passed through.

9. In addition, the actual customer impact of these increases will only really be understood by seeing how regulated businesses apply their current distribution pricing methodologies, the timing and approach of how retailers pass through these charges in RCP4 (and the rate of increases over the full five years). Consumers are also facing increases across the several other components that factor into electricity pricing for 2025 to 2030:

   - There is expected to be an uplift in transmission charges from Transpower's base expenditure sought through RCP4.
   - There will also be an uplift in transmission charges, resulting from major capex proposals such as NZGP1.
   - Alongside these regulated components, there is also an expected increase in the wholesale electricity price, which has more than doubled in the last six years.

10. As discussed in our submission on the EDBs DPP4 Issues Paper,[4] we recognise that the Commission can only consider the price impact of each regulated component in isolation. However, we repeat our call for Government to consider how it can look at the overall impact of electricity prices and whether the total level of forecast investment into the electricity system results in affordable prices for both consumers and businesses.

Approach to setting CAPEX still needs refinement

11. MEUG supports the Commission's draft decision to reduce the level of capital expenditure (CAPEX) approved, below that sought by EDBs in their Asset Management Plans (AMPs). We:

   - Remain unconvinced that the EDBs will be able to deliver such as substantive uplift in network investment. The Commissions states that EDBs have not been able to provide the necessary reassurance[5] to address this concern and recognise that deliverability is also an issue impacting Transpower. In this case, the Commission is proposing reductions to Transpower's work programme to reflect this deliverability issue for RCP4.
   - Are unconvinced that the demand may grow at the rate predicted by many of the EDBs. There has been a dampening in electricity demand following the change in government energy policy and a slowing economy – signalling that the EDBs estimates may be too optimistic. From our work with NZIER (see **Attachment 1**), there also seems to be inconsistences between demand forecasts outlined by Transpower and those provided by some EDBs.

[4] http://www.meug.co.nz/node/1335
[5] See paragraph 2.18, draft decision paper.

12. MEUG also questions the use of the 125% limit for setting CAPEX allowances. We are not convinced that sufficient justification has been given to move away from the 120% limit applied for DPP3. There may be higher forecast expenditure, but there is also greater uncertainty. We enquire if the Commission has undertaken CAPEX modelling applying the 120% limit and what impact this had on forecast revenue

13. Alongside these points, MEUG also considers that a reduction in CAPEX allowances is justified given the level of scrutiny applied for this reset. We do not believe that sufficient scrutiny is possible through the Commission's low-cost DPP regime, and given the scale of increased investment, consumers cannot be reassured that they may be overpaying for network investment. MEUG notes that:

    - The Commission has indicated that its own review of a selection of AMPs has indicated that "that it would be inconsistent with a relatively low-cost regime to undertake the level of assessment required to obtain assurance from AMPs".[6]

    - The findings of the IAEngg's review and significant variations in EDBs expenditure also raises questions about whether consumers can have confidence in EDBs' projected expenditure.

14. A conservative approach is therefore the best approach, enabling EDBs to seek reopeners or CPPs when greater information is available. We outline in the concluding section of this submission why, in the long-term, we consider that Individual Price-quality Paths (IPPs) may be the best option to oversee investment of the larger EDBs.

<u>Role of capital contributions and large connection contract mechanism</u>

15. 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.

16. MEUG supports the introduction of the Large Connection Contract (LCC) mechanism for DPP4. The LCC mechanism seems good in principle, but its usefulness will only be determined through its application by EDBs in coming years. MEUG is happy to provide feedback on this mechanism if it is used with our members.

<u>Reassurance needed of EDBs' deliverability of investment plans</u>

17. Given concerns with deliverability, MEUG strongly support the introduction of an annual deliverability report, 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.

18. We recognise that much of this information will be available via the Information Disclosure schedules completed annually by EDBs. However, we do not believe these documents are the most consumer friendly and require a degree of network knowledge to seek the information that will be of most important to a consumer. Given experience with CPP deliverability reports and proactive customer engagement by some EDBs, we encourage the Commission to look at what is best practice in this area, and what a simple template may look like. Testing this with consumers would also be a valuable step, to ensure its effectiveness.

[6] Paragraph 2.33, draft decision paper.

Use of reopeners

19. The use of re-openers is discussed multiple times in the draft decision paper, as an alternative mechanism available to EDBs if they require more CAPEX or OPEX for investments or projects (rather than a CPP). 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. The current two-week consultation period for recent re-openers is considerably short, particularly when decisions are being made during a busy period of consultation. A slightly longer timeframe would be preferred, particularly for any large or complex reopener applications.

20. In addition, 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.

Comfortable with broad approach taken to OPEX allowances

21. MEUG is reasonably comfortable with the approach the Commission has taken to forecasting OPEX, and the resulting OPEX allowances for the regulated EDBs over 2025 – 2030. We support the use of the 5% cap to the level of approved OPEX step changes in DPP4. This recognises the rising costs facing EDBs going forward, while still keeping pressure on efficient costs and ensuring the EDBs have clear rationale for any step changes.

22. We support *Draft decision O1.1*, applying a base-step-trend-approach to forecasting OPEX, as this ensures consistency between regulatory periods, and is an approach that is well understood by EDBs and interested stakeholders such as MEUG. However, we still have concerns with this approach as it relies on the assumption that historic expenditure is both efficient and prudent. We remain unconvinced that this is the case, and reports such as the Cambridge Economic Policy Associates (CEPA) draft report "EDB Productivity Study"[7] prepared for the Commission hints at issues with inefficiency and that New Zealand EDBs may not be performing as well as their international peers. We encourage the Commissions to continue to monitor the performance of EDBs closely, particularly with greater levels of OPEX forecast.

23. MEUG recognises that insurance costs across the country are rising for both businesses and households. However, the cost for regulated monopolies in electricity distribution and transmission sectors seem to be increasing at a much greater rate, primarily due to increases in occurrence and impact of severe weather events. We recommend that the Commission, EDBs and its supporting body, Electricity Network Aotearoa (ENA) investigate other options for insurance for electricity infrastructure to provide more cost-effective cover. This could take the form of a government body such as the Natural Hazards Commission (formerly EQC).

24. We note that only some EDBs have sought additional funding for consumer engagement during DPP4 (as summarised in Table C4). This raises questions about how consistent the approach to consumer engagement is across the 16 regulated EDBs and how EDBs may be performing in this space. We encourage the Commission to continue to monitor the type of customer engagement that is undertaken in DPP4, and what might be considered best practice.

Revenue path

25. We support continuation of a five-year regulatory period for DPP4. We do not believe the benefits of moving to a four-year regulatory period, to address uncertainty, outweigh the administrative burden of having to undertake the DPP reset process more frequently.

[7] https://comcom.govt.nz/__data/assets/pdf_file/0018/348111/CEPA-EDB-productivity-study-draft-report-March-2024.pdf

26. We support the Commission's decision to smooth the revenue recovery across the full DPP4 period. We appreciate consideration of the impact of price shock on consumers, while also considering the needs of regulated EDBs. However, as noted in our submission on Transpower's draft decision,[8] we 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.

Support for new INSTA mechanism but stronger focus is needed

27. MEUG supports the introduction of the Innovation and Non-Traditional Solutions Allowance (INTSA) scheme. It is important that EDBs are incentivised to innovate, pursue demand-side management and energy efficiency initiatives, and much greater progress is needed in this area to support the energy transition. We outlined the importance of this in our submission on the EDB DPP4 Issues Paper.

28. It is encouraging to see that the Commission has reviewed and applied its learnings from the offering of the Innovation Project Allowance (IPA) in DPP3. There was very limited uptake of this allowance, so a different approach is clearly needed. In terms of the INTSA proposed for DPP4, MEUG notes 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.
- The INTSA is still described as an additional mechanism for EDBs, with EDBs having to apply for it. This reinforces the status quo practice of EDBs continuing to build more network in line with historic approaches. Innovation should not be seen as an "add on;" rather, it should be considered BAU when operating distribution networks.
- The process for INTSA applications must be streamlined, to incentivise use of this options over Business as Usual (BAU) approaches. There should not be additional regulatory burden for EDBs.
- We support the requirement for EDBs to share learnings from their INTSA projects – this is a positive step in building up sector capacity in new areas or technology.
- We appreciate the Commission including equal IRIS incentives between CAPEX and OPEX (decision I1), but we do not believe this is sufficient to overcome the bias to build and ongoing returns that come from increasing the Regulated Asset Base (RAB).
- We question who will judge if a project is "riskier than BAU" – this seems quite subjective, especially as the Commission note that this could be approached differently amongst EDBs (paragraph D75).
- It is important that the Commission ensure sufficient focus is given to energy efficiency, as this is something that will benefit all consumers in the long-term. We need to avoid the risk of regulated EDBs spending the majority of the INTSA on high-tech devices and systems to aggregate load and control devices such as batteries, EV chargers and hot water cylinders to shift peak load (that don't reduce consumer bills) – rather than on energy efficiency (which does reduce consumer bills). The INTSA needs to be deployed for a range of options.

29. We welcome more engagement with EDBs on how they see this INTSA mechanism working and the types of projects that they may pursue.

[8] http://www.meug.co.nz/node/1373

Support for continued approach to quality

30. As noted in prior submissions,[9] MEUG supports retaining the existing quality standards and incentive schemes from DPP3. The existing quality standards provide sufficient insight and will ensure EDBs remain focused on providing consumers with a reliable and secure supply of electricity.

31. The only area that we consider needs improvement or greater emphasis is around EDBs' network capacity. It is important that EDBs are incentivised to optimise use of the existing network, ahead of new investments, to help drive down the costs facing consumers. As discussed with the Climate Change Commission,[10] MEUG considers that the current system for electricity infrastructure has a strong "bias to build" – EDBs and Transpower have continuously built "poles and wires" infrastructure to meet a relatively steady growth in demand, with assets historically sized to meet a network's peak capacity. The Part 4 regulatory model for both Transpower and EDBs is largely based around the Regulated Asset Base (RAB), which influences the revenue that a regulated entity can earn and the subsequent prices that will be charged onto consumers.

32. Enhanced reporting on network capacity (at a level digestible for consumers) would be a positive step, ahead of investigating capacity standards for future regulatory periods. MEUG would welcome the opportunity to discuss this idea further with both the Commission and EDBs.

Attention must be given to broader regulatory framework for EDBs

33. There are several broader issues, that while out of the exact scope of the DPP4 process, have impacted and will continue to impact on the regulatory framework for EDBs and the magnitude of distribution charges that consumers will face.[11] MEUG strongly recommends that the Commission, alongside the Electricity Authority and the Ministry of Business, Innovation and Employment (MBIE), reviews these issues and looks for ways to ensure that we have a regulatory framework that is future-proof and best considers both the short and long-term benefit of consumers, particularly during the energy transition.

- **Volatility in WACC over multiple regulatory periods**. Increases in inflation and interest rates have had a significant impact on the proposed WACC for DPP4, and this has been the driver for a large proportion (40%) of uplift revenue forecast for DPP4. However, stakeholders have very little ability to influence the WACC figure through the DPP4 reset, as it is set outside of the price-quality reset process. MEUG strongly recommends that the Commission review the process for setting WACC, looking at the methodology of how it is calculated and how the WACC percentile is applied. We believe that a less volatile and more consistent WACC would be beneficial for both consumers and regulated entities in the long-term.

- **Shift in balance of risk**: MEUG believes that there has been a shift in the balance of risk between regulated businesses and consumers over recent years. EDBs now have a greater range of re-openers available to them, greatly reducing the risk of underinvestment in the network. As advocated in many submissions, MEUG believes there is an increasingly strong case to move the WACC percentile for EDBs (and Transpower) down from 65 percentile towards the 50th percentile.

[9] https://comcom.govt.nz/__data/assets/pdf_file/0031/339763/Major-Electricity-Users-Group-MEUG-DPP4-issues-paper-submission-19-December-2023.pdf
[10] http://www.meug.co.nz/node/1366
[11] We also raised these issues as part of our submission on the draft decision for Transpower's RCP4.

- **Cross-checking of sector assumptions**: Due to the low-cost approach of the DPP, there does not appear to be any cross checking of the assumptions made by EDBs against Transpower, to ensure that they present a consistent approach to demand forecasting and infrastructure planning. Our report from NZIER provided in **Attachment 1** looks at this and we would welcome further analysis in this space.

- **IPPs for the largest EDBs**: Given the limitations of the low-cost DPP regime and the magnitude of the spending sought by many of the EDBs, MEUG considers that there is a growing case to introduce Individual Price-quality Paths (IPP) for the 6 largest EDBs in New Zealand. This would allow greater scrutiny of expenditure, provide for a more tailored approach and provide the level of assurance that consumers need. This is an idea that we will be advocating to government, as they consider if Part 4 is still fit for purpose through the energy transition.

- **Stronger focus on productivity and the ability to benchmark:** MEUG's submission on the CEPA report highlighted that the Commission is still left with a position where New Zealand 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.

- **Use of non-traditional solutions:** MEUG supports the greater use of non-traditional solutions (NTS), across the distribution and transmission network, where it is cost effective. We believe further work is needed in this area to understand what range of NTS are presently available to EDBs, and what is the state / maturity of the NTS market. Ideally, we want to encourage NTS across both transmission and distribution networks, and need to consider if there are any regulatory barriers to this market developing further.

- **Pass-through of charges will be determined by the DPM:** How these costs over DPP4 are passed through to consumers will ultimately be determined by how they are allocated out under the numerous Distribution Pricing Methodologies (DPM) and passed through by retailers. MEUG has several concerns with distribution pricing, including:

    - A lack of transparency around how distribution pricing is established, including how costs are allocated amongst customer groups.

    - Inconsistency in how EDBs operate across regions, including how they consult and share information on distribution pricing and the connection processes for new connections or expansion / reduction in capacity requirements.

    - How EDBs are passing through the new Transmission Pricing Methodologies (TPM) charges to customers.

  We refer the Commission to our submission[12] on the Electricity Authority's targeted reform of distribution pricing, where we expand on these issues. MEUG is seeking greater action in this area, as progress has been slow to date.

34. MEUG welcomed the opportunity to discuss these broader concerns with the Commission and have also discussed them with the Electricity Authority. We strongly recommend that more focus is put on these issues in the short term, to ensure that we have a regulatory and policy framework that supports electrification and decarbonisation, and that meets consumer demand at a fair and justifiable price.

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[12] http://www.meug.co.nz/node/1311

Next steps

35. We look forward to engaging with the Commission and stakeholders throughout the cross-submission process. If you have any questions regarding our submission, please contact MEUG on 027 472 7798 or via email at karen@meug.co.nz.

Yours sincerely

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Major Electricity Users' Group

EDB DPP4 Draft Decision

Capital expenditure plan and overall price increases

NZIER report to MEUG

12 July 2024

About NZIER

NZIER is a specialist consulting firm that uses applied economic research and analysis to provide a wide range of strategic advice.

We undertake and make freely available economic research aimed at promoting a better understanding of New Zealand's important economic challenges.

Our long-established Quarterly Survey of Business Opinion (QSBO) and Quarterly Predictions are available to members of NZIER.

We pride ourselves on our reputation for independence and delivering quality analysis in the right form and at the right time. We ensure quality through teamwork on individual projects, critical review at internal seminars, and by peer review.

NZIER was established in 1958.

Authorship

This paper was prepared at NZIER by Mike Hensen.

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Key points

The purpose of this report is to provide evidence that supports the following key messages:

- The low-cost light-handed approach to DPP regulation is not well suited to the size and uncertainty of the structural change required by electrification. It is also inconsistent with scrutiny applied to Transpower and has not been checked against Transpower's forecasts.
- The Commerce Commission's analysis of price changes did not consider the combined impact of its price quality path decisions on the total costs of energy and how those price increases along with wholesale market price pressures and supply constraints could affect the pace of electrification.

Contents

Appendices

Figures

Tables

1 Scope

1.1 Approach

The analysis focuses on the following key areas:

- Capital expenditure plans of the six largest EDBs (Vector, Powerco, Orion, Wellington Electricity, Unison and Aurora[1]) with respect to:
  - Forecast growth in peak demand versus volume for each EDB in the group.
  - Comparison of EDB peak demand forecasts with Transpower's forecasts.
  - Comment on evidence that EDBs are considering measures to flatten peak demand in their asset management plans
- Combination of the increases in the Commerce Commissions draft decisions with the estimated impact of recent wholesale price movements on consumer electricity prices forecast for the next three years.

This note comments on the Commerce Commission's 'DPP4 Draft Decision Reasons Paper'[2]. The primary focus of this report is the capital expenditure forecasts to which the Commerce Commission attributes 35 percent of the increase in DPP4 maximum allowable revenue (MAR).

2 Low-cost light-handed approach not suited for rapid growth

2.1 Cost increase drivers

As part of its 'low cost light-handed' approach to the DPP4 decisions, the Commerce Commission has set a capital expenditure limit for DPP4 at the lower of the EDB asset management plan forecast or a 25 percent increase on capital expenditure over a reference period of 2019 to 2023. The Commerce Commission also applied a similar rule to DPP3 capex with a maximum increase of 20 percent. The checks applied by the Commerce Commission that the cap is not excluding asset replacement and renewal or reliability and safety need to be tested. They assume that investment in asset can be unbundled into independent packets that each contribute to one of the five main categories disclosed in Schedule 11a(i).

This cap apparently does not consider differences in the timing of recent EDB capital expenditure or whether EDB have used increased investment in capacity as the first option for managing peak demand. The application of the rule does not discriminate between EDBs which have tariff structures that recover the cost of the increased capacity from those who contribute to the cost, as opposed to those that do not.

1 Although Auror Energy is currently on customised price quality path (CPP) it is included in this group because the CPP ends on 31 March 2026.

2 Commerce Commission May 2024, 'Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision, Reasons paper, Date of publication ; 29 May 2024'. Available at https://comcom.govt.nz/__data/assets/pdf_file/0031/353983/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2025-Draft-reasons-paper-29-May-2024.pdf

Also, it is inconsistent with the change in consumer behaviour and electricity pricing that will be needed for efficient responses to managing the risk of generation shortfalls as the system reliance on intermittent wind and solar energy increases.

2.2 Benefit of scrutiny

The Transpower IPP draft decision[3] illustrates the potential for reductions in expenditure proposals after scrutiny. The two separate tests that were considered for the Transpower decision, 'prudent and efficient expenditure' and 'deliverability,' are applied to the EDB decision.

Table 1 Transpower draft decision

Expenditure reported in $m 2023/23

Stage	Opex	Capex	RCP4 Total
Transpower proposal	1,961.4	2,449.8	4,411.2
Approved as prudent and efficient	1,946.0	2,426.5	4,372.5
Deliverability reduction	1,877.0	2,135.2	4,012.2
Total reduction	84.4	314.6	399.0

Source: NZIER

2.3 EDB capital spend compared to Transpower

Under the Commerce Commissions Draft Decision, the DPP4 capex allowance[4] for the non-exempt EDB totals $5.60bn (in 2024 dollars), more than double the capex allowance of $2.2bn (in 2023 dollars)[5] for Transpower over the same period. Capex allowances for Powerco ($1.59bn) and Vector ($1.36bn) accounted for 52.6 percent of the capex allowance. Orion ($0.59bn), Wellington Lines ($0.38bn), Unison ($0.37bn) and Aurora ($0.44bn) accounted for another 31.7 percent of the capex allowance.

Overall, the Commerce Commission does not appear to have considered how to compare the potential costs and benefits of a thorough review of EDB spending for the largest EDBs (Vector and Powerco) or considered where the cost benefit break-even point might lie for applying the "prudent and efficient" and "deliverability tests" to EDBs capital spending proposal, rather than focusing on arguments for a light-handed approach.

3 Commerce Commission May 2024 (1) 'Transpower's individual price-quality path for the regulatory control period commencing 1 April 2025, Draft decision paper, Date of publication: 29 May 2024' page 9.

4 Commerce Commission May 2024, 'DPP4 Draft Decision Reasons Paper', Table 2.2 DPP4 capex allowances, page 35. In nominal terms the capex allowance is $6.3bn.

5 We have not been able to find the exact adjustment factor used by the Commission to translate 2023 dollars into 2024 dollars. The New Zealand Consumer Price Index (CPI) increased by 4 percent over the 12 months to end of the March 2024 quarter. Applying this adjustment factor to the Transpower capex allowance would indicate a value of about $2.5bn in 2024 dollars. The increase in the CPI was higher than the increase in the All Groups Capital Goods Index over the same period (which was 3.2 percent). However, the Commission's approach to translating capital expenditure during the reference period into values that were comparable to the DPP4 starting point was to increase them by the change in *the 'All-Groups Capital Goods Price Index (CGPI) plus an additional 0.8% per annum*'. See Commerce Commission May 2024, 'DPP4 Draft Decision Reasons Paper', page 44 para 2.59.

2.4 Uneven impact on EDB capital expenditure plans

The application of the 25 percent threshold has not materially constrained the proposed capital spending by either Powerco, Vector, Aurora or Unison but has materially constrained capital expenditure by Orion and Wellington Lines. The application of the constraint as a total across the entire DPP4 period also raises the question about how the EDBs alter the profile of their capital expenditure. These questions are illustrated briefly in in the following sections.by comparing the capital expenditure plans of Vector, Powerco, Orion and Wellington Lines.

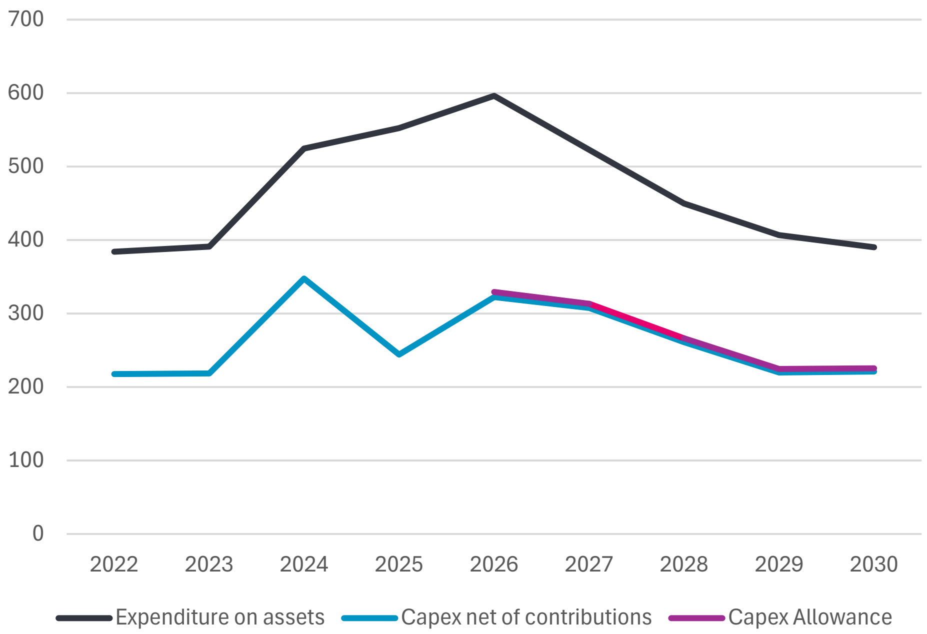
The following figures compare the capital expenditure plans of Vector and Powerco which are effectively not constrained by the Commerce Commission's 25 percent threshold with the plans by Powerco and Wellington Lines which are severely constrained by the application of the 25 percent threshold. The figures suggest the following questions:

- How does deliverability risk for Vector which is proposing a large step increase in spending in the first two years of its plan compare to that for:
  - Powerco and Orion which proposed a gradual increase in capital expenditure over the course of the planning period.
  - Wellington Lines which proposed a temporary lift in expenditure into the future with lead time to prepare for the increase.
- How do Orion and Wellington Lines adjust the delivery of their capital plans to the limitation of their capital expenditure to 67 percent and 39 percent respectively of their planned capital expenditure.

(The difference between the effect of DDP4 decisions on Vector and the EDB that are constrained by the capex allowance threshold is increased by the much higher use of capital contributions to fund capital expenditure than for other EDBs. [6])

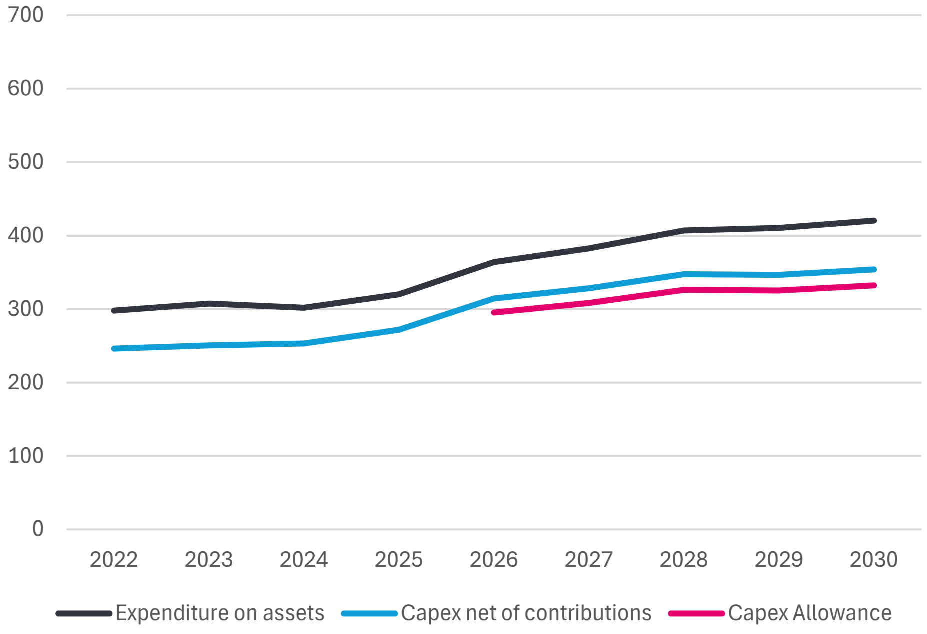
[6] Commerce Commission May 2024, 'DPP4 Draft Decision Reasons Paper', page 142,Paragraph B143 and B144.

Figure 1 Vector actual and forecast capital expenditure



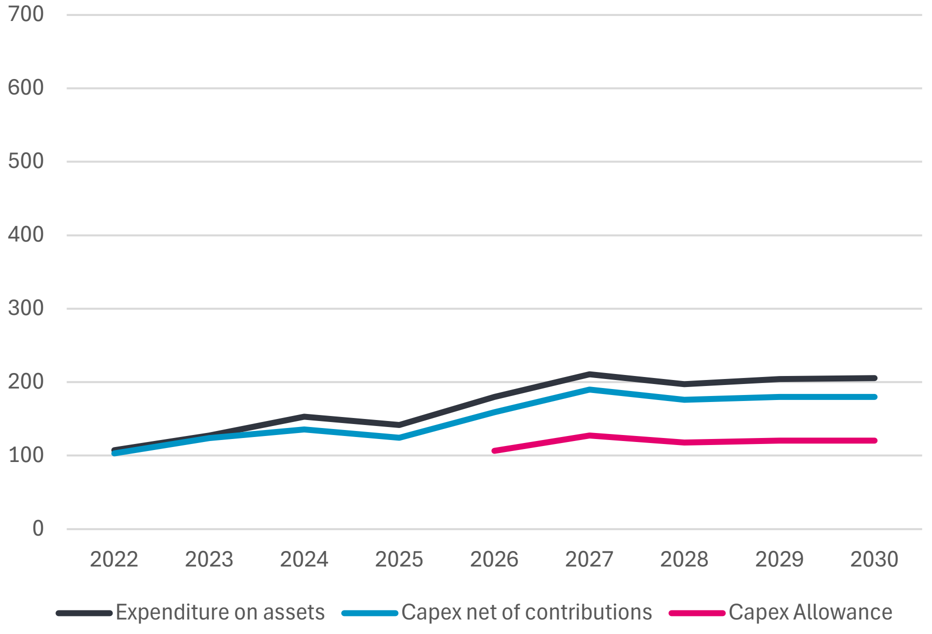
Source: NZIER

Figure 2 Powerco actual and forecast capital expenditure



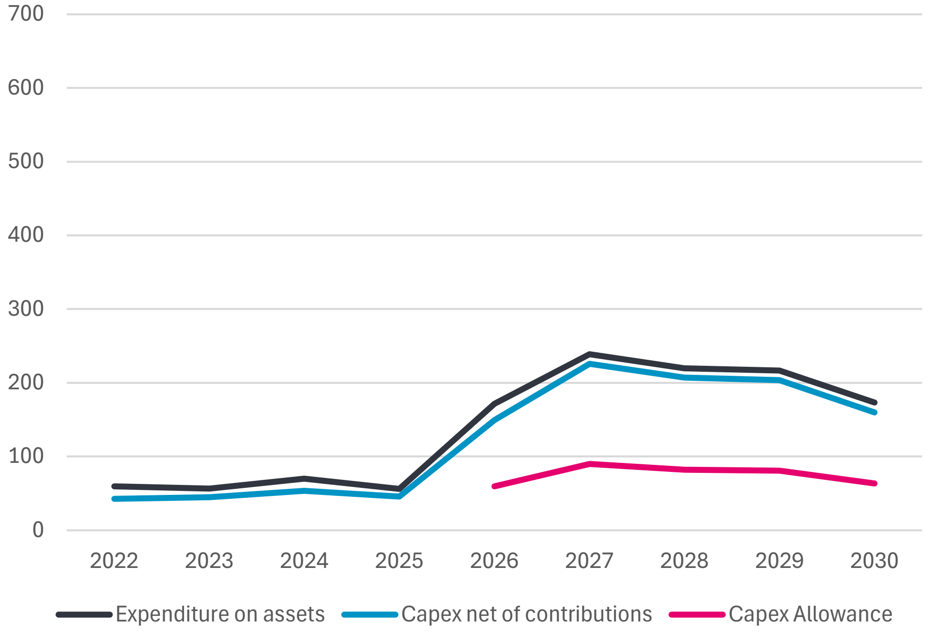
Source: NZIER

Figure 3 Orion actual and forecast capital expenditure



Source: NZIER

Figure 4 Wellington Lines actual and forecast capital expenditure



Source: NZIER

3 Growth in peak demand

3.1 Forecast growth in peak demand

The impact of projected growth in peak demand on EDB investment intentions is not discussed in detail in the capital expenditure sections of the DPP4 Draft Decision Reasons Paper. (Peak demand is considered as potential predictor of operational expenditure but it is the number of ICPs and line length that are the preferred predictors.[7]) However, we suggest that forecast peak demand is a useful cross check on both the outlook for the need for system growth investment and the consistency between EDB and Transpower outlooks for peak demand.

As part of their asset management plans, the EDB provide a five-year forecast of peak demand and the volume of energy delivered. Forecast growth in peak demand is a rough indicator of the driver of investment in network capacity.

[7] Commerce Commission May 2024, 'DPP4 Draft Decision Reasons Paper', page 214,Paragraph C208 and C211.

Table 2 below compares the 2022 starting point and the compound annual growth rate for both forecast peak demand and energy delivered for the six largest EDBs. (More detailed versions of the annual plan data for each EDB are included in **Appendix A**.) The summary data suggests the six EDBs, have similar rates of growth in volume of energy supplied can be separated into two groups based on peak demand growth profiles:

- Vector, Wellington Electricity, and Unison. These EDBs have reported large increases in forecast peak demand growth between their 2002 and 2024 plans and rates of growth in peak demand that are much higher than the rate of growth in the volume of energy delivered. This implies these EDB expect their demand to be much peakier than it is now. (Of these three, only Wellington Lines had its planned capital expenditure materially limited by the draft decision. Perversely Wellington Lines in 2024 seems to be forecasting a massive growth in energy delivered over the 2024 to 2029 period).
- Powerco, Orion and Aurora which forecast rates of growth in peak demand which are roughly similar to their forecast rates of growth in energy delivered. Aurora is forecasting energy delivered to grow slightly faster than peak demand. Of these EDBs, only Orion’s capital spending is constrained by the Commerce Commissions 25 percent and this constraint is modest.

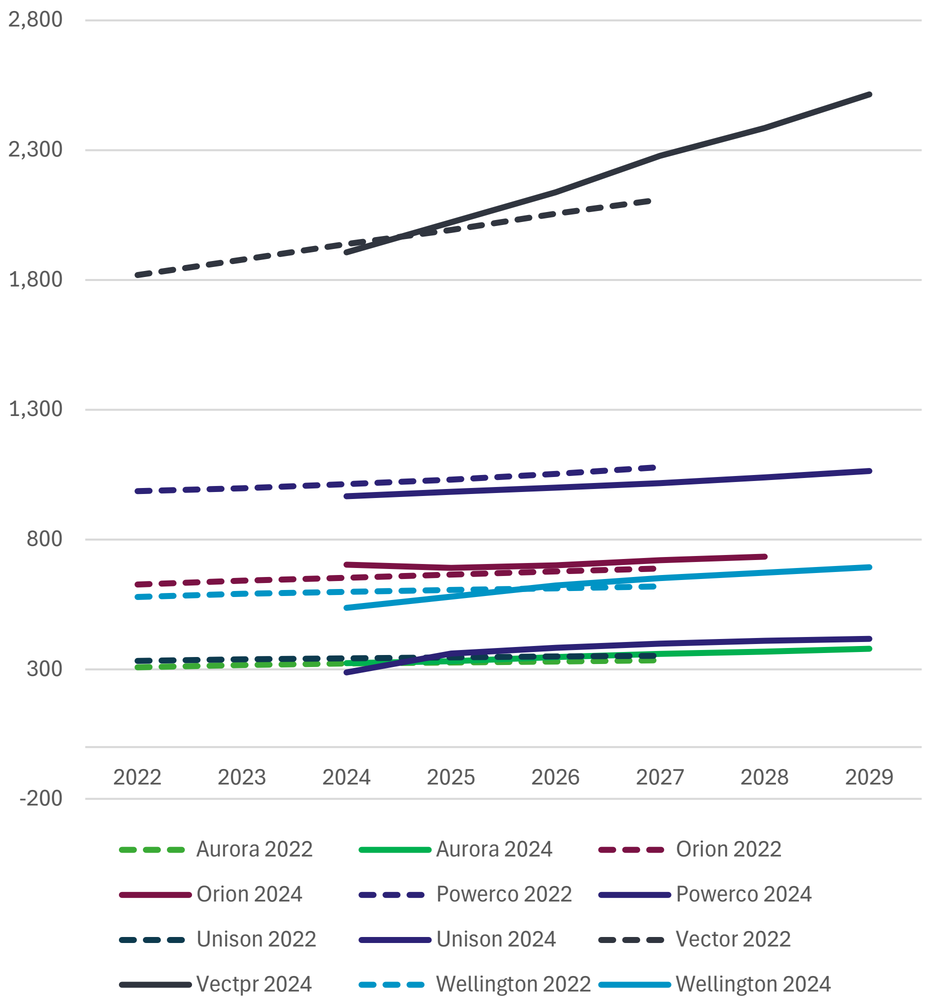
Table 2 EDB peak demand and volume supplied for plans from 2022 to 2024

Actual and forecast peak demand and energy entering system for supply to ICP

EDB	Peak Demand (MW)				Energy entering system for supply to ICP (GWh)			
	Actual 2022	Forecast CAGR			Actual	Forecast CAGR		
		2022 to 2027	2023 to 2028	2024 to 2029		2022 to 2027	2023 to 2028	2024 to 2029
Vector Lines	1,807.2	3.02%	4.81%	5.70%	8,724.0	0.40%	1.84%	2.20%
Powerco	986.0	1.80%	2.61%	1.93%	5,266.0	1.80%	2.61%	1.93%
Orion NZ	713.0	1.92%	2.30%	1.57%	3,415.8	1.43%	1.24%	1.21%
Wellington Electricity	579.0	1.35%	4.01%	5.26%	2,379.0	1.20%	1.21%	7.80%
Unison Networks	354.0	1.20%	8.70%	7.71%	1,750.4	0.06%	1.49%	1.48%
Aurora Energy	308.5	1.63%	2.82%	3.17%	1,382.4	0.76%	2.81%	3.70%

Source: NZIER

Figure 5 Peak demand forecasts in 2022 and 2024



Source: NZIER

3.2 EDB and Transpower peak forecasts

The most recent Transpower regional forecasts for peak demand are included in its latest Transmission Planning Report (TPR 2023)[8]. 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.

8 Transpower 2023 Transmission Planning Report

Table 3 EDB and Transpower forecast peak demand growth

Pea k demand measured in MW. Growth rate is the compound annual growth rate

EDB	2023 (MW)	Growth rate (%)	2029 (MW)	Transpower region	2023 (MW)	Growth rate (%)	2029 (MW)	2038 (MW)
Vector Lines	1,776.0	6.0%	2,515.0	Auckland	2,008	2.60	2,342	3,050
Powerco	973.6	1.5%	1,064.1	Bay of Plenty	392	3.10	471	623
				Central North Island	311	3.00	371	488
				Taranaki	231	1.60	254	294
Orion NZ	660.4	2.4%	760.0	Canterbury	820	2.00	923	1,101
Wellington Electricity	539.0	4.3%	692.9	Wellington	740	1.70	819	949
Unison Networks	351.0	2.9%	417.4	Hawkes Bay	379	1.10	405	445
				Bay of Plenty	392	3.10	471	623
Aurora Energy	312.4	3.3%	378.61	Otago-Southland	556	3.20	672	900

Source: NZIER

4 Retail electricity price increase drivers

4.1 Retail electricity price outlook

Retail electricity prices are about to come under sustained upward pressure from a combination of recent increases in wholesale electricity forward prices and the proposed increases in Transpower and EDB charges.

4.2 Commerce Commission presentation of price increases

The Commerce Commission described 'consumer bill impacts' on households in its stakeholder presentation as *'an additional $180 per year on average across most of New Zealand'*[9] and described the revenue allowance increase for Transpower as 15 percent for years one and two followed by 5 percent per year for years three to five; and for EDBs, 24 percent for year one followed by business specific increases for years two to five. The Commerce Commission presentation of the consumer bill impacts seems to have focused on the first-year increase in charges. The DPP4 Draft Decision Reasons Paper seems to follow the same approach of focusing on the first-year impact with substantive comment limited to:

- *To mitigate price shocks to consumers we have limited the initial nominal increase in distribution revenue to an average of 24%.5 This equates to approximately $15 per month (ex GST) on average for a household consumer electricity bill.*[10]

9 Commerce Commission May 2024 (c) 'Draft revenue limits and quality standards for electricity lines companies for 2025-2030, Transpower RCP4 and EDB DPP4 draft decisions, 29 May 2024, Vhari McWha, Commissioner', slides 5 and 20, available at https://comcom.govt.nz/__data/assets/pdf_file/0027/354447/RCP4-DPP4-draft-decisions-presentation-to-stakeholder-and-media-slide-deck-29-May-2024.pdf

10 Commerce Commission May 2024, 'DPP4 Draft Decision Reasons Paper', Summary of draft DPP4 price-quality path decisions, page 6.

- Charts showing '*estimated average consumer bill impact for each EDB between 2025 and 2026*'[11] and the effect of revenue smoothing on the change in EDB revenue from 2025 to 2026[12]
- Reference to consumer information web page '*Electricity Lines and Transmission Charges: What are they, why are they changing and what does this mean for your electricity bill?*'[13]

On its Consumer information webpage, the Commerce Commission makes the following observations:

- An average household bill contributes to the following costs: *generation 32%, transmission 10.5%, distribution 27%, retail 13%, metering 3.5%, market governance and services 1% and GST 13%.*
- An approximate estimate of the drivers of the increase in distribution and transmission charges are inflation 25 percent, interest rate increases 40 percent and higher levels of investment 35 percent. The Commerce Commission describes inflation and interest rate increases as 'externally driven' and ''higher levels of investment' as related to its draft decision.

4.3 Price increase pressures

Our starting point for analysing the impact of the proposed increases in distribution and transmission charges is the gentailer disclosures on the components of retail electricity prices in $ per MWh published by the EA (see **Appendix B** for details on the disclosure). The disclosures indicate the following price structure for the year ended June 2023.

Table 4 Gentailer retail price disclosure 2022 and 2023

Retail price components in $/MWh

	Average	
Component	2022	2023
Revenue	251.55	263.89
ITP	105.77	122.20
Metering	11.60	12.42
Distribution	97.64	103.61
Levies	1.08	1.40
Margin	35.46	24.27
Total Sales (GWh)	13,742	15,200

Source: NZIER

The ITP component is the internal transfer price set be generators for the price of electricity and is mainly determined by three year moving average of ASX electricity future prices plus

11 Commerce Commission May 2024, 'DPP4 Draft Decision Reasons Paper', Paragraph 4.57 and Figure 4.5, page 35

12 Commerce Commission May 2024, 'DPP4 Draft Decision Reasons Paper', Paragraph F43 and Figure F8, page 417

13 Available at https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-and-transmission-charges-what-are-they,-why-are-they-changing-and-what-does-this-mean-for-your-electricity-bill/_nocache

some adjustment factors for time-of-day seasonality and location. We expect that the ITP will increase to around $150 to $175 per MWh over the next two to three years as the moving averages catch-up with recent increases in futures prices. The outlook after this period is uncertain, but for the purpose of considering change in retail prices, we assume it will remain fall back to $125 to $150 within 3 years and then remain there (which reflects the current profile of forward prices out to 2027[14]). .

The distribution component includes both EDB and transmission charges which have increased by about 6.1 percent in 2023 compared to 2022.

(The increase in total sales from 13,742 to 15,200GWh suggests an expansion of coverage of the survey rather than an increase in demand . The Electricity Demand and Generation Scenarios July 2024 (EDGS) 'Reference' scenario reports residential electricity demand of 13,410 GWh in 2022 and 13770 GWh in 2023.)

4.3.1 Contribution from estimates of change in transmission and distribution costs

EDB MAR

Our simulations using data from the Commerce Commissions MAR calculation spreadsheet for individual EDB, which suggests the MAR increase path for the six largest EDB is a shown in Table 5 and the annual increase shown in Table 6.

Table 5 DPP4 Maximum Allowable Revenue (MAR) estimate for six largest EDB

$m

EDB	20225	2026	2027	2028	2029	2030	DPP4
Vector Lines	420.6	580.0	641.8	710.3	786.1	870.0	3,588.3
Powerco[1]	328.1	486.1	495.8	505.7	515.9	526.2	2,529.7
Orion NZ	171.5	219.5	253.0	291.6	336.1	387.4	1,487.5
Wellington Electricity	98.9	118.8	134.1	151.4	171.0	193.0	768.3
Unison Networks	108.2	136.1	157.4	182.1	210.6	243.6	929.8
Aurora Energy	94.5	157.3	160.5	163.7	167.0	170.3	818.7
Total	**893.8**	**1,211.6**	**1,346.8**	**1,499.1**	**1,670.7**	**1,864.3**	**7,592.5**

Note:

1 Values for Powerco for 2027 to 2030 are estimated using the data published in the DPP4 Draft Decision Reasons Paper' for 2025, 2026 and DPP4 combined with the application of a constant annual increase rate that generates values for 2027 to 2030 that with the published value for 2026 add to the published DPP4 total.

Source: NZIER[15]

[14] electricity Authority May 2024 'Forward price dip following new Tiwai smelter contracts' available at https://www.ea.govt.nz/news/eye-on-electricity/forward-price-dip-following-new-tiwai-smelter-contracts/

[15] Copied from 'Electricity Distribution Business, Price-Quality Regulation 1 April 2025 DPP Reset, MAR Waterfall model (MAR2021 to MAR2026), Draft DPP4 Determination, Published 17 June 2024v1.using worksheet 'Waterfall' and changing the name of the selected EDB.

Table 6 DPP4 MAR annual increase for six largest EDB

Year on year change

EDB	2026	2027	2028	2029	2030
Vector Lines	38%	11%	10.7%	11%	11%
Powerco	48%	2%	2%	2%	2%
Orion NZ	28%	15%	15%	15%	15%
Wellington Electricity	20%	13%	13%	13%	13%
Unison Networks	26%	16%	16%	16%	16%
Aurora Energy	66%	2%	2%	2%	2%
Total	36%	11%	11%	11%	12%

Source: NZIER

Assuming a load growth of 2 percent per year for EDBs, the MAR increase rate for the six largest EDB in Table 6 translates to a cost increase in $ per MWh of roughly 34 percent in 2026 and about 9 percent each of the following DPP4 year. (The 2 percent assumption is consistent with the EDGS Reference case assumption of 2.08 percent per year over the DPP period.

Transpower RCP4 MAR

Table 7 Transpower RCP4 Forecast MAR[16]

Transpower	2025	2026	2027	2028	2029	2030	DPP4
Revenue ($m)	840	969.8	1,119.4	1,175.4	1,234.2	1,295.9	5,794.7
Year on year change		15%	15%	5%	5%	5%	

Source: NZIER[17]

For the purpose of this price change estimate, we assume that the Transpower's MAR increases will translate to an increase in $per MWh costs of 13 percent.

Impact of MAR increases on distribution

We use the Commerce Commission's description of the components of the average household bill (*transmission 10.5%, distribution 27%)* to weight the impact of the MAR increases above on distribution expenses as measured in the gentailer disclosure.

The estimated increase in distribution cost as a result of the DPP4 and RCP4 decisions is 28 percent in 2026, 10 percent in 2027 and 8 percent for each of the years 2028, 2029 and 2030.

16 Commerce Commission May 2024 d, ' Transpower's individual price-quality path for the regulatory control period commencing 1 April 2025 Draft Decision Attachment A – Revenue path design, Date of publication: 29 May 2024page 12, 'Table 2.1 RCP4 Forecast MAR'.

17 Copied from 'Electricity Distribution Business, Price-Quality Regulation 1 April 2025 DPP Reset, MAR Waterfall model (MAR2021 to MAR2026), Draft DPP4 Determination, Published 17 June 2024v1.using worksheet 'Waterfall' and changing the name of the selected EDB.

If for example we assume that the 2025 starting value for the distribution component would be 5 percent above the 2023 level at $108.80, then the MAR increase would increase distribution expenses to about $139 per MWh in 2026 and $154 per MWh in 2027. This would be an increase of 12 percent 2026 and a further 6 percent increase 2027 followed by regular price increases of about 4 percent each year 2028 to 2030 on 2023 retail prices measured in $ per MWh. This bakes in price increases that are well above the expected rate of inflation.

Appendix A EDB peak demand and volume carried forecasts

The following tables include compare peak demand and volume of electricity carried for the six major EDBs.

Table 8 Vector Lines

Actual and forecast peak demand and energy entering system for supply to ICP

Year	Peak Demand (MW)				Energy entering system for supply to ICP (GWh)			
	Actual	Forecast			Actual	Forecast		
		2022	2023	2024		2022	2023	2024
2020	1,745.0				8,748.0			
2021	1,730.0				8,542.0			
2022	1,807.2	1,818.5			8,724.0	8,707.4		
2023	1,758.6	1,877.6	1,776.0		8,813.0	8,964.9	8,779.7	
2024		1,938.0	1,898.0	1,906.0		8,808.0	8,774.9	9,037.0
2025		1,992.7	2,013.0	2,022.0		8,852.0	9,226.2	8,678.0
2026		2,054.8	2,076.0	2,138.0		8,877.2	9,336.9	9,498.0
2027		2,109.8	2,137.0	2,278.0		8,882.0	9,447.0	9,692.0
2028			2,246.0	2,386.0			9,619.5	9,884.0
2029				2,515.0				10,076.0
CAGR		3.02%	4.81%	5.70%		0.40%	1.84%	2.20%

Source: NZIER

Table 9 Powerco

Actual and forecast peak demand and energy entering system for supply to ICP

Year	Peak Demand (MW)				Energy entering system for supply to ICP (GWh)			
	Actual	Forecast			Actual	Forecast		
		2022	2023	2024		2022	2023	2024
2020	923.0				5,181.0			
2021	944.0				5,154.0			
2022	986.0	986.0			5,266.0	5,234.0		
2023	974.0	997.0	973.6		5,225.0	5,292.4	5,349.0	
2024		1,013.0	1,009.5	967.0		5,377.3	5,546.0	5,317.5
2025		1,031.0	1,028.3	983.3		5,472.9	5,649.6	5,407.1
2026		1,053.0	1,050.8	999.3		5,589.7	5,772.9	5,495.1
2027		1,078.0	1,077.4	1,017.5		5,722.4	5,919.2	5,595.2
2028			1,107.5	1,038.9			6,084.6	5,712.9
2029				1,064.1				5,851.5
		1.80%	2.61%	1.93%		1.80%	2.61%	1.93%

Source: NZIER

Table 10 Orion NZ

Actual and forecast peak demand and energy entering system for supply to ICP

Year	Peak Demand (MW)				Energy entering system for supply to ICP (GWh)			
	Actual	Forecast			Actual	Forecast		
		2022	2023	2024		2022	2023	2024
2020	605.6				3,418.5			
2021	625.1				3,383.8			
2022	713.0	625.9			3,415.8	3,432.5		
2023	654.9	641.0	660.4		3,521.2	3,481.6	3,457.8	
2024		652.6	680.3	703.0		3,531.4	3,500.7	3,563.0
2025		664.4	695.9	691.0		3,581.8	3,544.1	3,605.5
2026		676.5	711.2	701.0		3,633.0	3,588.0	3,649.6
2027		688.4	724.2	720.0		3,684.8	3,632.4	3,693.1
2028			739.8	734.0			3,677.3	3,738.2
2029				760.0				3,783.8
CAGR		1.92%	2.30%	1.57%		1.43%	1.24%	1.21%

Source: NZIER

Table 11 Wellington Electricity

Actual and forecast peak demand and energy entering system for supply to ICP

Year	Peak Demand (MW)				Energy entering system for supply to ICP (GWh)			
	Actual	Forecast			Actual	Forecast		
		2022	2023	2024		2022	2023	2024
2020	520.8				2,393.9			
2021	557.0				2,379.0			
2022	579.0	579.0			2,379.0	2,404.0		
2023	537.8	591.0	539.0		2,370.6	2,449.0	2,481.0	
2024		598.0	566.0	536.3		2,473.0	2,527.8	2,399.0
2025		605.0	609.0	579.3		2,499.0	2,552.8	2,799.5
2026		612.0	628.0	622.8		2,525.0	2,579.9	3,065.3
2027		619.0	644.0	650.7		2,552.0	2,606.9	3,236.0
2028			656.0	671.6			2,635.0	3,383.3
2029				692.9				3,491.8
CAGR		1.35%	4.01%	5.26%		1.20%	1.21%	7.80%

Source: NZIER

Table 12 Unison

Actual and forecast peak demand and energy entering system for supply to ICP

Year	Peak Demand (MW)				Energy entering system for supply to ICP (GWh)			
	Actual	Forecast			Actual	Forecast		
		2022	2023	2024		2022	2023	2024
2020	329.0				1,712.0			
2021	339.0				1,710.0			
2022	354.0	331.6			1,750.4	1,783.0		
2023	350.9	337.9	351.0		1,728.2	1,788.0	1,729.0	
2024		342.1	493.4	288.0		1,788.0	1,762.8	1,765.0
2025		345.7	502.6	360.2		1,788.0	1,791.0	1,829.0
2026		349.6	520.7	382.4		1,788.0	1,811.9	1,847.0
2027		352.1	527.1	398.0		1,788.0	1,835.9	1,864.0
2028			532.6	409.2			1,862.1	1,882.0
2029				417.4				1,900.0
CAGR		1.20%	8.70%	7.71%		0.06%	1.49%	1.48%

Source: NZIER

Table 13 Aurora Energy

Actual and forecast peak demand and energy entering system for supply to ICP

	Peak Demand (MW)				Energy entering system for supply to ICP (GWh)			
	Actual	Forecast			Actual	Forecast		
Year		2022	2023	2024		2022	2023	2024
2020	283.2				1,431.1			
2021	298.6				1,385.4			
2022	308.5	308.0			1,382.4	1,388.0		
2023	308.7	316.0	312.4		1,434.6	1,396.1	1,401.1	
2024		322.0	327.3	323.9		1,407.2	1,467.3	1,487.0
2025		326.0	337.4	330.9		1,418.5	1,513.0	1,542.0
2026		330.0	346.2	346.7		1,429.9	1,552.3	1,599.0
2027		334.0	352.2	359.2		1,441.3	1,579.5	1,658.0
2028			358.9	367.5			1,609.4	1,719.3
2029				378.6				1,782.9
CAGR		1.63%	2.82%	3.17%		0.76%	2.81%	3.70%

Source: NZIER

Appendix B Gentailer retail electricity price components

B.1 Estimating price increases from 2024 in $ per MWh

The Commerce Commission's description of the price increase provides little context with respect to either the increases that are 'in the pipeline' up to 2025 or the overall level of increase in electricity prices that will occur at the beginning and during DPP4. In this section we combine estimates of the following:

- Expected increases in gentailers' internal transfer price for electricity as the three-year moving averages catch-up with the recent increase wholesale futures prices.
- Increases in distribution and transmission charges included in EDB pricing methodologies for 2024/25.
- Estimated Increases in transmission and distribution costs in 2025/26 and 2026/2027

We use this approach to make a rough estimate of the potential increase in retail energy prices that are already 'baked-in' as result of the approved increases in transmission and distribution charges and the momentum from adjustment to wholesale energy prices.

B.2 Retail price components in $ per MWh – 2023 starting point

The Electricity Authority has gathered data on average prices charged by gentailers and the methods used by gentailers to set retail energy prices. Essentially the gentailers determine an internal transfer price for energy based on an average of electricity forward contract prices (for a constant 24-hour supply) plus adjustments for seasonality and daily highs and lows. Other costs incurred from third party providers such as distribution, metering and levies are apparently passed through

Table 14 reports the gentailer price components for 2022 and 2023 published by the EA. The weighted average indicates that distribution cost (Transpower plus EDB charges) were about 38.8 percent and 39.3 percent of the retail electricity price in 2022 and 2023 respectively.

Table 14 Gentailer retail price disclosure 2022 and 2023

Retail price components in $/MWh

	Contact		Genesis		Mercury		Meridian		Average[1]	
Component	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
Revenue	235.30	269.00	281.00	269.22	262.00	278.00	226.08	234.26	251.55	263.89
ITP	107.00	129.55	111.16	125.53	104.00	122.00	99.62	111.06	105.77	122.20
Metering	12.30	14.00	10.86	11.55	14.00	14.00	9.62	9.76	11.60	12.42
Distribution	95.40	107.00	101.32	105.27	100.00	107.00	93.76	93.82	97.64	103.61
Levies	1.10	1.00	1.09	1.34	1.00	2.00	1.12	1.09	1.08	1.40
Margin	19.50	17.45	56.57	25.53	43.00	33.00	21.96	18.53	35.46	24.27
Sales (GWh)	3,689	3,500	3,877	3,900	2,870	4,400	3,305	3,400		

Note:

1 Average of retail price component for each gentailer weighted by each gentailers’ share of total gentailer sales.

Source: NZIER

Table 15 reports the internal transfer prices used by the gentailers. According to information published by the EA[18], four of the five gentailers base their transfer price on a simple average of ASX futures prices over the past three years with some variation in the contracts chosen within the three-year period. Mercury appears to be the only gentailer to use a forward-looking average, based on futures prices for the next three years.

18 See EA,' Retail category / Datasets Internal transfer pricing ITP disclosures for financial years ending in 2022' available at https://www.emi.ea.govt.nz/Retail/Datasets/InternalTransferPricing/2022

Table 15 Gentailer internal transfer prices

Prices in $/MWh

Component	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Contact	84.12	81.08	87.51	91.92	107.55	129.55
Genesis	80.16	83.53	84.40	87.30	111.16	125.53
Manawa	83.79	85.37	89.91	97.20	101.60	104.10
Mercury	88.00	88.00	89.00	99.00	104.00	115.00
Meridian	76.83	75.82	81.17	88.55	99.62	111.06
Simple average	82.58	82.76	86.40	92.79	103.79	117.05

Source: NZIER

B.3 MAR data

Table 16 MAR data for selected EDB

$ million

EDB	2025	2026	2027	2028	2029	2030	DPP4
Alpine Energy	46.2	70.2	73.4	76.8	80.3	83.9	384.7
Aurora Energy	94.5	157.3	160.5	163.7	167.0	170.3	818.7
EA Networks	36.0	45.8	52.1	59.2	67.4	76.6	301.1
Firstlight Network	26.0	35.7	40.3	45.5	51.3	57.9	230.7
Electricity Invercargill	13.3	17.0	19.0	21.3	23.9	26.8	108.1
Horizon Energy	25.9	34.1	36.0	38.1	40.3	42.6	191.2
Nelson Electricity	6.0	7.0	7.7	8.4	9.2	10.1	42.5
Network Tasman	28.6	37.0	41.3	46.1	51.5	57.5	233.3
Orion	171.5	219.5	253.0	291.6	336.1	387.4	1,487.5
OtagoNet	27.9	33.6	39.9	47.4	56.3	66.8	244.1
The Lines Company	37.6	48.4	52.7	57.4	62.5	68.1	289.1
Top Energy	41.1	53.0	61.3	71.0	82.2	95.1	362.6
Unison Networks	108.2	136.1	157.4	182.1	210.6	243.6	929.8
Vector Lines	420.6	580.0	641.8	710.3	786.1	870.0	3,588.3
Wellington Electricity	98.9	118.8	134.1	151.4	171.0	193.0	768.3
Powerco	328.1	486.1	*495.8*	*505.7*	*515.9*	*526.2*	2,529.7
Total	**1,510.4**	**2,079.5**	**2,266.4**	**2,476.1**	**2,711.4**	**2,976.0**	**12,509.5**

Source: NZIER

Table 17 MAR increase for selected EDB

Year on year change %

EDB	2026	2027	2028	2029	2030
Alpine Energy	52%	5%	5%	5%	5%
Aurora Energy	66%	2%	2%	2%	2%
EA Networks	27%	14%	14%	14%	14%
Firstlight Network	37%	13%	13%	13%	13%
Electricity Invercargill	28%	12%	12%	12%	12%
Horizon Energy	32%	6%	6%	6%	6%
Nelson Electricity	18%	9%	9%	9%	9%
Network Tasman	29%	12%	12%	12%	12%
Orion	28%	15%	15%	15%	15%
OtagoNet	21%	19%	19%	19%	19%
The Lines Company	29%	9%	9%	9%	9%
Top Energy	29%	16%	16%	16%	16%
Unison Networks	26%	16%	16%	16%	16%
Vector Lines	38%	11%	11%	11%	11%
Wellington Electricity	20%	13%	13%	13%	13%
Powerco	48%	2%	2%	2%	2%
Total	**38%**	**9%**	**9%**	**10%**	**10%**

Source: NZIER