19 December 2023

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Infrastructure Regulation
Commerce Commission
Wellington
Via email: infrastructure.regulation@comcom.govt.nz

Tēnā koe,

Powerco's submission on EDB DPP4 issues paper

Powerco Limited (Powerco) welcomes the opportunity to contribute to the discussion on the Commerce Commission's issues paper, "Default price-quality paths for electricity distribution businesses from 1 April 2025."

This reset is an important decision for EDBs and our customers as we strive to meet Aotearoa's electrification needs, contributing to a net-zero economy by 2050. As one of Aotearoa's largest gas and electricity distributors, servicing approximately 356,000 homes and businesses with electricity and 113,000 with gas across the North Island, our energy networks play a crucial role in achieving this goal.

Navigating the complex landscape of the DPP4 reset

The reset of Energy Distribution Businesses' (EDBs) price-quality paths for the DPP4 period aligns with a time when New Zealand, and indeed many nations, are actively pursuing aggressive transitions towards lower-emission energy systems and climate-resilient economies. Unfortunately, this endeavour unfolds against the challenging backdrop of a cost-of-living crisis fuelled by high inflation and interest rates. These converging factors create a complex decision-making environment for the reset where competing factors cannot be resolved through a traditional application of the regulatory framework.

On one hand, the Commission faces the task of setting EDB expenditure and revenues to support the energy transition. On the other hand, the anticipated increases in consumer bills between DPP3 and DPP4, coupled with the long-term price impacts of EDB investments, require the Commission to navigate this reset cautiously. The imperative is not only to support the energy transition and reflect the current context, but also to manage the impact on consumers as effectively as possible.

As the Commission deliberates on decisions for the DPP4 reset, it is compelled to weigh the purpose of Part 4 and the objectives of default/customised price-quality regulation. In the issues paper, the Commission highlights the key component of the Part 4 purpose statement is:

"The key component of this statement is that we are to promote the long-term benefit of consumers, and this is our concern in achieving the purpose of Part 4."[1]

While the purpose statement provides helpful overarching guidance, it does not diminish the necessity to make challenging decisions – that's an unavoidable reality in this reset. To assist the Commission in its decision-making, the primary goal of this consultation process should be to illuminate the choices that will ultimately deliver the greatest long-term benefit to New Zealand electricity consumers. In evaluating these choices, the Commission should consider whether a decision carries an asymmetric risk for consumers. If an imbalance in risk exists, favouring the option with lower risk will likely best promote the Part 4 purpose.

Feedback on the consultation paper

Our response to the issues paper questions is provided in Attachment 1. For additional information about Powerco and our network, please refer to Attachment 2. If you have any questions about this submission, please contact Nathan Hill (Nathan.Hill@powerco.co.nz).

Nāku noa, nā,

Stuart Dickson
General Manager, Customer
POWERCO

[1] DPP4 issues paper, page 66

Attachment 1: Powerco's response to the questions in the issues paper

Context and challenges

Question	Powerco's response
1. We are interested in your views on whether we have properly understood the changing industry context as it relates to the DPP4 reset. Have we properly understood and represented the changing industry context and are there other implications for the DPP4 you believe we should consider?	We appreciate the Commission's awareness of the dynamic industry landscape. When we reflect on this evolving context, we think the priorities for the DPP4 process and decisions are, in no particular order: 1. **Supporting accelerated renewables development**: EDB investments will facilitate renewables through the network infrastructure that enables the connection of new renewable generation to customers. 2. **Scaling up efficient distribution network investment**: Investment in energy infrastructure is needed now. Boston Consulting Group and Concept Consulting estimated that $22 billion is required in distribution sector investment in the 2020s to enable electrification and integrate distributed energy resources. This represents a 30% increase in total expenditure (totex) in 2026–30 relative to 2021–25 and a significant increase in growth capex. [2] Our own expenditure forecasts suggest a similar required uplift. DPP4 decisions should provide investment incentives and allowances for efficient distribution network enhancements, expansion, and non-network alternatives to effectively support the energy transition and drive electrification at pace. The assessment of EDB forecasts must prioritise the net benefits for electricity consumers. Favouring progress over perfection is key to expedite the expansion of energy infrastructure, allowing EDBs to secure a resilient supply chain and strategically spread-out investments and delivery over time. 3. **Providing operating expenditure allowances that facilitate the energy transition and minimise overall investment costs**: EDBs need opex allowances that enable them to adapt to the evolving energy system. This adaptation involves the transformation of system operation and network support, increased utilisation of smart technologies, data, and distributed flexibility, as well as enhanced management of cyber risk. Additionally, as

[2] BCG (2022). The Future Is Electric: A Decarbonisation Roadmap for New Zealand's Electricity Sector. Page 9. Available online at https://www.bcg.com/publications/2022/climate-change-in-new-zealand

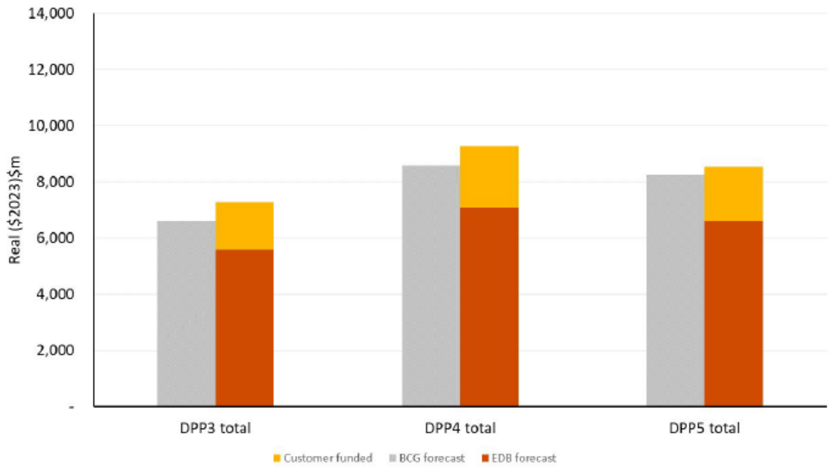
Question	Powerco’s response
	our IT systems and software are increasingly procured as services, allowances are necessary to cover associated operational costs. There might also be a requirement for additional business support, especially for larger research and development (R&D) programs. It is important to highlight that the additional opex would be offset by reductions in capex, increasing the use of non-network solutions, in particular, should reduce investment costs. 4. **Ensuring financial viability for EDBs to fund investments**: In addition to capital expenditure for increasing investment in infrastructure, parameters for cost of capital and opex inflation have changed significantly for the next DPP period and need to be accounted for as part of our changing landscape. In addition, underinvestment due to inadequate allowances could result in higher costs and price impacts for consumers in the long term. 5. **Enabling more flexibility to respond to uncertainty**: The years 2025-30 are marked by considerable investment uncertainties. Enabling agile in-period adjustments as circumstances evolve will allow EDBs and the Commission to navigate the changing landscape more effectively. It also provides the Commission the capability to exclude expenditures from the price path when the timing or extent of investment is uncertain, safeguarding consumers from the risk of incurring unnecessary costs. More flexibility will also support the Commission’s role to manage the known unknowns, rather than expecting to deal with multiple CPPs. 6. **Supporting improved network resilience**: There is increasing importance in enhancing network resilience, particularly in the face of recent events such as ex-Tropical cyclones Dovi and Gabrielle and the energy transition leading to increased customer reliance on electricity. These events serve as reminders of the widespread impacts resulting from prolonged electricity bulk supply failures. The Government policy review response to recent natural hazard events also illustrates a changing context for infrastructure investment and need for flexibility for EDBs to respond to changing expectations. 7. **Assessing consumer price shocks**: Fully understanding both financeability and price shocks will be important. The potential material increase in consumer bills between DPP3 and DPP4 will require measures such as revenue smoothing.

Question	Powerco’s response
	8. **Clearly communicating with consumers**: For the energy transition to succeed, it is crucial for the industry, including regulators, to participate in an open and honest dialogue with consumers regarding the implications of this transformative process. In the context of this reset, this involves clearly explaining the scale and key factors contributing to bill increases. It also involves effectively communicating the reduction in emissions, added value in terms of additional services, and the long-term recovery of short-term investment. 9. **Enabling and incentivising a smart electricity system**: Adopting an intelligent augmentation and network hardening approach, maximising asset utilisation without unduly increasing risk exposure, is imperative to reduce whole-of-system costs and deliver better consumer outcomes. Our changing energy system endorses the need to look forward, be flexible and use different approaches to incentives and allowances. For example, flexibility payments can be categorised as pass-through or recoverable costs, rather than forecasting an allowance, to address the challenge of accurately quantifying future expenditure in these areas. The potential value that can be unlocked by enabling a smart electricity system is significant. BCG suggests that a ‘smart system’ could save around $10 billion in costs on a net present value basis to 2050, and investment in smart technologies could unlock at least 2 GW of distributed flexibility by 2030, and 5.8 GW by 2050.[3]

Forecasting capital expenditure

Question	Powerco’s response
2. We are proposing to adapt our approach to capex for DPP4 based on feedback from EDBs, that past expenditure is not a good starting point for considering future spend. Do you have any particular concerns or issues with our proposed approach? If so,	We welcome the Commerce Commission's intention to update its approach to establishing EDB capital expenditure (capex) allowances for the upcoming default price-quality path (DPP4). We strongly advocate for an updated approach to unlock the full planning and investment potential of these businesses. A shift away from employing an aggregate percentage cap on historical expenditure is a crucial change needed for this reset. Considering the necessary increase in investment by EDBs for the electrification of the economy, relying on past spending as a baseline for future outlay is no longer viable.

[3] BCG (2022). The Future Is Electric: A Decarbonisation Roadmap for New Zealand’s Electricity Sector. Page 11. Available online at https://www.bcg.com/publications/2022/climate-change-in-new-zealand

Question	Powerco's response
how could these concerns or issues be resolved? What alternative data and external sources should we use to support our consideration of capex forecasts, beyond the information in 2023 Asset Management Plans (AMPs), responses to section 53ZD notices and 2024 AMPs, and why should these be used?	This viewpoint finds support in analysis conducted by PwC (see their capex modelling report in attachment 3). As depicted in figure 1 below, EDBs 2023 AMP capex forecasts are aligned with the trend predicted in 2022 by Boston Consulting Group (BCG) in their 'The Future is Electric' report. [4] Additionally, Figures 2 and 3 illustrates that applying a percentage cap to a historical average for non-exempt EDB DPPs is unlikely to effectively support the energy transition. ***Figure 1: EDB and BCG forecast capex (real)*** [5] 

[4] BGC, Distribution Investment, page 14
[5] PwC, Regulatory Outlook Capex Modelling, December 2023, page 5

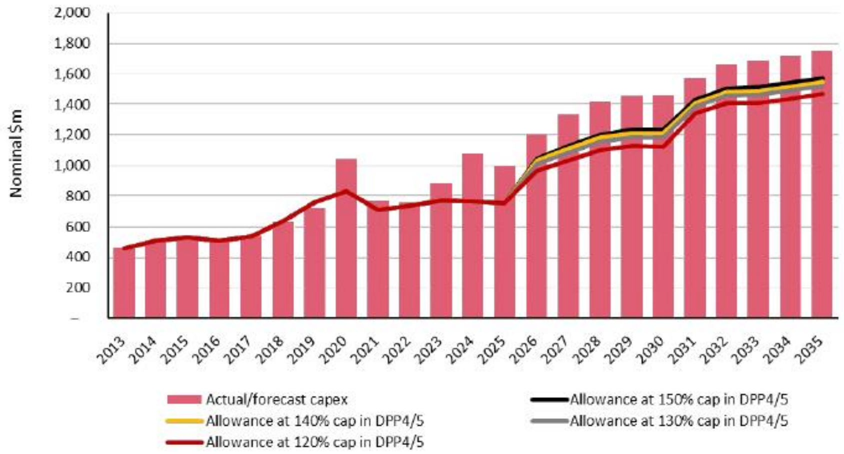
Question	Powerco's response
	Figure 2: Actual/forecast capex and DPP capex allowance (nominal)[6] 

Figure 3: Capex capped out of DPP4 and DPP5 ($m nominal)[7]

	DPP4	DPP5
120% cap	1,491.3	1,291.7
130% cap	1,227.9	1,038.3
140% cap	1,090.0	919.9
150% cap	1,001.5	801.6

PwC's revenue modelling analysis (refer to Attachment 4) indicates that the capex allowances for EDBs in DPP4 do not have a substantial influence on short-term allowable revenue. This is attributed to the methodology of recovering capital costs over the lifespan of the asset.

[6] PwC, Regulatory Outlook Capex Modelling, December 2023, page 6
[7] PwC, Regulatory Outlook Capex Modelling, December 2023, page 6

Question	Powerco's response
	In evaluating the capex forecasts of EDBs the Commission should give precedence to the net benefit to consumers stemming from an EDB's investment in DPP4. This methodology aligns with the Commission's draft decision on Transpower's Net-Zero Grid Pathways Phase One. Quoting directly from the media release: *"While we are mindful of the costs that will be incurred over time and reflected in electricity bills, we are confident that Transpower's proposed investments will yield net benefits for electricity consumers".* We support the proposed framework for setting capex forecasts, as illustrated in Figure E1 of the Issues Paper. Additionally, we endorse using Innovative Assets Engineering (IAEngg) to assess the reasonableness of EDBs' demand and expenditure forecasts. This approach helps ensures that approved expenditure allowances are underpinned by a robust rationale, instilling confidence among the Commission and other stakeholders that they are efficient and align with future needs.
3. We are proposing to apply the capital goods price index to forecast capex allocations. Is there a more appropriate index which could be applied; and, if so, why?	We agree that the capital good price index is broadly appropriate to forecast capex allocations.
4. We have concerns about the challenges in delivering increased programmes of work given current labour market, supply chain and economic challenges in New Zealand. How should our capex forecast take into account potential sector-wide deliverability constraints?	We understand the Commerce Commission's concerns about potential delivery risks associated with increased industry-wide programs of work. These concerns reflect a realistic awareness of the current labour market, supply chain, and economic challenges in New Zealand. To address these delivery challenges we have taken the following measures or are in the process of doing so: ***Increasing our delivery capability and capacity in recent years*** We transformed our delivery capability during our CPP Investment Program. The increase in annual investment during this period has significantly elevated our delivery capability and capacity. Despite the challenges presented by the COVID-19 pandemic and its supply chain implications, we effectively sustained our delivery momentum during this

Question	Powerco's response
	period. Our demonstrated track record instils confidence in our ability to execute our forecasted investments successfully. [redacted] ***Ensuring timely access to essential equipment*** Despite temporary relief in supply chain issues and slight reductions in shipping costs, we continue to grapple with extended delivery times and ongoing price escalation, particularly for critical components facing heightened demand from major projects like solar farms and battery bank connections in the US and Australia. To tackle these challenges, we are proactively making strategic purchasing decisions for items with prolonged delivery times. Recent actions include: • Reclosers: Executing bulk purchases of approximately 20 units, anticipating future needs. • Crossarms: To overcome wood supply challenges, we approved the use of composite crossarms, and a shipment of 1,300 units arrived in 2023.

[redacted]

Question	Powerco’s response
	• Voltage Regulators: Addressing the extended lead time of around 112 weeks, we are currently exploring options, as units from critical spares stock have been utilised on the network. ***Workforce development*** We are collaborating with our service providers to strengthen their workforce in essential skill sets. Powerco is an active participant in the ‘Champions of Change’ initiative. Collaboratively, the Champions have developed a comprehensive program focused on four key areas: Increasing Gender Diversity, Increasing Māori and Ethnic Diversity, Leading Inclusive Cultures and Influencing the Outside World. This initiative aligns with the industry's demand for a future-ready workforce. Supply chain risk emphasises the urgency of commencing electrification investments promptly. Initiating these projects earlier will give EDB’s a better opportunity to secure a resilient supply chain and will strategically spread out the investment and delivery over time. Time is of the essence, especially given our position as a relatively small market globally. Waiting to build closer to the time needed poses a significant risk; resources may already be fully allocated to larger international markets, potentially causing delays in the energy transition in New Zealand, or we may face higher prices to secure necessary resources.
5. We will be using the s 53ZD notice to collect information about how EDBs have reflected resilience in their expenditure forecasts. What engagement have EDBs had with consumers about resilience expectations, especially as it relates to significant step changes in forecast expenditure? What other considerations should we factor into our analysis of the resilience	Through a combination of advancing climate projection research, progress in environmental hazards mapping, and the energy transition leading to increased customer reliance on electricity, network resilience has gained heightened attention. Recent events, such as ex-Tropical cyclones Dovi and Gabrielle, also serve as reminders of the widespread impacts resulting from prolonged electricity bulk supply failures. Consequently, we are formulating strategies to ensure the optimal resilience of our networks. We are looking at how we can reduce vulnerability to major outages; this includes avoiding outages from major events, restoring supply quickly, and efficiently recovering following major events. Government policy reviews are currently in progress to assess policy and regulation for critical infrastructure resilience more comprehensively. In the meantime, the Commerce Commission can rely on existing EDB investment prioritisation processes, avoiding the creation of new expectations regarding how resilience investment levels are determined. Powerco employs an established value framework that quantifies network benefits to customers, using the Asset

Question	Powerco's response
expenditure information collected from the s 53ZD notice and/or what is unlikely to be visible in the forecasts that we should consider?	Investment Planning & Management software Copperleaf. Powerco is also certified to ISO55001, aligning with good practice asset management. If the ongoing policy reviews lead to changes in standards, resilience levels, or processes, deviating from current best practices and ISO standards, it may necessitate the revision of EDBs forecasts/allowances. In such a scenario, the Commission could consider the use of existing or implementing new reopener mechanisms. **How we developed our resilience expenditure forecast for AMP2024** Our focus on improving resilience centres on two main elements: 1. Conducting a thorough network assessment to identify vulnerabilities to natural hazards; and 2. Working closely with communities and stakeholders to pinpoint the locations and nature of welfare centres where areas face limited energy resilience. The overarching aim of these initiatives is to optimise the resilience of our networks and create customised energy resilience solutions for our more remote and vulnerable communities. We have provided further details on these endeavours below. ***Network assessment*** In anticipation of the 2024 AMP update, we conducted a comprehensive network-wide review to pinpoint vulnerabilities to natural hazards like coastal inundation, sea-level rise, inland flooding, land subsidence, and extreme winds—factors expected to escalate with climate warming. Employing a data-driven approach, we used geospatial information to identify hazards and conducted vulnerability assessments for existing network assets. The primary aim was to determine prudent levels of investment to enhance resilience. We have developed initial forecasts and justifications, which are included in the 2024 AMP update and our response to the 53ZD information request. While this review primarily focussed on existing vulnerabilities, our plans include scrutinising the architecture of our network and our design standards to ensure appropriate resilience. The redesigning of our network to be resilient to climate change impacts will be a pivotal focus.

Question	Powerco’s response
	We note our assessments are only as good as the hazard data available, and climate and natural hazards science is quickly advancing. Through the use of learning models and AI analysis of satellite imagery, better forecasting of future hazard areas is becoming available. Where the data is uncertain, we have adjusted our forecasts to the lower end and expect this to change as our confidence in the information increases. Of note, there are multiple science streams through central government such as NIWA for climate projections, GNS Science on their National Slip Model, and Volcanic Futures programmes that we will rely on. We expect our understanding of risk and prudent treatment will evolve as more information is developed and shared. ***Working closely with communities and stakeholders*** Powerco's Community Engagement Team is actively collaborating with community organisations such as Civil Defence groups, councils, and iwi to pinpoint the locations and needs for welfare centres within the Powerco footprint facing limited energy resilience. This involves a comprehensive assessment of various data points, including proximity to the substation, climate change risks, our energy hardship heat maps, and SAIDI/SAIFI measures. For sites identified as the highest priority based on this matrix, we initiated direct engagement with the community and support agencies, including public meetings and consultations, to install standalone emergency supplies, such as remote area power supply (RAPS). The first RAPS deployment is underway at the community hall in Akitio, Tararua District. Not all sites require a RAPS; some, like Tinui Hall, require a generator crossover switch, and we are facilitating those installations as well. In certain communities lacking suitable facilities for a Community Hub, we are collaborating with emergency management to help deploy ePods or shipping containers, potentially equipped with solar stack solutions. For communities where extended power to cell towers and rural Wi-Fi is crucial, we are working with Wireless Internet Service Providers and telecommunications companies to implement backup power solutions for these sites.

Question	Powerco’s response
	Given the collaborative nature of community resilience efforts, we are actively sharing information and ideas with key contacts from agencies such as MPI and MBIE to ensure coordinated support and avoid duplication of efforts, thus providing the most effective energy resilience support to the community. ***How we have reflected consumers’ expectations about resilience in our expenditure forecast*** For the 2024 AMP update, we have made assumptions about customer expectations. For instance, we identified critical health services, vital public services, and vulnerable areas most likely to have significant community resilience impacts during extended outages. Looking ahead to FY25 and beyond, the development of vulnerability maps will serve as a foundation for engaging our customers in understanding resilience options and developing effective plans that balance network service levels and costs. Additionally, we are establishing resilience measures that facilitate the incorporation of resilience thinking into our development and renewal planning processes.
6. We would like to understand how potential changes in capital contributions policies could be accommodated in DPP4. How could changes to capital contributions policies, either in advance of or within the regulatory period, be accommodated within our capex forecasts for DPP4?	EDBs face uncertainty regarding consumer connection demand, and they have a limited ability to offset this uncertainty through varying customer contributions. EDBs can also encourage decarbonisation investment by requiring lower contributions in certain circumstances. Policymakers wishing to change EDB capital contributions need to accommodate these risks and limitations. If policymakers initiate changes to EDB's capital contributions, the Commission should adjust EDB's capex allowances to ensure EDBs have the allowances required to fund consumer connections.
7. We are interested to understand if EDBs are assessing investments driven by expected pace of change which may not be consistent with choices otherwise made under a least cost lifecycle basis.	The least cost lifecycle principle will continue to apply to all investments. However, the rapid pace and scale of decarbonisation facing New Zealand necessitates a review of the input assumptions and approach to investment planning, to deliver the capacity needed in a timely and efficient manner.

Question	Powerco's response
Are there specific investment decisions being considered due to concerns on delivering increased scale of investment in limited time which are not consistent with a least cost lifecycle basis assessment; for example, areas where EDBs are intending to build well in advance of forecast need or for demand or generation that are only speculative? On what basis are these investments being assessed?	Most capacity and security investment is driven by forecast demand, reflecting the best estimate of future customer requirements. Whilst we can trend and forecast small-scale mass market demand growth with adequate accuracy, large-scale customer developments are by nature less predictable (in location, timing, and scale). These large-scale developments make up some of the most essential aspects of decarbonisation, and a continuation of past reactive approaches (i.e. waiting for certainty of customer needs and commitment) are unlikely to deliver on time. Therefore, sometimes, there is a need to start the investment and building process earlier than historical approaches. This reflects aspects of longer delivery times, staying ahead of the delivery peak (potentially 3 times the current rate), and managing the speed of uptake and intrinsic uncertainty associated with it. Perhaps, most importantly, it reflects a need to ensure we do not thwart customer decarbonisation aspirations by late delivery of electricity system capacity. We also note that most large-scale developments are impacted by industry and international markets and other pressures outside their control, and customers rarely can provide much advance notice of needs. The incremental (or marginal) cost of providing additional capacity for future needs ("anticipatory capacity") is very small once a driver to invest already exists, be that an immediate customer need, an existing capacity shortfall, network security, renewal or otherwise. One optimised investment that caters to all future requirements is preferable to multiple incremental upgrades. In terms of the mass market, we can cater to this adequately by testing proposed investments against multiple demand scenarios. With commercial developments, there is a need to relax the prior "minimal risk" approaches, which require absolute certainty of future requirements before commitment. Some additional capacity may ultimately be underutilised, but this should be more than offset by the efficiency gains of being able to optimise the timing and scale of investment overall.

Forecasting operating expenditure

Question	Powerco's response
8. We are considering updating our approach to forecasting opex input price escalation to better reflect the mix of inputs EDBs face. Do you have a view on another index, or weighted mix of indices, which would improve the quality of opex forecasting compared to our current approach? (Using a 60/40 mix of percent changes in Labour Cost Index (LCI) all-industries and Producers Price Index (PPI) input indices.) If so, what evidence supports this view?	We support consideration of a customised EDB index.
9. We are considering revising our approach to scale growth trend factors, to better reflect EDBs increasing focus on investing to meet growth and renewal needs. Do you support our emerging view that including forecast capex as a driver of non-network opex could improve opex forecasts, and that this conclusion makes sense in terms of the way EDBs run their businesses? Are there alternative drivers that we should consider, and what evidence is	Using forecast capex as a driver of non-network opex is appropriate but may not encapsulate all aspects of opex growth. The increased deployment of flexibility will significantly add opex that is inversely correlated to network capex (i.e. more flexibility uptake should drive lower network capex). This may require consideration of either more adaptable mechanisms for in-period adjustments of opex allowances or considering network flexibility independently of regulated opex allowances. Flexibility and managing open access smart networks require whole new capabilities associated with advanced distribution management systems, dynamic pricing, market administration, supporting data and analytics, etc. This requires expenditure in network visibility, ADMS systems, communications, interfaces to other stakeholders, IT, software platforms, applications and additional personnel and skill sets. These will heavily impact opex, especially as data and software platforms migrate to cloud based. The opex increase will not necessarily correlate with network capex (RAB)

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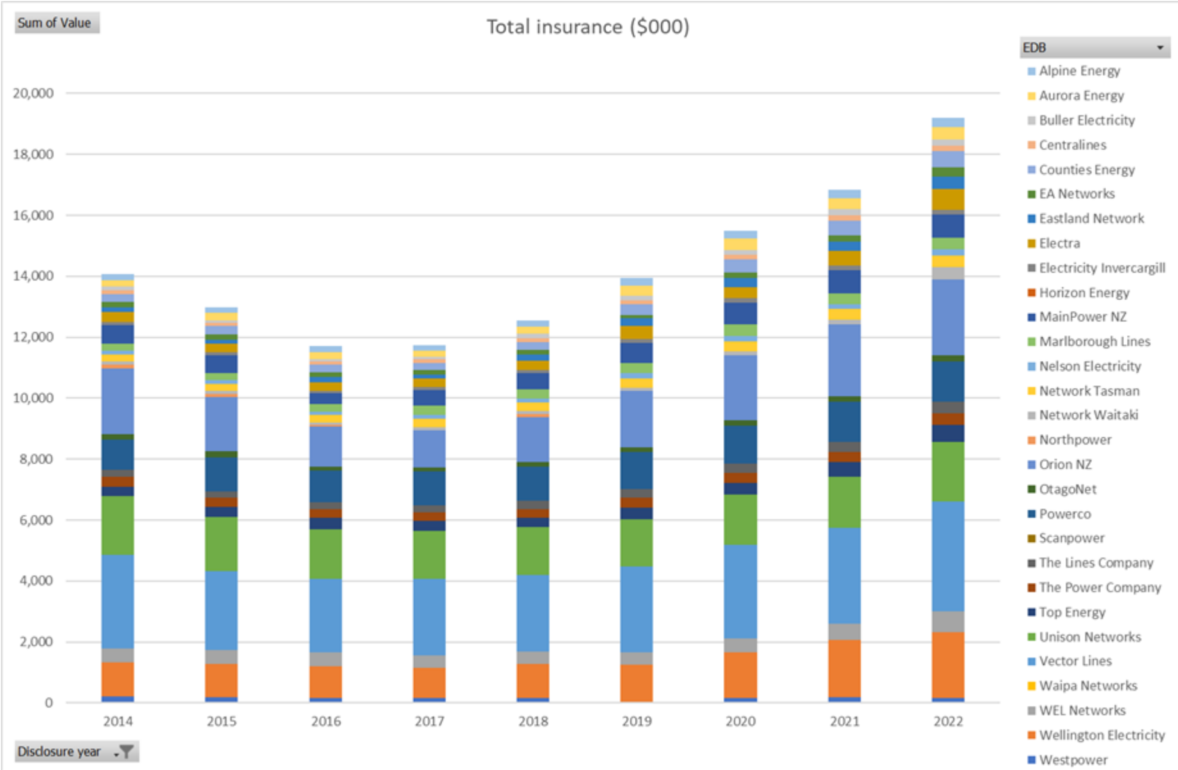
<tr><th>Question</th><th>Powerco's response</th></tr>
<tr><td>there that they can meaningfully predict EDB scale growth?</td><td>growth, and there appears a need for additional discrete allowances related to these new capabilities and associated expenses</td></tr>
<tr><td>10. EDBs have identified that insurance costs have been increasing at a greater rate than other costs they face.

What evidence do you have about how these costs are likely to evolve over time?

Is the option of trending insurance opex forward using a separate cost escalator workable? How could incentives on EDBs to make risk management decisions be maintained?</td><td>Electricity Networks Aotearoa recently highlighted that the sector had experienced premium increases of 63% over the last five years. Figure 4 below illustrates the change in EDB annual insurance premiums between 2014 and 2022.

Figure 4: EDB annual insurance premiums between 2014 and 2022[9]

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[9] EDB Information Disclosures, Schedule 6B

Question	Powerco's response
	In March 2023, Powerco experienced a 34% increase in premiums when renewing our material damage and business interruption insurance covers. Moreover, the renewal of natural disaster-only cover (volcanic, earthquake, tsunami, geothermal, or hydrothermal event) proved economically unviable, with a premium hike of 164%. Consequently, this resulted in approximately $700m of ground-mount distribution assets becoming self-insured. [redacted] It is expected that insurers will continue to impose double-digit rate increases and will remain selective when deploying capacity, especially relating to natural catastrophe perils. Weather related losses continue to be a growing factor, as evidenced by the two events that were experienced in the first quarter of 2023, Auckland floods and Cyclone Gabrielle. These were sufficient to shift the market and impact all insurance companies with business in New Zealand. We support the exploration of a separate insurance cost escalator.
11. Given the possibility of a greater need for step-changes in opex in a context of industry transition, we have clarified further how we are thinking of applying the step-change criteria and the supporting evidence we expect. Do you consider the expanded descriptions of the step-change criteria provide sufficient clarity about the types of step-changes we consider meet the Part 4 purpose?	The Commission's emerging view is to retain the base-step-trend approach to forecasting. Like any forecasting model, the base-step-trend approach exhibits shortcomings that demand careful consideration. For instance: 1. The base year opex may not accurately represent a realistic expectation of the efficient and sustainable ongoing level of opex required to provide distribution services in the next regulatory period. 2. The criteria for step changes can present significant evidence challenges. 3. Network scale factors might not encompass all the key drivers of network opex. 4. It is also important to note the limited availability of DPP opex reopeners poses a challenge in addressing changes in opex costs within a regulatory period. Ideally, we would like to see the Commission make greater use of EDBs AMP forecasts in setting opex allowances. However, we acknowledge the challenge of verifying all non-exempt EDBs' unique operating forecasts under a low-cost DPP. This challenge highlights a gap in the current regulatory framework, potentially constraining EDBs' capacity to

Question	Powerco’s response
	make prudent and efficient expenditures in the best interests of consumers. The increased utilisation and scrutiny of EDBs' opex forecasts for determining opex allowances is a key reason behind Powerco's suggestion to transition large distributors onto an Individual Price-Quality Path regime. If the base-step-trend approach is retained, we support the Commission’s intention to adjust components of the approach to respond to investment and uncertainty challenges. This flexibility is essential to ensure opex allowances accurately align with EDBs' forecast costs. Failing to adapt to the evolving context could also risk reinforcing any capex bias. **Base year opex** Under the base-step-trend approach, EDBs’ opex allowances are initiated by carrying forward expenses from a designated base year. In a period of escalating costs, this methodology holds the potential to sustain a recurring pattern of insufficient allowances. For instance, if the DPP opex allowance falls short of funding the expenditure to achieve the outcomes desired by consumers and stakeholders, EDBs may opt to curtail or delay certain operations to reduce opex. The motivation behind this decision often includes the desire to minimise opex IRIS penalties. This leads to the base-year opex being lower than what the EDB genuinely needs to spend. Beginning the next DPP with the "low" base year as the starting point for opex perpetuates continued under-compensation. To avoid this cycle of insufficient allowances, base year opex must reflect a realistic expectation of the efficient and sustainable ongoing level of opex required to provide distribution services in the next regulatory period. If the base year opex falls short of meeting this requirement, the Commission must make necessary adjustments. Given the significant uplift in investment needed in DPP4 and the opex associated with adapting to an evolving energy system and new operational models (e.g., cloud-based IT systems), historical information may not be a suitable measure for determining the nature and scale of future opex. **Comments on the step-change criteria** ***Significant***

Question	Powerco’s response
	In evaluating the significance of a step change, the Commission should consider the potential impact on consumers of rejecting or approving the request. ***Robustly verifiable*** We advocate for the flexibility to provide cost estimates rather than depending solely on invoices and quotes. The actual cost often remains uncertain until an EDB procures a service, particularly in market tenders. In such instances, the Commission should rely on expert cost estimates from quantity surveyors or procurement specialists to substantiate the costs. ***Outside the control of the distributor*** We think that the Commission should consider relaxing its "outside the control of the distributor" criterion for opex step changes. A strict application of this criterion may lead to the rejection of a step change for discretionary activities expected to benefit consumers through additional or improved services or reduced costs. ***Applicable to most or all distributors*** The Commission is proposing a more relaxed interpretation of this criterion for DPP4, allowing for the consideration of step changes affecting a group of EDBs. We support this "group" approach. Addressing step changes for groups of EDBs offers cost savings compared to individual assessments and would be considerably more efficient than EDBs submitting a CPP proposal. ***Process for providing step-change applications*** We appreciate the Commission's guidance on evidence for step changes, which has proven helpful. However, there is a lack of clarity regarding the application process for EDBs seeking step changes. Additional information on the procedural aspects of this process would be beneficial. [redacted]

Question	Powerco's response
	[redacted]

Question	Powerco's response
	[redacted]

Question	Powerco’s response
	[redacted]

Question	Powerco’s response
	[redacted]

Quality standards

Question	Powerco’s response
12. Our initial view is to maintain the principle of no material deterioration and set quality standards on a basis consistent with that established in DPP3. Do you agree with our proposed approach of maintaining the principle of no material deterioration and setting the quality standards on a basis consistent with DPP3? With regard to the quality standards, are the existing reporting obligations appropriate?	We support the principle of no material deterioration for determining the unplanned SAIDI SAIFI quality limits. Refer to our response to question 15 for the modifications we recommend for the quality standards.
13. Our initial view is to maintain the DPP3 settings of a 10-year reference period updated for the most relevant information	**10-year reference period** Powerco supports the continuation of the 10-year reference period. **MED normalisation**

Question	Powerco’s response
and normalisation approach for major events. Do you think that we should maintain a 10-year reference period updated for the most relevant information and normalise major events on the same basis as DPP3?	Powerco supports the continuation of the DPP3 normalisation approach. Considering the impact of climate change and the subsequent increase in extreme weather events, the expectation of 2.3 major event days per annum is no longer accurate, in our view. We urge the Commission to engage with the Institute of Electrical and Electronics Engineers to ascertain whether they are updating their normalisation standard to reflect changing climate patterns. The issues paper highlights the Commission's intention to assess the effectiveness of the DPP3 normalisation approach and its outcomes. If the Commission decides to alter the MED normalisation approach for DPP4, it should carefully consider whether this adjustment might elevate the risk of random volatility and false positives. Consequently, there may be a need to reconsider the reinstatement of the 2 out of 3-year rule. The modifications introduced in the normalisation methodology during DPP3 were instrumental in the Commission's decision to eliminate the two-out-of-three-year rule. Quoting from the DPP3 Reasons paper: • Paragraph L35- *We recognise the volatility issue, and have only removed the two-out-of-three-year rule because we have simultaneously made other changes that will reduce volatility and the chance of ‘false-positives’* • Paragraph L36 - *The improvements that we have made to the normalisation methodology will also reduce the volatility of SAIDI and SAIFI.* **A ±5% limit on inter regulatory period changes in unplanned SAIDI and SAIFI limits** Powerco supports a ±5% limit on inter-regulatory period change in unplanned reliability limits. We agree that a limit is appropriate. Without a limit, deteriorating performance would be inappropriately rewarded with more relaxed standards and improved performance inappropriately penalised through stricter standards.
15. Our initial view is to not introduce new additional quality of service measures.	The current quality standards are limited in how well they capture the experience of many of our customers and the effectiveness of the incentives to improve network performance. SAIDI and SAIFI in particular, as currently applied, are broad averages that do not reflect variances in service quality across different parts of networks, wholly exclude outages that occur on the low voltage network and do not afford any form of weighting to customers’ consumption levels or

Question	Powerco's response
Are there any other quality of service measures beyond those currently required within DPP3 that we should consider introducing, and why?	their varying value of supply. The overall impact of this inhibits effective management or well-targeted investment for service quality reasons. As we move to a decarbonised future, where electricity use will play an increasingly important role as primary energy source, these shortcomings will become increasingly acute. This will be particularly evident in low voltage networks, where many of the emerging changes in energy use, with associated congestion and quality issues, will occur – but which are currently excluded from service quality measures. We appreciate that major changes to the quality standards will take time, effort and investment to achieve and are not realistically achievable for DPP4. However, we advocate for better standards, which, at the very least, should include more granular reliability reporting and load-at-risk measures, to be implemented by DPP5. To realise this, the preparatory work, including collection of better disaggregated information, would have to occur during the DPP4 period.

Other issues

Question	Powerco's response
16. Aurora Energy is scheduled to rejoin the DPP from 1 April 2026. Do you agree with how we propose to transition Aurora Energy to the DPP in 2026?	Given the timing of when Aurora Energy is scheduled to re-join the DPP, within 1 year of the start of the DPP period, we agree with the proposed transition. If the transition was later in the DPP, (e.g. year 2-5), key inputs to the price/quality path may have moved further from the DPP settings and would require updating, much like Powerco's transition from our CPP to DPP for the 2024/2025 period.
17. Section 53M(5) allows us to reduce the regulatory period if this would better meet the purposes of Part 4 of the Act. We are considering whether we should reduce the regulatory period from five to four years.	Our assessment suggests that the adoption of a four-year regulatory period is likely, on balance, to serve the long-term benefit of consumers. However, this matter is nuanced. On one hand, it is a useful option for addressing the challenges posed by forecasting uncertainty and policy changes, providing regulators and regulated the opportunity to change more quickly. However, the DPP reset process demands substantial resources. Reducing the regulatory period would increase the frequency of resets, resulting in heightened costs and increased resource demands for both EDBs and the Commission.

Question	Powerco's response
What particular challenges do you perceive may arise from shortening the regulatory period? What are the potential benefits to consumers from maintaining or shortening the length of the regulatory period?	
18. The DPP sets annual deadlines by which suppliers must make Customised Price-Quality Path (CPP) applications to enter into effect the following year. Do you support retaining a similar approach to setting CPP application windows as was undertaken for DPP3?	We support retaining a similar approach to setting CPP application windows as was undertaken for DPP3.
19. The current IMs provide for a discretionary shortening of asset lives. Do you have views on the framework for assessing accelerated depreciation applications?	Our view is that the existing framework for assessing accelerated depreciation applications is appropriate.

Quality incentives

<table>
<tr><th>Question</th><th>Powerco's response</th></tr>
<tr><td>20. Our initial view for DPP4 is to retain revenue-linked quality incentives for both planned and unplanned SAIDI, with targets, caps, collars, incentive rate and revenue at risk set on a consistent basis with DPP3.

Are EDBs considering the quality incentive scheme (QIS) in their investment decisions?

Do you consider the proposed settings are appropriate for the QIS, including whether the incentive rate is driving appropriate outcomes with regards to consumer quality expectations?</td><td>Consideration of the quality incentive scheme (QIS) in our investment decisions
We take into account the QIS and broader reliability considerations in various ways when making investment decisions. For instance:
Potential QIS penalties are included within our Copperleaf investment optimisation tool – it shows up as financial risk.
Replacement and renewal works are strategically coordinated across portfolios to minimise customer interruptions, ensure efficient delivery, and optimise QIS outcomes.
Our asset management objectives are also strongly aligned with realising QIS benefits. An example is our Asset Stewardship objective; wherein our assets are designed to provide a safe and reliable supply to customers cost-effectively throughout their anticipated lifespan.
Planned SAIDI quality incentive target
The Commission should consider whether the planned SAIDI target should be raised above the historical average. This adjustment may be needed to align with the expectation that increased investment by EDBs will necessitate more planned outages; the historical average may no longer be suitable as a target.</td></tr>
<tr><td>21. Caution around treatment of non-performance of less proven solutions may create a reticence by EDBs to implement these types of solutions and result in a focus on more proven established technologies, typically, capex investments. Our intention is that the compliance with the quality standards and penalties under the QIS do not act as a potential impediment to innovation.</td><td>We support the Commission's intention to exclude interruptions related to innovative/less proven solutions to ensure quality standards and incentive schemes are not an impediment to their use by EDBs. The Commission could also consider excluding the SAIDI / SAIFI incurred to implement these types of solutions.</td></tr>
</table>

Question	Powerco's response
How should we account for non-performance of non-network solutions (regulatory sandboxing)?	

Innovation

Question	Powerco's response
22. The regime's baseline incentives may be insufficient to support innovation, such that we consider it is appropriate to have an innovation (and/or non-traditional solutions) incentive scheme. Do you agree with our understanding of the regime's baseline incentives to support innovation, and the need for an innovation and/or non-traditional solutions scheme? Would you be interested in participating in a targeted workshop, and if so, are there any topics you consider should be covered?	We support the Commission's intention to introduce an innovation (and/or non-traditional solutions) incentive scheme. Promoting innovation and non-traditional solutions will be instrumental in the process of decarbonising the energy sector, to improve asset utilisation and reduce the need for additional expenditure. The current regulatory framework provides too little incentive for distribution businesses to undertake research and development, or reward for successful innovation. Without specific regulatory incentives or allowances, consumers will likely suffer higher costs in the future because of underinvestment in innovation by EDBs now. Under investment in innovation and non-traditional solutions will create risks that: • the adoption of lower cost new technologies is delayed • a reactive response materially increases costs • relatively low asset utilisation levels will persist • asset management processes and capabilities aren't maximised • EDBs are unable to perform the functions demanded by consumers when required • feasible commercial opportunities for third-party flexibility service providers, or for customers to participate in providing these services, are not realised • the electricity distribution industry doesn't maximise it's potential to help New Zealand reach its low carbon economy goals The introduction of an incentive scheme could help mitigate these risks. We are interested in participating in a workshop to contribute to the design of this new incentive scheme.

Question	Powerco's response
23. We are interested in feedback on our initial thinking about how to design an incentive scheme to encourage innovation and/or non-traditional solutions in DPP4. What are your views on the key principles (see Attachment I)? Are they effective as the basis of an innovation and/or non-traditional solutions scheme? Are there others you think may be suitable? What are your views on the potential scheme design characteristics? Are they effective as the basis of an innovation and/or non-traditional solutions scheme? Are there others you think may be suitable? How could these principles and characteristics be best applied in designing a potential scheme? We would also welcome submissions with examples of overseas schemes/characteristics that you consider appropriate for a DPP.	We are interested in participating in a workshop to contribute to the design of this new incentive scheme. We recommend that the principles and characteristics of the scheme be collaboratively developed through the proposed targeted workshop.

Setting revenue allowances

Question	Powerco's response
26. We are proposing to retain our approach of setting a 'default' X-factor of 0% (before considering price shocks or supplier financial hardship). We are interested in your views on whether this approach (where long-run changes in sector productivity are accounted for in our building blocks analysis) remains appropriate.	We support the approach of setting the default X-factor of 0%. In principle, it should not alter the timing of revenue over the regulatory period, as suppliers need to fund expenditure when it occurs. Our view is that the Commission should account for long-run changes in productivity in the building blocks analysis, rather than with the default X factor. The advantage of this approach is that it applies only to the BBAR/revenue input to which it relates (opex), rather than impacting total revenue timing. When assessing productivity, the Commission needs to ensure that it considers all outputs of an EDB. The existing network scale factors may not do this.
27. Our emerging view is to assess price shocks for consumers using the real change in aggregate distribution revenue from year-to-year, with a particular focus on the change between regulatory periods. Do you agree with this approach? If not, are there other alternatives we should consider? When applying this (or any other) analysis, what factors should we consider in determining whether a price change amounts to a price shock?	We support the evaluation of price shocks for consumers in real terms and the use of alternative x factors to manage such shocks, tailored to an individual EDB's circumstances and consumers. As per s 53K of the Commerce Act, the Commission should do this in a relatively low-cost way. While analysing price shocks, the Commission must carefully assess and strike a delicate balance among various factors. This includes the need for increased investment to enable decarbonisation - providing long-term benefits for consumers with lower overall energy costs. Simultaneously, the Commission must consider the potential drawbacks of underinvestment, guard against fianceability issues and undue financial hardship for suppliers and prevent adverse price shocks to consumers. We support the analysis process outlined in "Attachment H" of the paper (H24, H25) to determine whether an alternative X factor is necessary. We support the assessment of price shock and alternative x factors focusing on: 1. **Real changes above CPI inflation**. EDBs do not have influence or control over CPI inflation. 2. **Aggregate revenue**. Assessing price changes at a price category level for all non-exempt EDBs may be too complex for a DPP.

Question	Powerco’s response
	3. **Price change per user and unit supplied**. As the network grows, costs are shared over more consumers/units of demand, softening any price impacts. Increased revenue reflects, in part, a higher RAB base and expenditure, which has grown over time to supply more consumers and deliver larger quantities of electricity over the network. Comparing absolute revenue to the past is not directly comparable, as the circumstances and services provided have changed. 4. **Price shock thresholds**. Careful consideration needs to be had for the threshold that makes up a price shock, including the drivers of any increases and acknowledgement of the net benefits consumers will receive. 5. **Potential washup balances**. Analysis within any revenue assessment should include potential washup balances of each EDB, as any limits applied may cause washup balances to build up and not allow EDBs to recover them in a reasonable time frame. 6. **Financial hardship and financeability issues**. An alternative rate of change that aggressively changes the recovery of revenue for a supplier will have impacts on incentives to invest and would delay cash flow, which may cause financial hardship and financeability issues, especially at the beginning of the DPP. 7. **Consumers’ ability to absorb price increases.** Examining the ability of each EDB’s customer base to absorb price increases could be useful, particularly given the substantial disparities in this capacity across various regions of New Zealand. A helpful approach to framing this analysis would involve forecasting changes in consumers' total energy costs. The analysis should use forecast growth in the number of connections, as network costs will be shared over a larger number of customers as time progresses.
28. Our emerging view is that financial hardship will be ‘undue’ only where it is to such an extent that it is inconsistent with the long-term benefit of consumers. Do you agree with this approach? If not, are there other alternatives we should consider?	In a period of decarbonisation and increased electrification, it is in the long-term benefit of customers to ensure that suppliers have the resources and funding to deliver the assets and services needed to enable the energy transition. Suppliers have the detailed plans and foresight for what needs delivering to enable the best possible outcomes for customers and their future electricity needs. We support the idea that the long-term benefit of customers should be taken into account when looking at supplier financial hardship. Setting a price path at an impractical level that impedes suppliers is not in the long-term interest of consumers. While a price path that merely allows suppliers to meet immediate service needs, without preparing for

Question	Powerco's response
When applying this (or any other) analysis, what factors should we consider in determining whether a supplier faces undue financial hardship?	future electrification needs, constrains progress, and limits essential maintenance and capital works. Delivery of services within this analysis must recognise that the transition involves not only delivering core electricity line services now but also ensuring readiness and resources for the extensive work and expenditure required for New Zealand's electrification in the future. Increased RAB values from DPP3 expenditure and increasing funding costs (via the risk-free rate) reflected in the WACC value is driving up suppliers DPP4 revenue requirements. Failing to adequately compensate EDBs for assets already in the regulated asset base could, on its own, induce financial hardship before considering additional DPP4-period expenditure. At a minimum, revenue changes arising from the updated WACC should be allowed to flow through without moderation, with any necessary revenue smoothing applied post-accounting for this. Additionally, the DPP4 revenue timing/profile needs to align with the assumed BBB+ credit rating of EDB's in the IM calculation of the cost of capital. If the assumed credit rating is not attained, it poses a risk of causing undue financial hardship for the supplier. The Commission has outlined potential alternatives for mitigating financial hardship, which we discuss below: 1. **Ability to reprioritise discretionary capex within revenue allowance** Powerco does not consider any of its capital expenditure as discretionary, rather there are risk considerations in the timing and scale of certain investments. There is some ability to flex the timing of certain investment in the short term (such as risk-based asset renewal decisions, or the timing of upstream network reinforcement). However this comes with additional risks and is to the detriment of the long-term interests of customers, such as the potential for degraded network reliability, or constrained progress towards decarbonisation and increased electrification. 2. **Ability to raise additional capital (through retained earnings or debt/equity issuance)** Raising additional capital comes at a cost and would need to be compensated for in Revenue allowances. If additional debt is required during a DPP, leverage assumptions of 41% would likely undercompensate a

Question	Powerco’s response
	supplier for debt held. Amounts of additional capital required would be unknown at the time of setting the DPP leading to further compensation issues. Suppliers have debt covenants and metrics to manage which is another limiting factor when raising additional capital. **3. Ability to reallocate costs to consumers driving demand** Reallocating costs to consumers could discourage increased electrification and decarbonisation. Our mission to connect customers and support New Zealand decarbonise is promoted by lowering customer contributions. **4. Availability of a CPP** We acknowledge that a CPP may serve as a potential alternative to address financial hardship issues. However, it is crucial for the DPP to remain a low-cost option that is applicable to the majority of non-exempt EDBs. This means the DPP must adapt to the current context that requires increased levels of investment by EDBs. Additionally, it's important to recognise that implementing a CPP is a resource-intensive endeavour, consuming substantial EDB and Commission resources. Therefore, when resetting the DPP, careful consideration should be given to the potential volume of EDBs that may need to apply for a CPP. Many suppliers seeking CPPs may pose challenges for the Commission in processing them in a timely manner.

Consumer bill impacts

Question	Powerco’s response
29. Previously we have forecasted indicative consumer bill impacts from information disclosed by EDBs. We are interested in understanding what other information may help refine our approach.	Anticipated increases in consumer bills for electricity distribution services during the DPP4 period prompt a need for clarity from the Commission regarding the specific components and segments of the revenue building blocks driving these increases. We expect that the primary driver behind the increase in revenue for the upcoming DPP period is the Weighted Average Cost of Capital (WACC), particularly the risk-free rate, which has experienced a substantial uplift from an abnormally low level in the DPP3 period. The reduction in WACC from DPP2 to DPP3 offset allowable revenue increases

Question	Powerco's response
What models or data inputs could be provided by EDBs which would improve our approach to modelling consumer bill impact?	by 23%. [10] It is crucial to communicate to consumers that we are transitioning back to a more typical level of cost of capital in DPP4. To enhance consumer understanding, a waterfall graph presenting the impacts of different components of the building blocks on EDB allowable revenues would provide transparency on the drivers of changes in customer bills. This breakdown could be further communicated at an ICP level, dividing revenue allowances by actual or forecast ICPs would allow consumers to gauge the likely average impact on their electricity bills. Secondary drivers contributing to rising revenues for EDBs and subsequent impacts on customer bills encompass factors such as high inflation affecting input costs for both capital and operational expenditures, which are reflected in our Asset Management Plan forecasts. The effects are discernible in the escalation of indices such as CGPI, PPI, and LCI. Additionally, the indexation of the RAB to inflation is noteworthy, maintaining the value of suppliers' RAB in real terms over time but delaying the cashflow profile for suppliers. Customers benefit from lower prices now, with revenues spread over a larger consumer base in the future. In a high inflation environment, RAB values grow at a faster rate, leading to an increase in the return on assets building block in absolute terms at future resets. Presenting the real change in customer bills over a period (e.g., illustrating changes in 2019 real terms) would provide beneficial context. This breakdown could be further detailed at an aggregate level per ICP, providing customers with a comprehensive view of bill changes over time.

[10] DPP3 Final Decision Reasons Paper, page 15

Attachment 2 – Information about Powerco and our network

Providing an essential service

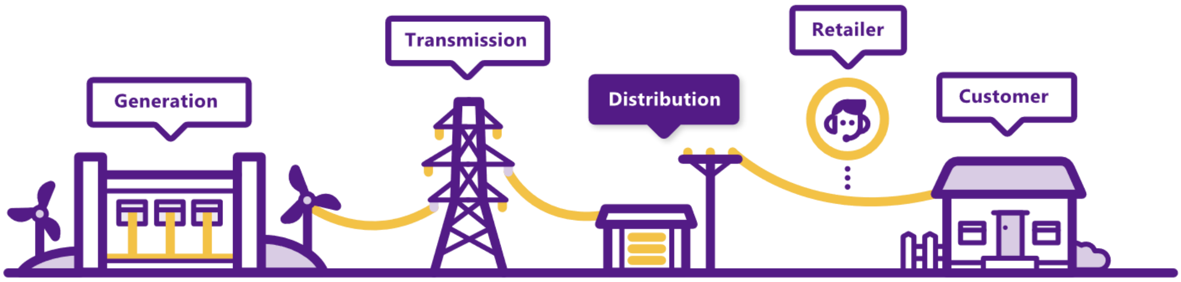
We bring electricity and gas to around 1 million customers across the North Island. We're one part of the energy supply chain. We own and maintain the local lines, cables and pipes that deliver energy to the people and businesses who use it. Our networks extend across the North Island, serving urban and rural homes, businesses, and major industrial and commercial sites. We are also a lifeline utility. This means that we have a duty to maintain operations 24/7, including in the case of a major event like an earthquake or a flood.

The cost of operating our business is not dependent on the amount of gas or electricity we distribute in our networks. These costs reflect the need to maintain the safe operation of the network and are mostly driven by compliance with safety regulations. This includes replacing assets when they reach their end of life. Additional costs to grow the size or the capacity of the network are often met by customers requiring the upgrade or new connection.

Under Part 4 of the Commerce Act, Powerco's revenue and expenditure are set by the Commerce Commission as part of monopoly regulation. We are also subject to significant information disclosure requirements, publicly publishing our investment plans, technical and financial performance, and prices. The regulatory regime allows us to recover the value of our asset base using a regulated cost of capital (WACC) set by the Commission, and a forecast of our expenditure. Every five years, the Commission reviews its forecasts and resets our allowable revenue. This process is designed to ensure the costs paid by customers for us to manage and operate our network is efficient given we are a monopoly and an essential service.

Our electricity customers

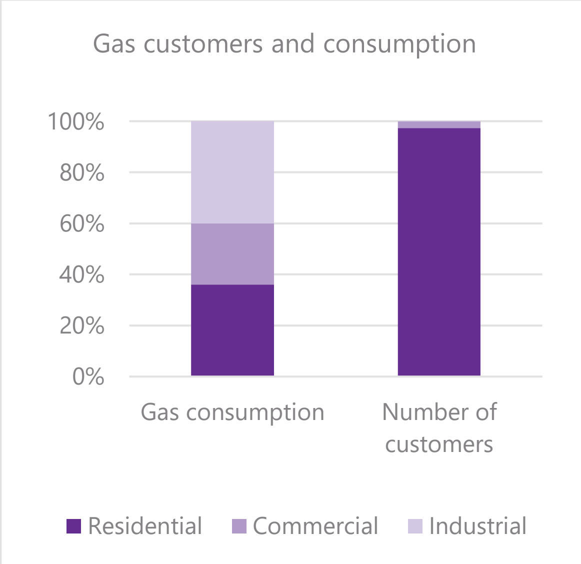
Powerco is New Zealand's largest electricity utility by the area we serve. Our electricity networks are in Western Bay of Plenty, Thames, Coromandel, Eastern and Southern Waikato, Taranaki, Whanganui, Rangitikei, Manawatu and Wairarapa. We have 29,087 km of electricity lines and cables connecting 356,000 homes and businesses. Our place in the electricity sector is illustrated below.



Our network contains a range of urban and rural areas, although is predominantly rural. Geographic, demographic, and load characteristics vary significantly across our supply area. Our development as a utility included several mergers and acquisitions that have led to a wide range of legacy asset types and architecture across the network.

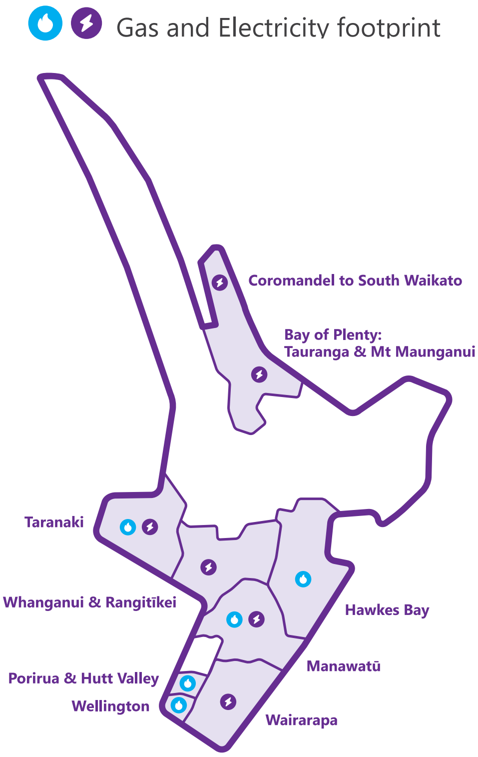
Powerco is one of 29 electricity distribution companies. Our customers represent around 13% of electricity consumption (similar in magnitude to the Tiwai aluminium smelter) and around 14% of system demand. Powerco's network is almost three times the size of Transpower's in terms of circuit length. The peak demand on our combined networks (2023) was 974 MW, with an energy throughput of 5,225 GWh.

Our gas customers



Powerco is New Zealand's largest gas distribution utility. Our gas pipeline networks are in Taranaki, Hutt Valley, Porirua, Wellington, Horowhenua, Manawatu and Hawke's Bay. We have 6,227 km of gas pipes connecting over 113,000 homes and businesses to gas. Our customers consume around 8.6 PJ of gas per year.

Our industrial customers are less than 1% of our customer base and consume approximately 40% of gas on our network. Our residential customers are 97% of our customer base and consume approximately 35% of gas on our network. The remaining 25% of gas is consumed by our commercial customers. Around 30% of our larger customers are in the food processing sector, around 20% in the manufacturing sector and around 10% in the healthcare sector.



Our network footprint

Our network represents 46% of the gas connections and 16% of the electricity connections in New Zealand. We operate assets within six regions and across 29 district or city council areas.

Attachment 3 PWC capex modelling report

Regulatory Outlook - Capex Modelling

Powerco Limited
December 2023

Chris Taylor
Chief Financial Officer
Powerco Limited
35 Junction Street
New Plymouth

15 December 2023

Regulatory outlook - Capex modelling

Dear Chris,

We are pleased to provide you with our report which summarises capex modelling to support Powerco Limited's (Powerco's) regulatory outlook analysis. This report is provided in accordance with the terms and conditions set out in Appendix A. If you have any queries, please do not hesitate to contact us.

Yours sincerely,

Lynne Taylor
Executive Director
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Simon Healy
Partner
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Summary of observations

Introduction

If New Zealand is to meet its 2030 and 2050 emission reduction targets, additional electricity distribution business (EDB) investment needs to start now.

The regulatory settings need to adapt to accommodate this additional investment, otherwise the policy targets will not be met.

Default price-quality paths (DPPs) will be reset on 1 April 2025, and again on 1 April 2030. These decisions need to reflect adequate future expenditure allowances for non-exempt EDBs. Future expenditures are likely to be much higher than historical expenditures.

This report examines EDB capex forecasts and allowances for price-quality paths. A brief summary of our findings is presented below.

Capex trends

- Significant increases in capex are forecast, most notably by non-exempt EDBs.
- The capex forecasts are currently aligned with the trend predicted in 2022 in BCG's '*The Future is Electric*' report.

DPP capex allowances

- We estimate that significant forecast capex will be disallowed during DPP4 and DPP5 if the DPP3 '*120% cap with seven year reference period*' approach to setting capex allowances is applied.
- Our estimates are 21.8% of forecast capex in DPP4 and 15.4% of forecast capex in DPP5 disallowed by DPP capping.

CPPs

- Wellington Electricity, Orion NZ and Firstlight Network are forecasting very significant increases in capex.
- These circumstances are well suited to CPPs. However, CPPs take some time to determine, and therefore we predict that these EDBs will be subject to DPP capex constraints in early DPP4.
- Assuming CPPs for the 3 EDBs above from year 3 (FY28) of DPP4, our estimates of disallowed capex reduce to 10.1% in DPP4 and 6.3% in DPP5 using the current (120% cap) capex allowance method.

Alternative capex allowance thresholds

- Increasing the percentage cap, and reducing the historical reference period generates DPP capex allowances which are more consistent with the anticipated levels of investment required to enable the energy transition.
- For example, we estimate that with 3 CPPs, a 140% cap and a five year reference period, just 5.5% of forecast capex is disallowed in DPP4.
- The majority of this disallowed capex is for the EDBs who we consider are most likely to transition to CPPs, based on their 2023 AMP forecasts.
- We note that not all non-exempt EDBs receive higher capex allowances with the shorter reference period. This is because while most EDBs have increased their capex in recent years, a few EDBs have not.

Introduction, scope and assumptions

Introduction

EDBs will be 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 2030 and 2050 emission reduction targets, this investment needs to start now, and together with additional generation and transmission investment, will result in renewable electricity meeting more of New Zealand's energy needs.

The regulatory settings need to adapt to accommodate this additional investment, otherwise the policy targets will not be met. For EDBs such as Powerco, the revenue caps which are determined by the Commerce Commission are the most important feature of the regulatory regime which must align with the emissions reduction policy settings.

DPPs will be reset on 1 April 2025, and again on 1 April 2030. These decisions need to reflect adequate future expenditure allowances for non-exempt EDBs. Notably with the investment required in New Zealand's electricity networks, future expenditures are likely to be much higher than historical expenditures.

Exempt EDBs have more freedom to determine their own expenditure profiles and revenues. However, non-exempt EDBs have historically been constrained by these settings and, if continued, this could impact on future network development and New Zealand meeting its net zero goals.

Scope of this report

We have undertaken regulatory modelling and analysis, to support discussion about the appropriate regulatory settings for EDBs for DPP4 and DPP5. We are interested in testing the consistency or otherwise between the energy transition targets and the Commerce Commission's rules and processes. This is to inform Powerco's own planning, and wider energy sector stakeholder engagement leading into the next regulatory period.

This report presents outputs for the capex modelling component of the regulatory outlook analysis. Our focus has been on analysis of capex forecasts and allowances.

Key inputs and assumptions supporting our analysis

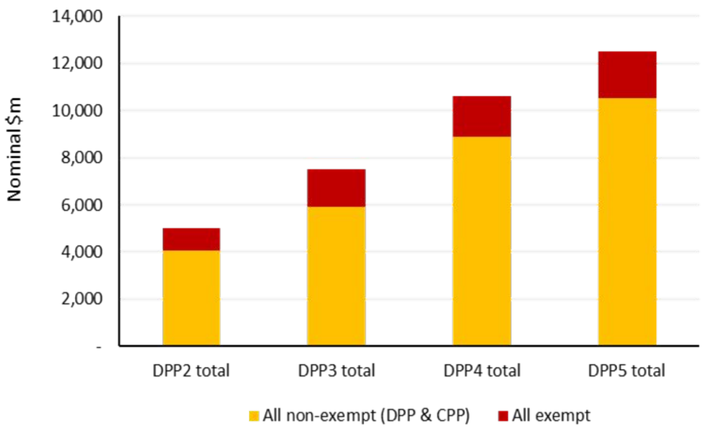
- Capex data, including capital contributions, is sourced from historical disclosures and 2023 AMPs for FY24 - FY33 (refer Appendix B)
- FY34 and FY35 capex is extrapolated from FY33 using forecast CPI
- When calculating capex allowances, exempt EDBs are assumed to be unconstrained, and non-exempt EDBs are assumed to be subject to an overall percentage cap. This ignores the DPP3 capex category gating approach which was used in addition to the 120% overall cap. If applied, category gating could reduce allowances further than the overall percentage cap
- Future CPPs apply from year 3 of a regulatory period, allowing for 2 years for pre-verification and assessment. CPPs apply for five years.
- Non-exempt EDBs deliver their forecast capex during DPP4, even if it is disallowed. This impacts the DPP5 capex allowance.

Capex trends

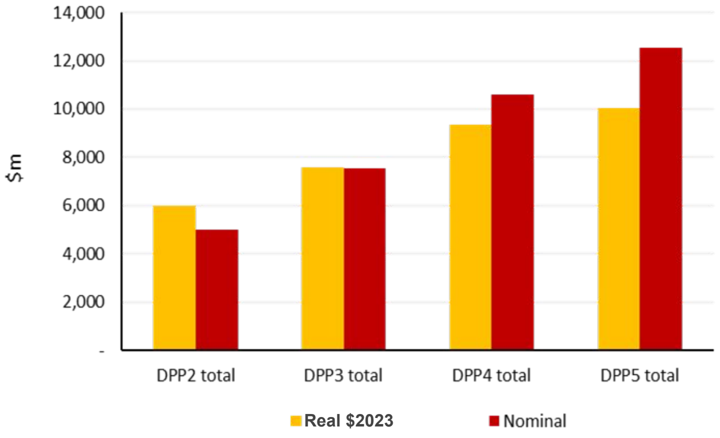
EDB capex is forecast to increase, in line with predictions

- Actual and forecast capex from DPP2 to DPP5 reveals the step change in forecast capex which is emerging, as illustrated in 1) and 2) below.
- This step change is more significant for non-exempt EDBs as illustrated in 1).
- The data on this page is gross capex, before deducting capital contributions. Forecast data reflects 2023 EDB AMPs.
- The capex forecasts are currently aligned with the trend predicted in 2022 in BCG's '*The Future is Electric'* report[1] as illustrated in 3) below.
- In Figure 3 we also show the proportion of EDB capex which is forecast to be funded upfront by customers. We assume it is included in the BCG comparator values, but the report does not confirm this.

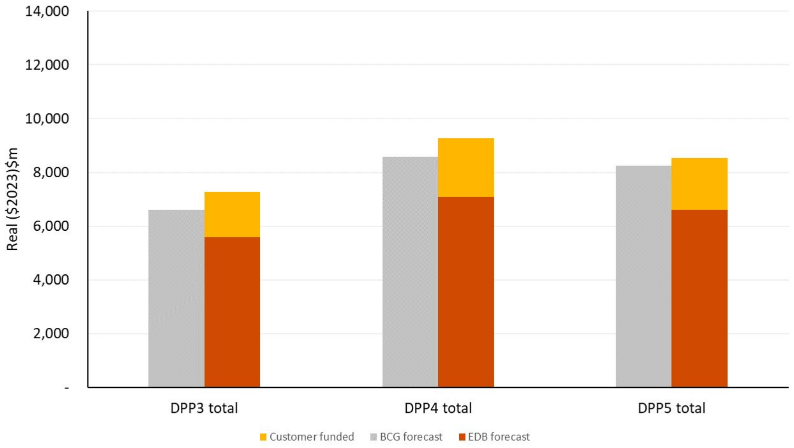
1) Actual/forecast capex (nominal)



2) Actual/forecast capex (nominal and real)



3) EDB and BCG forecast capex (real)



[1] BCG, The Future is Electric, 2022, Distribution Investment, page 14

Non-exempt EDB capex allowances for DPP4 and DPP5

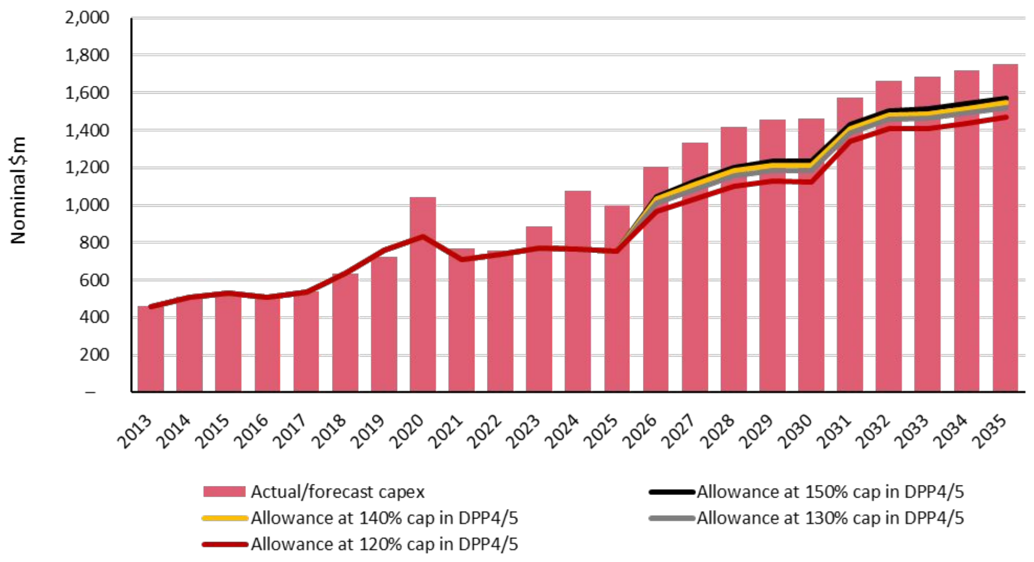
Capex allowances for non-exempt EDBs are impacted by the percentage cap

- We estimate that significant forecast capex will be disallowed from DPP allowances if the 120% cap is applied to DPP4 and DPP5.
- The capex data used for the capex allowance is net of forecast capital contributions.
- The caps are calculated with reference to the historical average (in real terms) over seven years.
- The impact of lifting the cap to 130%, 140% and 150% is illustrated in 4) and 5) below. This reduces the impact of the capping, but does not resolve it.
- Applying a percentage cap to a historical average for DPP4 and DPP5 may be inconsistent with the investment required to support the energy transition.

4) Capex disallowed from DPP4 and DPP5 ($m nominal)

	DPP4	DPP5
120% cap	1,491.3	1,291.7
130% cap	1,227.9	1,038.3
140% cap	1,090.0	919.9
150% cap	1,001.5	801.6

5) Actual/forecast capex and DPP capex allowance (nominal)



The capping impact is more significant for some EDBs

Capping impacts for Powerco and other non-exempt EDBs vary

- Figure 6) illustrates the impact of applying a 120% cap to the 2023 capex forecasts of each exempt EDB.
- Wellington Electricity, Orion NZ and Firstlight Network are the most significantly impacted by the capping in DPP4, and this continues into DPP5 for Orion NZ.
- All capex is included in Powerco's estimated capex allowances with higher percentage caps.

7) Capex disallowed for Powerco (%, $m nominal)

	DPP4	DPP4	DPP5	DPP5
120% cap	8.5%	140.3	6.2%	133.6
130% cap	0.9%	15.0	-	-
140% cap	-	-	-	-
150% cap	-	-	-	-

6) Capex disallowed, by EDB, ranked (%, $m nominal)

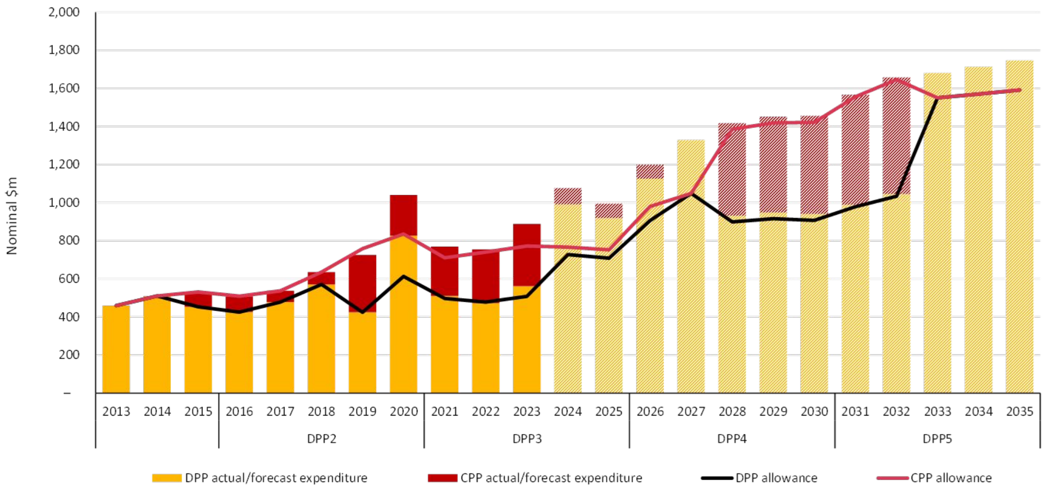
Non-exempt EDB	DPP4	DPP4	DPP5	DPP5
Wellington Electricity Lines	59.0%	448.8	-	-
Orion New Zealand	54.6%	789.7	44.9%	1,157.6
Firstlight Network	23.5%	25.6	0.5%	0.6
Electricity Invercargill	14.9%	6.6	-	-
Unison Networks	14.4%	65.4	-	-
Powerco	8.5%	140.4	6.2%	133.6
Horizon Energy Distribution	5.7%	4.1	-	-
Network Tasman	5.6%	5.3	0.9%	1.1
Alpine Energy	3.3%	5.1	-	-
Nelson Electricity	3.2%	0.4	-	-
Vector	-	-	-	-
The Lines Company	-	-	-	-
Aurora Energy	-	-	-	-
Top Energy	-	-	-	-
OtagoNet Joint Venture	-	-	-	-
EA Networks	-	-	-	-
All non-exempt EDBs	**21.8%**	**1,491.3**	**15.4%**	**1,291.7**

CPPs for some EDBs are part of the solution

CPPs for those EDBs most impacted by the DPP capping can help to resolve the problem

- If we assume that Wellington Electricity, Orion NZ and Firstlight Network transition to CPPs for the FY28 to FY32 period, the capex allowances for non-exempt EDBs are much closer to forecast, even when applying the 120% DPP cap, as illustrated in 8) below.
- This modelling assumes Aurora transitions to a DPP at the end of their CPP in FY27, and that when EDBs transition from CPPs to DPPs, their DPP allowances reflect the higher capex permitted during the CPP.
- Higher CPP allowances for 3 EDBs significantly reduce the disallowed capex as shown in 9) below. This assumes no capex capping during CPPs.
- But the delay in setting CPPs means that the material capex overspend which has emerged during DPP3, will continue for the first two years of DPP4.
- Allowances in DPP5 are not sufficient to meet forecast capex needs, even with the 3 CPPs.

8) Actual/forecast capex and allowances with CPPs (120% DPP cap)



9) Capex disallowed (%, $m nominal)

	DPP4	DPP4	DPP5	DPP5
120% cap	21.8%	1,491.3	15.4%	1,291.7
120% cap with 3 CPPs	10.1%	609.5	6.3%	422.2
130% cap	17.9%	1,227.9	12.4%	1,038.3
130% cap with 3 CPPs	7.5%	454.3	4.7%	314.2

Options for DPP4 capex allowances

There are a number of options which could be employed when setting DPP4 capex allowances

- Figures 10) and 11) below illustrate how much of the 2023 AMP forecast capex is disallowed under alternative DPP/CPP scenarios. We have flexed the percentage caps, reference periods and number of CPPs for this purpose.
- Our modelling indicates that 3 CPPs are required when the caps increase to 140% and 150%, but more CPPs are required with lower caps.
- The shorter (5 year) reference period reduces total disallowed capex, but Horizon Energy, Electricity Invercargill and Alpine Energy are worse off under this scenario.
- A cap of 140% with a five year reference period, assuming 3 CPPs from FY28, would allow most of the 2023 AMP forecast capex to be recoverable. The most significant leakage is for those EDBs who require CPPs, because of the delay in implementing CPPs.
- The tables overleaf illustrate the impact of DPP4 scenarios on each non-exempt EDB, before CPPs.

10) Capex disallowed - 7 year reference period (%)

	DPP4			
	3 CPPs	4 CPPs	5 CPPs	Powerco
120% cap	9.9%	9.3%	9.3%	8.5%
130% cap	6.9%	6.6%	6.6%	0.9%
140% cap	5.7%			-
150% cap	5.2%			-

11) Capex disallowed - 5 year reference period (%)

	DPP4			
	3 CPPs	4 CPPs	5 CPPs	Powerco
120% cap	8.6%	8.3%	8.2%	5.3%
130% cap	6.1%	6.0%	6.0%	-
140% cap	5.5%			-
150% cap	4.9%			-

DPP4 capex scenario outputs (no CPPs)

12) Capex disallowed, by EDB, ranked - 7 year reference period (%)

	DPP4			
Non-exempt EDB	**120% cap**	**130% cap**	**140% cap**	**150% cap**
Wellington Electricity Lines	59.0%	55.6%	52.2%	48.8%
Orion New Zealand	54.6%	50.8%	47.0%	43.2%
Firstlight Network	23.5%	17.3%	11.2%	5.0%
Electricity Invercargill	14.9%	7.8%	0.8%	-
Unison Networks	14.4%	7.3%	0.2%	-
Powerco	8.5%	0.9%	-	-
Horizon Energy Distribution	5.7%	-	-	-
Network Tasman	5.6%	-	-	-
Alpine Energy	3.3%	-	-	-
Nelson Electricity	3.2%	-	-	-
Vector	-	-	-	-
The Lines Company	-	-	-	-
Aurora Energy	-	-	-	-
Top Energy	-	-	-	-
OtagoNet Joint Venture	-	-	-	-
EA Networks	-	-	-	-
Total (%)	**21.8%**	**18.0%**	**16.0%**	**14.7%**
Total ($m)	**1,497.1**	**1,233.9**	**1,096.2**	**1,007.6**

13) Capex disallowed, by EDB, ranked - 5 year reference period (%)

	DPP4			
Non-exempt EDB	**120% cap**	**130% cap**	**140% cap**	**150% cap**
Wellington Electricity Lines	57.8%	54.3%	50.8%	47.2%
Orion New Zealand	51.7%	47.7%	43.6%	39.6%
Firstlight Network	21.7%	15.4%	9.1%	2.8%
Electricity Invercargill	19.4%	12.6%	5.9%	-
Unison Networks	7.8%	-	-	-
Powerco	8.5%	-	-	-
Horizon Energy Distribution	16.6%	9.7%	2.7%	-
Network Tasman	-	-	-	-
Alpine Energy	8.2%	0.6%	-	-
Nelson Electricity	1.4%	-	-	-
Vector	-	-	-	-
The Lines Company	-	-	-	-
Aurora Energy	-	-	-	-
Top Energy	-	-	-	-
OtagoNet Joint Venture	-	-	-	-
EA Networks	-	-	-	-
Total %	**20.0%**	**16.6%**	**15.1%**	**13.7%**
Total ($m)	**1,372.9**	**1,138.0**	**1,038.0**	**941.5**

Appendix A: Restrictions

This report has been prepared for Powerco Limited to provide capex scenario outputs to support Powerco Limited's regulatory outlook analysis.

This report has been prepared solely for this purpose and should not be relied upon for any other purpose. We accept no liability to any party should it used for any purpose other than that for which it was prepared.

To the fullest extent permitted by law, PwC accepts no duty of care to any third party in connection with the provision of this report and/or any related information or explanation (together, the "Information"). Accordingly, regardless of the form of action, whether in contract, tort (including without limitation, negligence) or otherwise, and to the extent permitted by applicable law, PwC accepts no liability of any kind to any third party and disclaims all responsibility for the consequences of any third party acting or refraining to act in reliance on the Information.

We express no opinion on the reliability, accuracy, or completeness of the information provided to us and upon which we have relied. The statements and opinions expressed herein have been made in good faith, and on the basis that all information relied upon is true and accurate in all material respects, and not misleading by reason of omission or otherwise. The statements and opinions expressed in this report are based on information available as at the date of the report. We reserve the right, but will be under no obligation, to review or amend our report, if any additional information, which was in existence on the date of this report, was not brought to our attention, or subsequently comes to light.

We have relied on forecasts and assumptions prepared by electricity distributors about future events which, by their nature, are not able to be independently verified. Inevitably, some assumptions may not materialise, and unanticipated events and circumstances are likely to occur. Therefore, actual results in the future will vary from the forecasts upon which we have relied. These variations may be material.

This report is issued pursuant to the terms and conditions set out in our engagement letter dated 10 October 2023.

Appendix B: Source data

Actual/forecast capex (gross) (nominal $000) - DPP1, DPP2 and DPP3

	2011	2012	2013	2014	2015		2016	2017	2018	2019	2020		2021	2022	2023	2024	2025	
	DPP1					DPP1 total	DPP2					DPP2 total	DPP3					DPP3 total
	Actual	Actual	Actual	Actual	Actual		Actual	Actual	Actual	Actual	Actual		Actual	Actual	Actual	Forecast	Forecast	
Alpine Energy	14,965	18,230	28,858	19,283	17,481	**98,817**	21,095	23,868	31,563	18,486	16,051	**111,064**	19,535	24,094	25,282	34,298	32,539	**135,749**
Aurora Energy	22,294	16,514	17,642	15,919	29,162	**101,531**	29,040	30,138	69,297	69,923	61,819	**260,217**	66,145	85,378	97,155	95,068	87,716	**431,462**
Buller Electricity	1,448	1,320	1,921	1,949	1,999	**8,637**	1,494	1,543	2,261	1,781	1,344	**8,423**	2,594	2,868	3,226	3,628	5,159	**17,475**
Centralines	5,563	2,634	3,303	2,624	2,691	**16,815**	2,469	1,929	2,456	5,746	4,742	**17,342**	5,886	12,943	11,197	12,121	7,795	**49,942**
Counties Energy	11,851	7,592	13,358	16,545	31,040	**80,386**	23,060	22,146	26,039	34,544	53,766	**159,555**	47,975	61,931	61,773	58,826	53,303	**283,808**
EA Networks	16,383	15,463	24,936	16,827	15,006	**88,615**	19,751	20,648	16,416	19,556	29,436	**105,808**	17,323	15,810	14,207	17,160	16,272	**80,772**
Electra	6,547	7,393	6,434	7,523	9,113	**37,010**	14,328	11,110	11,712	11,593	25,358	**74,101**	14,259	13,503	13,591	25,100	28,277	**94,730**
Electricity Invercargill	3,872	3,628	3,979	4,514	8,596	**24,588**	6,275	3,763	5,754	4,824	4,730	**25,346**	4,320	6,681	5,294	622	5,608	**22,526**
Firstlight Network	5,118	5,216	4,572	5,374	18,869	**39,149**	6,287	7,673	8,027	10,719	9,015	**41,720**	9,229	9,005	15,224	14,949	16,796	**65,203**
Horizon Energy Distribution	6,009	6,123	6,878	8,972	7,369	**35,351**	7,328	10,251	7,186	14,342	8,008	**47,115**	7,942	7,034	7,634	10,352	9,701	**42,664**
MainPower New Zealand	12,184	12,340	23,722	37,918	27,980	**114,144**	24,919	14,882	10,274	10,561	25,887	**86,522**	26,394	30,014	29,458	27,582	31,222	**144,671**
Marlborough Lines	15,244	13,587	14,023	12,930	12,267	**68,050**	11,375	7,669	11,520	14,115	12,166	**56,844**	9,324	10,356	12,195	27,395	29,760	**89,030**
Nelson Electricity	1,896	1,183	4,959	12,563	1,265	**21,866**	482	809	943	1,885	1,788	**5,906**	1,056	1,451	1,818	2,029	2,185	**8,539**
Network Tasman	6,108	4,030	7,047	5,589	15,254	**38,028**	7,370	5,850	6,131	10,053	12,097	**41,501**	9,597	11,959	13,827	23,535	23,775	**82,693**
Network Waitaki	4,788	3,467	4,925	5,194	9,903	**28,277**	9,256	9,475	8,664	8,701	7,098	**43,194**	9,046	8,958	9,236	21,851	17,786	**66,877**
Northpower	10,559	9,584	10,884	17,378	13,253	**61,658**	17,762	12,603	16,063	21,248	24,467	**92,143**	24,608	29,982	29,236	46,556	52,712	**183,094**
Orion New Zealand	–	53,892	64,948	81,790	84,875	**285,505**	90,350	68,603	76,098	75,925	68,418	**379,395**	81,604	90,678	120,604	153,770	149,357	**596,012**
OtagoNet Joint Venture	9,448	8,784	9,656	9,984	13,429	**51,301**	12,832	14,942	14,306	16,177	19,632	**77,889**	21,128	19,649	20,151	18,756	17,081	**96,765**
Powerco	79,778	90,279	97,907	107,945	119,765	**495,674**	129,975	153,560	174,483	220,471	195,365	**873,854**	241,689	252,058	291,659	307,482	333,764	**1,426,652**
Scanpower	1,510	722	1,604	2,710	2,118	**8,664**	1,811	1,870	3,676	1,880	3,258	**12,495**	3,774	4,249	3,016	3,341	4,501	**18,881**
The Lines Company	6,210	13,606	8,159	9,437	10,616	**48,028**	10,384	10,403	14,460	22,359	16,465	**74,071**	19,312	15,924	14,054	24,851	27,081	**101,222**
The Power Company	12,314	16,890	21,731	22,503	25,126	**98,564**	24,500	23,660	28,676	23,406	26,346	**126,589**	25,133	24,786	32,238	39,287	41,015	**162,459**
Top Energy	18,117	15,416	31,562	18,899	24,638	**108,632**	16,461	14,939	21,506	17,726	37,909	**108,540**	16,670	13,813	16,054	21,719	21,680	**89,936**
Unison Networks	36,242	30,058	29,954	43,624	46,082	**185,960**	50,862	46,191	41,723	48,205	59,245	**246,226**	52,916	59,430	83,922	91,879	102,612	**390,758**
Vector	149,632	135,289	148,232	174,264	164,185	**771,602**	157,908	201,935	230,484	258,367	580,881	**1,429,575**	296,492	325,155	371,047	534,357	512,358	**2,039,409**
Waipa Networks	5,269	4,843	6,026	7,797	7,361	**31,295**	16,224	8,134	6,303	6,365	12,557	**49,584**	11,583	19,035	19,288	23,358	31,486	**104,749**
WEL Networks	50,330	38,459	50,394	51,023	54,619	**244,825**	39,033	30,187	35,353	39,953	47,204	**191,731**	42,879	54,812	78,177	79,705	74,389	**329,962**
Wellington Electricity Lines	27,300	24,820	27,889	35,656	31,678	**147,344**	29,932	36,440	39,053	49,494	56,422	**211,342**	49,628	50,481	53,385	65,452	67,706	**286,652**
Westpower	3,956	4,824	4,294	2,607	2,138	**17,819**	2,719	1,831	1,679	2,580	3,172	**11,981**	2,691	3,321	4,349	5,066	6,078	**21,506**
Total	**544,935**	**566,186**	**679,796**	**759,341**	**807,877**	**3,358,135**	**785,282**	**797,052**	**922,108**	**1,040,984**	**1,424,647**	**4,970,073**	**1,140,735**	**1,265,359**	**1,458,297**	**1,790,094**	**1,809,714**	**7,464,199**

Source: Information Disclosures, Asset Management Plans - Note Orion NZ was exempt from disclosures in 2011

Source data (cont,)

Actual/forecast capex (gross) (nominal $000) - DPP4 and DPP5

	2026	2027	2028	2029	2030	DPP4 total	2031	2032	2033	2034	2035	DPP5 total
	DPP4						DPP5					
	Forecast	Forecast	Forecast	Forecast	Forecast		Forecast	Forecast	Forecast	Forecast	Forecast	
Alpine Energy	34,814	36,423	36,704	32,378	34,467	**174,786**	31,404	32,666	32,053	32,053	32,053	**160,229**
Aurora Energy	85,778	87,769	92,619	97,712	95,581	**459,459**	96,666	105,621	101,631	101,631	101,631	**507,180**
Buller Electricity	2,829	2,250	2,350	2,408	2,559	**12,397**	2,465	2,517	2,565	2,565	2,565	**12,676**
Centralines	7,387	5,898	5,875	10,682	11,114	**40,955**	5,556	5,606	9,614	9,614	9,614	**40,004**
Counties Energy	63,130	56,426	53,559	37,058	41,334	**251,507**	38,898	45,039	58,810	58,810	58,810	**260,367**
EA Networks	16,657	14,514	15,954	15,360	15,056	**77,541**	13,993	11,972	12,203	12,203	12,203	**62,573**
Electra	27,382	26,815	27,798	26,930	28,320	**137,245**	29,153	29,578	30,487	30,487	30,487	**150,192**
Electricity Invercargill	7,184	9,212	9,851	8,196	9,785	**44,228**	8,571	9,488	8,273	8,273	8,273	**42,878**
Firstlight Network	18,699	18,859	18,459	19,431	18,000	**93,448**	19,114	21,844	18,430	18,430	18,430	**96,248**
Horizon Energy Distribution	12,987	13,316	14,662	14,888	14,191	**70,044**	14,335	15,254	15,278	15,278	15,278	**75,423**
MainPower New Zealand	29,721	27,300	28,542	30,725	28,695	**144,984**	30,342	30,693	34,834	34,834	34,834	**165,537**
Marlborough Lines	27,181	20,916	23,737	21,264	21,648	**114,746**	21,700	21,351	22,530	22,530	22,530	**110,641**
Nelson Electricity	2,279	2,549	2,588	2,377	2,218	**12,011**	2,386	2,307	2,354	2,354	2,354	**11,755**
Network Tasman	18,219	18,037	15,973	17,056	18,340	**87,625**	21,751	32,342	19,413	19,413	19,413	**112,332**
Network Waitaki	15,874	14,121	10,435	13,334	14,193	**67,957**	15,965	18,647	25,496	25,496	25,496	**111,100**
Northpower	45,071	44,279	43,356	42,616	48,865	**224,187**	53,355	58,544	59,595	59,595	59,595	**290,684**
Orion New Zealand	217,500	285,083	303,224	362,602	406,458	**1,574,868**	468,119	522,967	573,378	573,378	573,378	**2,711,220**
OtagoNet Joint Venture	20,505	25,915	23,451	27,020	29,251	**126,142**	30,735	26,905	27,443	27,443	27,443	**139,969**
Powerco	340,633	373,825	413,921	449,107	436,964	**2,014,450**	473,207	517,728	519,438	519,438	519,438	**2,549,249**
Scanpower	5,215	5,346	3,143	7,245	2,908	**23,857**	2,966	4,029	4,110	4,110	4,110	**19,325**
The Lines Company	31,682	33,854	21,415	19,954	23,436	**130,341**	19,434	18,943	20,315	20,315	20,315	**99,322**
The Power Company	31,527	32,150	33,539	33,877	34,728	**165,821**	35,603	34,371	35,098	35,098	35,098	**175,268**
Top Energy	19,601	19,697	19,475	23,146	19,540	**101,458**	19,906	21,396	21,075	21,075	21,075	**104,527**
Unison Networks	102,339	105,360	104,976	106,096	119,796	**538,568**	121,459	125,276	128,771	128,771	128,771	**633,048**
Vector	560,847	537,820	542,351	526,483	519,166	**2,686,667**	542,129	540,915	535,455	535,455	535,455	**2,689,409**
Waipa Networks	23,816	14,413	13,988	14,877	14,521	**81,615**	14,720	14,605	14,896	14,896	14,896	**74,014**
WEL Networks	69,924	74,350	77,183	80,674	87,170	**389,300**	92,732	97,978	106,376	106,376	106,376	**509,839**
Wellington Electricity Lines	165,784	199,171	208,167	163,892	135,620	**872,633**	137,679	116,841	119,732	119,732	119,732	**613,716**
Westpower	4,545	2,711	2,251	2,038	1,869	**13,414**	2,569	1,811	1,761	1,761	1,761	**9,665**
Total	**2,009,112**	**2,108,378**	**2,169,546**	**2,209,426**	**2,235,793**	**10,732,255**	**2,366,914**	**2,487,235**	**2,561,414**	**2,561,414**	**2,561,414**	**12,538,390**

Source: Information Disclosures, Asset Management Plans

Source data (cont.)

Actual/forecast capex net of capital contributions (nominal $000) - DPP1, DPP2 and DPP3

	2011	2012	2013	2014	2015	DPP1 total	2016	2017	2018	2019	2020	DPP2 total	2021	2022	2023	2024	2025	DPP3 total
	DPP1						DPP2						DPP3					
	Actual	Actual	Actual	Actual	Actual		Actual	Actual	Actual	Actual	Actual		Actual	Actual	Actual	Forecast	Forecast	
Alpine Energy	14,965	18,230	28,250	14,229	14,012	**89,685**	15,264	20,855	27,429	14,499	13,234	**91,281**	15,547	20,614	21,482	29,298	26,891	**113,833**
Aurora Energy	22,294	16,514	14,599	11,832	24,728	**89,967**	22,926	26,639	64,546	66,047	57,084	**237,242**	58,010	71,426	86,530	82,830	74,814	**373,610**
Buller Electricity	1,448	1,320	1,921	1,739	1,695	**8,123**	1,345	1,347	2,229	1,740	1,290	**7,950**	2,454	2,309	2,708	3,368	4,909	**15,748**
Centralines	5,563	2,634	3,059	2,286	2,348	**15,890**	2,189	1,552	2,072	5,198	3,888	**14,899**	4,469	11,879	9,698	10,683	6,324	**43,053**
Counties Energy	11,851	7,592	10,967	14,657	26,803	**71,871**	18,750	15,928	17,853	25,427	45,350	**123,308**	36,243	36,091	38,675	43,826	42,179	**197,014**
EA Networks	16,383	15,463	24,401	16,115	14,184	**86,546**	18,458	19,927	16,215	18,504	28,930	**102,035**	16,447	14,947	12,703	15,617	15,831	**75,545**
Electra	6,547	7,393	6,434	7,523	9,113	**37,010**	14,328	11,110	11,712	11,593	25,358	**74,101**	14,259	13,503	13,591	24,020	27,197	**92,570**
Electricity Invercargill	3,872	3,628	3,822	4,450	8,548	**24,319**	6,132	3,715	5,718	4,653	4,689	**24,907**	3,597	5,755	4,881	402	5,388	**20,023**
Firstlight Network	5,118	5,216	4,450	4,820	18,779	**38,384**	6,287	7,673	8,027	10,668	9,015	**41,669**	9,229	9,005	15,224	14,949	16,796	**65,203**
Horizon Energy Distribution	6,009	6,123	6,020	8,950	7,232	**34,335**	7,058	10,218	7,039	14,259	7,990	**46,564**	7,932	7,009	7,634	9,928	9,192	**41,695**
MainPower New Zealand	12,184	12,340	18,075	32,027	22,906	**97,532**	19,923	10,508	5,612	6,524	25,147	**67,713**	11,819	14,600	22,505	23,846	27,332	**100,101**
Marlborough Lines	15,244	13,587	13,121	12,733	12,122	**66,807**	11,309	7,373	11,421	14,043	12,083	**56,229**	8,285	10,195	11,900	27,395	29,760	**87,535**
Nelson Electricity	1,896	1,183	4,766	12,396	1,212	**21,453**	455	712	868	1,783	1,682	**5,500**	1,056	1,447	1,818	2,029	2,185	**8,535**
Network Tasman	6,108	4,030	6,945	5,472	14,787	**37,342**	7,183	5,745	5,759	9,917	12,039	**40,643**	9,570	11,317	13,796	23,483	23,630	**81,796**
Network Waitaki	4,788	3,467	3,798	3,571	6,541	**22,165**	6,856	7,440	6,996	6,910	5,269	**33,471**	6,965	6,569	7,021	19,771	16,056	**56,382**
Northpower	10,559	9,584	9,785	15,359	11,389	**56,676**	15,785	9,960	11,884	16,967	20,476	**75,072**	21,026	22,642	21,844	40,675	46,690	**152,878**
Orion New Zealand	–	53,892	60,707	77,224	78,408	**270,231**	83,296	58,747	65,216	70,425	64,844	**342,529**	79,526	87,033	117,291	136,200	125,359	**545,409**
OtagoNet Joint Venture	9,448	8,784	8,619	9,491	11,393	**47,735**	11,469	14,211	13,564	15,543	18,734	**73,520**	19,772	17,816	18,085	16,952	16,244	**88,869**
Powerco	79,778	90,279	83,453	95,677	101,950	**451,137**	110,015	128,012	150,774	186,816	164,341	**739,957**	214,325	208,220	237,425	251,395	274,977	**1,186,342**
Scanpower	1,510	722	1,604	2,710	2,118	**8,664**	1,811	1,870	3,676	1,880	3,258	**12,495**	3,774	4,249	3,016	3,341	4,501	**18,881**
The Lines Company	6,210	13,606	8,089	9,257	10,595	**47,757**	10,384	10,403	13,095	22,334	16,374	**72,590**	19,229	15,865	12,218	21,092	21,481	**89,885**
The Power Company	12,314	16,890	19,823	20,593	22,217	**91,837**	21,973	20,945	27,058	21,549	23,159	**114,683**	23,068	22,148	22,462	32,107	33,188	**132,972**
Top Energy	18,117	15,416	30,961	18,410	24,042	**106,946**	14,934	13,922	20,301	14,878	35,817	**99,851**	14,473	9,807	11,774	18,219	18,559	**72,832**
Unison Networks	36,242	30,058	22,466	39,048	41,282	**169,097**	46,325	39,832	34,886	41,458	50,278	**212,779**	42,905	48,914	72,561	75,439	77,913	**317,732**
Vector	149,632	135,289	124,343	144,999	127,012	**681,275**	119,453	143,084	170,707	186,584	501,472	**1,121,300**	208,482	184,014	207,276	297,530	223,370	**1,120,672**
Waipa Networks	5,269	4,843	5,403	5,334	5,503	**26,352**	15,177	5,744	4,238	3,880	10,095	**39,135**	7,073	15,808	13,906	19,828	27,291	**83,907**
WEL Networks	50,330	38,459	45,574	45,320	50,206	**229,889**	34,553	23,531	27,919	30,841	35,595	**152,440**	34,854	45,523	65,082	69,114	66,892	**281,465**
Wellington Electricity Lines	27,300	24,820	23,051	31,142	26,970	**133,283**	25,001	29,123	27,624	43,444	46,333	**171,524**	42,246	36,010	42,581	55,690	57,514	**234,041**
Westpower	3,956	4,824	4,294	2,445	2,088	**17,607**	2,125	1,831	1,679	2,580	3,172	**11,387**	2,691	3,321	4,349	5,066	6,078	**21,506**
Total	**544,935**	**566,186**	**598,801**	**669,809**	**700,182**	**3,079,913**	**670,763**	**651,955**	**766,120**	**870,942**	**1,246,996**	**4,206,776**	**939,326**	**958,036**	**1,120,036**	**1,374,094**	**1,328,541**	**5,720,032**

Source: Information Disclosures, Asset Management Plans - Note Orion NZ was exempt from disclosures in 2011

Source data (cont.)

Actual/forecast capex net of capital contributions (nominal $000) - DPP4 and DPP5

	2026	2027	2028	2029	2030	DPP4 total	2031	2032	2033	2034	2035	DPP5 total
	DPP4						DPP5					
	Forecast	Forecast	Forecast	Forecast	Forecast		Forecast	Forecast	Forecast	Forecast	Forecast	
Alpine Energy	30,054	31,028	31,401	26,765	28,741	**147,989**	25,564	26,709	25,977	25,977	25,977	**130,204**
Aurora Energy	72,770	75,526	79,846	84,389	81,687	**394,218**	82,180	90,521	85,894	85,894	85,894	**430,383**
Buller Electricity	2,579	2,186	2,286	2,344	2,495	**11,891**	2,401	2,453	2,501	2,501	2,501	**12,356**
Centralines	5,887	4,367	4,314	9,090	9,489	**33,147**	3,899	3,916	7,891	7,891	7,891	**31,487**
Counties Energy	51,991	46,100	42,923	26,103	30,050	**197,167**	27,276	33,068	46,480	46,480	46,480	**199,784**
EA Networks	16,357	14,264	15,704	15,110	14,806	**76,241**	13,743	11,722	11,953	11,953	11,953	**61,323**
Electra	26,302	25,735	26,718	25,850	27,240	**131,845**	28,073	28,498	29,407	29,407	29,407	**144,792**
Electricity Invercargill	6,874	8,992	9,631	7,976	9,565	**43,038**	8,351	9,268	8,053	8,053	8,053	**41,778**
Firstlight Network	18,699	18,859	18,459	19,431	18,000	**93,448**	19,114	21,844	18,430	18,430	18,430	**96,248**
Horizon Energy Distribution	12,546	12,866	14,203	14,420	13,714	**67,749**	13,848	14,758	14,772	14,772	14,772	**72,922**
MainPower New Zealand	25,724	23,224	24,394	26,494	24,380	**124,215**	25,939	26,203	30,253	30,253	30,253	**142,901**
Marlborough Lines	27,181	20,916	23,737	21,264	21,648	**114,746**	21,700	21,351	22,530	22,530	22,530	**110,641**
Nelson Electricity	2,279	2,549	2,588	2,377	2,218	**12,011**	2,386	2,307	2,354	2,354	2,354	**11,755**
Network Tasman	18,003	17,807	15,828	16,890	18,146	**86,674**	21,486	31,848	19,231	19,231	19,231	**111,027**
Network Waitaki	14,158	12,067	8,369	11,199	12,046	**57,839**	14,188	16,864	23,694	23,694	23,694	**102,134**
Northpower	38,910	37,995	36,946	36,078	42,196	**192,125**	46,553	51,606	52,518	52,518	52,518	**255,713**
Orion New Zealand	183,474	253,858	274,902	327,508	357,891	**1,397,635**	401,751	437,970	465,526	465,526	465,526	**2,236,299**
OtagoNet Joint Venture	19,645	25,036	22,554	26,105	28,318	**121,658**	29,783	25,934	26,453	26,453	26,453	**135,076**
Powerco	281,528	312,101	348,139	375,117	355,429	**1,672,314**	382,789	416,962	406,077	406,077	406,077	**2,017,982**
Scanpower	5,215	5,346	3,143	7,245	2,908	**23,857**	2,966	4,029	4,110	4,110	4,110	**19,325**
The Lines Company	28,182	33,854	18,415	19,954	23,436	**123,841**	19,434	18,943	20,315	20,315	20,315	**99,322**
The Power Company	26,166	26,532	28,791	31,033	31,827	**144,349**	32,644	31,353	32,019	32,019	32,019	**160,054**
Top Energy	16,788	17,598	17,334	20,962	17,313	**89,994**	17,634	19,079	18,711	18,711	18,711	**92,846**
Unison Networks	79,904	87,146	88,528	90,475	104,102	**450,156**	105,047	107,856	110,281	110,281	110,281	**543,744**
Vector	270,785	241,720	286,140	289,723	281,735	**1,370,103**	293,030	285,686	274,691	274,691	274,691	**1,402,789**
Waipa Networks	18,637	8,217	7,670	8,433	7,949	**50,905**	8,017	7,769	7,923	7,923	7,923	**39,555**
WEL Networks	62,191	66,370	68,968	72,081	78,107	**347,717**	83,125	87,869	95,530	95,530	95,530	**457,582**
Wellington Electricity Lines	146,183	179,041	187,492	152,483	124,083	**789,282**	126,014	105,047	107,806	107,806	107,806	**554,479**
Westpower	4,545	2,711	2,251	2,038	1,869	**13,414**	2,569	1,811	1,761	1,761	1,761	**9,665**
Total	**1,513,557**	**1,614,011**	**1,711,674**	**1,768,938**	**1,771,387**	**8,379,566**	**1,861,506**	**1,943,242**	**1,973,139**	**1,973,139**	**1,973,139**	**9,724,166**

Source: Information Disclosures, Asset Management Plans

Attachment 4 PWC revenue modelling report

Regulatory Outlook - Revenue modelling

Powerco Limited
December 2023

Chris Taylor
Chief Financial Officer
Powerco Limited
35 Junction Street
New Plymouth

15 December 2023

Regulatory outlook - Revenue modelling

Dear Chris,

We are pleased to provide you with our report which summarises revenue modelling to support Powerco Limited's (Powerco's) regulatory outlook analysis. This report builds on our capex modelling provided separately. The report is provided in accordance with the terms and conditions set out in Appendix A. If you have any queries, please do not hesitate to contact us.

Yours sincerely,

Lynne Taylor
Executive Director
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Simon Healy
Partner
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Summary of observations

Introduction

If New Zealand is to meet its 2030 and 2050 emission reduction targets, additional electricity distribution business (EDB) investment needs to start now.

The regulatory settings need to adapt to accommodate this additional investment, otherwise the policy targets will not be met.

Default price-quality paths (DPPs) will be reset on 1 April 2025, and again on 1 April 2030. These decisions need to reflect adequate future expenditure allowances for non-exempt EDBs. Future expenditures are likely to be much higher than historical expenditures.

In addition, revenue must adjust to reflect increases in the cost base. This will ensure that there are sufficient incentives for EDBs to continue to invest in new infrastructure, and that users pay for the reasonable costs of the electricity distribution services provided to them.

This report examines revenue forecasts for DPPs and builds on the capex modelling provided separately. A brief summary of our findings is presented below.

BBAR trends

- As DPP3 building block allowable revenue (BBAR) was determined in an abnormally low inflation, low interest rate environment, the step into DPP4 will be significant.
- Our total BBAR estimate, for all non-exempt EDBs, is 64% higher in year 1 of DPP4, than at the end of DPP3, based on the modelling assumptions documented on page 4.

Comparison to DPP2

- Of the estimated 64% increase in BBAR between DPP3 and DPP4, approximately one half is a real increase from the BBAR at the end of DPP2.

Drivers of increases in BBAR

- Regulatory asset base (RAB) growth and the higher forecast weighted average cost of capital (WACC) are the main contributors to the predicted step change in BBAR at the beginning of DPP4.
- Higher capex allowances do not have a significant impact on short term BBAR.
- This suggests that decisions about price steps for DPP4 can be considered separately from decisions about capex allowances.

Price path smoothing

- Historically the Commission has limited annual step changes in revenue to 10% to manage price shocks. But that will not be possible for DPP4, as the DPP3 revenue caps were abnormally low.
- A 10% per annum revenue cap, combined with a 10% limit on the step between DPP3 and DPP4 results in significant DPP4 BBAR ($4.6b) not being recovered in the regulatory period. Under this scenario, revenue is lower than BBAR in every year of DPP4.
- We estimate that annual price caps of about 20% may be required during DPP4 to provide an ex ante expectation of recovering BBAR during the regulatory period.

Introduction, scope and assumptions

Introduction

EDBs will be 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 2030 and 2050 emission reduction targets, this investment needs to start now, and together with additional generation and transmission investment, will result in renewable electricity meeting more of New Zealand's energy needs.

The regulatory settings need to adapt to accommodate this additional investment, otherwise the policy targets will not be met. For EDBs the revenue caps which are determined by the Commerce Commission are the most important feature of the regulatory regime which must align with the emissions reduction policy settings.

DPPs will be reset on 1 April 2025, and again on 1 April 2030. These decisions need to reflect adequate future expenditure allowances for non-exempt EDBs. Notably with the investment required in New Zealand's electricity networks, future expenditures are likely to be much higher than historical expenditures.

In addition, revenue must adjust to reflect increases in the cost base. This will ensure that there are sufficient incentives for EDBs to continue to invest in new infrastructure, and that users pay for the reasonable costs of the electricity distribution services provided to them.

Scope of this report

We are undertaking regulatory modelling and analysis, to support discussion about the appropriate regulatory settings for EDBs for DPP4 and DPP5. We are interested in testing the consistency or otherwise between the energy transition targets and the Commerce Commission's rules and processes. This is to inform energy sector stakeholder engagement leading into the next regulatory period.

This report presents outputs for phase two of the regulatory outlook modelling, following phase one which focussed on capex forecasting. In this report we present analysis of the building block components of forecast revenue and how these may impact future price-quality paths and options for smoothing price steps for non-exempt EDBs.

Key inputs and assumptions

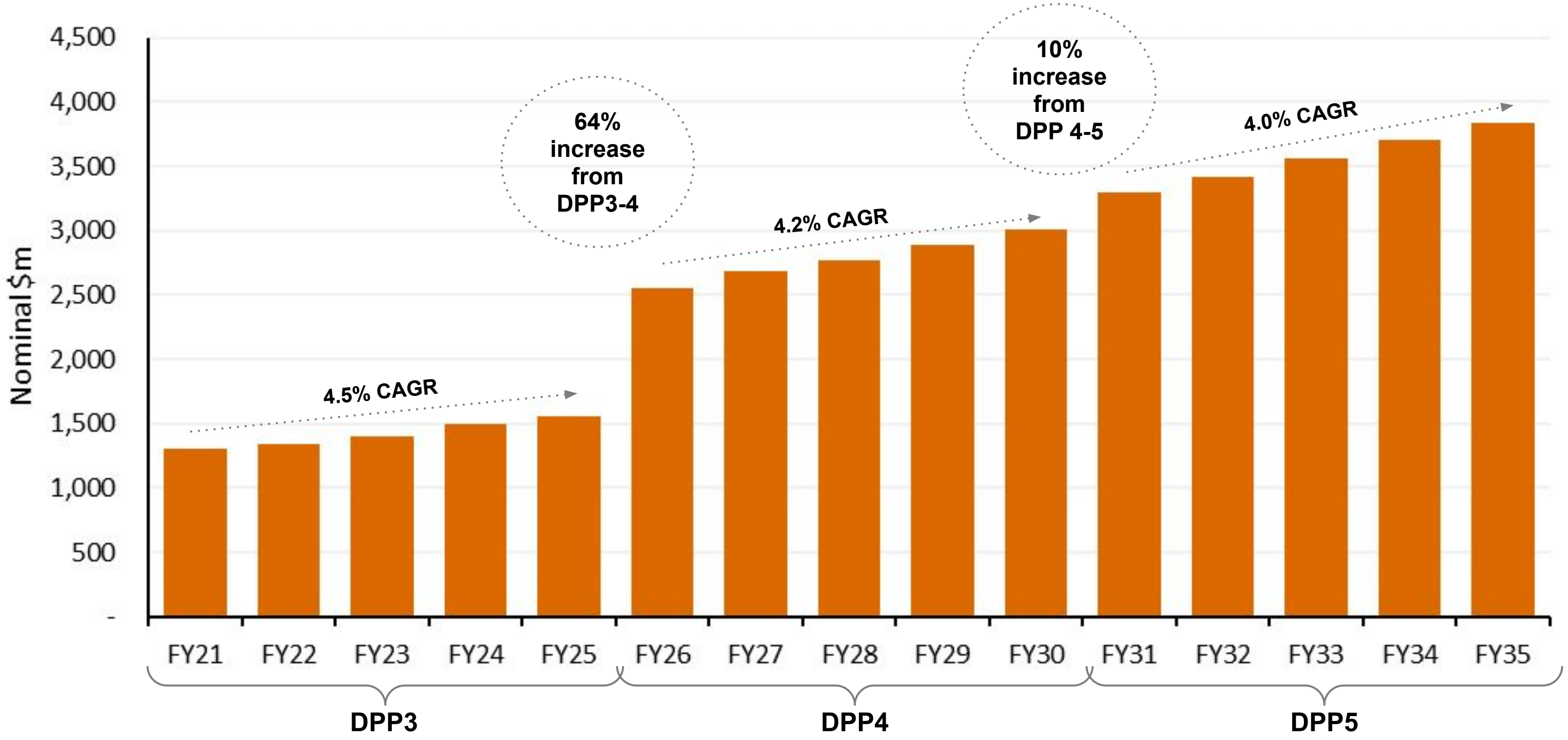
- The DPP3 financial model is extended to DPP4 and DPP5, and updated with actual data to FY23.
- Forecast capex scenarios are sourced from our capex modelling report.
- Commissioned asset and capital contribution forecasts are consistent with the chosen capex scenario.
- Forecast DPP5 RABs assume that EDBs will invest according to their 2023 AMPs during DPP4, irrespective of DPP4 capex allowances.
- Forecast asset disposals are determined using the average historical asset disposals adjusted for inflation.
- Forecast DPP4 and DPP5 opex allowances are equal to forecast 2023 AMPs, and extrapolated to FY35 using CPI.
- Forecast WACC is 7.5% for DPP4 and 7.7% for DPP5.
- Forecast CPI is sourced from the NZIER Q3 2023 forecasts and averages 2% over DPP4 and DPP5.

BBAR trends

Total non-exempt EDB building block allowable revenue (BBAR) is forecast to increase significantly at the beginning of DPP4

- The data shown in 1) below is for all non-exempt EDBs, using the '*120% cap with a seven year reference period'* capex scenario, assuming no CPPs.
- As DPP3 BBAR was determined in a low inflation, low interest rate environment, the step into DPP4 is significant.
- The BBAR growth from the beginning of DPP4 reflects the forecast capex within the assumed 120% cap, as a reference case.
- The step to DPP5 reflects RAB growth during DPP4, including actual capex above allowances, and the forecast DPP5 WACC.

1) Actual/forecast BBAR with reference case capex ($m nominal)

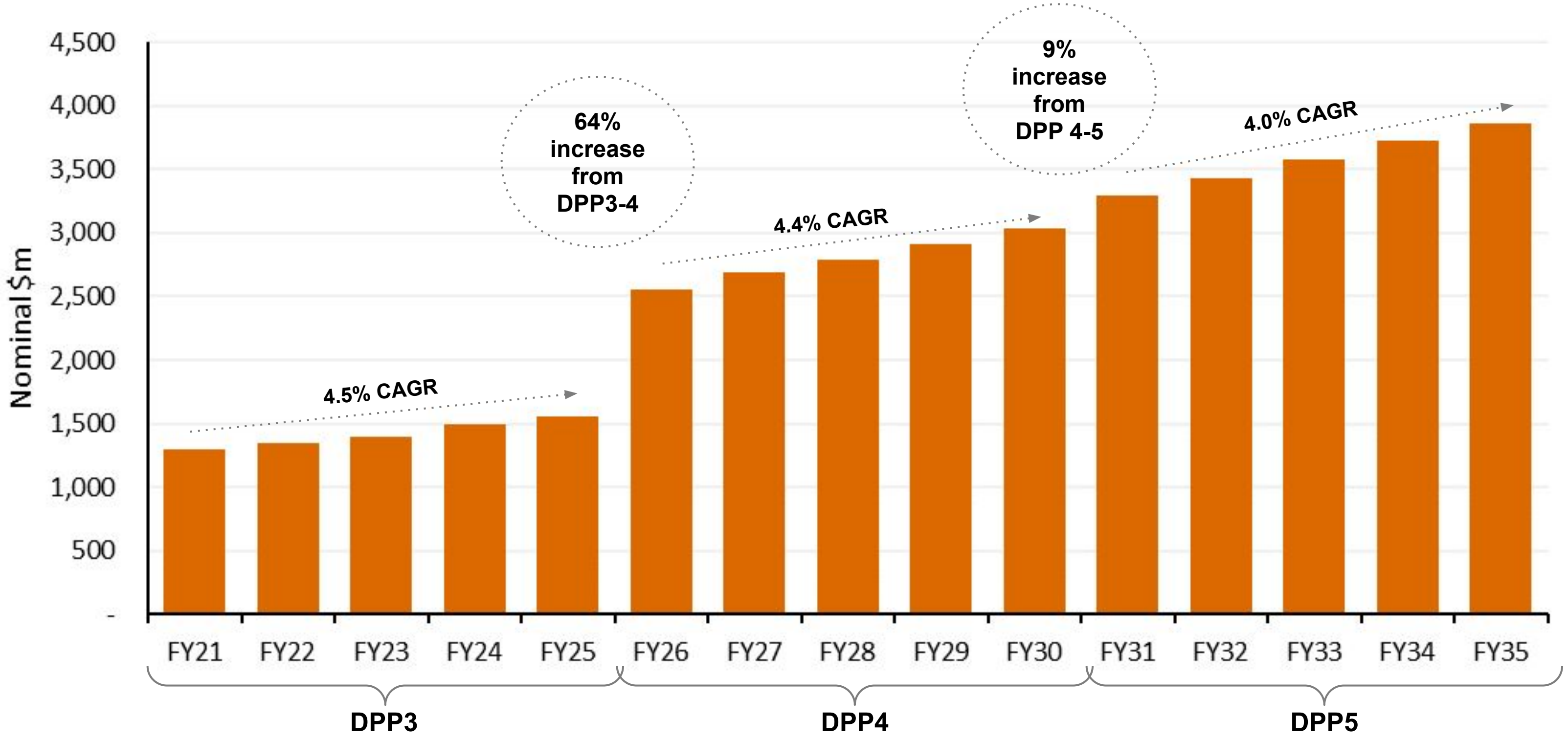


Impact of capex allowances on forecast BBAR

Higher capex allowances do not have a significant impact on short term BBAR

- The data shown in 2) below is for all non-exempt EDBs, using the '*140% cap with a 5 year reference period capex scenario*', assuming no CPPs.
- The step changes in BBAR between the regulatory periods are not materially different to the reference case shown on the previous page.
- There is a slightly higher BBAR growth rate during DPP4 due to the higher capex allowance under this scenario. The percentage step into DPP5 is slightly lower as a result.
- This suggests that the decision about price steps for DPP4 can be largely separated from the decision about DPP4 capex allowances.

2) Actual/forecast BBAR with higher capex ($m nominal)

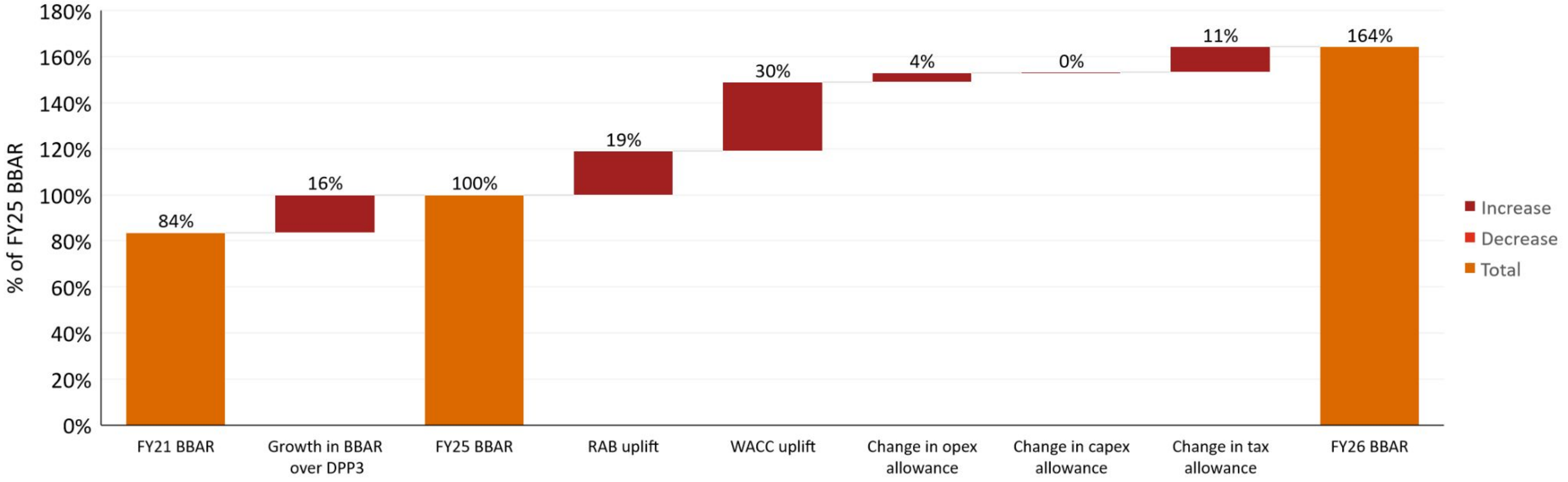


DDP3 to DPP4 BBAR waterfall

RAB and WACC will have a significant impact on DPP4 BBAR relative to DPP3

- DPP3 provided for 16% growth in total BBAR for all non-exempt EDBs between FY21 and FY25 as shown below.
- We estimate there will be a 64% uplift in BBAR between the end of DPP3 and the first year of DPP4, based on our modelling assumptions documented on page 4. RAB growth during DPP3 and the anticipated uplift in the regulatory WACC are the main contributors to this, as shown below.
- These are factors which are outside the control of the Commission and non-exempt EDBs given they reflect the Input Methodologies and past investment.
- The DPP4 capex and opex allowances have very little impact on the estimated step change in BBAR in year 1 of DPP4 in comparison.
- Note this analysis ignores regulatory adjustments such as IRIS and quality incentives and the revenue cap wash-up. It also ignores BBAR smoothing.

3) DPP3 to DPP4 BBAR waterfall



Price path smoothing

BBAR will be smoothed when DPP4 and DPP5 revenue caps are determined

- Maximum allowable revenue (MAR) will reflect a revenue profile which the Commission will determine for each non-exempt EDB.
- Figure 4) overleaf shows the impact of alternative smoothing assumptions for DPP4 for all non-exempt EDBs combined.
- The adjusted DPP3 MAR represents the MAR set by the Commission, adjusted for the revenue cap CPI wash-up reflecting a two year lag.
- The closing adjusted MAR is an estimate of the net allowable revenue at the end of DPP3. This is a simplification as each EDB will have its own wash-up balance at the end of DPP3 reflecting additional factors.
- The closing DPP3 unrecovered wash-up balance is not included in the analysis overleaf. Other pass through and recoverable costs, such as transmission charges, are also excluded.

10% revenue cap

- Historically the Commission has limited annual step changes in MAR to 10% to manage price shocks.
- But that will not be possible for DPP4, as the DPP3 revenue caps are abnormally low.
- As shown in Figure 4) a 10% per annum revenue cap, combined with a 10% limit on the P0 step between DPP3 and DPP4 results in significant DPP4 BBAR ($4.3b) not being recovered in the regulatory period. Under this scenario revenue is lower than BBAR in every year of DPP4.
- This scenario would not be consistent with the financeability thresholds which EDBs need to be able to fund capex.

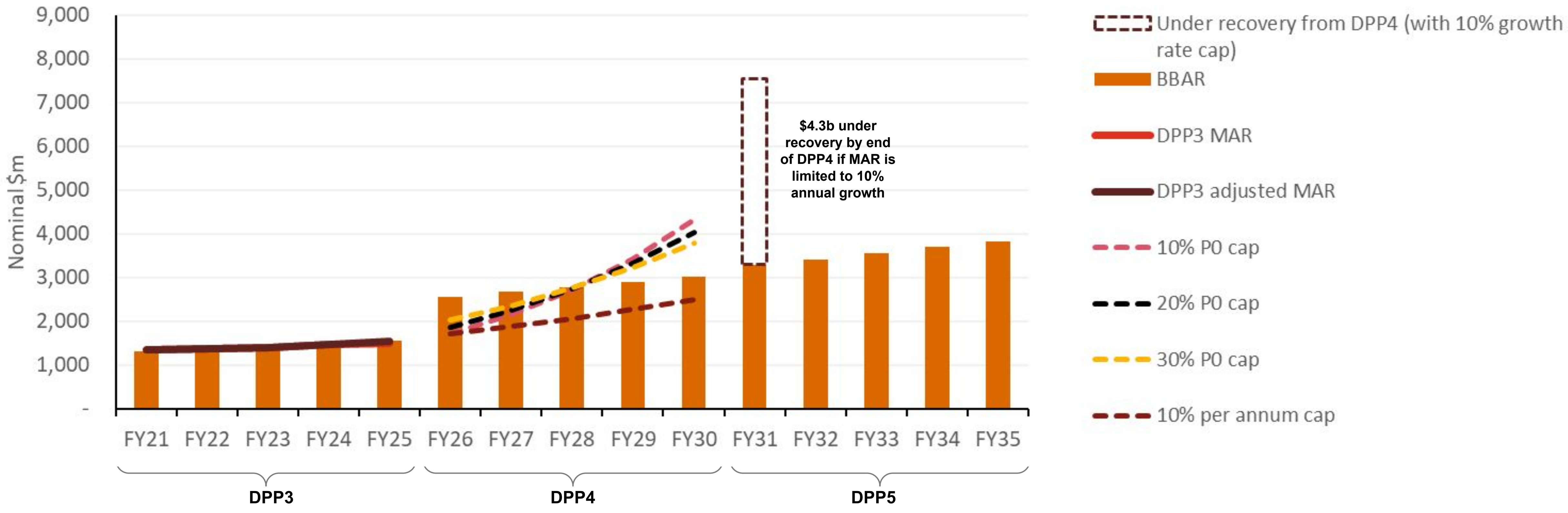
Other P0 options

- We have also tested smoothing options with initial P0 steps of 10%, 20% and 30%. In these scenarios, the annual rate of change (X factor and CPI) is assumed to be sufficient to recover all BBAR within DPP4. The average rates of change are shown opposite, and in each case significantly exceed the maximum 10% cap threshold previously applied.
- As illustrated overleaf, under all scenarios, revenues at the end of DPP4 are much higher than BBAR and than at the start of DPP4, due to the high rates of change required to recover all BBAR.
- Under these scenarios, a step down in revenue between DPP4 and DPP5 would be expected.

DPP4 P0 scenarios	Average rate of change (incl. CPI)
10% P0 Cap	23.6%
20% P0 Cap	19.0%
30% P0 Cap	14.8%

DPP4 price path smoothing

4) BBAR and alternative DPP4 MAR profiles ($m nominal)

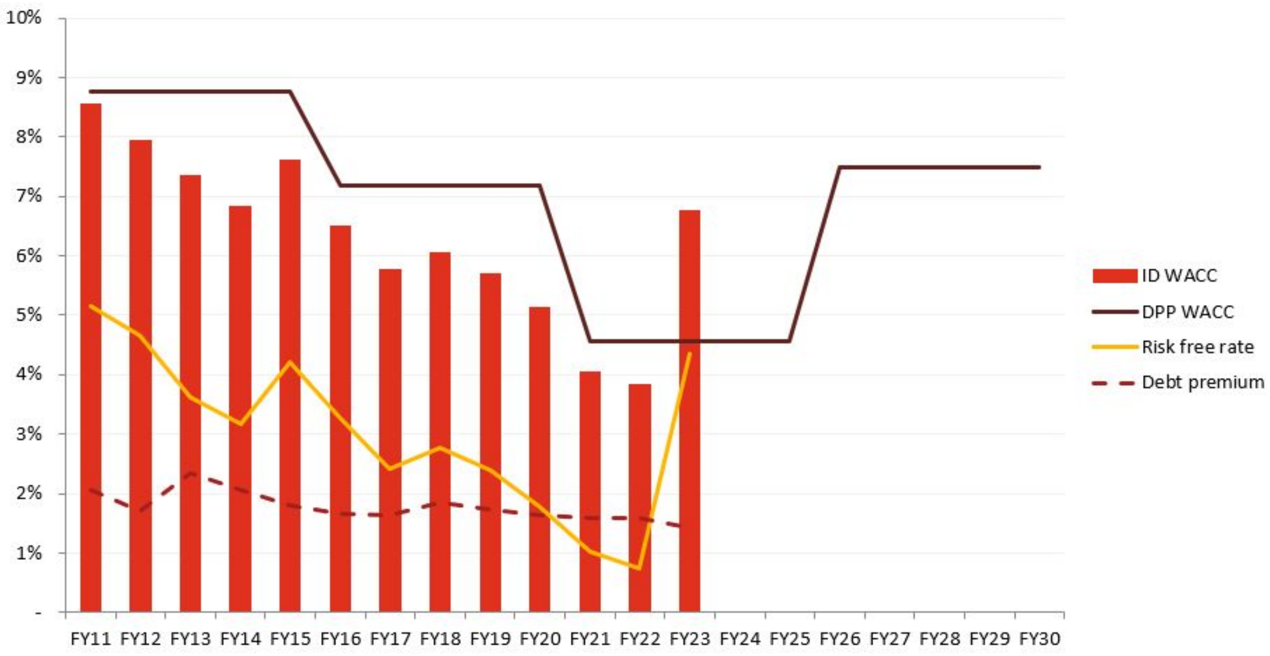


Revenue reduced from DPP2 to DPP3

DPP3 reflected abnormally low revenues and prices for electricity distribution services

- This was a continuation of a falling WACC trend from DPP1 to DPP3, as shown in 6) below.
- Our WACC estimates for DPP4 reflect the reversal of that trend, which is also evident in the Information Disclosure WACC for FY23.

6) Regulatory WACC estimates, DPP1 - DPP4



- The transition from DPP2 to DPP3 reduced revenues for most non-exempt EDBs as illustrated in 7) below. Aurora Energy was an exception due to their accelerated investment prior to their CPP.
- In some cases the percentage reductions in revenue were considerably more than the 10% annual revenue cap applied to minimise price shocks for consumers.

7) Changes in allowable revenue from 2019/2020 to 2020/2021

Distributor	Revenue increase from 2019/20 estimate of allowable revenue to 2020/21 MAR
Alpine Energy	-14.2%
Aurora Energy	30.3%
Centralines	-35.2%
EA Networks	-10.4%
Eastland Network	-13.8%
Electricity Invercargill	-12.1%
Horizon Energy	1.3%
Nelson Electricity	-19.1%
Network Tasman	-6.4%
Orion NZ	-5.2%
OtagoNet	-5.2%
The Lines Company	-15.0%
Top Energy	-21.8%
Unison Networks	-11.4%
Vector Lines	-6.9%

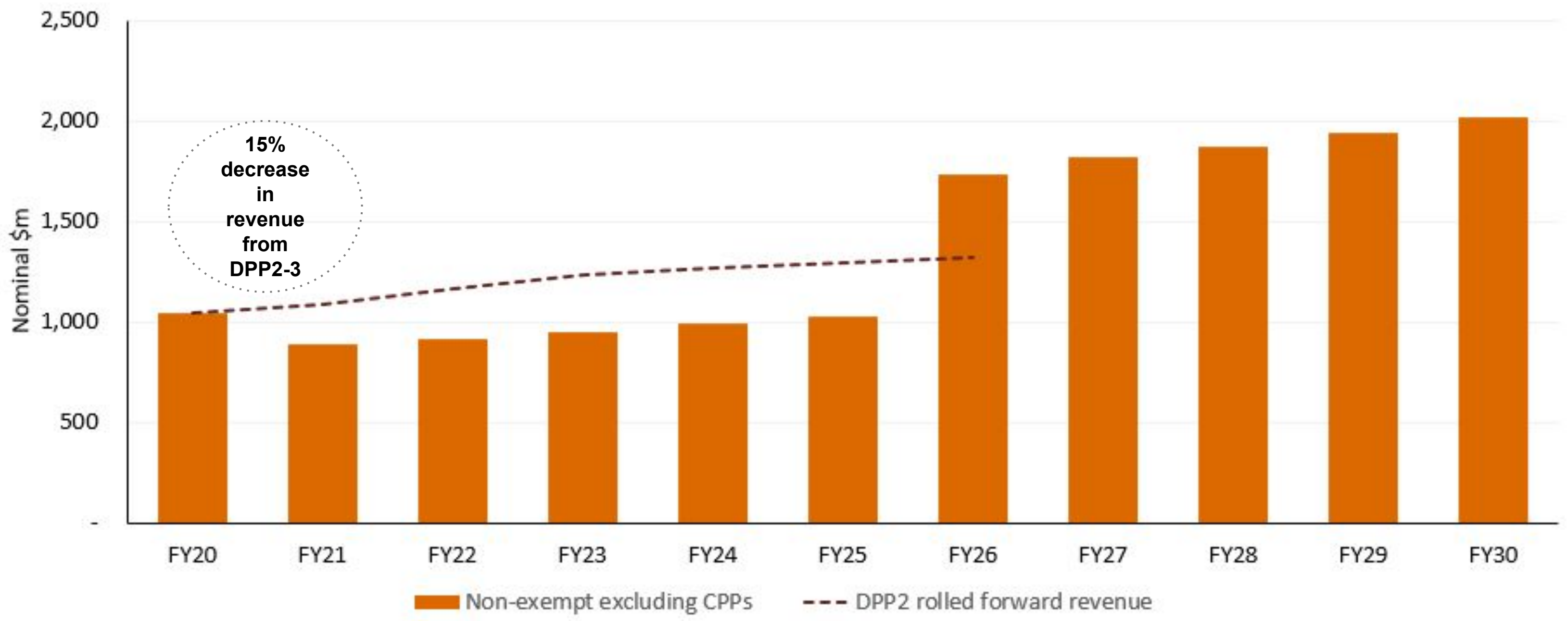
Source: Commerce Commission, Revenue Change Model, DPP3 Final Decision

DPP2 revenue is relevant for the DPP3 to DPP4 transition

Revenues were higher at the end of DPP2, than in DPP3

- For EDBs subject to the DPP (ignoring those on CPPs), there was, on average, a 15% reduction in BBAR in the first year of DPP3, as shown in 8).
- At that time the Commission had the option of rolling over DPP2 revenue (at CPI) or resetting it based on current and future profitability (which they did).
- Had the DPP2 revenues been rolled over, they would be 30.5% higher in FY25 than our projected DPP3 BBAR.
- This increase is consistent with maintaining revenue in real terms between the end of DPP2 and DPP3.
- Thus, of the estimated 64% increase in BBAR between DPP3 and DPP4, about one half reflects a real increase from FY20 DPP2 BBAR.

8) DPP2 to DPP4 BBAR transitions - non-exempt EDBs subject to DPPs



Appendix A: Restrictions

This report has been prepared for Powerco Limited to provide revenue scenario outputs to support Powerco Limited's regulatory outlook analysis.

This report has been prepared solely for this purpose and should not be relied upon for any other purpose. We accept no liability to any party should it used for any purpose other than that for which it was prepared.

To the fullest extent permitted by law, PwC accepts no duty of care to any third party in connection with the provision of this report and/or any related information or explanation (together, the "Information"). Accordingly, regardless of the form of action, whether in contract, tort (including without limitation, negligence) or otherwise, and to the extent permitted by applicable law, PwC accepts no liability of any kind to any third party and disclaims all responsibility for the consequences of any third party acting or refraining to act in reliance on the Information.

We express no opinion on the reliability, accuracy, or completeness of the information provided to us and upon which we have relied. The statements and opinions expressed herein have been made in good faith, and on the basis that all information relied upon is true and accurate in all material respects, and not misleading by reason of omission or otherwise. The statements and opinions expressed in this report are based on information available as at the date of the report. We reserve the right, but will be under no obligation, to review or amend our report, if any additional information, which was in existence on the date of this report, was not brought to our attention, or subsequently comes to light.

We have relied on forecasts and assumptions prepared by electricity distributors about future events which, by their nature, are not able to be independently verified. Inevitably, some assumptions may not materialise, and unanticipated events and circumstances are likely to occur. Therefore, actual results in the future will vary from the forecasts upon which we have relied. These variations may be material.

This report is issued pursuant to the terms and conditions set out in our engagement letter dated 10 October 2023.