COMMERCE COMMISSION NEW ZEALAND
Te Komihana Tauhokohoko

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# Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision

## Reasons paper

**Date of publication:** 29 May 2024

# Associated documents

| Publication date | Reference | Title |
|---|---|---|
| 29 May 2024 | N/A | Understanding how changes to line charges may impact your electricity bill webpage. |
| 29 May 2024 | ISBN 978-1-991287-34-2 | [Draft] Electricity Distribution Services Default Price-Quality Path Determination 2025 [2024] |
| 29 May 2024 | ISBN 978-1-991287-23-6 | Transpower's individual price-quality path for the regulatory control period commencing 1 April 2025: Draft Decision |
| 22 February 2024 | ISBN 978-1-991085-90-0 | DPP4 reset – Financeability of electricity distribution services in the default price-quality path – Issues paper |
| 13 December 2023 | ISBN 978-1-991085-65-8 | Report on the IM Review 2023: Part 4 Input Methodologies Review 2023 – Final decision |
| 2 November 2023 | ISBN 978-1 -991085-51-1 | Default price- quality paths for electricity distribution businesses from 1 April 2025 – Issues paper |
| 20 May 2020 | ISBN 978-1-869458-16-4 | Electricity Distribution Services Default Price-Quality Path Determination 2020 — consolidated principal determination and amendment determination as of 20 May 2020 |
| 27 November 2019 | ISBN 978-1-869457-68-6 | Default price-quality paths for electricity distributors from 1 April 2020 – Final decision reasons paper |

Commerce Commission

Wellington, New Zealand

# Contents

# Executive summary

## Purpose of the paper

X1 This paper sets out draft decisions on the default price-quality path (DPP) for non-exempt electricity distribution businesses (EDBs) that would apply from 1 April 2025 (DPP4).[1] We seek feedback on the draft decisions before we make final decisions by 29 November 2024.

X2 Submissions can be emailed to infrastructure.regulation@comcom.govt.nz using the subject line 'Submission on EDB DPP4 draft decision'. Please see **Chapter 5** for more details on how to make a submission. Please submit your views within the following timeframes:

X2.1 submissions by 5pm on **Friday 12 July 2024**, and

X2.2 cross-submissions by 5pm on **Friday, 2 August 2024**.

X3 This summary sets out:

X3.1 our role and our approach to making draft decisions

X3.2 the key draft decisions for the DPP4

X3.3 the anticipated outcomes for consumers and EDBs, and

X3.4 the challenges the draft decisions address.

## Our role and approach to making draft decisions

X4 Our role is to provide EDBs with incentives that benefit consumers over the long-term, given their position as natural monopolies. More specifically, our regulation aims to ensure EDBs are incentivised to innovate, invest, improve efficiency, and provide services at a quality that reflects consumers' demands - while also being limited in their ability to extract excessive profits.[2]

X5 A key tool in achieving this is price-quality regulation. Price-quality regulation limits the maximum revenues non-exempt EDBs can recover from consumers, via retailers, for their services, while imposing minimum standards for the service quality consumers receive in return.

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[1] **Chapter 1** lists the 16 'non-exempt' EDBs that are required to comply with price-quality regulation. The remaining EDBs are 'exempt', by virtue of meeting statutory 'consumer ownership' criteria and are subject to information disclosure regulation only.

[2] Commerce Act 1986, section 52A.

X6 The current default price-quality path is due to expire on 31 March 2025, and these draft decisions set out the proposed new path that will replace it from 1 April 2025.[3]

X7 When we last set revenue allowances for EDBs in 2019, inflation and interest rates were low, and the decarbonisation/electrification imperative had not yet translated to substantial network investment needs. By contrast, in 2024, the environment has moved on with inflationary cost pressures over recent years, and significantly higher expenditure being forecast to support the energy transition and maintain reliability.

X8 While this document outlines the draft decisions for the DPP reset only, the DPP is part of a wider price-quality toolkit that works together to achieve the aims set out in Part 4 of the Commerce Act. The toolkit also includes in-period adjustments, such as reopeners and Large Connection Contracts (LCC). Those, along with Customised Price-quality Paths (CPPs), enable EDBs to respond to changing circumstances and better manage uncertainty. See **Chapter 1** for more about the price-quality toolkit and the list of non-exempt EDBs.

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[3] All references to years in this paper (unless otherwise stated) are to regulatory years ending 31 March. So '2026' is a reference to the year commencing 1 April 2025 and ending on 31 March 2026.

## Summary of draft DPP4 price-quality path decisions[4]

**Total revenues** (see **Chapter 4**):

- We are consulting on forecast net allowable revenue allowances of $12 billion in nominal terms over a five-year DPP4 regulatory period. This represents an increase of 50% in real terms compared to the five-year DPP3 regulatory period.
- To mitigate price shocks to consumers we have limited the initial nominal increase in distribution revenue to an average of 24%.[5] This equates to approximately $15 per month (ex GST) on average for a household consumer electricity bill.
- Revenue increases over the remainder of the period then differ for each EDB to ensure revenues cover forecast costs within the regulatory period.

**Expenditure allowances** (see **Chapter 2**):

- Our draft decision is to allow total ex ante expenditure allowances for capital expenditure (capex) and operating expenditure (opex) combined of $10.2 billion (nominal, net of capital contributions) for DPP4. The allowance is $1.6 billion or 14% less than EDBs' 2024 asset management plan forecasts of $11.9 billion. This DPP4 total expenditure allowance is 28% higher than the DPP3 allowance in real terms.
- EDBs have the opportunity to apply for an increase to their expenditure allowances during the period through flexibility mechanisms, including reopeners and CPPs.

**Capex** (see **Chapter 2**):

- Our draft decision includes a capex allowance of $6.3 billion (nominal, net of capital contributions) for DPP4. The allowance is $1.3 billion or 17% less than EDBs' 2024 asset management plan forecast of $7.6 billion for the DPP4 period**.**
- The draft DPP4 capex allowance is 35% higher than the DPP3 allowance in real terms.

**Opex** (see **Chapter 2**):

- Our draft decision includes an opex allowance of $3.9 billion (nominal) for DPP4. The allowance is $0.3 billion or 7% less than EDBs' 2024 asset management plan forecast of $4.2 billion for the DPP4 period.
- The draft DPP4 opex allowance is 19% higher than the DPP3 allowance in real terms.
- The draft opex allowance includes provision for five step-changes in relation to: insurance, low voltage monitoring, cybersecurity, consumer engagement, and software-as-a-service.

**Incentives** (see **Chapter 3**):

- Similar to DPP3, our DPP4 draft decision provides separate allowances for capex and opex. Our draft decision for DPP4 is to maintain equal rates of Incremental Rolling Incentive Scheme (IRIS) incentives for capex and opex efficiencies. This would ensure the regime continues to incentivise EBDs to choose the most efficient solution, regardless of expenditure category.

**Innovation and non-traditional solutions allowance** (see **Chapter 3**):

- Our draft decision is to introduce an innovation and non-traditional solutions allowance (INTSA), available upon application, capped at 0.6% of allowed revenue for each EDB over the DPP4 period.

**Quality standards and incentives** (see **Chapter 3**):

- Our draft decision is to retain the current SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) approach from DPP3, with no new measures added, while making minor refinements to how we set and apply the quality standards and incentives for DPP4.[6]

X9 These decisions are described in the below sections. See **Chapters 2 - 4** for more rationale, and **Attachments B – H** for background analysis for each draft decision. **Attachment A** provides a full list of the draft decisions for DPP4.

## Key draft decisions for DPP4

### Revenue path

X10 The revenue path that EDBs must comply with has two parts:

X10.1 forecast net allowable revenue, that allows for recovery of the EDB's forecast costs – this is what we determine in the DPP, and

X10.2 forecast allowable revenue, that also includes recovery of pass-through costs (eg, transmission charges) and recoverable costs (eg, revenue wash-up amounts and incentive scheme carry-forward amounts). These components are largely determined by the EDB Input Methodologies (IMs).

*Starting prices*

X11 The net revenue path allows EDBs the opportunity to recover the forecast costs of investing in and running their networks – also known as 'building blocks' revenue. Between resets, these costs may change due to factors like inflation, changes in demand, or changes to the cost of capital.

X12 The costs EDBs face, including both their operating costs and their cost of capital, have increased over the DPP3 period. If real-terms revenue allowances remain at their current levels, EDBs would on average under-recover their costs by 48% over DPP4. The specific drivers of this need for an increase are illustrated in Figure X1. To respond to this, we have allowed revenue allowances to increase in two steps, with an initial increase followed by smaller increases over the remainder of the period.

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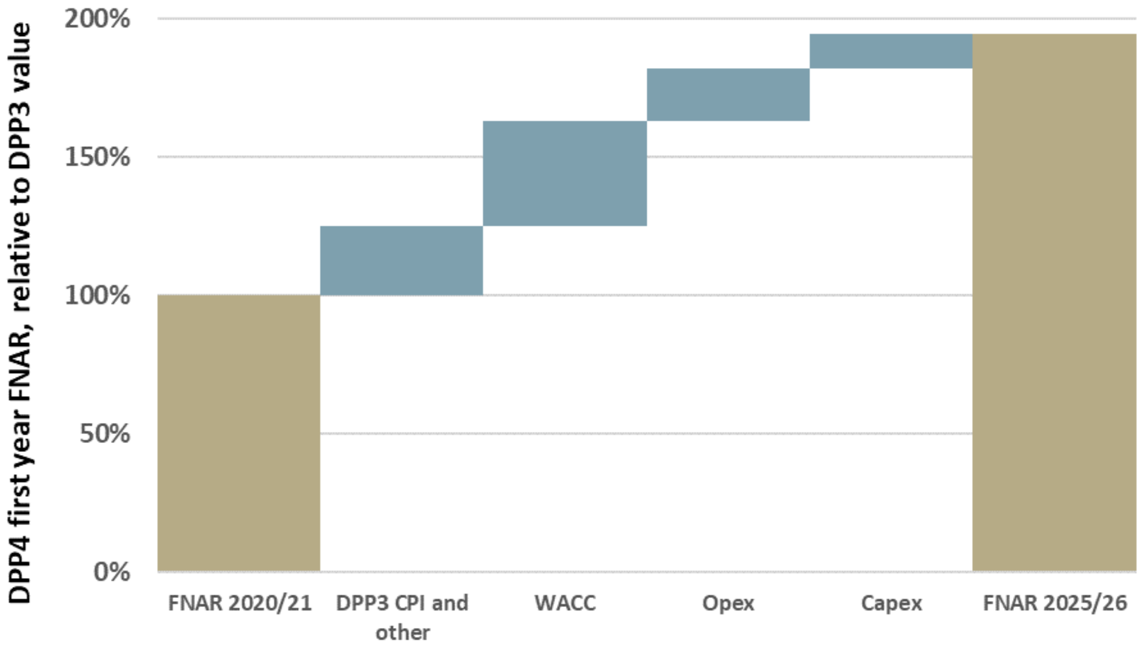
[4] Some figures quoted in this summary do not sum up due to rounding.

[5] We use the term 'distribution revenue' to refer to forecast net allowable revenues plus recoverable costs. This is because certain recoverable costs – IRIS incentives and wash-up drawdowns – have a material effect on the revenues EDBs can recover and a flow on effect on consumer prices and EDB financeability. As we have assessed 'price-shocks' on real per-ICP basis, the initial nominal total increase differs between EDBs.

[6] SAIDI refers to the average total duration of interrupted power supply in a year per customer in minutes. SAIFI refers to the average number of interruptions to power supply per customer in a year. Both SAIDI and SAIFI exclude interruptions originating on the low voltage portion of the network.

**Figure X1 Components of change in forecast net allowable revenues between DPP3 and DPP4[7]**

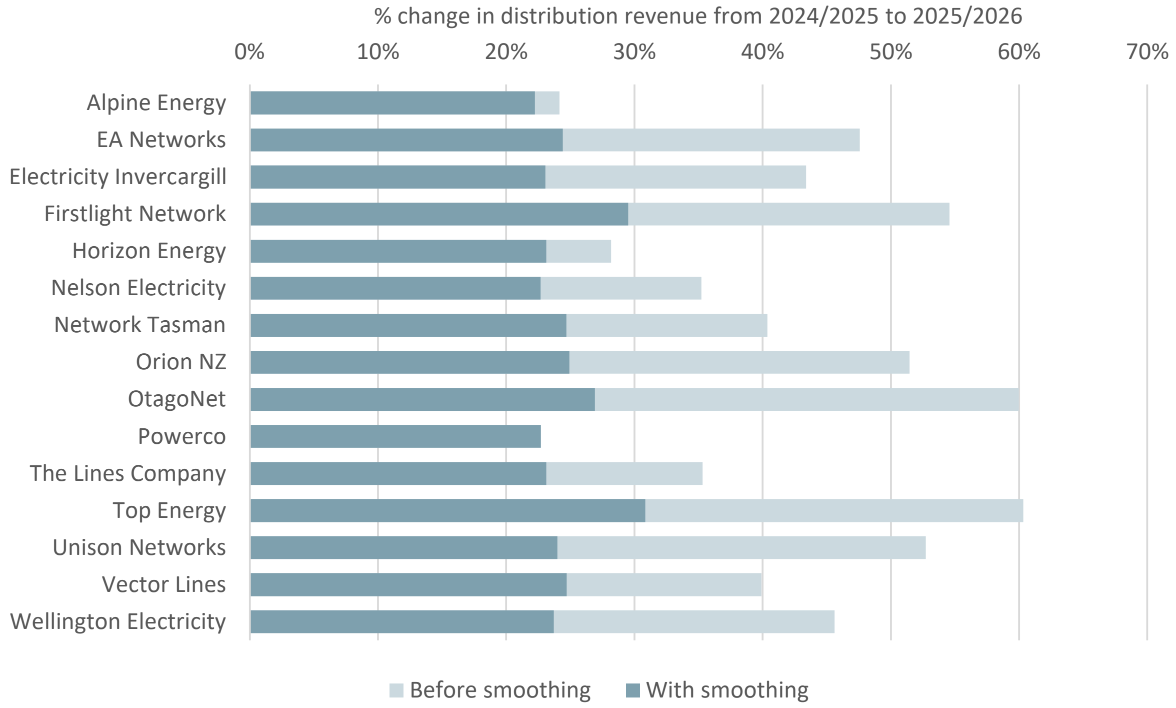



X13 To accommodate the inflation and WACC components shown in Figure X1, and to enable EDBs to invest to provide services at a quality that reflects consumers demands, our draft decision is to allow EDB 'distribution revenues'[8] to increase by 24% on average in nominal terms between 2025 (the last year of DPP3) and 2026 (the first year of DPP4). The specific draft changes in distribution revenue for each EDB are shown in Figure X2.

[7] The item 'DPP3 CPI and other change' includes changes in opening RAB and other financial model initial conditions over the course of DPP3 (largely driven by higher than forecast inflation), forecasts of CPI over DPP4, forecasts of disposed assets, and tax allowance changes. WACC refers to the weighted average cost of capital.

[8] We use the term 'distribution revenue' to refer to forecast net allowable revenues plus recoverable costs. This is because certain recoverable costs – IRIS incentives and wash-up drawdowns – will have a material effect on the revenues EDBs can recover and a flow on effect on consumer prices and EDB financeability.

**Figure X2 Nominal change in smoothed distribution revenue from 2025 to 2026**[9]




X14 The 2026 forecast net allowable revenues (**draft decision P1**) that result from this are set out in Table X1.

*Mitigating price-shocks to consumers*

X15 To mitigate price-shocks to consumers, we aimed to limit the initial increase in real per-consumer (ICP) revenue to 20% (**draft decision P3**).[10]

X16 To further mitigate price-shocks over the regulatory period we have:

X16.1 limited annual average forecast increases in distribution revenue to 10% (again on a real per-ICP basis)

X16.2 set a revenue smoothing limit (**draft decisions R2.1 and R2.2**) that limits the extent to which recoverable costs (principally the wash-up drawdown) can increase allowable revenues to 10% (over and above the CPI-X rate of change), and

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[9] Aurora Energy is not included in this figure as they are on a Customised Price-quality Path until 2026.

[10] This 20% increase is based on forecast CPI inflation of 2.2% between 2025 and 2026, and EDB-specific customer growth of on average 1.4%, resulting in an average nominal increase of 24%.

X16.3 set an undercharging limit (**draft decision R1.3**) that allows EDBs to defer up to 10% of their forecast allowable revenue each year via the wash-up account, to enable further revenue smoothing beyond what we have required where they consider doing so would benefit their customers and their financial position allows it.

**Table X1 Starting prices and X-factors[11]**

| EDB | Starting prices – FNAR in 2026 ($m, nominal) | X-factor – rate of change relative to CPI [12] |
|---|---:|---:|
| **Alpine Energy** | 70.2 | -2.5% |
| **EA Networks** | 45.8 | -11.5% |
| **Electricity Invercargill** | 17.0 | -9.9% |
| **Firstlight Network** | 35.7 | -10.6% |
| **Horizon Energy** | 34.1 | -3.7% |
| **Nelson Electricity** | 7.0 | -7.2% |
| **Network Tasman** | 37.0 | -9.5% |
| **Orion NZ** | 219.5 | -13.0% |
| **OtagoNet** | 33.6 | -16.4% |
| **Powerco** | 486.1 | 0.0% |
| **The Lines Company** | 48.4 | -6.8% |
| **Top Energy** | 53.0 | -13.5% |
| **Unison Networks** | 136.1 | -13.4% |
| **Vector Lines** | 580.8 | -8.5% |
| **Wellington Electricity** | 118.8 | -10.7% |

*Managing EDB financeability*

X17 To mitigate risks to EDB financeability, enabling them to invest in meeting consumers' needs, our draft decision is to:

X17.1 allow EDBs the prospect of fully recovering building blocks revenue plus accrued wash-up balance over DPP4 (with no forecast deferral into future periods), and

[11] Aurora Energy is not included in this table as they are on a Customised Price-quality Path until 2026.

[12] Section 53P(5) of the Act and the EDB DPP4 determination expresses X-Factors in 'CPI *minus* X' terms. As such, while the X-factor values presented here are negative, they will allow forecast net allowable revenue to *increase* at these rates.

X17.2 set EDB-specific alternative rates of change (**draft decision P3**) to enable this, as set out in Table X1.

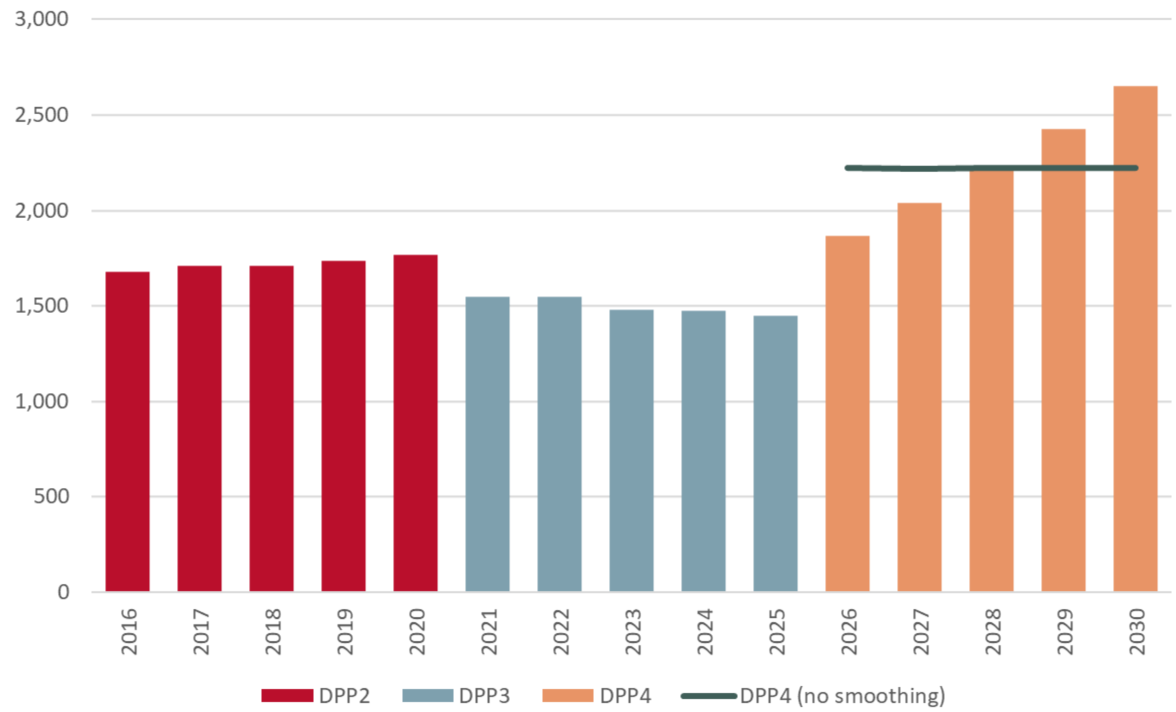
X18 As a sense-check of our draft revenue decisions for their effect on EDBs' financeability, we have applied a notional assessment using Standard & Poor's FFO/Debt and Debt/EBITDA ratios as indicators (**draft decision P5**).

*Long term change in revenue*

X19 To put the revenue change between DPP3 and DPP4 in context, Figure X3 illustrates the change in net allowable revenue over DPP2 to DPP4. As Figure X3 shows, consumers have benefited from reduced (and declining in real terms) revenues over DPP3. This reverses in DPP4, for the reasons described above.

X20 The impact of our draft decisions on smoothing is shown in Figure X3 by the difference between the DPP4 draft revenue (orange bars) and the unsmoothed DPP4 revenue (green line).

**Figure X3 Long-term revenue paths – all DPP EDBs, excluding Aurora ($m, real 2025)**

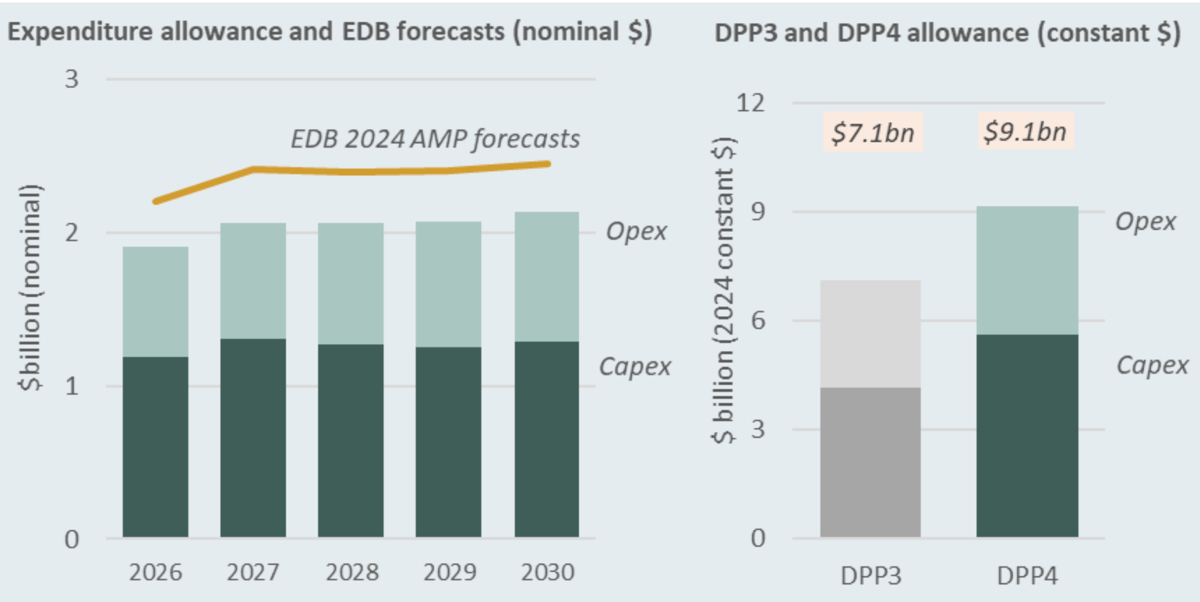


**Total expenditure allowances**

X21 Our draft decision is to allow a DPP4 total expenditure ex ante allowance of $10.2 billion for opex and capex combined (nominal, net of capital contributions). Our draft decision assumes that recent high rates of increase in input costs faced by EDBs will continue to persist to some extent. The DPP4 allowance we are consulting on is $1.6 billion or 14% less than EDBs' 2024 asset management plan forecasts of $11.9 billion.

X22 Figure X4 shows that when comparing between regulatory periods, in 2024 constant prices the expenditure allowance for DPP4 of $9.1 billion is $2.0 billion or 28% higher than the DPP3 allowance of $7.1 billion.

**Figure X4 DPP3 and DPP4 expenditure allowances and 2024 AMP forecasts**[13]




X23 Table X2 shows the DPP4 total expenditure allowance for each EDB, a breakdown of the allowance into constant 2024 dollars and the allowance we have made for input price inflation. For comparison we have also shown DPP3 period allowances.

[13] AMP refers to each EDB's asset management plan.

**Table X2 DPP3 and DPP4 expenditure allowances with input cost adjustment[14]**

| EDB | DPP3 period allowance (2024 $m) | DPP4 expenditure allowance (2024 $m) | DPP4 allowance for input costs (nominal $m) | DPP4 expenditure allowance (nominal $m) |
|---|---|---|---|---|
| **Alpine Energy** | 193.1 | 289.5 | 33.5 | 323.0 |
| **Aurora Energy[15]** | 628.1 | 694.9 | 86.0 | 780.9 |
| **EA Networks** | 157.5 | 160.6 | 18.6 | 179.2 |
| **Electricity Invercargill** | 56.6 | 72.1 | 8.6 | 80.8 |
| **Firstlight Network** | 111.1 | 157.1 | 18.3 | 175.4 |
| **Horizon Energy** | 98.6 | 134.8 | 15.8 | 150.7 |
| **Nelson Electricity** | 21.6 | 24.2 | 2.9 | 27.1 |
| **Network Tasman** | 117.0 | 170.3 | 19.5 | 189.8 |
| **Orion NZ** | 779.9 | 1,030.7 | 123.9 | 1,154.6 |
| **OtagoNet** | 138.9 | 199.8 | 25.0 | 224.8 |
| **Powerco** | 1,724.7 | 2,241.1 | 275.1 | 2,516.2 |
| **The Lines Company** | 172.4 | 204.9 | 23.9 | 228.8 |
| **Top Energy** | 174.8 | 243.3 | 28.4 | 271.7 |
| **Unison Networks** | 496.8 | 652.4 | 78.9 | 731.3 |
| **Vector Lines** | 1,843.5 | 2,274.8 | 263.7 | 2,538.6 |
| **Wellington Electricity** | 407.8 | 585.8 | 70.5 | 656.3 |
| **Total** | **7,122.4** | **9,136.5** | **1,092.5** | **10,229.0** |

X24 EDBs have the opportunity to apply for an increase to their expenditure allowances during the period through flexibility mechanisms, including reopeners, and can apply for a CPP.

X25 Similar to DPP3, the DPP4 draft decision provides separate allowances for capex and opex. Our incentive mechanisms provide financial equivalence between capex and opex, enabling efficient investment choices.

X26 Below we explain our key draft decisions for capex and opex.

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[14] DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora Energy, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

[15] The values included for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from their CPP to the DPP in 2026.

**Capex**

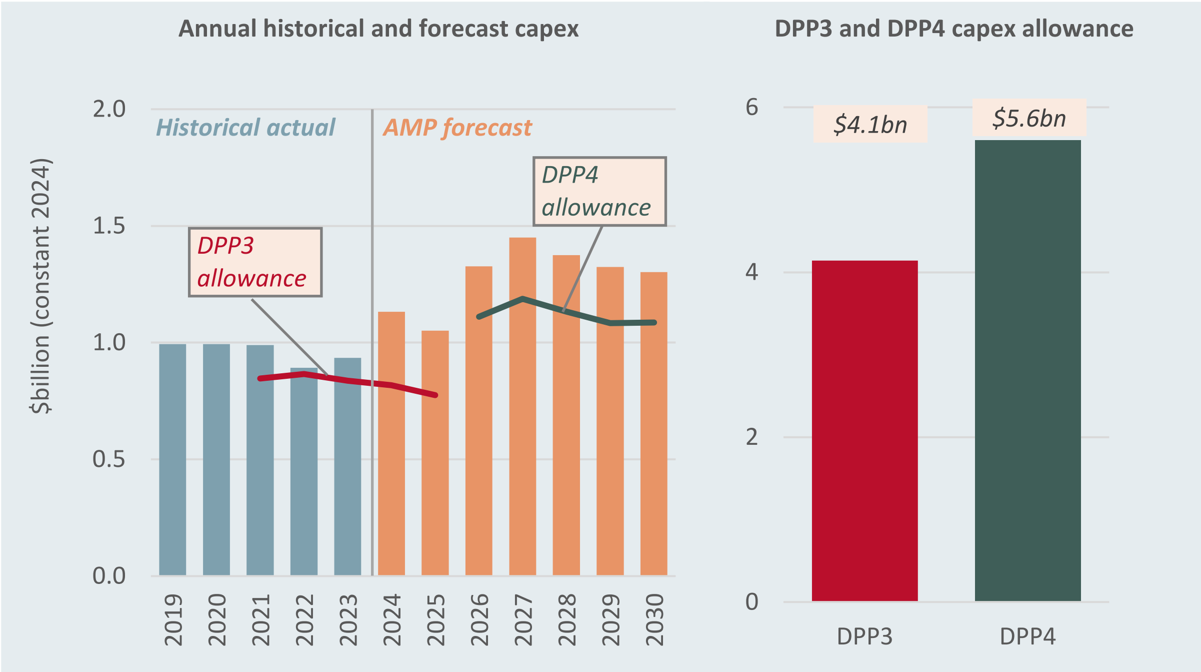
X27 **Draft decision C2** is that the DPP4 allowance provides for either an EDB's forecast capex or an increase of 25% relative to the 2019 to 2023 historical reference period (in constant prices, net of forecast capital contributions), whichever is lower. We consider this approach is appropriate given the context for DPP4 of large uplifts with ranging need, evolving environment, expenditure drivers that are subject to significant uncertainty, and deliverability challenges facing the sector.

X28 **Draft decisions C3** and **C6** provide allowances for the additional input cost of investments by escalating the historical reference period and forecast capex by the All-Groups CGPI, with adjustments to reflect historical and expected input cost growth above CGPI. See *'Comparing DPP4 and DPP3 caps and cost escalation assumptions'* section in **Chapter 2** for further information.

X29 The outcome of these draft decisions is a DPP4 capex allowance of $6.3 billion (nominal, net of capital contributions). The allowance is $1.3 billion or 17% less than EDBs' 2024 asset management plan forecast of $7.6 billion for the DPP4 period.

X30 Comparing between regulatory periods in 2024 constant prices, the DPP4 capex allowance of $5.6 billion is $1.5 billion or 35% higher than the DPP3 allowance of $4.1 billion.

**Figure X5 Capex profile and DPP3 and DPP4 allowances comparison[16]**




X31 Our draft decisions on capex reflect:

X31.1 A higher allowance for DPP4 is appropriate to recognise EDBs are facing cost increases and greater investment is required to maintain reliability and meet consumer demand. For example, assets increasingly need replacing on networks largely built last century and Aotearoa New Zealand's response to climate change is driving increasing demand and reconsideration of network resilience.

X31.2 EDBs' AMP forecasts are prepared using a variety of assumptions and approaches. There is significant uncertainty about the timing, scale, and location of forecast demand increases. The primary purpose of the AMP is as an asset management tool, they are not necessarily an appropriate forecast for investment for revenue setting purposes. Nonetheless they represent the most comprehensive information available for understanding likely capex needs. While capex allowances are based on AMP forecasts, we do not consider it appropriate to set allowances based on full acceptance of EDBs' forecasts. Therefore, while we are proposing EDBs be able to spend more in DPP4, it is less than the total forecast by EDBs over the DPP4 period.

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16 DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

X31.3 There are opportunities for EDBs to apply for additional allowances or CPPs during the regulatory period where better information is available or new events occur. We consider our assessment is consistent with the relatively low-cost intent of the DPP, the information available to us, and the need for consumers to have confidence that step changes in investment are assessed via the appropriate regulatory tool.

X32 See **Chapter 2** and **Attachment B** for detail about the draft decisions and our approach for setting capex allowances.

**Opex**

X33 **Draft decision O1.1** reflects our view that our base-step-trend approach remains appropriate to set forecast opex allowances over the DPP4 regulatory period. This approach takes current levels of cost and productivity and projects them into the future, with additional allowances for approved step changes. This approach meets the need for EDBs to fund ongoing and new activities while also providing incentives for EDBs to improve efficiency over time.

X34 Within the base-step-trend approach, our draft decisions make a number of changes to better reflect the likely opex needs and cost inflation pressures affecting EDBs. These changes include:

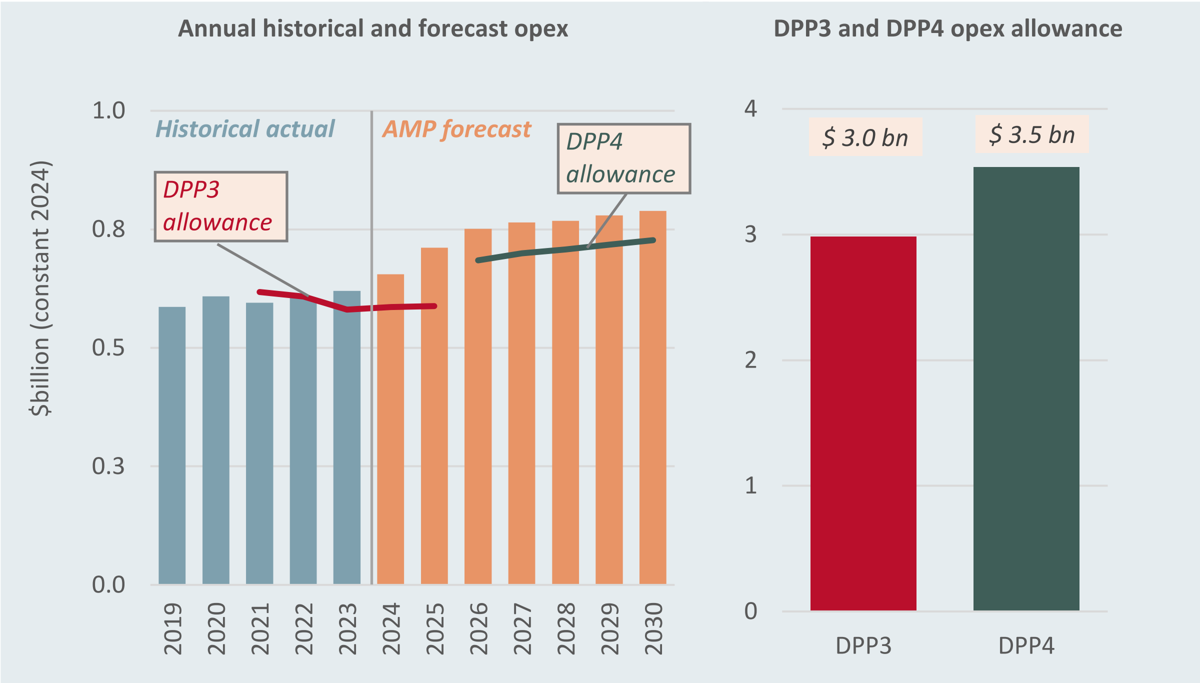
X34.1 **changing our approach to assessing step changes** to help ensure prudently incurred costs are not unreasonably excluded and to better reflect the fast-changing context within which we are setting DPP4 (**draft decisions O2.1-O2.6**)

X34.2 **including step-changes** for: insurance costs, low voltage monitoring and data, consumer engagement, cybersecurity, and greater use of Software-as-a-Service (**draft decisions O3.1-O3.5**), and

X34.3 **updating our trends** to include industry-specific inflation increases and to include capex growth as a driver of opex, to better account for and predict changes to the opex requirements across DPP4 (**draft decisions O4.1 – O6.1**).

X35 The opex allowances are shown in Figure X6 along with comparisons to DPP3.

**Figure X6 Opex profile and DPP3 and DPP4 allowances**




**Incentives**

X36 The price-quality regime provides incentives for efficient investment by EDBs. While we determine opex and capex allowances separately given their different drivers, EDBs have the flexibility under our regime to substitute between opex and capex responses where it is efficient to do so. In addition, EDBs have the flexibility to over or underspend their total allowances, subject to the Incremental Rolling Incentive Scheme (IRIS). These features are central to the regime, and of increasing importance in DPP4 given the uncertainty in elements of EDBs' forecasts and the opportunities offered by emerging technologies.

X37 **Draft decision I1** is to maintain equal IRIS incentive rates between capex and opex, to provide financial neutrality for spend decisions. With opportunities to substitute between traditional and non-traditional solutions expected to rise, we consider that financial neutrality between spend categories is important in providing suppliers with incentives to innovate and implement the most efficient solution regardless of expenditure category. See **Chapter 3** and **Attachment D**.

**Innovation**

X38 **Draft decision U1** is to introduce an Innovation and Non-traditional Solutions Allowance (INTSA), capped at 0.6% of DPP4 allowed revenue.

X39 EDBs have the flexibility to prioritise spending their opex and capex allowances, including on innovative projects and non-traditional solutions. The INTSA is an additional incentive to further encourage EDBs to try out new things that are likely to benefit their consumers, either on their own or collaboratively.

X40 We expect that technologies, such as the use of batteries and managed electric vehicle charging, are likely to become increasingly prevalent in Aotearoa New Zealand over the DPP4 period. Our intention for the INTSA is to provide EDBs with an additional incentive to trial new solutions through the DPP4 period to find alternative ways to adapt their networks to decarbonisation trends, resilience expectations and changing consumer preferences.

X41 Consumers could benefit from this when distribution costs are lower because one or more EDB have found alternative approaches that enable the deferral or avoidance of major capex on traditional pole and wire solutions.

X42 EDBs would be able to recover additional revenue up to 0.6% of their allowed revenue on one or more eligible projects over the DPP4 period, see Table D2 in **Attachment D** for the allowance figures per EDB. They could recover either up to 75% or up to 100% of project costs depending on the nature of the project. See Table 3.1 in **Chapter 3** for INTSA policy criteria.

**Quality**

X43 Quality standards are an important part of a price-quality path and are intended to ensure that any cost savings sought by EDBs do not come at the expense of quality of service. We have fundamentally retained our approach from DPP3 to setting network quality standards and incentives.

X44 The starting point for our approach to quality is that there should be no material deterioration in reliability, as assessed using the quality standards. The quality incentive scheme (QIS) encourages EDBs to make appropriate trade-offs about the level of quality they deliver, and the cost incurred in doing so.

X45 Our view is that the current quality standards and QIS are fit for purpose (**draft decisions QS1 – QS11, and QIS1 – QIS10**) to encourage EDBs to invest in network capability and resilience. The draft decision is to retain the quality standards based on network reliability, measured by SAIDI and SAIFI, as the most important dimension of quality to consumers.[17]

[17] SAIDI refers to the average total duration of interrupted power supply in a year per customer in minutes. SAIFI refers to the average number of interruptions to power supply per customer in a year. Both SAIDI and SAIFI exclude interruptions originating on the low voltage, portion of the network.

X46 Our draft decision is to make minor adjustments to the financial incentive scheme for EDBs to maintain or improve the quality of service they deliver. **Draft decision RP7** reflects that outages directly associated with an INTSA project would be able to be excluded from assessment against the quality standards and incentives up to a specified limit. See **Chapter 3** and **Attachment E**.

## Anticipated outcomes for consumers and EDBs

X47 Our regulation under Part 4 of the Commerce Act is a package designed to promote the long-term benefit of consumers through providing incentives to EDBs. This section notes the anticipated outcomes for consumers and EDBs drawing on the regime design, our recent IM decisions published in December 2023, and the draft decisions for DPP4 set out in this paper**.**

### Anticipated outcomes for consumers

X48 Through our application of price-quality regulation, we expect that consumers benefit by:

X48.1 DPP4 helping to enable an appropriate level of investment in the networks they rely on to maintain reliability of service and to support greater demand as part of the shift towards decarbonisation.

X48.2 Some forecast expenditure being excluded from DPP4 due to uncertainty and deliverability risks. This provides confidence that what consumers pay for electricity distribution services represents value for money and does not contribute to excessive profits.

X48.3 Paying less over the long-term due to incentives on EDBs to improve their productivity and efficiency.

X48.4 A smoother and more gradual revenue recovery profile over DPP4 for EDBs that aims to mitigate the impact of price shocks.

### Anticipated outcomes for EDBs

X49 Through our application of price-quality regulation, we expect EDBs to be enabled to:

X49.1 Invest more in DPP4 compared to previous regulatory periods, while also retaining the flexibility under the regime design to prioritise their spending as they see fit within their overall revenue allowance.

X49.2 Respond to greater incentives to improve their productivity and efficiency.

X49.3 Manage specific cost pressures in DPP4 through an updated cost of capital, recent high inflation being taken account of, and growth in other business costs such as cybersecurity being recognised.

X49.4 Explore innovative and non-traditional solutions with greater confidence through our 2023 IM Review and DPP4 decisions providing a new mechanism with a wider scope.

X49.5 Better understand their network through an allowance to purchase low voltage monitoring data in DPP4. This data is important to providing an appropriate quality of service for consumers, informing efficient investment decisions and enabling non-traditional solutions where lower cost.

X49.6 Have more flexibility to seek additional revenues when more is known about uncertain projects. They retain the ability to apply for a CPP as part of the existing regime design if that better suits their consumers' needs.

X50 To achieve these anticipated outcomes that promote the long-term benefit of consumers, we must adequately address the contextual challenges described below.

## The challenges the draft decisions aim to address

X51 What EDBs do in the next regulatory period will have significant implications for the longer-term capability, capacity, and resilience of their networks.

X52 In the DPP4 Issues paper we identified three challenges inherent in setting DPP4. The challenges were drawn from the context we described at that time. Our view is that recent changes to the operating environment reinforce those challenges.

X53 The challenges relate to how we can apply the DPP regulatory tools, in tandem with other price-quality regulation tools and information disclosure regulation, to promote the long-term benefit of consumers. These challenges form the structure of our substantive chapters (**Chapters 2 – 4**). Each chapter explains how the draft decisions address the challenges in a way that promotes the long-term benefit of consumers. The challenges are how we:

X53.1 **Enable EDBs to spend and invest to meet forecast consumer demands** (see **Chapter 2**). This challenge relates primarily to uncertainty about the need, timing, cost, and deliverability of investments and new operating activities. We need to set DPP4 in a relatively low-cost way that enables EDBs to meet consumers' needs in an efficient and effective way, acknowledging that other in-period adjustment mechanisms may be appropriate in instances of uncertainty or where EDBs require step changes in investment. This is particularly important given the uncertain pace of electrification, questions about where and when to make significant resilience investments to support future-proofing network systems and infrastructure, and the increasing role of innovative and non-traditional solutions.

X53.2 **Incentivise performance and improvement during the energy transition** (see **Chapter 3**). This challenge relates to how to tailor the incentives, provided for by the IMs[18], within the DPP for EDBs to continuously improve efficiency and deliver the appropriate quality of electricity distribution services. EDBs need to adapt to meet the needs of the energy transition, manage uncertainty and provide benefit for consumers. To do so, EDBs need to innovate and implement non-traditional solutions, likely at a rate not seen in prior periods.

X53.3 **Manage price shock risks and the ability for EDBs to finance investments** (see **Chapter 4**). We acknowledge that New Zealanders are facing rising costs of living on a range of fronts. It is also in consumers long-term interest for EDBs to be compensated for efficient costs and to have incentives to invest. This challenge relates to the size of the forecast revenue increases in DPP4 and the extent of any mitigations of associated price shocks.

[18] Commerce Commission "Part 4 Input methodologies Review 2023 - Final decision. Report on the IM Review 2023" (13 December 2023).

# Chapter 1 Introduction

## Purpose of this chapter

1.1 This chapter briefly outlines our role, how and why we apply price-quality regulation to non-exempt EDBs, and other relevant regulatory tools. It also includes an explanatory note about how we have applied numbers in this document (specifically when we have used constant or nominal numbers).

1.2 The following chapters then cover the draft decisions which contribute to addressing the three challenges we have explained are relevant to the DPP4 reset (see *'The challenges the draft decisions aim to address'* section above). The attachments provide more detail and reasons for the key specific aspects of our draft decision.

## How we regulate price and quality under Part 4 of the Commerce Act

1.3 Through regulating price and quality, the Commerce Commission promotes the long-term benefit of consumers of electricity distribution services.[19] We ensure that, through price-quality regulation, non-exempt EDBs have incentives to innovate, invest, improve efficiency, and provide services at a quality that reflects consumer demands.

1.4 We also aim to ensure the benefits of efficiency gains are shared with consumers, including through lower prices, and to limit the ability of EDBs to earn excessive profits. Our DPP determination affects both the revenue for EDBs and the reliability of their supply of electricity lines services. The statutory framework we must apply, and the other principles we use when setting a DPP are explained in the DPP4 Issues paper.[20]

1.5 The current default price-quality path (DPP3) for EDBs is due to expire on 31 March 2025 and we must set DPP4 by 29 November 2024.[21] DPP4 will determine the maximum revenues and the required quality standards for non-exempt EDBs over the next five years from 1 April 2025.[22]

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[19] Commerce Act 1986, Section 52A.

[20] Commerce Commission "Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), see Attachments A and B from page 65.

[21] All references to years in this paper (unless otherwise stated) are to regulatory years ending 31 March. For example, '2026' is a reference to the year commencing 1 April 2025 and ending on 31 March 2026.

[22] More information about DPP4 can be found on our "Electricity lines default price-quality path" webpage.

1.6 Of the 29 EDBs, 13 are exempt from price-quality regulation because they meet the statutory definition of 'consumer-owned'.[23] The EDBs we regulate using price-quality regulation, both DPPs and customised price-quality paths (CPPs), are set out in Table 1.1.

**Table 1.1 Non-exempt EDBs currently subject to price-quality regulation**

| EDBs subject to the default price-quality path (DPP) | | | |
|---|---|---|---|
| Alpine Energy | Horizon Energy | OtagoNet Joint Venture | Unison Networks |
| EA Networks | Nelson Electricity | Powerco | Vector |
| Electricity Invercargill | Network Tasman | The Lines Company | Wellington Electricity |
| Firstlight Network | Orion | Top Energy | |
| **EDBs subject to a customised price-quality path (CPP)** | | | |
| Aurora Energy (ends 2026, at which time they will join the DPP4) | | | |

### Draft decisions relating to Aurora Energy

1.7 We have made specific draft decisions for Aurora Energy's quality standards as part of the DPP4 process (see Table 3.2). It should be noted that the capex and opex draft decisions are indicative only (see Tables 2.1 and 2.3). The capex and opex draft decisions are included in this document to give Aurora Energy and other interested parties an early sense of how DPP4 settings may apply when Aurora Energy returns to the DPP from 1 April 2026. See **Attachment H** for more detail about the transition of Aurora Energy to the DPP.

### Other price-quality regulation tools

1.8 The DPP is a relatively flexible tool that allows EDBs to spend how they see fit within the revenue allowance irrespective of what was included in the expenditure forecasts used to set the DPP. We recognise that a lot can change for EDBs and their consumers over a five-year period. Where changes occur, we expect that EDBs would firstly look to reprioritise expenditure to meet the needs of their consumers.

[23] 'Consumer-owned' is defined in the Commerce Act 1986, section 54D.

1.9 In some cases, however, an EDB on a DPP may forecast a need to incur additional expenditure that it may not be able to accommodate within the settings of its current price-quality path through reprioritisation of expenditure.[24] This is why the price-quality regulation toolkit includes flexibility mechanisms, such as recoverable and pass-through costs, reopeners, and large connection contracts, and Customised Price-quality Paths (CPPs).[25]

1.10 **Pass-through costs and recoverable costs** are costs that can be funded by consumers above the EDB's net allowable revenue.[26] There are costs we allow EDBs to 'pass-through' to their consumers which are generally outside a supplier's control, eg, Transpower's transmission charges and local body rates. There are also specific costs that can be recovered from consumers such as efficiency incentive payments under IRIS, quality incentive amounts, or wash-up amounts set by us. These amounts are collectively called pass-through costs and recoverable costs.

1.11 **Reopeners** allow for EDBs to apply for changes to the revenues and quality path in specified circumstances during the regulatory period, usually in response to unforeseen events, or where new information becomes available. The scope and process for reopeners is set out in the Input Methodologies (IMs), and our recent 2023 IM Review decisions expanded their scope for DPP4 and beyond.[27]

1.12 Examples of reasons for seeking a reopener are when an EDB experiences a 'catastrophic event' such as an extreme weather event or an earthquake, or when they must undertake an 'unforeseeable major capex project'. Similarly, EDBs may seek a reopener when there are legislative or regulatory requirement changes, for example, Electricity Authority code amendments.[28]

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[24] The price-quality paths we set do not restrict a regulated supplier in their extent of spending. If a supplier chooses to spend and, in doing so, exceeds the revenue limits set by our price-quality path, the IRIS scheme shares a proportion of that overspend with consumers. The scheme is symmetrical, with consumers receiving the same proportion of any underspend. See **Chapter 3** for how we have updated the capex IRIS incentive rate (noting that the opex IRIS incentive rate is a function of the IMs).

[25] We use the term 'flexibility mechanisms' to refer to changes which can be applied during a DPP regulatory period which includes DPP related in-period adjustment mechanisms and CPPs.

[26] For a detailed explanation for the different components of an EDB's revenue path and the terminology we use to describe it, see **Attachment F**.

[27] Commerce Commission "CPP and in-period adjustment mechanisms topic paper: Part 4 Input Methodologies Review 2023 – Draft decision" (14 June 2023), paragraphs X4, and 3.7 – 3.9.

[28] Code amendments would also be covered under the requirements within s 54V of the Commerce Act.

1.13 **Large Connection Contracts (LCC)** are a new addition to the DPP/CPP regime introduced in the 2023 IM Review, as an alternative optional mechanism to a reopener for large new customer-initiated and funded connections that meet certain criteria. LCCs can address connection forecast uncertainty in situations where the EDB and connecting party agree in writing that the terms and conditions of the contract between them are reasonable and can apply where a large new connection project has not been provided for in DPP/CPP allowances and meets the required thresholds.

1.14 **CPPs** are an integral part of the default/customised regime under Part 4 and provide the EDB with an option to move to a customised path to better meet its particular circumstances. Given the substantial uplift in expenditure that some EDBs have forecast for the DPP4 period, we expect that some EDBs may require a CPP.

## Other relevant regulatory tools

### Information disclosure regulation

1.15 The information disclosure (ID) requirements we set apply to all EDBs and help stakeholders assess whether the purpose of Part 4 regulation is being achieved. We recently completed a targeted review of EDB ID requirements to reflect the changing context of decarbonisation and a need for greater network resilience.[29] We have expanded ID requirements to capture more information on network constraints, the use of non-network solutions, pricing, quality of service and asset management.

### Broader regulatory landscape

1.16 Our DPP4 decisions seek to encourage EDBs to plan and deliver efficient investment, innovate, and meet quality standards for services to benefit consumers. We work closely with the Electricity Authority (EA) to ensure our work programmes are aligned. Our DPP4 draft decisions are complemented by the EA's work that looks at the regulatory settings for distribution networks, including:

1.16.1 the requirements, pricing, and processes for new and expanding network connections

1.16.2 how to ensure flexibility providers have access to data about network flexibility opportunities

[29] Commerce Commission "Targeted Information Disclosure Review (2024) Electricity Distribution Businesses - Final decisions reasons paper" (29 February 2024).

1.16.3 how to enable EDBs to see, and signal, current and impending congestion, and

1.16.4 how to maintain network security and reliability levels for all users throughout the transition period.[30]

## Explanation of how we have used numbers in this document

1.17 The revenue path and expenditure allowances we determine are required to be specified in nominal terms.[31] Consumers also face costs in nominal dollars. In this document we provide allowances for the DPP4 period and compare our allowances to EDB AMP forecasts for DPP4 in nominal terms.

1.18 When explaining trends in revenue over time we do this in constant 2025 dollars – the terms that will apply at the start of DPP4 on 1 April 2025. We deflate revenue to 2025 price terms using the consumer price index as a measure of economy-wide inflation.

1.19 When explaining how we have built up our expenditure allowances we do this in 2024 constant dollar terms. This enables like-for-like comparisons between expenditures over time, and comparisons between regulatory period allowances. We translate expenditure to 2024 price terms using the same approaches used to set DPP4 allowances for increases in input costs (ie, cost escalation indices relevant to opex and capex with adjustments for input cost growth beyond these indices). For purposes of comparison, DPP3 allowances are escalated using the consumer price index as a measure of economy-wide inflation. In all cases, we clarify the terms being used.

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30 Electricity Authority "Updating regulatory settings for distribution networks" and "Distribution pricing" webpages.

31 Both the revenue path and IRIS expenditure incentives include a 'wash-up' for the impact of actual inflation differing from forecast inflation.

# Chapter 2 Enabling EDBs to spend and invest to meet forecast consumer demands

## Purpose of this chapter

2.1 This chapter:

2.1.1 explains the challenge of enabling EDBs to spend and invest to meet consumer demands

2.1.2 identifies, and briefly explains, the rationale for each of the draft decisions which relate to:

2.1.2.1 DPP regulatory period length

2.1.2.2 capital expenditure (capex), and

2.1.2.3 operating expenditure (opex)

2.1.3 directs readers to further information about the regulatory period length (see **Attachment H**) and the development of the capex and opex draft decisions (see **Attachments B, C** and **F**).

## The challenge of enabling EDBs to make investments to meet consumer demands

2.2 EDBs who are investing and operating efficiently will be planning to meet expected current and future consumer demands on a least-cost lifecycle basis, which includes investing ahead of demand or in larger increments where it is prudent. Our regime acts as a whole to align EDB interests with the long-term benefit of consumers, including providing incentives for the EDB to select the lowest cost approach to meet consumer demand and quality standards, once allowances have been determined.

2.3 We set expenditure allowances to reduce the risk to consumers that EDBs forecasts may be too high, or overly ambitious to deliver. A DPP is intended to be relatively low-cost and therefore likely to be unsuitable in certain circumstances, such as a significant step change in investment or where there is a high level of uncertainty in underlying investment drivers.

2.4 There are specific tools (reopeners and CPPs) in the regime that enable uncertain or large step increases in expenditure to be appropriately assessed.[32] We consider the additional assessment under these alternatives to DPP ex ante allowances is appropriate to ensure planned investments in network or non-network solutions by EDBs to provide electricity lines services are in the long-term benefit of consumers. Given the context for DPP4, EDBs may choose to make greater use of these tools, if their investment need is greater than provided for upfront by the DPP reset due to their unique circumstances. See **Chapter 1**.

2.5 Setting allowances for DPP4 is particularly challenging because we are doing this within the context of an energy sector that is in a period of change and uncertainty. Where, when and how much investment will be required by EDBs will depend on a number of factors, including:

2.5.1 how consumer demand evolves

2.5.2 how EDBs' strategies for meeting demand for electricity lines services adapt in light of evolving market offerings to complement or substitute for EDBs' investments in network and non-network solutions

2.5.3 expected improvements to investment information (eg, network risk modelling and demand forecasts); in particular, by incorporating better information on low voltage networks into investment planning, and how this information is reflected in renewal and growth/enhancement investment decisions, and

2.5.4 further developments in industry and stakeholder views on what investments are needed, alongside developments in government policy including the national adaptation guidance and DPMC's work on critical resilience, including to improve the resilience of electricity lines services, to address climate change-related risks. [33,34]

2.6 There are two broad views on how these factors shape the need for EDBs' investment over DPP4 in the provision of electricity lines services to meet consumers' energy needs. Under both views electricity lines services provided by EDBs will play a key role in enabling the electrification of Aotearoa New Zealand, but the quantum of additional investment in networks differs materially.

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[32] See **Chapter 1** for more about the price-quality regulatory toolkit.

[33] Ministry for the Environment "Aotearoa New Zealand's First National Adaptation Plan" (August 2022).

[34] Department of the Prime Minister and Cabinet "Critical Infrastructure Resilience" webpage.

2.7 One view is that to meet consumers' additional demand, a material uplift in investment is needed for network solutions to provide additional capacity. Non-network solutions have an increasing but relatively modest role.

2.8 Another view, held for example by Rewiring Aotearoa[35], SolarZero[36] and MEUG [37], is that the current capacity provided by distribution networks will need to be maintained and EDBs need to use distribution pricing to influence demand at a granular level (including the residential level). Under this view EDBs' investment should largely focus on investing in renewing their existing networks because sufficient incentives exist for demand to be smoothed and shifted to time periods of available capacity. With required additional capacity provided by distributed energy resources (DER), including solar PV (solar photovoltaics) and batteries owned by consumers. Similar views have also been represented that a bias to network capex risks making the energy transition more expensive than it needs to be, and that additional focus is required to ensure efficient use of existing infrastructure.

2.9 The Electricity Authority (EA) has published an open letter to EDBs on pricing reform.[38] It includes guidance on setting peak signalling prices for EDBs, and the level at which they should be set. It will be asking EDBs to reexamine the locational granularity of their network pricing, particularly if there are sections of their networks facing constraints sooner than others.

2.10 The EA is currently investigating further the recommendations from the Market Development Advisory Group (MDAG) relating to more granular dynamic pricing for distribution networks. We note that developments such as this will help challenge the need for traditional investment in distribution networks by incentivising consumers and businesses to consider using new technologies to help better manage network congestion.

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35 Rewiring Aotearoa "Default Price Path 2025-2030 (DPP4) cross-submission from Rewiring Aotearoa New Zealand" (26 January 2024).

36 SolarZero "Submission: Default price-quality paths for electricity distribution businesses from 1 April 2025" (15 December 2023).

37 MEUG Submission to the Electricity Authority on "The future operation of New Zealand's power system" (12 April 2024).

38 Electricity Authority "Open letter to distributors - distribution pricing reform" (20 May 2024).

2.11 A price-quality determination provides a revenue allowance, but not a cap on what can be spent. It also does not specifically allocate expenditure to particular categories. While we determine opex and capex allowance separately given their different drivers, EDBs have the flexibility under our regime to substitute between opex and capex responses where they can make cost savings by doing so.

2.12 This gives EDBs flexibility to reprioritise expenditure to respond to a change in circumstances, including changing allocations between opex or capex solutions. We consider there may be greater opportunities in the short to medium term for opex solutions (such as purchasing demand response or flexibility products) where previously a capex investment would be made.

2.13 In addition to flexibility to reprioritise expenditure the DPP has features which respond to the issue of efficient investment choices, which will continue to apply in DPP4. In particular:

2.13.1 the regime incentivises innovation where it results in a lower cost to serve, as EDBs retain a proportion of any efficiency gain

2.13.2 the IRIS mechanism equalises the strength of the financial incentive to be efficient across the regulatory period, and

2.13.3 our draft decision is to maintain equal incentive strength across opex and capex, ensuring that they are incentivised to choose the most efficient solution regardless of expenditure category (see **draft decision I1** in **Chapter 3**).

2.14 The INTSA scheme is intended to encourage EDBs to undertake more projects that benefit consumers but are riskier than business as usual, as well as projects where the benefits to the EDB are realised in future regulatory periods or accrue entirely to third parties (**draft decision U1**). The INTSA is further discussed in **Chapter 3**.

## Draft decision for DPP regulatory period length

2.15 Section 53M(4)(5) of the Act allows us to reduce the regulatory period from five years to four years where we consider this would better meet the Part 4 purpose.[39] **Draft decision X1** is for the next regulatory period to be five years. Maintaining the regulatory period at five years provides regulatory continuity for EDBs and prevents the need for EDBs to incur the administrative costs of a reset earlier than usual. See **Attachment H**.

[39] Commerce Act 1986, s 53M(4)(5) and s 52A.

2.16 While our draft decision is for a five-year period, the heightened levels of uncertainty mean that there may be advantages in reducing the time until the next reset. We are interested to hear your views about whether a four-year DPP4 period would be more likely to meet the Part 4 purpose, particularly when considering the capex draft decisions below.

## Draft decisions for Capex

### Capex allowances

2.17 Our draft decision includes an allowance of $6.3 billion (nominal, net of capital contributions) for DPP4. The allowance is $1.3 billion or 17% less than EDBs' 2024 asset management plan forecast of $7.6 billion for the DPP4 period.[40]

2.18 Comparing between regulatory periods in 2024 constant prices, the DPP4 capex allowance of $5.6 billion is $1.5 billion or 35% higher than the DPP3 allowance of $4.1 billion.[41] While we have set a higher allowance, we have not set it as high as EDBs have forecasted for DPP4 in their 2024 asset management plans (AMPs). We consider this is appropriate given EDB AMPs reflect large uplifts driven by expenditure drivers that are subject to significant uncertainty due to the evolving environment. We also have reservations about the deliverability of the large increases signalled in AMPs for DPP4, including the feasibility of such large increases ramping up over a relatively short time frame and the uncertainty in growth projections.

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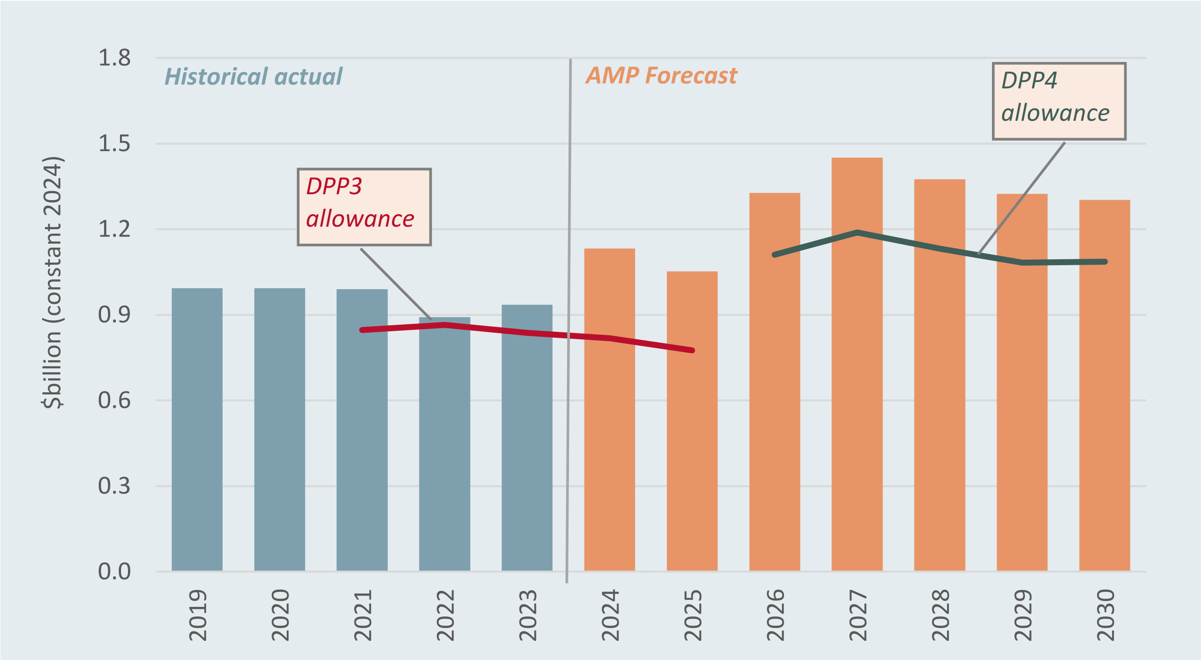
[40] Capex allowances are based on forecast commissioned asset values (net of capital contributions).

[41] DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

**Figure 2.1 Capex profile with DPP4 and DPP3 allowances[35]**




2.19 The capex allowances for each EDB that result from our draft decisions are summarised in Table 2.1 and Figure 2.2. See **Attachment B** for more detail.

### Table 2.1 DPP4 capex allowances ($m, nominal)

| EDB | 2026 | 2027 | 2028 | 2029 | 2030 | DPP4 Total |
|---|---|---|---|---|---|---|
| **Alpine Energy** | 32.9 | 30.8 | 27.9 | 24.9 | 29.4 | **145.9** |
| **Aurora Energy**[42] | 66.6[43] | 97.7 | 110.5 | 111.8 | 111.9 | **498.6** |
| **EA Networks** | 18.6 | 16.1 | 16.1 | 16.0 | 16.2 | **83.0** |
| **Electricity Invercargill** | 6.8 | 9.2 | 9.8 | 8.1 | 9.7 | **43.6** |
| **Firstlight Network** | 18.8 | 19.1 | 15.1 | 17.3 | 16.9 | **87.2** |
| **Horizon Energy** | 14.5 | 17.0 | 16.4 | 15.0 | 15.0 | **77.9** |
| **Nelson Electricity** | 2.5 | 3.0 | 3.1 | 2.7 | 2.7 | **14.0** |
| **Network Tasman** | 25.4 | 21.6 | 19.2 | 17.0 | 17.1 | **100.3** |
| **Orion NZ** | 113.6 | 139.4 | 132.6 | 139.1 | 143.0 | **667.8** |
| **OtagoNet** | 23.7 | 32.8 | 33.5 | 36.2 | 38.0 | **164.2** |
| **Powerco** | 314.9 | 337.9 | 367.2 | 375.8 | 394.3 | **1,790.2** |
| **The Lines Company** | 29.5 | 27.2 | 23.6 | 25.0 | 24.1 | **129.3** |
| **Top Energy** | 28.5 | 26.0 | 26.4 | 27.2 | 26.4 | **134.4** |
| **Unison Networks** | 73.1 | 82.8 | 80.4 | 82.8 | 101.3 | **420.4** |
| **Vector Lines** | 351.4 | 343.0 | 299.5 | 259.5 | 267.7 | **1,521.1** |
| **Wellington Electricity** | 63.3 | 98.3 | 92.5 | 93.5 | 75.3 | **422.8** |
| **Total** | **1,184.0** | **1,301.8** | **1,273.9** | **1,251.9** | **1,288.9** | **6,300.5** |

**Note:** The capex allowance for Vector in our draft decision package (the determination, this paper and models) reflects an adjustment for forecast capital contributions that was inadvertently applied in the modelling. The result of the error is that Vector's draft decision capex allowance states $1,521.1m when it should state $1,544.6m, in effect it is understated by $23.5m (1.5% of allowance). Instead of a capex allowance equal to Vector's 2024 AMP forecast, the allowance, in error reflects Vector's 2024 AMP forecast less an adjustment of $23.5m (see Figure 2.2). We uncovered the issue with the allowance in the final stages of our quality assurance. Due to time constraints, the volume of consequential changes and the relatively small size of the error we chose not to update our draft decision documentation in light of this error. We will correct for this error in our final decision.

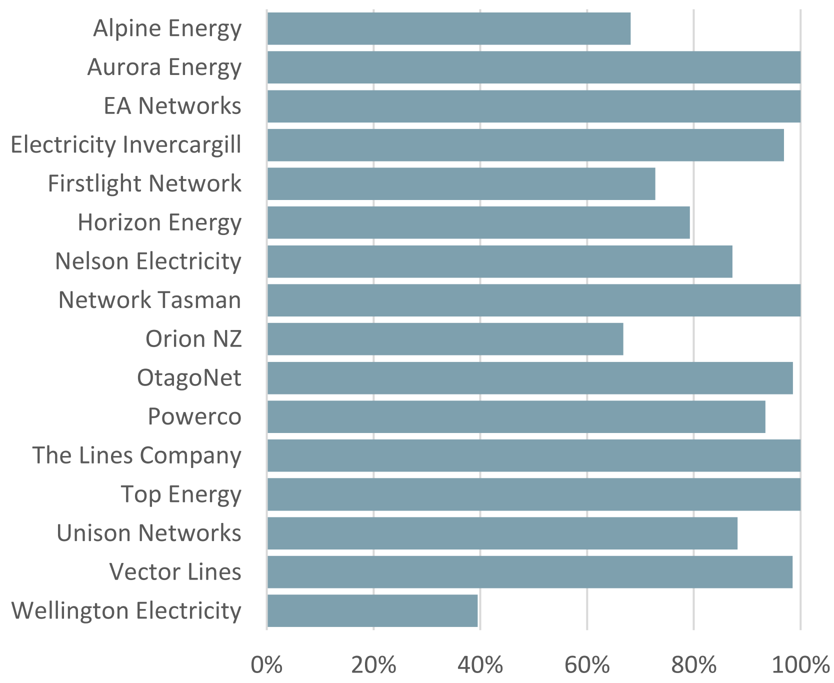
Changes to the capex allowance have consequential impacts on revenue and opex allowances where these link to capex programme. We have not run this through the financial models with full quality assurance processes and to determine if other consequential changes are required but indicatively, we have estimated the impact would be an approximately 0.14% increase in Vector's revenue allowance.

[42] The values included here for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from their CPP to the DPP in 2026.

[43] The 2026 value here is from the Aurora Energy CPP.

2.20 Figure 2.2 expresses the DPP4 allowance as a proportion of each EDB's 2024 AMP forecast. Our draft decision means that most EDBs will have allowances that are 70% or more of their capex forecast, which includes over half having allowances of at least 90% of their forecast, and three EDBs with allowances of less than 70% of their forecast. As mentioned above, where an EDB considers the ex ante DPP allowances do not meet their needs, they are able to make use of reopeners where appropriate or consider applying for a CPP.

**Figure 2.2 DPP4 capex allowance as proportion of EDBs' AMP forecasts**




2.21 The corresponding DPP4 capex allowance in constant and nominal dollars is included in Table 2.2. Table 2.2 also compares the draft decision DPP4 capex allowances with DPP3 allowances.

**Table 2.2 DPP3 and DPP4 comparison ($m)[44]**

| EDB | DPP3 period capex allowance (constant 2024 $) | DPP4 capex allowance (constant 2024 $) | DPP4 allowance for input costs ($ nominal) | DPP4 capex allowance (nominal $) |
|---|---|---|---|---|
| **Alpine Energy** | 83.5 | 130.0 | 15.8 | 145.9 |
| **Aurora Energy[45]** | 367.6 | 441.0 | 57.6 | 498.6 |
| **EA Networks** | 90.3 | 73.9 | 9.1 | 83.0 |
| **Electricity Invercargill** | 27.6 | 38.7 | 4.9 | 43.6 |
| **Firstlight Network** | 51.5 | 77.7 | 9.5 | 87.2 |
| **Horizon Energy** | 42.8 | 69.3 | 8.6 | 77.9 |
| **Nelson Electricity** | 8.9 | 12.4 | 1.5 | 14.0 |
| **Network Tasman** | 53.8 | 89.7 | 10.6 | 100.3 |
| **Orion NZ** | 413.6 | 592.6 | 75.2 | 667.8 |
| **OtagoNet** | 87.3 | 145.2 | 18.9 | 164.2 |
| **Powerco** | 1,150.7 | 1,587.6 | 202.6 | 1,790.2 |
| **The Lines Company** | 88.8 | 115.3 | 14.0 | 129.3 |
| **Top Energy** | 84.1 | 119.7 | 14.8 | 134.4 |
| **Unison Networks** | 261.2 | 372.6 | 47.8 | 420.4 |
| **Vector Lines** | 1,111.7 | 1,358.9 | 162.1 | 1,521.1 |
| **Wellington Electricity** | 217.6 | 375.6 | 47.2 | 422.8 |
| **Total** | **4,141.1** | **5,600.2** | **700.2** | **6,300.5** |

2.22 For all EDBs combined the DPP4 allowance is 35% higher than the DPP3 allowance (in constant 2024 price terms), with significant variation across EDBs. This illustrates that despite some EDBs getting allowance significantly below their forecast (as shown in Figure 2.2), DPP4 allowances generally are significantly above DPP3 allowances.

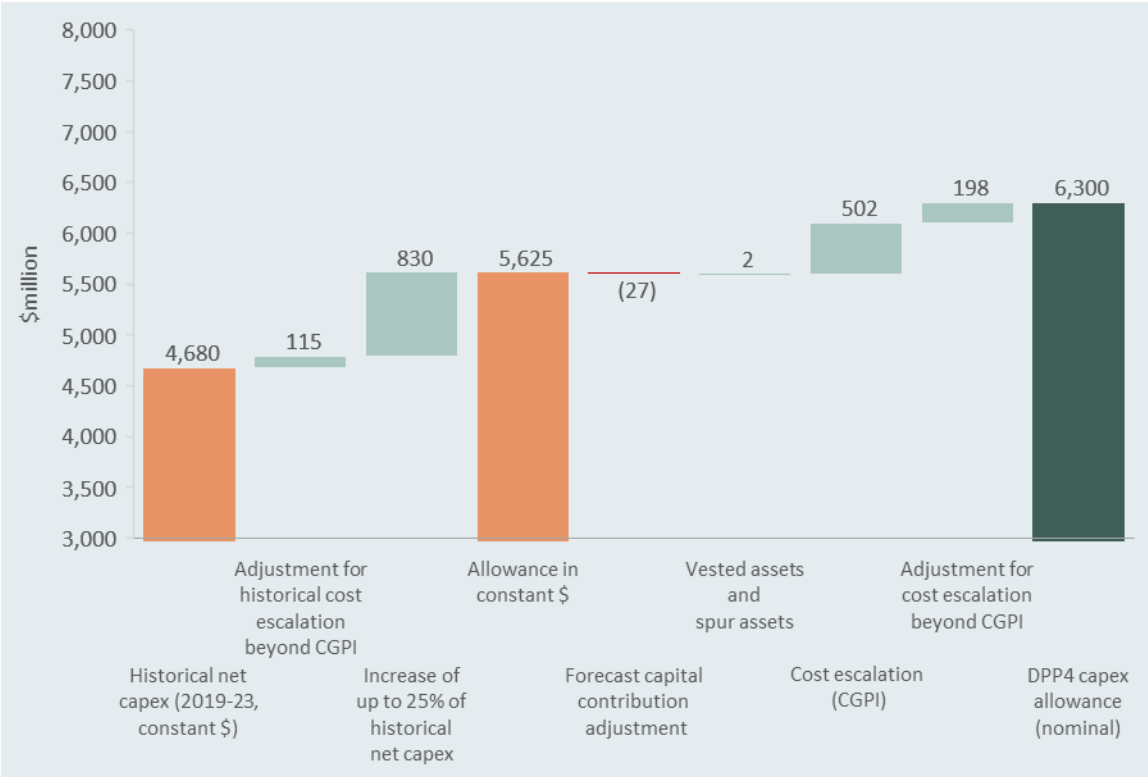
44 DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora Energy, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

45 The DPP values included for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from its CPP to the DPP in 2026.

*Comparing DPP4 and DPP3 caps and cost escalation assumptions*

2.23 The components of the DPP4 capex allowance are summarised in Figure 2.3.

**Figure 2.3 Components of the DPP4 capex allowance**




2.24 Key differences in our approach to setting DPP4 ex ante capex allowances compared to the approach used for DPP3 are:[46]

[46] For all EDBs combined the DPP4 allowance is 35% higher than the DPP3 allowance (in constant 2024 price terms). We note that this percentage difference is not directly comparable to the explanation of the percentages in this paragraph, which focuses on key differences in input assumptions between DPP4 and DPP3. The DPP4 draft decision reference period (2019 to 2023) only partly overlaps with DPP3 (2021 to 2025), noting that for the final decision we intend to adopt 2020 to 2024 as the reference period. The DPP4 reference period —in relation to which the maximum increase of 25% is assessed— is generally higher than DPP3 allowances (in constant dollars). Some of the increase in DPP4 allowances compared to DPP3 is attributable to that rather than key input assumptions.

2.24.1 The draft decision provides for an increase of 25% relative to the 2019 to 2023 reference period (in constant dollars, net of capital contributions). The result of applying the 25% limit, whereby EDBs either get their 2024 AMP forecast or a 25% uplift (whichever is lower), is a 17% or $830m increase above reference period capex (adjusted for historical cost escalation beyond CGPI). For DPP3 we limited increases to 20% of the reference period capex.

2.24.2 Based on evidence of higher capital goods price inflation (CGPI) for EDBs than in the general economy, we applied adjustments for input price growth beyond the All-Groups CGPI, which as for previous resets, continues to be our preferred cost index. The adjustment of approximately 0.8% per year to the CGPI, to historical net capex and to forecast cost escalation, results in an additional allowance amount of $313m ($115m adjustment to historical net capex and $198m to forecast escalation). For DPP3, cost escalation was a less material issue and we did not provide for adjustments.

*Context for DPP4*

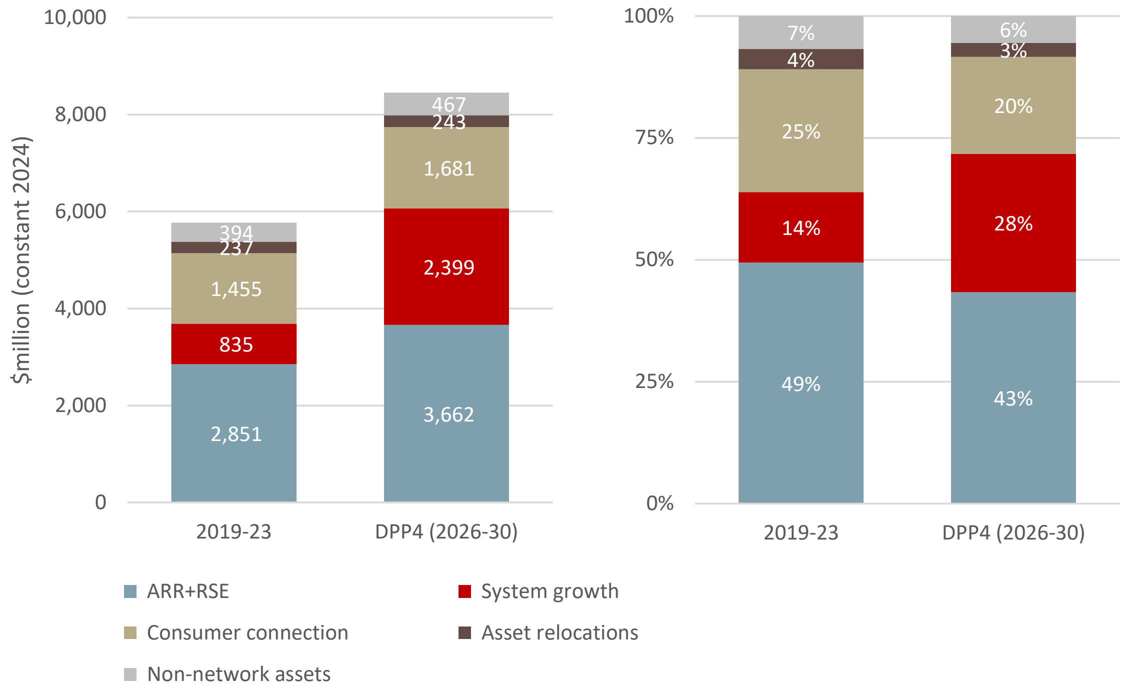
2.25 There are significant challenges and uncertainty for the energy sector to respond to over the next five to ten years. Given the context of change, unknowns regarding pace, constrained labour market, supply chain challenges, and the forecast uplift in investment indicated in AMPs we have been particularly interested in understanding:

2.25.1 how EDBs have responded to these challenges and the uncertainty this has created in their forecasts, and

2.25.2 the deliverability of elevated work programmes at a sector and individual EDB level.

2.26 The total AMP forecasts (in constant dollar terms) gross of capital contributions for all non-exempt EDBs for DPP4 is $8.5 billion compared with actual spend of $5.8 billion from 2019 to 2023. The forecast shows that both lifecycle renewal and system growth capex are expected to significantly increase in DPP4, with system growth forecast to have the largest increase across EDBs combined. There is also great diversity across EDBs, both in the size and makeup for the forecast uplift.

**Figure 2.4 Composition of capex – forecast (DPP4 period) vs actual (2019-2023) in $m and as a percentage of total capex[47]**




2.27 We have investigated how the DPP allowance setting process could accommodate the elevated investment profile in a way that enables prudent investment and mitigates risks to consumers.

*Targeted reviews of 2023 AMPs confirmed that we are unable to use AMPs in a relatively low-cost way to set allowances*

2.28 In the DPP4 Issues paper, we acknowledged that EDBs have told us that past expenditure is not a good basis for assessing future capex and there was a view that there should be a greater reliance on EDBs' AMP forecasts to set allowances. We have undertaken targeted reviews of AMPs to understand how we can make greater use of these in DPP4.

2.29 Innovative Assets Engineering (IAEngg) were commissioned to support the review of the 2023 AMPs.[48] As part of that review, they were asked to identify and analyse key drivers of change, uncertainties, and variables in financial and demand forecasts to enable them to provide an independent opinion on the reasonableness of the variations contained in EDBs' 2023 AMPs.

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[47] ARR is short for asset replacement and renewal and RSE is short for reliability, safety and environment.

[48] IAEngg, "NZ EDB 2023 AMP Review Forecasting and planning assessment report" Report prepared for the Commerce Commission (29 January 2024)

2.30 We were not expecting the IAEngg review to 'verify' AMP forecasts to be used in our capex framework, but to inform our capex forecasting approach including providing confidence in the approaches which EDBs take to setting forecasts.

2.31 In a letter to stakeholders[49] we noted that the DPP is intended to be a relatively low-cost regulatory tool, and we did not expect that the extent of analysis or level of assurance which would be provided by IAEngg would be at a similar level to CPP proposals, which are supported by independent verification.

2.32 The final IAEngg report provides overall comfort that non-exempt EDBs' capex forecasting approaches as explained in their AMPs broadly aligns with good industry practice and provided useful insights that informed our approach for capex. The review confirmed that the content in AMPs is unlikely to enable opinions to be provided on the reasonableness of EDB expenditure forecasts or provide sufficient comfort for setting allowances at an individual EDB level: [50]

> While IAEngg can provide an opinion on the reasonableness of the forecasting approach based on assessing the quality of the forecasting model, we cannot provide an assurance of the forecasting output (volume of assets to be replaced) without examining the model inputs. In the same way, IAEngg cannot provide an opinion on the reasonableness of the expenditure forecast without access to the unit rates used to convert volumes of work into expenditure.

2.33 Our own targeted review of the 2023 AMPs and responses to the s 53ZD notice[51] indicated to us that it would be inconsistent with a relatively low-cost regime to undertake the level of assessment required to obtain assurance from AMPs. Our review found AMPs to be an informative source in some instances for identifying where flexibility mechanisms were accessible for expenditure that is likely unable to be accommodated within the DPP. We note that this view is based on a targeted review of a selection of AMPs.

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49 Commerce Commission "External reviews of electricity distribution businesses' 2023 asset management plans and of efficiency and productivity" (31 August 2023).

50 IAEngg, "NZ EDB 2023 AMP Review Forecasting and planning assessment report" Report prepared for the Commerce Commission (29 January 2024), p. 73.

51 In addition to submissions on the DPP4 Issues paper on this topic, we used a s 53ZD notice (issued in November 2023) to get early disclosure of draft 2024 AMP capex forecasts and additional information requesting the primary driver for increases in expenditure.

*We have not been able to identify metrics and thresholds that can assess forecast capex, in a relatively low-cost way, given the context of step changes and wide-ranging needs*

2.34 The uncertain nature, pace and scale of investment needed by EDBs, and the variability across EDBs, in DPP4 compared with past resets means that relatively low-cost analytical approaches that can be consistently applied across all non-exempt EDBs in a meaningful way are difficult to identify.

2.35 Our view is that application of metrics and thresholds would not allow us to form a view within the DPP on whether capex forecasts in asset management plans are reasonable (or prudent and efficient).

2.36 We tested our emerging views on our capex framework, including metrics and thresholds at our capex workshop on 26 February 2024.[52] We did not receive any submissions following that workshop that identified new metrics, additional information on the metrics and thresholds or alternative analytical approaches that changed our view about the application of these in our approach.

*Our approach for setting capex allowances*

2.37 The capex allowance across all regulated EDBs for DPP4 (in nominal dollars, net of capital contributions) is $6.3 billion. The allowance is $1.3 billion or 17% less than EDBs' 2024 AMP forecast of $7.6 billion for the DPP4 period.

2.38 The allowance is based on four main decisions:

2.38.1 Use EDB 2024 AMP forecasts as the starting point for setting capex allowances (**draft decision C1**).

2.38.2 Set the capex allowance in constant dollars based on the lower of an EDB's total forecast capex or 125% of its historical reference period capex, with an adjustment for forecast capital contributions (**draft decision C2**).

2.38.3 Use a five-year historical reference period for setting capex allowances (2019 to 2023 for the draft and 2020 to 2024 for the final determination). The historical data are escalated using the All-Groups CGPI with an additional cost escalation adjustment (**draft decision C3**).

2.38.4 Use the All-Groups CGPI forecast with an additional adjustment to escalate the constant price capex allowance to a nominal allowance (**draft decision C6**).

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[52] Commerce Commission "Capital expenditure framework design – workshop" (26 February 2024).

2.39 In addition to the main decisions, similar to DPP3, the final allowance will also include an allowance for the cost of financing, scaled in proportion to the capex allowance (**draft decision C4**) and an allowance for the value of considerations for vested assets and spur assets equal to 2024 AMP forecasts (**draft decision C5**).

2.40 These decisions are summarised in the following paragraphs and explained in detail in **Attachment B.**

2.41 Our capex draft decisions have been informed by:

2.41.1 Insights from our targeted reviews of 2023 AMPs and analysis of analytical approaches for DPP4 that have led us to conclude that assessing and setting allowances is better undertaken at a total capex level rather than by expenditure category in a less certain environment.

2.41.2 Submissions on the DPP4 Issues paper and capex workshop, which includes EDBs informing us about the difficulties with providing information on resilience and deliverability in a disaggregated way that would enable assessment consistent with a DPP.

2.41.3 Updated 2024 AMP information, including early visibility of the draft forecasts and investment driver information provided in response to the s 53ZD notice.

**Draft decision C1:** Use EDB 2024 AMP forecasts as the starting point for setting capex allowances

2.42 In the context of a relatively low-cost regime, AMPs are the most complete information available to us for determining capex allowances. EDBs are in a good position to understand the needs of their consumers and communities, and they ought to understand the health of their assets, the risks to delivering safe and reliable electricity, and what is required to manage those risks. This information should be represented within their AMP.

2.43 We note that both the 2023 AMPs and the 2024 AMP updates by their nature have been produced at a point in time and reflect a range of assumptions and scenarios which may occur at a different pace in a relatively dynamic economic and policy environment.

**Draft decision C2:** Set the capex allowance in constant dollars based on the lower of an EDB's total forecast capex or 125% of its historical reference period capex, with an adjustment for forecast capital contributions

2.44 We have a range of options it can use to determine the capex allowances for DPP4. This includes fully relying, wholly or partly, on the capex forecasts in AMPs, setting a limit on total capex, applying different limits to different categories of spend, and setting different limits for different groups of EDBs. The options can be applied at an aggregate or category level and defined in dollar or percentage terms.

2.45 Our draft decision for DPP4 is to set capex allowance by limiting forecast capex to 125% of historical expenditure (historical reference period). The historical costs have been adjusted for input cost inflation and forecast capital contributions.

2.46 This differs from our approach in DPP3 where we applied caps at category level before applying an overall cap of 120%. This meant that 10 EDBs were capped on individual categories before the 120% overall cap was applied. The 120% cap reflected the point at which we considered the cost impact on consumers justified further assessment of expenditure and was likely to be more appropriate to assess as a CPP application.

2.47 Given the context for DPP4, and the information that is available to us, we consider a single cap applied to total capex is consistent with the relatively low-cost nature of a DPP and the high degree of uncertainty affecting expenditure forecasts at a category level. Setting a cap for total capex acknowledges, and provides for, EDBs having different investment profiles and priorities and enables deliverability and resilience to be considered at an aggregate level.

2.48 We considered applying caps at a capex category level but, in contrast to DPP3, have opted to apply an aggregate cap to avoid:

2.48.1 addressing inconsistencies in how EDBs classify expenditure across different capex categories, and

2.48.2 unintended consequences of constraining EDBs that run cyclical programmes for different types of works.

2.49 We consider a maximum increase of 25% is appropriate given the context for DPP4 of large uplifts with ranging need, evolving environment, key drivers that are subject to significant uncertainty, limited information to understand drivers for the uplift and deliverability challenges facing the sector. We consider within the context of the DPP and the availability of reopeners and CPPs a maximum increase of 25% will promote incentives to invest while limiting EDBs ability to extract excessive profits.

2.50 In forming our view, we:

2.50.1 analysed past step increases in capex, deliverability insights from independent reports, and considered the increase provided for in DPP3 to form a high-level view of the level of expenditure that is likely to be deliverable

2.50.2 analysed input cost trends, to determine an appropriate uplift to historical capex spend to enable these to be an appropriate basis for comparison with forecast capex

2.50.3 considered submissions received, our findings from targeted reviews of AMPs, and insights from the IAEngg report (which gives an expert opinion on EDB forecasting practices) that they are generally good which gives some comfort in providing for an additional increase on DPP, and

2.50.4 considered the implications for EDBs of having capped forecasts.

2.51 The decision to set the cap at 125% also considers the role of the DPP within the broader price-quality regime, the flexibility mechanisms available to EDBs within the regime and the risk to consumers of setting allowances too high or low.

2.52 EDBs have access to other tools (flexibility mechanisms like reopeners, CPPs and large connection contracts) if their investment need is greater than provided for in the DPP. We consider the additional assessment under these alternatives to DPP ex ante allowances is appropriate to ensure planned investments in network or non-network solutions by EDBs to provide electricity lines services are in the long-term benefit of consumers.

2.53 The price-quality path provides a revenue allowance, but not a cap on what can be spent. EDBs are also able to operate within their revenue limits, by reprioritising and substituting between opex and capex, given these are fungible and have equalised incentives.

**Draft decision C3:** Use a five-year historical reference period for setting capex allowances (2019 to 2023 for the draft and 2020 to 2024 for the final determination) with an additional cost escalation adjustment

2.54 Our DPP4 Issues paper noted we were 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.[53] The use of a reference period does not require that the values are capped at historical levels and can consider changes in underlying demand or cost factors.

2.55 Without reference to a historical reference period, it would be difficult to understand relative scale of change. EDBs have wide variability in the size and nature of network, consumer base, and how they respond to drivers. Using past expenditure enables us to reflect these characteristics in a relatively low-cost way and is also reflective of each EDBs baseline capacity to deliver.

2.56 We sought feedback on this view at our Capex workshop on 26 February 2024. The feedback indicated that stakeholders understood the need for this approach given the relatively low-cost nature of the DPP. There were no workshop submissions that objected to the use of a historical reference period for assessment purposes.

2.57 Based on our analysis of historical trends and consideration of feedback from interested stakeholders,[54] our draft decision is to use a reference period of five years, ie, 2019 to 2023 for the draft, updated to 2020 to 2024 for the final determination. This five-year period reflects the higher capex profiles of EDBs post the COVID-19 period and reflects an increased focus on decarbonisation, we note it is similar to the 10-year average. This compares to the seven-year reference period used in DPP3.

2.58 EDBs have told us that they have experienced higher input prices in recent years and that this increase has been reflected in their capex forecasts. Our analysis of price indices and other alternative sources of evidence, confirm that some form of adjustment to the reference period is warranted.

2.59 In establishing comparative values for the reference period which account for the impact of price inflation, we have inflated the historic reference period values by the All-Groups Capital Goods Price Index (CGPI) plus an additional 0.8% per annum.

[53] Commerce Commission "Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), p. 27.

[54] See **Attachment B** for more details.

2.60 The 0.8% per annum adjustment is based on our analysis of the All-Groups CGPI and the CGPI- Construction of Electricity distribution lines (EDB-specific CGPI), which shows that over the past five years the EDB-specific CGPI has been tracking on average 0.8% per annum higher than the All-Groups CGPI.

2.61 In forming our decision to apply an adjustment to the reference period, we analysed information collated by Electricity Networks Aotearoa (ENA) on the cost inputs from its members, average historical variances between the All-Groups CGPI and the EDB-specific CGPI, Powerco and Aurora's annual delivery reports, and Energy Network Consulting's Aurora Energy's CPP mid-period review report.

2.62 Further information is located in the *'Recent input price pressures'* section of **Attachment B**.

**Draft decision C6:** Use the All-Groups CGPI forecast with an additional adjustment to escalate the constant price capex allowance to a nominal allowance

2.63 The capex allowance needs to be expressed in nominal terms, through an appropriate cost escalation index. In DPP3, we used NZIER's forecast for the All-Groups CGPI to escalate the capex allowance from constant to nominal dollars.

2.64 Based on the feedback from submissions on the DPP4 Issues paper and analysis of other indices, including sub-indices identified as being appropriate for an EDB index, our draft decision is to use the CGPI to escalate the capex allowance from constant to nominal dollars for DPP4.

2.65 The draft decision is to apply an input cost adjustment of 0.8% per annum to the All-Groups CGPI because our view is that input price pressures are likely to continue over the short to medium term. The 0.8% per annum figure represents the additional inflation beyond the All-Groups CGPI over the past five years (the same value as for **draft decision C5**), which we consider to be a reasonable proxy of future input price pressures.

*Other regulatory tools within the DPP/CPP regime*

2.66 A mentioned in **Chapter 1**, the DPP reset is one tool in the wider price-quality toolkit. The toolkit also includes the DPP recoverable costs, pass-through costs, reopeners, LCCs and CPPs.

2.67 The following paragraphs sets out our response to concerns raised in submissions about the regulatory tools as they relate to capex. Our proposal to implement the LCC mechanism that was recently introduced in the IMs is detailed in **Attachment B.**

*Flexibility mechanisms have been reviewed and updated to accommodate the changing operating environment and emerging uncertainty facing EDBs*

2.68 Stakeholders asked for a wider range of flexibility mechanisms (such as use-it-or lose-it allowances, contingent funding and quantity wash-up mechanisms) as part of their submissions on the DPP4 Issues paper and Capex workshop.

2.69 We also received a number of submissions indicating concerns about how reopeners will operate with the expected pace and volume of change without becoming an unnecessarily administrative and cost prohibitive barrier.

2.70 We note that flexibility mechanisms were a key focus of the 2023 IM Review and as part of that review, we introduced new mechanisms and expanded the scope of some existing reopeners in recognition of the emerging uncertainty facing EDBs.[55] The potential viability of other DPP flexibility mechanisms were also considered and were not introduced because the added complexity in implementing them for a relatively low-cost DPP outweighed the potential added value.

2.71 Given the extent of the changes made to flexibility mechanisms during the 2023 IM Review, including clarification of process, and particularly that these changes were very recent, the draft decision is not to make further refinements to the flexibility mechanisms. In setting capex limits we have been mindful of the availability of reopeners and CPPs, and the implications of increased use of these mechanisms.

## Draft decisions for Opex

2.72 Opex allowances provide resources for EDBs to fund recurring activities that are not capex, including activities essential to the network operation such as maintenance and planning.

2.73 Opex has a direct effect on the revenue EDBs can earn, with opex representing about 32% of EDB's net revenue allowances.[56] As opex is fully recovered within the period, immediate revenues are more sensitive to opex than capex (which is recovered over multiple periods).

2.74 From an efficiency point of view, the opex allowance we set is the baseline against which opex IRIS incentives are measured.

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[55] Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments topic paper" (13 December 2023).

[56] The exact proportion varies by EDB. See the 'BBAR' sheet of the "Electricity Distribution Business Price-Quality Regulation 1 April 2025 DPP Reset – Financial model – May 2024 draft decision" (published on our website alongside this paper).

2.75 Decisions relating to opex are grouped here into:

2.75.1 overall approach and choice of base-year (**draft decisions starting O1**)

2.75.2 step changes (**draft decisions starting O2 and O3**), and

2.75.3 trends, including scale input cost escalation (**draft decisions starting O4**), scale trends (**draft decisions O5**), and opex partial productivity (**draft decision O6.1**).

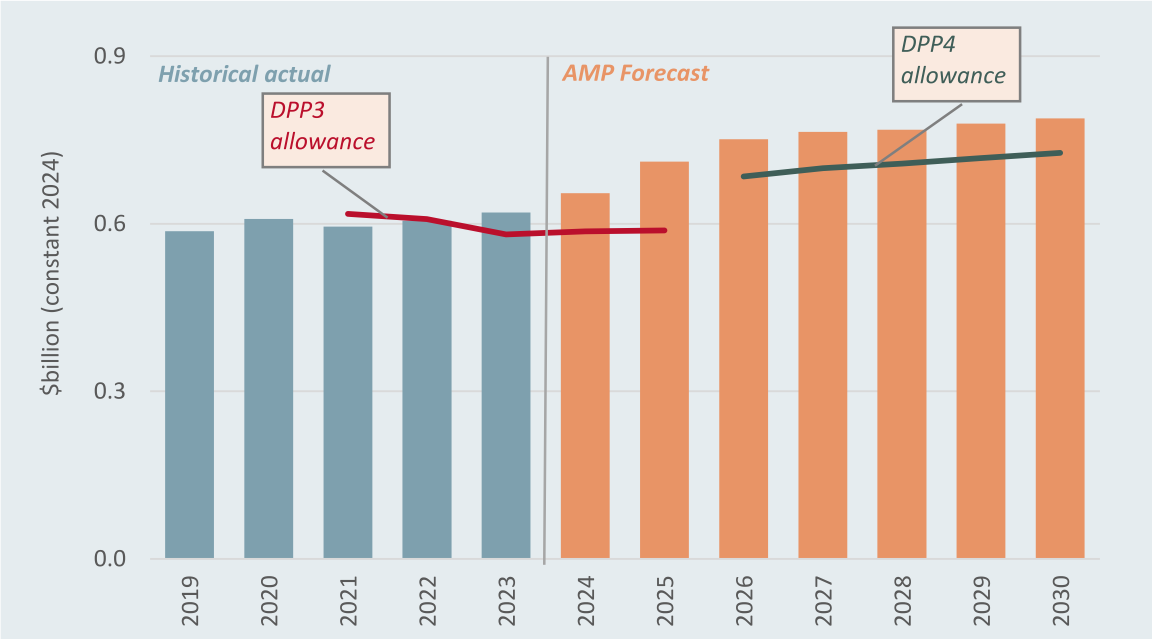
**Table 2.3 DPP4 opex allowances ($m, nominal)**

| EDB | 2026 | 2027 | 2028 | 2029 | 2030 | DPP4 Total |
|---|---|---|---|---|---|---|
| **Alpine Energy** | 33.1 | 34.2 | 35.3 | 36.6 | 37.9 | **177.1** |
| **Aurora Energy**[57] | 47.6[58] | 55.8 | 57.6 | 59.6 | 61.7 | **282.3** |
| **EA Networks** | 18.6 | 18.9 | 19.2 | 19.6 | 20.0 | **96.2** |
| **Electricity Invercargill** | 7.0 | 7.2 | 7.4 | 7.7 | 7.9 | **37.2** |
| **Firstlight Network** | 16.7 | 17.1 | 17.6 | 18.1 | 18.6 | **88.2** |
| **Horizon Energy** | 14.0 | 14.0 | 14.4 | 14.9 | 15.5 | **72.8** |
| **Nelson Electricity** | 2.5 | 2.5 | 2.6 | 2.7 | 2.8 | **13.1** |
| **Network Tasman** | 16.7 | 17.3 | 17.9 | 18.5 | 19.2 | **89.6** |
| **Orion NZ** | 89.4 | 93.0 | 96.8 | 101.7 | 105.8 | **486.8** |
| **OtagoNet** | 11.2 | 11.7 | 12.1 | 12.6 | 13.1 | **60.6** |
| **Powerco** | 134.3 | 138.9 | 145.1 | 150.6 | 157.2 | **726.0** |
| **The Lines Company** | 18.8 | 19.3 | 19.9 | 20.5 | 21.1 | **99.5** |
| **Top Energy** | 26.0 | 26.7 | 27.4 | 28.2 | 29.0 | **137.3** |
| **Unison Networks** | 57.2 | 60.3 | 61.6 | 64.4 | 67.4 | **310.9** |
| **Vector Lines** | 188.3 | 195.5 | 203.0 | 211.1 | 219.6 | **1,017.5** |
| **Wellington Electricity** | 43.7 | 45.1 | 46.6 | 48.2 | 49.9 | **233.5** |
| **Total** | **724.8** | **757.4** | **784.6** | **815.0** | **846.7** | **3,928.6** |

57 Figures for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from CPP to the DPP in 2026.

58 The value for 2026 here is the allowance from Aurora Energy's CPP.

**Figure 2.5 Opex profiles with DPP3 and DPP4 allowances**




**Overall approach**

*Choice of base-step-trend approach and decisions on the base year (O1)*

2.76 We have retained from previous resets the 'base-step-trend' approach used to forecast opex allowances: taking a base level of opex, projecting forward trends, and applying any step changes.[59] As we discuss further below, to ensure the base-step-trend approach remains fit for purpose in a changing context, **draft decision O1.1** is to revise how we apply it. At the same time, we consider the approach is fundamentally sound and appropriate for a relatively low-cost DPP.

2.77 **Draft decision O1.2** While using year four of the current regulatory period (2024) is required for consistency with the opex IRIS IMs, the base year still plays an important role in ensuring opex forecasts reflect EDBs' prudent and efficient costs. Starting our opex forecasts with an updated base year ensures future allowances capture EDB's current level of operating efficiency, including any changes that have occurred over the DPP3 period.

2.78 We have used 2024 AMP forecasts for the base year in our draft opex forecasts, rather than the latest available actual data (2023 ID). Doing so better reflects where final opex allowances are expected to land. As in the DPP3 final decision, in the DPP4 final decision we intend to update this to 2024 ID data.

[59] As noted in the IAEngg report into asset management practices, many EDB's own AMP opex forecasts apply variations of a 'base-step-trend' methodology.

**Step Changes: step change framework and decisions (O2, O3)**

*O2: Amend the decision-making framework for assessing step changes*

2.79 **Draft decision O2.1** is to assess step changes against five factors. For a step change to be accepted it does not have to satisfy every factor. Instead, the degree to which the step change satisfies each factor would be considered and weighed in making the final recommendation. Overarching this decision-making process would be whether a decision to approve the suggested opex step change will promote the Part 4 purpose.

2.80 The assessment factors we have applied in reaching our draft decision are whether the opex step change is:

2.80.1 significant (**draft decision O2.2**)

2.80.2 adequately justified with reasonable evidence in the circumstances (**draft decision O2.3**)

2.80.3 not be captured in the other components of the DPP allowance (**draft decision O2.4**)

2.80.4 have a driver outside the control of a prudent and efficient supplier (**draft decision O2.5**), and

2.80.5 be widely applicable (**draft decision O2.6**).

2.81 These changes respond to feedback received on submissions on the DPP4 Issues paper and to the changing context within the electricity sector.

2.82 A number of submitters stated the opex step change decision-making criteria applied in DPP3 were too strict. They stated that some declined step changes for new activities were nevertheless undertaken by EDBs during DPP3.

2.83 To respond to these issues and to adapt our approach to the different environment we face ahead of DPP4, we have amended the approach to some of the previously applied criteria. For example, a step change must now 'be adequately justified with reasonable evidence in the circumstances', where previously it had to be 'robustly verifiable'.

2.84 Our draft decision is to apply the criteria as 'factors to be considered in the assessment of a step change'. This would enable, where appropriate, a step change to be approved where it doesn't satisfy all the criteria. For example, a step that may not clearly be 'widely applicable' but clearly satisfies the other four factors.

2.85 This DPP is being set within a context of decarbonisation and cost pressures facing both EDBs and consumers. Increasing flexibility into the step change decision-making process will help ensure EDBs have sufficient revenue to run and maintain the network in a way that meets consumers evolving needs over the long-term.

*O3: Decisions to approve and decline suggested step changes*

2.86 Applying the decision-making framework outlined above, we consider that including additional opex for the following changes would better promote consumers' long-term benefit:

2.86.1 Insurance (**draft decision O3.1**)

2.86.2 Greater consumer engagement (**draft decision O3.2**)

2.86.3 Low voltage (LV) monitoring and smart meter data (**draft decision O3.3**)

2.86.4 Cybersecurity (**draft decision O3.4**), and

2.86.5 Software as a Service (**draft decision O3.5**)

2.87 See **Attachment C** for more information about the rationale for including these step changes and commentary on our analysis and response to submissions.

2.88 The step changes shown in Table 2.4 do not sufficiently satisfy enough factors, and a decision to approve would not be consistent with s 52A and s 53K of the Commerce Act 1986.

## Table 2.4 Reasons for declining suggested step changes

| Suggested step change | Rationale for declining |
|---|---|
| **Resilience** | Insufficient information to evidence a step above base year expenditure, step change does not apply widely. For two EDBs, the step-change was significant and would be more appropriately assessed under a CPP or a resilience reopener. |
| **Decarbonisation related step change from process heat conversion** | Insufficient information to provide enough certainty that the cost will occur during DPP4 or will be widely applicable. Spend driven by additional capex partially captured by the addition of a capex driver of non-network opex scale trends (see **draft decision O5.4**). |
| **Distribution system operation** | Underlying uncertainties about the role of the distribution system operator (DSO). Insufficient information to provide enough certainty that the cost will: occur at all, occur during DPP4, and would necessarily all apply to regulated electricity lines services |
| **Renewal of ageing assets portfolio** | Insufficient evidence provided about connection between asset health information and cost impact, and where ageing assets drive increased capex partially captured in the addition of a capex driver of non-network opex scale trends (**draft decision O5.4**). |
| **Routine and corrective maintenance and inspection** | Was only mentioned by one EDB and should be already captured in allowances. |
| **Operating costs to support the increasing demand on the electricity network driving increases in capex.** | Spend driven by additional capex partially captured by the addition of a capex driver of non-network opex scale trends (see **draft decision O5.4**). |
| **Retendering of Field Service Agreements** | Insufficient information that it will not be captured by new cost escalators. |
| **Workforce requirements related to network growth.** | Already captured via opex scale drivers (see **draft decisions O5.3 and O5.4**). |
| **Operating costs related to service interruptions and emergencies** | Insufficient evidence provided to support this step-change, and likely accounted for through quality incentives. |
| **Workforce related step-changes not linked to system growth – environmental, social, governance reporting functions** | This step was not widely applicable, and there was insufficient evidence provided to properly assess factors two and four (adequately justified and due to a driver outside the control of a prudent and efficient supplier). |

2.89 **Draft decision O3.7** is to apply an aggregate cap on step-change increases of 5% of total opex.[60] In approving the above step changes, some EDBs have submitted for significant cost increases, that if approved in full, would lead to increases of up to 10% over and above the base and trend components. Applying the proportionate scrutiny principle, this level of increase would suggest a level of assessment beyond what is appropriate for a DPP reset process. We consider this 5% cap is appropriate and proportionate to the 25% cap applied to capex.[61]

**Opex Trend Decisions (O4, O5, O6)**

2.90 Our forecasting of opex trends has three components: input prices, cost increases with scale, and productivity. We aim to forecast opex trends over the DPP4 period based on fair estimation of expected changes in these factors and in a way which incentivises efficiency.

*O4. Cost escalation*

2.91 Stakeholders have highlighted the impact rising input prices over recent years – and the prospect of future increases over-and-above inflation – as a major concern for this reset. Our recent IM change to measure efficiency incentives in inflation-adjusted terms (known as a "real IRIS") substantially reduces the risk to EDBs and to consumers from inflation being over- or under-forecast.[62] This helps better manage uncertainties about future cost rise (as implemented by **draft decision I2,** see **Attachment D**).

2.92 However, cost escalator forecasts still need to account for forecast changes relative to overall inflation – or 'real price effects'.

2.93 **Draft decision O4.1** is to escalate all opex cost using the same cost escalator.

2.94 **Draft decision O4.2** to forecast opex escalation using:

2.94.1 forecasts of the all-industries forecasts of the labour cost (60% weighting) and producers price indices (40% weighting), and

[60] In real 2024 terms, as a percentage of total DPP4 opex including trend factors but before step-changes are applied.

[61] As opex allowances are recovered directly via revenue over the regulatory period, whereas capex is added to the RAB and recovered over the life of the asset.

[62] Commerce Commission "Report on the IM Review 2023: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023); and Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper - Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), topic 5c.

2.94.2 a +0.3% per year uplift, reflecting recent cost increase in the electricity, gas, waste, and water (EGWW) labour cost index over and above the all-industries index.[63]

2.95 As discussed in **Attachment C**, we considered the alternative of applying escalation at a more specific cost-category level. This approach would aim to capture EDB-specific drivers such as traffic management costs or particular skilled labour constraints; however, we did not consider we had the necessary data to justify taking this approach in DPP4.

*O5. Scale trends*

2.96 The cost of maintaining and managing a network is expected to increase as it grows. As in DPP3, we approach opex scale trends with an econometric method to model historical opex across EDBs with scale factor variables. The aim of this modelling is to identify which set of scale factors best explains recent opex trends which can then be used to forecast opex growth over DPP4 using trends in the scale drivers. We separate scale trends from input cost trends by modelling historical costs after deflating with observed values of the above cost escalation series.

2.97 Overall, we have retained the key features of this approach from DPP3, updated for new data and informed by external review[64] and submissions.[65]

2.98 For modelling and forecasting, **draft decision O5.1** is to retain the split into network and non-network opex. Disaggregation into sub-components was considered but, as at DPP3 reset, rejected due to weaker explanatory power of fitted models.

2.99 **Draft decision O5.2** is to update the reference period for ID data used in scale factor modelling to be 2018-2023 for DPP4 draft decisions. ID data for 2024 will be available for final DPP4 decisions. Following analysis of longer date ranges, we consider 2018-2023 is suitable because it captures the most recent trends, while also requiring enough data points for reliable modelling. This is the same number of years used in the DPP3 reset.

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[63] Please note: the CGPI sub-categories are referred to as "groups", the LCI and PPI ones are "industries."

[64] We engaged CEPA to report on opex trends before we published our DPP4 Issues paper.

[65] In particular, opex trend modelling by Frontier Economics - Frontier "Opex econometric modelling", prepared for Electricity Networks Aotearoa, (9 January 2024).

2.100 **Draft decision O5.3** is to model growth in network opex with the same scale factors as in DPP3, that is ICP count and total lines length for supply. This selection follows review of alternatives, including capex as a driver of non-network opex[66] and the use of a time variable.[67]

2.101 **Draft decision O5.4** is to model non-network opex growth with ICP count, lines length and capex (expenditure on assets). The change to include a capex term follows consultation on this possibility, motivated by improved model fits, and by submissions supporting the business logic of this relationship.

2.102 Submissions on opex econometric models included the suggestion to include a time variable in both network and non-network opex scale-trend models.[68] Adding a time variable does improve model fit on historic data but does so without attributing the effect to a driver than can be forecast. We consider an approach where scale trends are linked to known factors, and any time effects are captured by forecasts in cost escalators (where they relate to input costs) or forecast change in productivity (where they cannot be explained by input or output trend) is a more transparent approach. In addition, step change allowances would be correlated with some of the time-based movements, especially insurance, which we understand has increased at above the rate of input price inflation.

2.103 In DPP3 we applied an iterative method to remove data outliers and re-fit our econometric models. We have retained this method. Following inspection of ICP and lines data over time for each EDB, we have also identified and excluded from analysis data for years in which ICP or lines data (or both) clearly departed from trend for that EDB.

2.104 Applying this approach results in the elasticities shown in Table 2.5.

**Table 2.5 Elasticities for network and non-network opex**

| Opex category | Elasticity to ICP growth | Elasticity to lines length growth | Elasticity to capex |
|---|---|---|---|
| **Network opex (draft decision O5.3)** | 0.45 | 0.52 | n/a |
| **Non-network opex (draft decision O5.4)** | 0.22 | 0.35 | 0.30 |

66 This review was undertaken by CEPA. We included commentary of their review in the DPP4 Issues paper.

67 Frontier Economics "Opex econometric modelling" prepared for Electricity Networks Aotearoa (9 January 2024), p. 3-4.

68 Frontier Economics "Opex econometric modelling" prepared for Electricity Networks Aotearoa (9 January 2024).

2.105 These elasticities are multiplied by forecast growth rates in the associated scale factors over the DPP4 period. We have forecast growth rates in ICP count and lines length with trend projections, as used for lines length in DPP3. For ICP counts, this replaces the use of Statistics NZ Household Growth (HHG) forecasts for ICP growth in DPP3. We found HHG forecasts generally under forecast recent ICP growth in large urban areas, and over forecasting in smaller rural areas.

*O6. Partial Productivity*

2.106 **Draft decision O6.1** is to apply an opex partial productivity factor (PPF) of 0%. This figure draws on recent trends in price-quality-regulated EDB productivity and is mindful of the prospect of opex-capex substitution (suggesting a lower PPF) alongside the possibility of innovations and new approaches improving operating productivity (suggesting a higher PPF). As set out in **Attachment C**, this decision has been informed by findings from CEPA's draft productivity study.[69]

[69] CEPA "EDB Productivity Study: A report prepared for the Commerce Commission (Draft Report)" (26 March 2024). We note that submissions on the draft CEPA report were received 24 April 2024. We have not responded to these submissions in this draft decision, but will consider that feedback and any changes in CEPA's final report as part of our final decision in November 2024.

# Chapter 3 Incentivising performance and improvement during the energy transition

## Purpose of this chapter

3.1 This chapter:

3.1.1 explains the challenge of incentivising performance and improvement during the energy transition

3.1.2 identifies, and explains the rationale for, each of the draft decisions which relate to:

3.1.2.1 incentives for innovation, energy efficiency, demand-side management, and the reduction of energy line losses

3.1.2.2 quality standards and incentives, normalisation and reference period

3.1.3 directs readers to further information about the development of the draft decisions for innovation and quality (see **Attachments D** and **E**).

## The challenge of incentivising performance and improvement during the energy transition

### Incentives

3.2 DPP/CPP regulation provides baseline incentives for EDBs to innovate and achieve efficiencies that maintain and improve the performance of electricity lines services (see paragraph 3.9). These incentives could also play a significant role in the energy transition. Shaping those incentives for DPP4 is challenging when considered in the context of the increasing demand for electrification, climate change impacts on weather patterns, significant cost pressures on EDBs, and uncertainty around the need and timing for some significant capital investments.

### Innovation incentives

3.3 EDBs already have incentives to innovate and implement non-traditional solutions where these are lower cost than traditional solutions; for example, if the solution allows the EDB to defer or avoid capital investments they can retain a share of the savings that are made. Innovative approaches to capacity constraints are likely to include a range of potential non-network solutions. Some non-traditional solutions are already well-proven in Aotearoa New Zealand, such as diesel generation sets, and to a lesser extent batteries. If tested, trialled, and optimised, we expect that proven solutions could be of significant benefit to consumers, and, over time, could become business as usual for EDBs.

3.4 We consider that under the DPP3, EDBs may not currently have explicit incentives to try non-traditional solutions that are less proven. For example, less proven non-traditional solutions include new distributed energy resource solutions, or dynamic pricing responses (noting that the Electricity Authority regulates pricing). We acknowledge that trying less proven ways of doing things can place temporary risks on quality performance in some instances. We have considered how to address this challenge while developing the draft decisions for innovation incentives.

### Quality

3.5 We are required by the Part 4 of the Commerce Act to set quality standards that must be met by regulated suppliers when setting price-quality paths.[70] We may also set incentives for an EDB to maintain or improve its quality of supply.[71]

3.6 These quality standards and incentives are a crucial part of promoting the purpose of Part 4 of the Act; they are important for ensuring EDBs have incentives to provide services at a quality that reflects consumer demands. As EDBs' revenues are constrained by the price path, quality standards are important for ensuring EDBs have incentives to invest and are constrained in their ability to earn excessive profits at the expense of quality.

3.7 No material deterioration in reliability is the starting point for our approach to quality at every DPP reset, as assessed using the quality standards. We also acknowledge the need for EDBs to make trade-offs about the level of quality they deliver, and the cost they incur in doing so. It is important for EDBs to consider price-quality trade-offs at the margins, and to have the ability to move towards a level of quality that better reflects consumers' demands and the EDB's cost to serve those consumers. These considerations are reflected in the quality incentive scheme (QIS).

## Decisions for innovation incentives

3.8 When setting the DPP, we must make decisions about how to promote outcomes such that suppliers of regulated lines services have incentives to innovate.[72] We must also consider how we promote incentives (and not impose disincentives) for EDBs to invest in energy efficiency and demand-side management measures, and to reduce energy losses.[73]

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70 Commerce Act 1986, Section 53M(1)(b).

71 Commerce Act 1986, Section 53M(2).

72 Commerce Act, s 52A(1)(a); and Commerce Commission "Report on the IM Review 2023: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023).

73 Commerce Act, s 54Q.

3.9 The DPP already includes incentives for EDBs to invest in innovative and non-traditional solutions, by having:

3.9.1 flexibility to spend their capex and opex allowances as they see fit

3.9.2 a revenue cap with an IRIS that incentivises EDBs to seek the most efficient solution, and

3.9.3 a QIS.

3.10 In addition, we propose in **draft decision I1** to set the capex IRIS incentive rate at 33.18% for DPP4, to match the incentive rate that will apply to opex and continue the approach applied in DPP3.[74] We consider that equalising EDB's financial incentives between opex and capex solutions ensures that they are incentivised to choose the best solution, regardless of expenditure category (eg, capex vs opex). We expect opportunities for this style of substitution will increase over DPP4. This decision is explained in **Attachment D**.

3.11 We recognise that in some instances, non-exempt EDBs may still lack strong enough incentives for projects that have higher risk, and/or where financial benefits are unlikely to be awarded to the EDB.

3.12 To address these potential gaps in incentives, and to supplement the requirements already in place via our Information Disclosure regulation, the 2023 Input Methodologies (IM) Review provided for an Innovation and Non-traditional Solutions Allowance (INTSA) through the DPP (and any CPPs) from DPP4.[75] At a high level, our **draft decision U1** for the INTSA, allows EDBs to have greater access to funding to deliver innovative projects or non-traditional solutions.

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[74] This is an increase from DPP3 where the incentive rate was 23.5% and is driven by an increase in the opex retention rate, which is a function of the WACC and retention period. This means that approximately 67% of any overspend incurred by an EDB and approximately 67% of any underspend would be shared with consumers.

[75] Commerce Commission "Report on the IM Review 2023: Part 4 Input Methodologies Review 2023: Final decision" (13 December 2023), see Decision SP05, paragraph 7.31.4.

3.13 EDBs have shared their ambitions to invest in innovation and non-traditional solutions, in particular to test and roll-out flexibility services and/or use DER, to better meet peak demands on their network.[76] **Draft decision U1** to introduce INTSA provides an additional incentive for EDBs to find alternative ways to adapt their networks to decarbonisation trends, resilience expectations and changing consumer preferences.

3.14 An INTSA scheme, in line with the policy criteria described in Table 3.1, could encourage EDBs to deliver long-term benefit to consumers through innovation projects and non-traditional solutions:

3.14.1 **that are riskier than business as usual projects, and wouldn't otherwise happen.** This is because some innovation and non-traditional solutions involve higher risk than business as usual solutions, or

3.14.2 **that are riskier than business as usual, but where EDBs would be unlikely to otherwise result in any financial benefits**. This is because there are no explicit financial incentives for EDBs if the benefits accrue entirely to third parties or are not realised because of a change in regulatory period.

[76] EDBs have shared ambitions both in conversations with the Commission in 2023 and 2024, and by contributing to the development of the Electricity Networks Aotearoa (ENA), "Powering up for change: New Zealand Electricity Distributor Network Transformation Roadmap: A three-year update" April 2022.

### Table 3.1 DPP4 draft INTSA policy characteristics

| Criteria type | INTSA policy criteria |
|---|---|
| **Project type – what the project is for** | An innovative or non-traditional solutions project that fits within the three eligibility criteria:<br>1. relates to the supply of electricity lines services<br>2. promotes the Part 4 purpose of the Act, and<br>3. must be riskier than business as usual (BAU) for the non-exempt EDB such that the non-exempt EDB would not carry out the project if it could not recover some or all of the forecast costs of the project from the non-exempt EDB's INTSA.<br>Where an EDB wishes to seek approval for a share of project expenditure that is more than 75% of the project costs (up to a cap of 100% of project costs), it must demonstrate how the project is unlikely to otherwise result in any financial benefits to the non-exempt EDB. |
| **Approval timing** | Ex ante |
| **Expenditure approved** | Forecast |
| **Share of expenditure approved (%)** | Up to 75% for all projects that are riskier than BAU for the EDB.<br>Up to 100% for all projects where it is unlikely to otherwise result in any financial benefits to the EDB (such as when benefits are not realised in future regulatory periods). |
| **When and on what conditions approved expenditure is received** | Expenditure may be recovered upon project completion. |
| **Maximum permissible expenditure** | 0.6% of EDB's DPP4 maximum allowable revenue (MAR) over the regulatory period for one or more projects. |
| **Supporting evidence** | Project specific information. |
| **Sharing learning** | Close out report must be sent to us within 50 days of project completion. |
| **Penalty/reward mechanism** | None [77] |

3.15 We consider that the INTSA design finds common ground between offering more financial incentives for EDBs to undertake projects that fit the categories above, while ensuring that consumers are afforded the right protections for any INTSA funding that is spent. It is broad enough to incentivise a variety of projects that could contribute to the long-term benefit of consumers of electricity lines services.

[77] This is with respect to an explicit penalty/reward mechanism specified as a part of the INTSA. Expenditure incurred undertaking an eligible INTSA project would still be subject to IRIS. See Commerce Commission "Input Methodologies Review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), topic 5e.

3.16 **Attachment D** provides the rationale for each of the nine criteria in depth, and includes a table outlining the maximum allowable INTSA expenditure per EDB. EDBs will be able to apply one of two levels of share recovery percentage in the scheme based on the nature of the specific projects they wish to seek INTSA funding to deliver (see Table 3.1).

3.17 A requirement of the INTSA will be for EDBs to share their learnings so the sector, consumers, other electricity market participants, and regulators can benefit from the knowledge, from both successful and less successful projects. We expect to be able to draw insights from more completed innovative and non-traditional solutions projects, and this growing body of shared learnings, when reviewing the innovation incentives in future DPP resets.

3.18 Under s 54Q of the Commerce Act, the Commission must promote incentives, and avoid imposing disincentives for electricity lines suppliers to invest in:

3.18.1 energy efficiency

3.18.2 demand-side management, and

3.18.3 reduction in energy losses.[78]

3.19 We consider the INTSA also provides incentives for energy efficiency, demand-side management (**draft decision U2**), or for the reduction of energy losses (**draft decision U3**) because projects such as these will be provided for through the INTSA scheme, where they meet the eligibility criteria (including relating to the supply of electricity lines services). See **Attachment D**.

3.20 **Draft decision RP7** is to reduce the risk that EDBs are discouraged from trialling non-traditional solutions by allowing EDBs to exclude interruptions directly associated with INTSA approved projects subject to an aggregate cap for all such projects. See *'Draft decisions for reference period'* section and **Attachment E**.

3.21 We considered a range of alternative options for the INTSA policy design. These included a more ambitious, outcomes-based option that would have allowed EDBs significantly more funding and to recover more costs than the INTSA scheme we have presented here. This option was not progressed for DPP4 draft decisions as it would likely require high transaction costs and provide less certainty to EDBs as they would likely only be able to recover expenditure ex post when outcomes were evidenced. We are interested in your views as to the appetite for an outcomes-based scheme. See **Attachment D** for more details.

[78] Commerce Act 1986, Section 54Q.

## Decisions for quality standards and quality incentives

3.22 Significant revisions to the quality standards and quality incentive schemes were made for DPP3, compared to DPP2. We consider the DPP3 quality standard settings, normalisation approach for major events and QIS settings are largely fit for purpose. Our draft decisions contain minor changes to better reflect the operating environment in DPP4.

3.23 Decisions related to quality are outlined against four themes:

3.23.1 the quality standards that EDBs must meet (**decisions QS1 – QS11**)

3.23.2 the quality incentives which apply to EDBs (**decisions QIS1 – QIS10**)

3.23.3 reliability normalisation, which reflects how major events are accounted for within the standards and incentives (**decisions N1 – N5**), and

3.23.4 reference period which applies for establishing planned and unplanned interruption settings (**decisions RP1- RP7**).

## Draft decisions for quality standards

3.24 Table 3.2 presents the draft decisions for quality standards.

**Table 3.2 Quality standards for DPP4**

| EDB | Unplanned SAIDI (1-year) | Unplanned SAIFI (1-year) | Planned SAIDI (5-year) | Planned SAIFI (5-year) | Extreme outage (per event)[79] |
|---|---|---|---|---|---|
| **Alpine Energy** | 121.69 | 1.1372 | 742.38 | 3.1437 | 120 SAIDI |
| **Aurora Energy** | 122.05 | 1.9675 | 1077.78 | 6.0924 | 6m CIM |
| **EA Networks** | 90.84 | 1.3110 | 1238.47 | 4.4045 | 120 SAIDI |
| **Firstlight Network** | 230.43 | 3.2346 | 1161.61 | 6.7271 | 120 SAIDI |
| **Electricity Invercargill** | 27.15 | 0.7060 | 125.94 | 0.5702 | 120 SAIDI |
| **Horizon Energy** | 184.80 | 2.2709 | 944.50 | 5.9856 | 120 SAIDI |
| **Nelson Electricity** | 18.62 | 0.4063 | 165.72 | 2.1297 | 120 SAIDI |
| **Network Tasman** | 97.73 | 1.1358 | 1019.65 | 4.4119 | 120 SAIDI |
| **Orion NZ** | 80.47 | 0.9819 | 215.41 | 0.6866 | 6m CIM |
| **OtagoNet** | 168.37 | 2.4935 | 1945.75 | 8.7119 | 120 SAIDI |
| **Powerco** | 189.27 | 2.1550 | 781.17 | 3.4964 | 6m CIM |
| **The Lines Company** | 190.55 | 3.4333 | 1245.95 | 7.8774 | 120 SAIDI |
| **Top Energy** | 399.25 | 4.8196 | 1714.83 | 7.4615 | 120 SAIDI |
| **Unison Networks** | 86.46 | 1.8737 | 688.37 | 4.9114 | 6m CIM |
| **Vector Lines** | 110.07 | 1.4034 | 643.92 | 3.1661 | 6m CIM |
| **Wellington Electricity** | 37.84 | 0.5829 | 76.66 | 0.6089 | 6m CIM |

3.25 **Draft decision QS1** is to maintain a separate standard for planned outages, rather than combined with unplanned. This avoids a potential perverse incentive for EDBs to defer network investment or maintenance needed to prevent unplanned outages. Otherwise where an EDB is incurring higher unplanned outages than anticipated, the EDB may defer planned investment that helps maintain reliability, but creates an interruption, to stay within its overall cap in the short term. This also gives EDBs greater flexibility on the timing of work requiring planned outages.

79 The extreme event standard is specified in SAIDI minute and CIM terms. CIM means customer interruption minutes, which is the sum of the total duration in minutes accumulated for each ICP for each interruption, with “m” representing millions.

3.26 **Draft decision QS2** is to maintain annual unplanned interruptions reliability standards for SAIDI and SAIFI. We consider an unplanned standard, assessed annually, can be set in a way that reduces the risk of false positives and allows for more timely compliance investigations.

3.27 **Draft decision QS3** is to retain the 2.0 standard deviation buffer for setting the unplanned interruptions reliability standards limit.[80] In the absence of a buffer compared to the historic average, the quality standards we set for unplanned interruptions would be vulnerable to random volatility. Our draft decision is to maintain the buffer at 2.0 standard deviations above the historical average.

3.28 **Draft decision QS4** is to maintain the planned SAIDI and SAIFI interruptions standard assessed over the length of the regulatory period. There are long-term benefits to consumers stemming from the network investment and maintenance that is associated with planned interruptions. Applying the planned interruptions quality standard over the full regulatory period allows EDBs to schedule planned work in a way that works best for their business and consumers.

3.29 **Draft decision QS5** is to change the buffer for the planned interruptions reliability standard to be a 100% uplift on the historic average, capped at a +/- 10% movement from the current standard.

3.30 A buffer above the historical average considers that there are long-term benefits to consumers from the network investment and maintenance that is associated with planned interruptions and allows for some flexibility in work practices. Shortening of the reference period proposed for planned interruptions to reflect current network practices more accurately (see **draft decision RP2**), will significantly increase annual average planned SAIDI and SAIFI for most EDBs. As such, we have decided on a reduction in the buffer and introducing a +/-10% cap to reduce movement across regulatory periods.

3.31 **Draft decision QS6** is to retain the de-weighting of notified planned interruptions by 50% in the assessment of compliance with planned interruption standards. This is due to the reduced impact of notified interruptions on consumers.

[80] 'Buffer' refers to the uplift applied between the 'target' which represents historic performance and the 'limit'.

3.32 **Draft decision QS7** is to retain SAIDI extreme event standard set at 120 SAIDI minutes or 6,000,000 customer minutes where specified. The 'extreme event standard' deals with extreme one-off events. In the absence of a standard relating to extreme events, the unplanned reliability standards (with normalisation) may miss large interruption events that are caused by not applying good electricity industry practice or under-spending on network maintenance and investment.

3.33 **Draft decision QS8** is to retain enhanced automatic reporting following a breach of a quality standard. Such disclosures help to improve our ability to assess compliance with the price-quality path, and to reduce the cost and uncertainty involved when an EDB contravenes its quality standards. Such disclosures also provide greater transparency and accountability of EDBs for their quality performance.

3.34 **Draft decision QS9** is that no new quality measures be introduced as part of the quality standards applying in DPP4. While there is merit in considering a wider range of measures of quality of service, we consider that quality standards should align with what consumers value, be measurable, and have clarity on what an appropriate target would be such that EDBs can be influenced towards outcomes that represent value for consumers. Some aspects of network performance may be better addressed through our programme of information disclosure and performance analysis.

3.35 **Draft decision QS10** is to set quality standards and incentives for Aurora transitioning from a CPP to the DPP on the same basis as for other EDBs on the DPP. We do not consider that Aurora is such an outlier that it requires a different application of the quality standard and incentives from other EDBs to maintain consistency with our principle of no material deterioration. The change to Aurora's targets and limits will be capped relative to its current CPP quality targets and limits.

3.36 **Draft decision QS11** is to retain the requirement for reasonable reallocation of SAIDI and SAIFI following an asset transfer between EDBs. Consumers should not bear the risk of being worse-off due to an asset transfer transaction, in terms of quality of service. When an EDB engages in a transaction where it transfers assets to another entity, and this transfer results in consumers no longer being served by the transferring EDB, an adjustment needs to be made to both the transferring and receiving EDBs' quality standards and quality incentives.

### Draft decisions for quality incentive scheme

3.37 For DPP4, our draft decision is to retain the QIS which currently applies under DPP3. The QIS defines the range within which EDBs can make marginal trade-offs between the quality and price of the services they provide. It creates a relationship between changes in network reliability and increased or lower revenue allowances, and consumers cost-quality preferences. The QIS is linked to the Value of Lost Load (VoLL), to approximate the value consumers place on reliability, and a sharing factor that matches the IRIS retention factor, so benefits are shared between consumers and EDBs.

3.38 **Draft decision QIS1** is to retain the revenue-linked quality incentive scheme for planned and unplanned SAIDI; SAIFI is excluded. Similar to DPP3, the QIS only applies to planned and unplanned SAIDI. Applying the QIS to both SAIDI and SAIFI risks double-counting the SAIFI impact because SAIDI is a function of interruption frequency (SAIFI) and interruption length (CAIDI). SAIFI will still be subject to compliance standards and SAIFI, as well as CAIDI, are indirectly captured through SAIDI incentives.

3.39 **Draft decision QIS2** is unplanned incentive rates are informed by the VoLL, discounted by (1-IRIS retention factor) to reflect expenditure incentives, and a further 10% to reflect quality standard incentives, with VoLL set at $35,374/MWh. We have increased the VoLL given recent inflation to more accurately represent the current value for consumers. We have factored in the expenditure incentive because EDBs only bear a proportion of additional expenditure associated with quality improvements, as determined by the IRIS mechanisms. The further 10% reduction reflects the incentive provided from incentives associated with not contravening the quality standard.

3.40 **Draft decision QIS3** is that planned interruption incentive rates are reduced by 35% relative to the unplanned interruption incentive rate. The de-weighting is reflective of planned interruptions generally having lower consumer impacts than an unplanned interruption, even where the EDB does not meet the strict criteria for notifications associated with the 'notified' interruptions category.

3.41 **Draft decision QIS4** is that 'notified' interruptions are reduced by 75% relative to the unplanned incentive rate to reflect less inconvenience to consumers. We have reduced the strength of the planned incentive rate, compared to DPP3, but maintained the strength of the notified interruption incentive given consumers' preference for greater notification of interruptions.

3.42 **Draft decision QIS5** is that the incentives are revenue-neutral at the average of the reference period, also known as the target. The quality target is the level of reliability performance at which the revenue impact of an EDB's performance is zero, ie, it is the point at which losses turn into gains and vice versa.

3.43 Without better information about the level of reliability consumers demand, we consider historical reliability provides an appropriate proxy for the level of reliability consumers expect.

3.44 **Draft decision QIS6** is for the SAIDI caps (which determine maximum losses) to be set equal to the SAIDI limits for planned and unplanned SAIDI. We consider that it is not appropriate to allow EDBs to continue to make trade-offs beyond the minimum level of reliability determined by the quality standard, so a cap above the limit is inappropriate.

3.45 On the other hand, we consider that it is appropriate for EDBs to consider trade-offs all the way up to the limit, as this preserves the marginal incentive to improve reliability (or avoid further declines) regardless of their performance up to that point in the assessment period.

3.46 **Draft decision QIS7** is to set the SAIDI collars (which determine maximum gains) at zero for unplanned and planned SAIDI. We have previously set planned and unplanned SAIDI collars at zero, subject to a specified maximum revenue exposure. In other words, we have removed the collars in our incentive scheme. This means that financial incentives for reliability will always apply below the SAIDI limits.

3.47 **Draft decision QIS8** is to set a cap of 2% on total planned-unplanned revenue at risk. Revenue at risk is the total pool of incentives an EDB may gain or lose based on its performance. We consider the 2% cap means the SAIDI incentive rate applies for an appropriate range of performance and ensures variations in quality performance, which can be driven by external factors, does not create an excessive level of revenue exposure.

3.48 **Draft decision QIS9** is not to implement any new incentives. We received a small number of submissions on potential new quality incentive schemes (see **Attachment E**). Most submitters agreed we should not implement any new incentive schemes.

3.49 **Draft decision QIS10** is not to make an explicit adjustment to match the duration of retention benefits between EDBs and consumers for the quality incentive scheme. We adjust the quality incentive rate for the impact of the IRIS schemes, which reduces the cost to an EDB of improving quality. However, we do not make a similar adjustment to account for the fact that EDBs only keep the quality incentive payments associated with reliability improvements until they are reflected in the reference data used to set the quality targets. We are not convinced that strengthening EDBs incentives to invest in reducing SAIDI impact will move us closer to the social optimum for reliability.

**Draft decisions for normalisation**

3.50 The process of normalisation is intended to remove larger events from consideration that are unlikely to reflect the underlying performance of an EDB. **Draft decision N1** is that normalisation only applies to unplanned interruptions, which are the only initiators of a major event day.

3.51 **Draft decision N2** is to retain the normalisation approach used in DPP3, being:

3.51.1 define a major event as 24-hour rolling periods (assessed in 30-minute blocks)

3.51.2 the major event boundary value has been identified as the 1104th highest rolling 24-hour period for SAIDI and SAIFI over the 10-year reference period

3.51.3 normalisation is applied on half-hour blocks, within a major event, where the SAIDI figure exceeds 1/48th of the boundary value, and

3.51.4 treat major events by replacing any half-hour that is greater than 1/48th of the boundary value with 1/48th of the boundary value if that half-hour is part of the major event (can exceed 24 hours in duration).

3.52 We consider that maintaining the replacement of identified major events with a reduced replacement value is appropriate, given that:

3.52.1 enhanced major event reporting requirements, can provide more transparency and incentives around the main cause of events

3.52.2 reducing a large source of volatility may provide a clearer indication of the underlying reliability of the network

3.52.3 the extreme event standard, places further onus on EDBs to take practicable steps to minimise the likelihood of high impact, low probability events that are within their control as well as mitigating the extent of them, and

3.52.4 there are other incentives at play which may mitigate some of the above risks, such as customer complaints and reputational risk.

3.53 **Draft decision N3** is that SAIDI and SAIFI major events are triggered independently. We consider the logic which applied in DPP2 and DPP3 for these being triggered independently still holds. Major events may affect a large number of consumers in an urban area for a relatively short period of time and therefore triggering SAIFI but not SAIDI. Alternatively, a relatively small number of consumers may be affected for a significant length of time and therefore triggering SAIDI but not SAIFI; eg, a severe storm in a remote area.

3.54 **Draft decision N4** is to set a higher boundary for very small EDBs. Smaller networks, all else being equal, can expect to have fewer interruptions relative to larger networks. This is because there is less equipment that can fail at any given time, and consequently less equipment at risk of truly experiencing a major event.

3.55 **Draft decision N5** is to retain additional reporting by EDBs for each unplanned major event in its compliance statement, consistent with DPP3. We consider that when a major event is identified, there should be transparency as to when and why the major event happened, and the impact of normalising the major event. This is important given our normalisation approach is to replace major events with a pro-rated boundary value, rather than the full boundary value.

**Draft decisions for reference period**

3.56 **Draft decision RP1** is to use a 10-year reference period from 1 April 2013-31 March 2023 to inform the parameters for unplanned reliability standards and incentives, with the period adjusted to 1 April 2014 to 31 March 2024 for the final determination. The use of a historical reference period as a baseline aligns with the principles of 'no material deterioration' and better reflects the underlying characteristics of the network.

3.57 Following the same approach under DPP3, we consider that setting the reference period using the latest 10 years for unplanned interruptions is appropriate, as the period is:

3.57.1 long enough to account for longer term weather cycles

3.57.2 long enough to mitigate year-on-year variation due to circumstances outside the EDBs’ control

3.57.3 long enough in that it better reflects the operating environment of EDBs and evens out changes, and

3.57.4 best reflects the current underlying level of reliability performance, given the availability of reliable and consistent data.

3.58 **Draft decision RP2** is to apply a reference period of 2017-2023 for planned interruptions for the draft decision, extended to 2017-2024 for the final decision.

3.59 Unlike unplanned interruptions, we have seen a step change during 2017-2022 where planned interruptions have increased significantly across nearly all non-exempt EDBs compared to previous periods. A shortening of the 10-year reference period for unplanned interruptions is appropriate to reflect current network practices more accurately.

3.60 **Draft decision RP3** is to retain the cap on inter-period movement, ±5% for unplanned interruptions for both the SAIDI and SAIFI unplanned target and apply this to the SAIDI and SAIFI unplanned limits.

3.61 Aside from acceptable movements within the cap-collar range where EDBs already receive rewards and penalties, we do not consider it appropriate that deteriorating performance should be rewarded with more relaxed standards and improved performance penalised through stricter standards.

3.62 **Draft decision RP4** is to not make explicit step changes to reliability targets or limits. We have considered certain factors that could be considered to reflect a step change to reliability parameters for quality standards and incentives as compared to the reference period. Our draft decision is not to make any step changes due to climate change, changes in operational procedures (other than as reflected in the shortening of the planned interruption reference period), bush fire risk, emergency services prohibiting access to outage sites at this time.

3.63 **Draft decision RP5** is not to make any explicit adjustments for instances of non-compliance contained within the unplanned interruption reference period dataset. We note there are instances of non-compliance contained within the unplanned interruption reference period dataset. We consider the 5% cap which applies to both the unplanned reliability targets and limits appropriately address the risk that deteriorating performance is rewarded with relaxed standards, consistent with the 'no material deterioration' principle.

3.64 **Draft decision RP6** is that EDBs must record successive interruptions on the same basis they employed in responding to the s 53ZD notice.[81,82] In establishing quality standards for DPP3 we identified that EDBs were applying different recording practices for successive interruptions. This approach maintains internal consistency of assessment.

3.65 **Draft decision RP7** is to exclude interruptions directly attributable to INTSA approved projects or programmes from assessed SAIDI and SAIFI subject to an aggregate 0.5% cap of the respective SAIDI and SAIFI limits for the quality standards and quality incentive scheme. We consider that excluding certain interruptions from the quality standards and quality incentive scheme to account for non-performance of innovative solutions may address concerns that the regime may discourage innovation.

[81] A successive interruption means an interruption that follows an initial interruption that either relates directly to that initial interruption; or occurs as part of the process of restoring supply of electricity lines services following that initial interruption.

[82] We intend to issue a further s 53ZD notice, which will gather the required audited interruption data series for the period 1 April 2019 to 31 March 2024. The approach applied in responding to this notice will be the approach required to be applied by EDBs during DPP4.

# Chapter 4 Managing price shock risks and the ability for EDBs to finance investments

## Purpose of this chapter

4.1 This chapter:

4.1.1 explains the challenge of managing price shock risks and the ability for EDBs to finance investments

4.1.2 identifies and explains the rationale for draft decisions that relate to:

4.1.2.1 setting net allowable revenues on a build-blocks basis and smoothing revenues over the regulatory period to manage price-shocks

4.1.2.2 matters that related to the revenue path and wash-up mechanism during the regulatory period, and

4.1.2.3 other inputs to our building blocks financial model, and

4.1.3 directs readers to further information about:

4.1.3.1 consumer price impacts on the Commerce Commission website[83], and

4.1.3.2 the development of the draft decisions for net allowable revenue, the revenue path and financeability (see **Attachments F** and **G**).

4.2 For background information on how we set revenue allowances using a building-blocks model and how we smooth revenue allowances over the regulatory period, see the introductory material in Attachment B of our DPP4 Issues Paper.[84]

[83] Commerce Commission "Understanding how changes to line charges may impact your electricity bill" webpage.

[84] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues Paper" (2 November 2023), Attachment B.

## The challenge of managing price shocks and the ability for EDBs to finance investments

4.3 Investment in distribution networks is financed up front by EDBs, then repaid by their consumers over time as they benefit from the network. Each DPP reset must manage the tension between consumers' interests in:

4.3.1 having access to a network that can deliver the energy services they need at the quality they expect, and

4.3.2 avoiding paying more than is necessary to maintain and expand the network.

4.4 This includes avoiding financial hardship to suppliers on the one hand and avoiding price shocks to consumers on the other.

4.5 This tension is especially acute for DPP4 due to factors impacting EDBs and consumers. Rather than either a price-shock challenge or an investment challenge, both are occurring simultaneously.

4.6 To enable EDBs to invest in their networks and earn a normal return on their investment, we set their revenue allowance on a 'building blocks' basis so that forecast revenues equal forecast costs (including the cost of capital).

4.7 Inflation has been higher than forecast over the DPP3 period. Between 2019 (the base year for DPP3) and 2025 (the end of DPP3), cumulative CPI will have been 27% which is more than double the forecast figure used when setting DPP3 (12%). This inflation has led to:

4.7.1 an increase in EDBs' operating costs

4.7.2 higher historical capex, and

4.7.3 higher regulatory asset base (RAB) growth via revaluations.

4.8 Additionally higher interest rates mean EDBs will face a higher cost of capital for financing their investments.

4.9 The impacts of these factors on EDBs' allowable revenue are set out in Figure 4.1. At an industry-wide level for the draft decision:

4.9.1 changes in DPP3 CPI and other components (that primarily reflects RAB growth over the DPP3 period) contributes 26% of the change

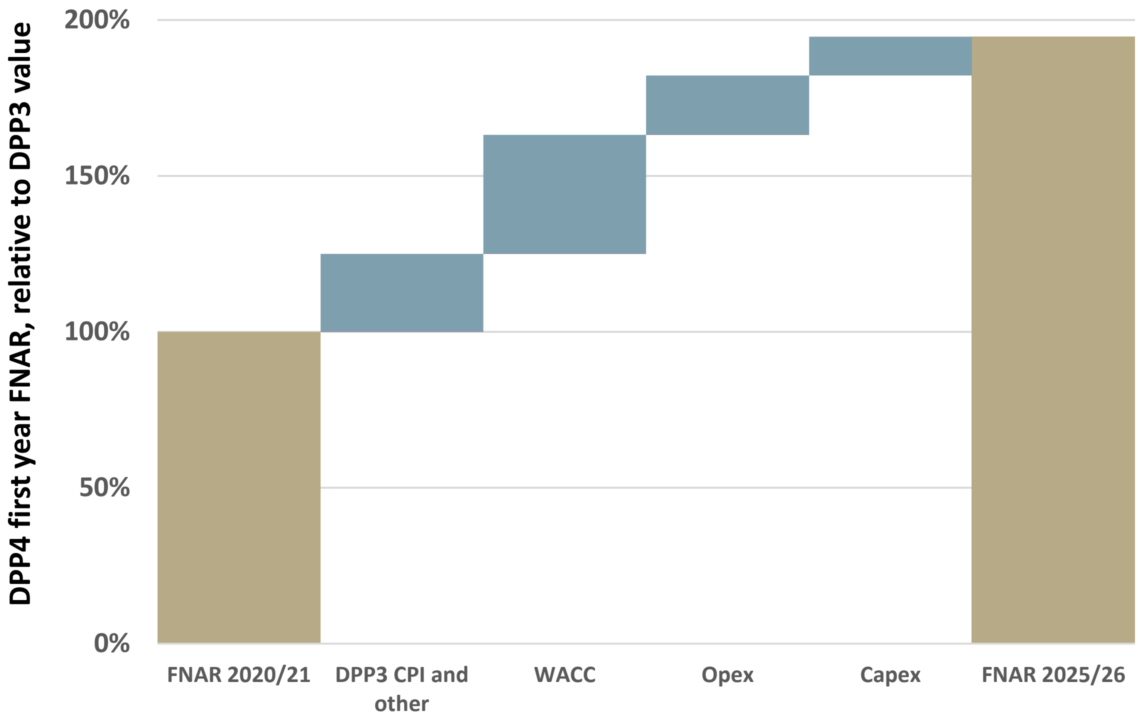
4.9.2 the increase in the estimated cost of capital (WACC) contributes 40%

4.9.3 increases in opex contributes 20%, and

4.9.4 increases in capex contributes 13%.

4.10 For a more detailed analysis of these drivers, see **Attachment F**.

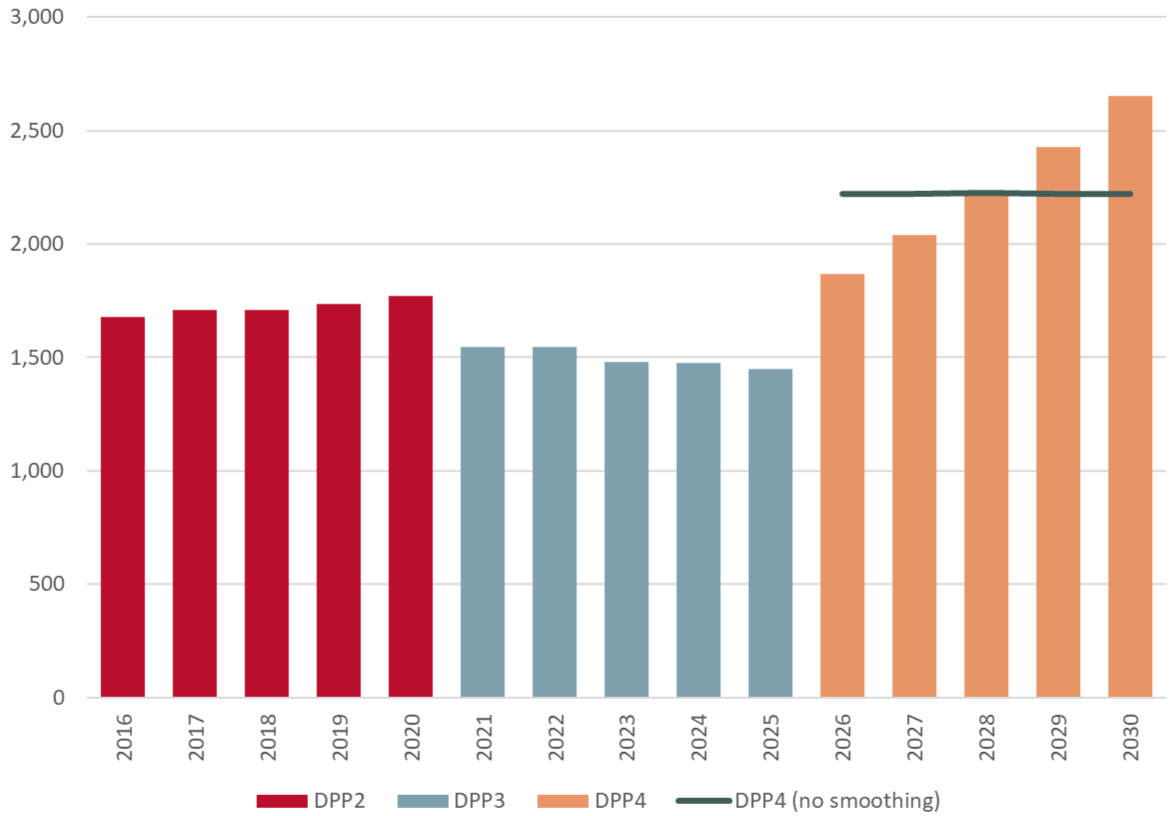
**Figure 4.1 Drivers of change in forecast net allowable revenues between DPP3 and DPP4**[85]




[85] The item "DPP3 CPI and other change" includes changes in opening RAB and other financial model initial conditions over the course of DPP3 (largely driven by higher than forecast inflation), forecasts of CPI over DPP4, and forecasts of disposed assets. WACC refers to the weighted average cost of capital.

4.11 Under DPP3 settings consumers have benefitted in the short-term from these cost increases not immediately passing through to distribution prices, as shown in Figure 4.2.[86] These declining real revenues have been reflected in consumer bills, where the distribution portion of bills has declined in real terms over the DPP3 period so far.[87]

**Figure 4.2 Long-term revenue paths – all DPP EDBs, excluding Aurora ($m, real 2025)**




4.12 However, over the medium- and longer-term, artificial price suppression is not in consumers' interests because:

4.12.1 where EDB's revenue is insufficient to cover its cost, there is a risk that necessary investment will not occur, and

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[86] Under DPP3 (and prior to amendments made in the 2023 IM review, differences between forecast and actual inflation were accrued to the wash-up balance, and available to be recovered on a two-year lag). As discussed below, wash-up balances resulting from this remain largely unrecovered.

[87] Ministry of Business Innovation and Employment "Electricity cost and price monitoring" webpage; see section titled "Quarterly Survey of Domestic Electricity Prices (QSDEP)."

4.12.2 artificial distortions to prices may weaken consumers' incentives to manage demand efficiently including through investing in DER.

4.13 We also note that while price-smoothing decisions are neutral in present-value terms, because EDBs earn a time-value of money adjustment on any deferred wash-up balances, consumers pay more overall in nominal terms the more revenue is smoothed.

4.14 There is a general acknowledgment of the need to invest in maintaining resilience in response to increased risk of more extreme events, including storm damage or cybersecurity threats. Some EDBs have been exposed to higher costs to respond to events, and all EDBs have had to reconsider how they forecast expenditure for network resilience to better prepare for a wider range of potential extreme events.

4.15 EDBs are expected to contribute to the energy transition by ensuring networks can support growth and variability in demand and supply. EDBs need to determine where and when the increasing demand for electrification will emerge in their networks, and what traditional solutions, innovative projects and/or non-traditional solutions to invest in to manage demand.

**We have heard concerns about consumer bill impacts**

4.16 Revenue allowances for EDBs in DPP4 would be recovered by higher prices paid by consumers. We are aware that both the high general inflation across the economy and high interest rates in recent years have added to the wider affordability challenges facing consumers.[88]

**We have also heard concerns from EDBs about financeability**

4.17 Some EDBs have told us they have concerns about their ability to finance necessary investments in the DPP4 period if significant amounts of revenue are deferred. This issue has been termed 'financeability.'

4.18 We have defined 'financeability' as "the ability of a prudent and efficient notional supplier to raise and repay debt and raise equity in financial markets, readily and on reasonable terms."[89] As we described in **Chapter 2,** the energy sector is in a period of change, with some uncertainty as to where, when and how much investment will be required by EDBs. This uncertainty, together with the significant uplift in known investment requirements, heightens financeability concerns.

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88 Reserve Bank of New Zealand "Economic Indicators" webpage.

89 Commerce Commission "DPP4 reset – Financeability of electricity distribution services in the default price-quality path – Issues paper" (22 February 2024), paragraph X4.

4.19 We published an issues paper on financeability in February 2024 to ensure we had sufficient information to support DPP4 decisions.[90] In that paper we expressed our view that while financing significant new capacity and new investment is the responsibility of the businesses through normal, efficient capital raising and management, we will consider issues of financeability where they relate to the provision of the regulated service (rather than the financial position of the supplier of that service). We explain how we have taken account of financeability in arriving at our draft decisions in the *'Draft decision P5 – assessing notional EDB financeability'* section.

## Draft decisions on starting prices and revenue smoothing

4.20 This section sets out and explains out draft decisions on starting prices and revenue smoothing.

4.21 It starts with a brief overview of the components of the revenue path and the relevant terminology. It then covers our draft decisions on:

4.21.1 starting prices for each EDB (**draft decision P1**)

4.21.2 the default rate of change over the regulatory period (**draft decision P2**)

4.21.3 alternative rates of change (**draft decision P3**) including how we have assessed consumer price shocks (**draft decision P4**) and EDB financeability (**draft decision P5**)

4.21.4 the 'revenue smoothing limit' that applies during the regulatory period (**draft decisions R2.1 and R.2**), and

4.21.5 EDBs ability to apply additional discretionary revenue smoothing via undercharging their allowance (**draft decision R1.3**).

### Overview of the revenue path and terminology

4.22 This section explains the key components of the revenue path, how they operate together to regulate the revenue EDBs can recover, and the terminology we use.

[90] Ibid.

*Prices vs revenues*

4.23 While the term used in section 53M of the Act is 'prices' (hence *price*-quality path), the Act defines 'prices' as including revenues, and allows us to set a revenue cap as the form of control on EDB prices. Under the EDB IMs, EDBs are subject to a revenue cap, so we generally refer to revenues for the sake of clarity. Where we refer to 'price' or 'prices', this will generally mean the prices consumers face (or the proxies we use to estimate them).

*Controls on revenue*

4.24 The regulatory rules and processes that we apply when determining a revenue path for EDBs are set out in Part 3 subpart 1 of the EDB IMs.[91]

4.25 We regulate the revenue EDBs can recover from their customers using two regulatory controls:

4.25.1 the (primary) revenue path that determines the total revenue an EDB may recover from its customers and that is defined in terms of 'forecast allowable revenue', and

*4.25.2* the (secondary) revenue smoothing limit that can require EDBs to defer revenue recovery in a present-value neutral way in some circumstances.

*Forecast allowable revenue*

4.26 The primary revenue path defined by forecast allowable revenue is made up of four parts:

4.26.1 forecast net allowable revenue, that allows EDBs to recover forecast costs over the regulatory period

4.26.2 forecasts of pass-through costs, that allow EDBs to pass on certain costs beyond their control to consumers (for example industry levies or transmission charges)

4.26.3 forecasts of recoverable costs, that (largely) implement regulatory adjustments such as wash-ups or incentives amounts, and

4.26.4 forecasts of revenue received under large connection contracts.

[91] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clauses 3.1.1-3.1.4.

4.27 The decisions described below primarily relate to forecast net allowable revenue. Under the EDB IMs and consistent with section 53P(5) of the Act, forecast net allowable revenue over the regulatory period is specified in terms of:

4.27.1 'starting prices' – forecast net allowable revenue in the first year of the regulatory period[92]

4.27.2 the annual change in forecast CPI[93], and

4.27.3 an annual rate of change relative to forecast CPI, or "X-factor".

**Draft decision P1 – starting prices**

4.28 Our draft decision is to determine the starting price for each non-exempt EDB using a building blocks model, and to not defer any building blocks allowable revenue (BBAR) into DPP5.

4.29 As noted above in describing the twin price shock and financeability challenges the sector faces, EDBs' costs have risen significantly such that rolling their current revenue paths forward would not provide the ex ante expectation of a normal return. As explained in more detail in **Attachment F**, this 'roll-over' counter factual would see EDBs under-recover their forecast costs by around 50% on average.

4.30 The draft starting prices and draft rates of change for each EDB are set out in Table 4.1.[94] The changes in total distribution revenue (including wash-up drawdown amounts and IRIS incentive amounts) that results from this is shown in Figure 4.3.

92 Starting prices are specified in Schedule 1.1 of the draft EDB DPP4 determination.

93 The methodology for calculating CPI is specified in Schedule 1.3(2) of the EDB DPP4 determination.

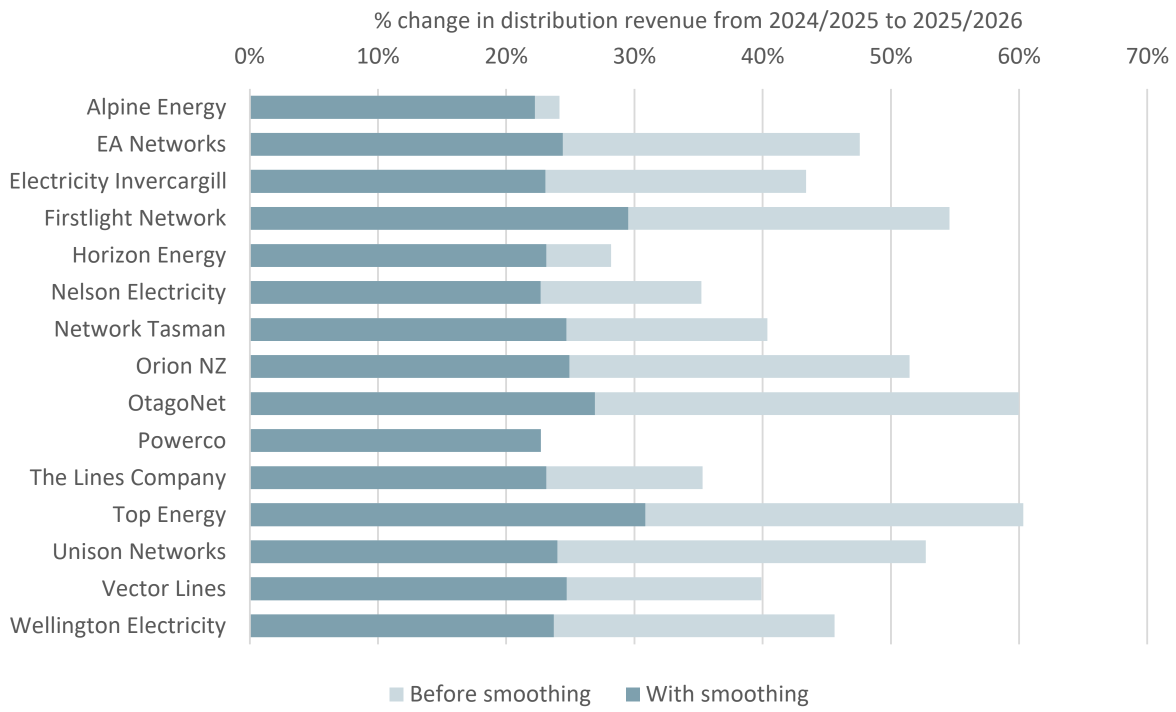
94 As the CPI component of the change in forecast net allowable revenue is determined based on updated values each year of the regulatory period, it is not set out here. This change was made as part of the 2023 IM review.

Table 4.1 DPP4 draft starting prices and rates of change

| EDB | Starting prices – FNAR in 2026 ($m) | X-factor – rate of change relative to CPI [95] |
|---|---|---|
| **Alpine Energy** | 70.2 | -2.5% |
| **EA Networks** | 45.8 | -11.5% |
| **Electricity Invercargill** | 17.0 | -9.9% |
| **Firstlight Network** | 35.7 | -10.6% |
| **Horizon Energy** | 34.1 | -3.7% |
| **Nelson Electricity** | 7.0 | -7.2% |
| **Network Tasman** | 37.0 | -9.5% |
| **Orion NZ** | 219.5 | -13.0% |
| **OtagoNet** | 33.6 | -16.4% |
| **Powerco** | 486.1 | 0.0% |
| **The Lines Company** | 48.4 | -6.8% |
| **Top Energy** | 53.0 | -13.5% |
| **Unison Networks** | 136.1 | -13.4% |
| **Vector Lines** | 580.8 | -8.5% |
| **Wellington Electricity** | 118.8 | -10.7% |

95 Section 53P(5) of the Act and the EDB DPP4 determination expresses X-Factors in 'CPI minus X' terms. As such, while the X-factor values presented here are negative, they will allow forecast net allowable revenue to increase at these rates.

**Figure 4.3 Nominal change in smoothed distribution revenue from 2025 to 2026**




4.31 In Figure 4.3 the pale blue bars ('Before smoothing') show what the change in distribution revenue would be absent any smoothing, discussed further below. The dark blue bars ('With smoothing') show change in distribution inclusive of smoothing. These figures average around 24% in nominal terms. This is consistent with our decision to:

4.31.1 cap real per-ICP increases at 20% in most cases

4.31.2 forecast CPI of 2.1%, and

4.31.3 weighted-average ICP growth of 1.4%.

4.32 Variations between EDBs are explained by:

4.32.1 variations in forecast ICP growth (between 0.2% to 3.2%), and

4.32.2 for Firstlight and Top Energy, our draft decision to allow higher than 20% real per-ICP increases to avoid on-going price shocks over the regulatory period.

4.33 On balance, we consider allowing EDBs to fully recover BBAR and any accrued wash-up amounts within the DPP4 regulatory period, with no deferral into DPP5, better promotes the purpose of Part 4 than the alternatives.

4.34 Deferral of revenue increases over the short term (within a regulatory period) has less of an effect on the outcomes in the Part 4 purpose described above and are discussed below in relation to alternative rates of change.

**Draft decision P2 – default rate of change**

4.35 Section 53P(1) of the Act requires us to determine a 'rate of change', which is used to determine net revenue for each year after the first of the regulatory period. The rate of change comprises:

4.35.1 the rate of increase in forecast CPI, the treatment of which is determined in the specification of price IMs, and

4.35.2 a default rate of change relative to forecast CPI (the default X-factor).

4.36 Our draft decision is to determine a default X-factor of 0%.

4.37 Because our draft decision is to set starting prices using a building blocks model, the forecast net allowable revenue over the period already incorporates forecast changes in productivity, so the rate of change in productivity in the EDB sector relative to the economy as a whole will be 0%.[96] Our draft decision is therefore to set a default X-factor of 0%. This view was supported by submissions on the DPP4 Issues paper.[97]

4.38 Given the draft decisions below on alternative rates of change to mitigate price shocks, the default rate of change will only apply to one EDB (Powerco).

**Draft decisions P3, P4, and P5 – alternative rates of change, price shocks, financeability**

4.39 Section 53P(8) of the Act gives us a discretion when resetting a DPP for a particular regulatory period to set 'alternative rates of change' for a particular supplier(s). This is a tool that can be used to manage the challenge of minimising price shocks to consumers, and the ability for EDBs to finance investments where there is undue financial hardship.

4.40 Our approach on smoothing forecast net allowable revenue via alternative rates of change is made up of three interlocking draft decisions:

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96 For more detail, see Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), p. 55 and Attachment H.

97 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 17; Horizon Networks "DPP4 Issues paper submission" (19 December 2023) p. 21; Orion "DPP4 Issues paper submission" (19 December 2023), p. 24; Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 24, Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 74.

4.40.1 the alternative rates of change we set (**draft decision P3**)

4.40.2 our approach to considering consumer price shocks (**draft decision P4**), and

4.40.3 our approach to considering EDB financeability (**draft decision P5**).

4.41 The smoothing we apply to EDB's net allowable revenue is supported by our application of a 'revenue smoothing limit' as a secondary control on increases including recoverable costs EDBs also have the ability to smooth revenues via temporary undercharging within the undercharging limit (discussed in more detail below).

*Draft decision P3 – alternative rates of change*

4.42 The draft specific alternative rates of change for each EDB are set out in Table 4.1. We have based these rates on:

4.42.1 over DPP4, allowing full recovery of BBAR and previously accrued wash-up balances

4.42.2 constraining price shocks (in the terms discussed below) to 20% (or approximately 6% on an average retail bill) between DPP3 and DPP4

4.42.3 constraining price shocks over the remainder of the regulatory period to 10% per year (or approximately 3% on a retail bill), and

4.42.4 evidence of financeability suppliers may face (based on the assessment discussed below).

4.43 Where limiting the initial and on-going price shocks on this basis would result in deferral of building blocks allowable revenue into DPP5, our draft decision is to allow an initial increase in estimated prices greater than 20%.

4.44 This applies to two EDBs:

4.44.1 Firstlight Network, and

4.44.2 Top Energy.

4.45 For both EDBs, the initial change in real distribution revenue per ICP we have allowed is 27%, the amount necessary to limit on-going increases to 10% without deferral into DPP5.

4.46 We do not consider it necessary to adjust our draft decision on alternative rates of change for financeability reasons for any EDB. Based on our notional analysis, no EDB will face a financeability issue that would need to be addressed to better promote the Part 4 purpose.

4.47 As noted above, because Powerco will not see an initial distribution revenue increase of greater than 20% in real per-ICP terms, we have not applied an alternative rate of change.

4.48 As alternatives to this 'medium smoothing' approach (allowing a greater initial increase with smaller increases over the regulatory period), we also considered:

4.48.1 no smoothing (allowing the full revenue increase in year one of the period, with growth at CPI over the remainder of the period), and

4.48.2 uniform (or maximum) smoothing, such that the change in year one of the period is the same as the average change over the subsequent years of the period.

4.49 The 'no smoothing' option would lead to an estimated initial price shock in year one of DPP4 ranging between 19% and 60% for each EDB, with a weighted average of 38% across EDBs.

4.50 The 'uniform smoothing' option would lead to a lower initial price shock but would give rise to annual increases in estimated prices of over 10% on average, and as high as 15% some EDBs. As well as deferring EDBs' revenue recovery and potentially detrimentally affecting financeability, the uniform smoothing option provides less room to adjust in the out-years should revenue grow from reopeners.

*Draft decision P4 – assessing price shocks for consumers*

4.51 We have assessed price shocks for consumers both at the start of the period and over the course of the regulatory period:

4.51.1 based on 'distribution revenue' – that is forecast net allowable revenue plus recoverable costs (principally IRIS incentive amounts and wash-up drawdowns)

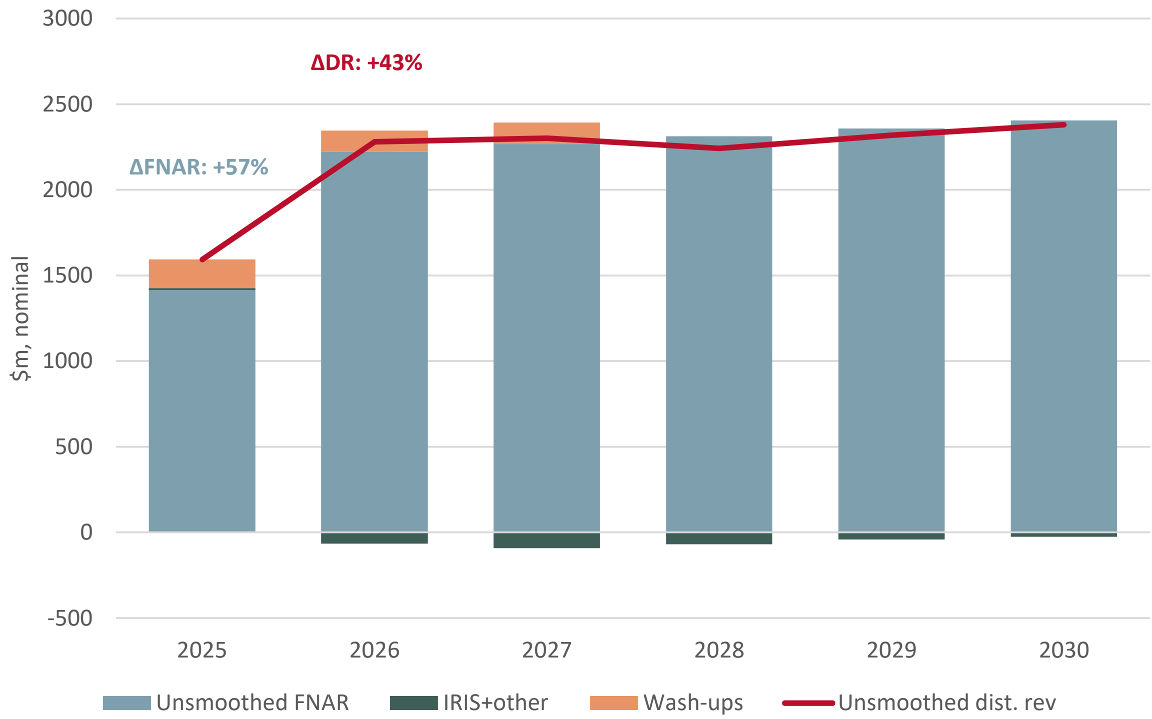
4.51.2 in real terms (net of forecast CPI), and

4.51.3 on a per-ICP basis as a proxy for demand growth.

4.52 We chose to analyse price shocks in distribution revenues because wash-up drawdowns, IRIS incentives and other recoverable costs can have a material influence on the revenue EDBs recover from their consumers.

4.53 As illustrated by Figure 4.4, were we to ignore this impact the unsmoothed changed in FNAR would be 57% in nominal terms across all DPP EDBs. Analysing this more inclusive measure of allowable revenue shows a change of 43% in nominal terms. As explained in more detail in **Attachment F**, the impacts for different EDBs vary significantly.

**Figure 4.4 Draft unsmoothed distribution revenue – all DPP EDBs (excludes Aurora)**



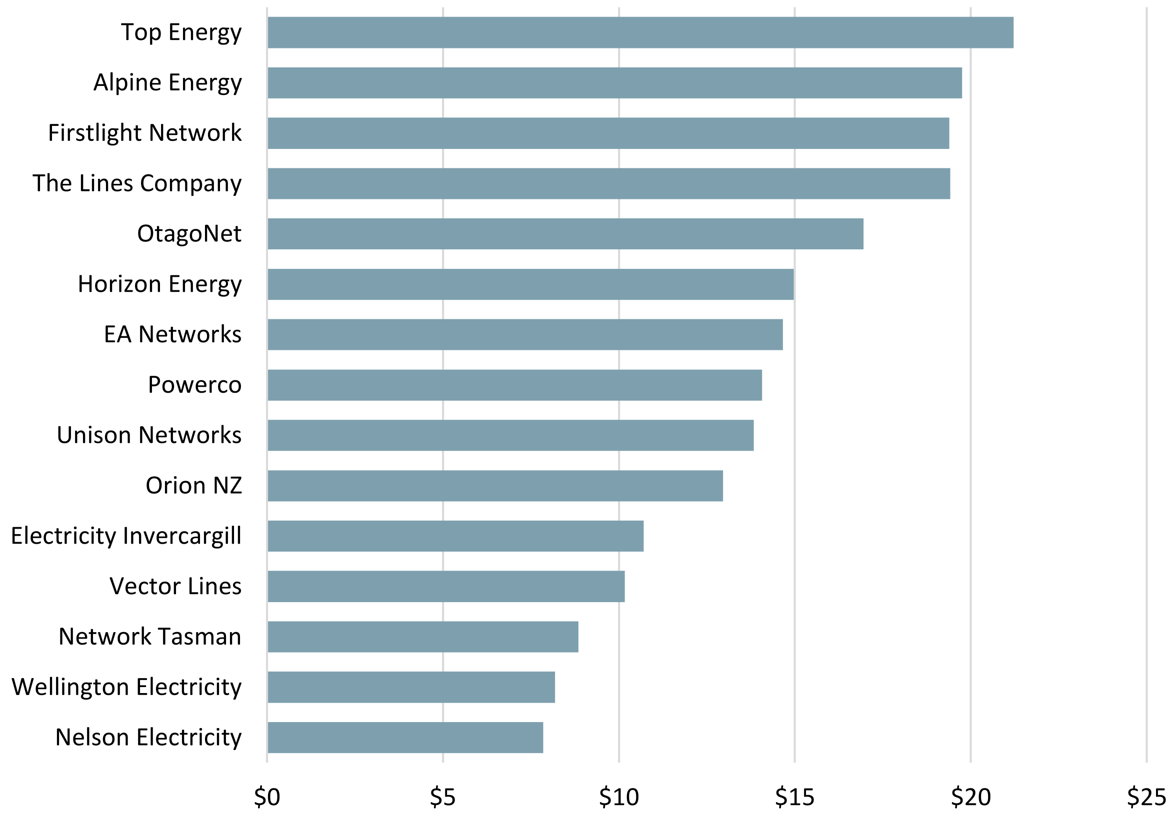

4.54 Assessing price shock in nominal terms risks suppressing EDBs' real revenues which could lead to substantial future wash-up balances (as has been the case over DPP3), resulting in price shocks in the future. While this would be present-value neutral to EDBs consistent with the FCM principle, substantially deferring the timing of cashflows in this way may cause financeability concerns in the future.

4.55 Finally, we have used a per-ICP measure rather than a total revenue measure to proxy the impact on consumer prices. Where a network is forecast to see higher growth (and is spending and investing to meet this growth) price shocks could be mitigated by increasing revenues being spread over an increasing number of consumers. The ICP forecasts we have used are the same ones applied for our forecasts of opex scale growth.

4.56 While we have not attempted to assess the impact of growth in (per-user) demand for example in kWh or peak kWh terms, we note that where EDBs see such demand growth due to wider electrification, price shocks may be further mitigated.

4.57 The estimated average consumer bill impact for each EDB between 2025 and 2026 that results from our draft decision is shown in Figure 4.5.

**Figure 4.5 Estimated average increase in monthly distribution component of a household's electricity bill from DPP3 to DPP4**




*Draft decision P5 – assessing notional EDB financeability*

4.58 Given the importance stakeholders have placed on financeability in previous consultations, and because of the potential impact on incentives for EDBs to invest, we have applied a financeability 'sense check' to our draft revenue smoothing decisions.

4.59 This analysis is described in greater detail in **Attachment G** of this paper. The two core metrics we considered are:

4.59.1 funds from operations (FFO) as a percentage of notional debt, and

4.59.2 notional debt to EBITDA.[98]

[98] Earnings Before Interest Tax Depreciation and Amortisation, calculated as revenue less opex.

4.60 We also evaluated:

4.60.1 FFO interest cover ratio, and

4.60.2 notional leverage based on forecast free cashflows.

4.61 We have assessed these metrics against the levels consistent with a BBB+ rating for a notional EDB.

4.62 On this analysis, with one exception no EDB faces a financeability issue. The exception is Powerco, whose Debt/EDBITDA ratio is above 4.15 compared to the reference level of 4.0. While this could suggest a concern, this result is due to a negative wash-up balance and repayments owed to consumers arising from over-recovery of revenue in previous years.[99] As such, we do not consider it would promote the Part 4 purpose to make an adjustment.

**Draft decision R2.1 and R.2.2 – revenue smoothing limit**

4.63 In addition to smoothing net allowable revenues via alternative rates of change, we also managed potential price shocks caused by recoverable costs via the revenue smoothing limit.

4.64 As part of the 2023 IM Review, we made a package of changes to more efficiently allocate the risk of revenue volatility, in the context of higher and less predictable inflation, and greater uncertainty about the future development of energy networks.[100]

4.65 The effect of the revised IMs is to limit the role of the 'revenue smoothing limit' (RSL) to smoothing year-on-year changes in forecast net allowable revenue and recoverable costs within a regulatory period. Specifically, the RSL is intended to prevent the combined impact of wash-up drawdowns, IRIS and quality incentives, or other recoverable costs from causing revenue and price volatility. It does not apply to pass-through costs (which now includes transmission charges – any smoothing of Transpower's revenue is a matter for the IPP and transmission pricing methodology).

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[99] Because Powerco transitioned to the DPP in 2023 and its revenue allowance was determined based on (higher) forecasts of inflation at that time, it has not accrued the same level of CPI wash-ups as other EDBs who have been on the DPP since 2021.

[100] See Commerce Commission "Report on the IM Review 2023: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), paragraph 7.5, p. 79 and, for more detail, Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), Attachment D.

4.66 **Draft decision R2.1** is to specify the RSL with reference to the sum of forecast net allowable revenue for the current year and forecast recoverable costs for the previous year, with adjustments to preserve the revenue path for forecast net allowable revenue and for CPI. This is consistent with our decision to allow EDBs the opportunity to recover DPP4 net allowable revenue and any wash-ups already accrued over DPP3 within the DPP4 period and aligns with decisions in the 2023 IM Review on the treatment of inflation.

4.67 **Draft decision R2.2** is to set the revenue smoothing limit at the level of 10% over and above the X-factor and CPI adjustments. In effect, this will only apply to changes in revenue caused by changes in recoverable costs.

4.68 Defining the limit relative to each year's forecast net allowable revenue and recoverable costs means that in most cases, an EDB should be able to recover its full revenue entitlement over the regulatory period. The 10% limit was informed by analysing historical volatility in EDB revenue and recoverable costs.[101] As shown in Table 4.2, this differs from the "limit on the annual maximum percentage increase in forecast revenue from prices (FRP)" under DPP3.

**Table 4.2 Revenue smoothing limit draft decisions vs DPP3 limit on increase in FRP**

| DPP4 draft decisions: Revenue smoothing limit | DPP3: Limit on increase in FRP |
|---|---|
| In effect, applies only to increases in revenue caused by increases in recoverable costs. | Applied to total forecast revenue from prices, including transmission charges and pass-through costs. |
| Preserves EDBs' expectation of recovering NPV of BBAR within the regulatory period. | In extreme cases, potential for some deferral of BBAR into the following regulatory period. |
| Applied on a real (CPI-adjusted) basis; EDBs do not bear inflation risk. | Applied on a nominal basis; EDBs bear inflation risk. |

4.69 We consider this approach meets the need for revenue smoothing to protect consumers from mid-period price shocks arising from volatility in recoverable costs, while also ensuring that suppliers can expect full recovery of revenue during the DPP regulatory period under most circumstances.

### Draft decision R1.3 – undercharging limit

4.70 Finally, in addition to the revenue smoothing we require EDBs to undertake via alternative rates of change and the revenue smoothing limit, EDBs have the ability to under-recover their allowable revenue on a temporary basis via undercharging.

[101] See **Attachment F** for more detail on the analysis supporting our draft decisions on the RSL.

4.71 To enable this, where an EDB considers it in their customers' interests and has the financial capacity to do so, we have specified an undercharging limit (the point at which voluntary under-recovery does not accrue to the wash-up account) at 90% of forecast allowable revenue. As with DPP3, we have proposed this limit to allow EDBs some flexibility to smooth their revenue recovery, while at the same time minimising the risk of future price shocks.

## Draft decisions on other aspects of the revenue path

4.72 We are implementing amendments to the wash-up from the 2023 IM Review. The revenue path includes a 'wash-up' mechanism that manages defined uncertainties by making consumers or EDBs whole in present-value terms for differences between forecasts and actual.[102] As part of the 2023 IM Review, we made a number of changes to the wash-up mechanism, with the intent of improving the functionality of the mechanism.

4.73 We included a wash-up for differences between forecast and actual CPI in year one of a regulatory period. We also made a number of other changes to the mechanism to improve the speed that an EDB can draw down on any wash-up balance that may accrue over the course of the regulatory period.

4.74 Schedules 1.7 and 1.8 of the DPP4 Draft determination implement the changes arising from the 2023 IM Review (**draft decision R3.1**).

4.75 The revised IMs provide for the following specific matters to be decided in setting DPP determinations (see **Attachment F** for further discussion):

4.75.1 **Draft decision R3.2** (calculation of the year-one inflation wash-up) is that, for the purpose of calculating the new wash-up for inflation in the first year of a regulatory period:

4.75.1.1 'forecast CPI change' is 2.12%

4.75.1.2 'actual CPI change' is specified in accordance with the formula:

$$\Delta CPI = \frac{CPI_{Jun,t-1} + CPI_{Sep,t-1} + CPI_{Dec,t-1} + CPI_{Mar,t}}{CPI_{Jun,t-2} + CPI_{Sep,t-2} + CPI_{Dec,t-2} + CPI_{Mar,t-1}} - 1$$

Where: $\boldsymbol{CPI_{q,t-n}}$ is the CPI for the quarter year ending $\boldsymbol{q}$ in the 12-month period $\boldsymbol{n}$ years prior to the year $\boldsymbol{t}$; and $\boldsymbol{t}$ is the year 2026.

[102] The list of what is covered by the wash-up is defined in clause 3.1.4 of EDB IMs.

4.75.2 **Draft decision R3.3** (base wash-up drawdown) is ***not*** to specify a base wash-up drawdown amount for non-exempt EDBs, in DPP4.

4.75.3 **Draft decision R3.4** (time value of money adjustment for the opening wash-up balance) is to calculate the time-value of money of the opening wash-up balance using one year of the DPP3 WACC and one year of a blended DPP3/DPP4 WACC (for a value of 5.25%).

4.75.4 **Draft decision R1.4** (forecast large connection contract compliance) is to include a large connection contract (LCC) wash-up term in the wash-up accrual formula, to avoid recovery of LCC revenue from other consumers.

## Draft decisions on other inputs to the financial model

4.76 In addition to forecasts of expenditure and decisions on revenue smoothing, we need to make a number of decisions about other inputs to the DPP financial model:

4.76.1 **draft decision R1.2:** Forecast CPI based on the four-quarter average change in CPI between the first year of the regulatory period and the current year

4.76.2 **draft decision M1:** The weighted average cost of capital (WACC) in the draft financial model is 7.37%, based on the most recent Information Disclosure cost of capital determination. We will update this WACC as part of our final decisions for data up to 31 August 2024

4.76.3 **draft decision M2:** To include an allowance for disposed assets, based on historical levels

4.76.4 **draft decision M3:** Forecast depreciation on existing assets based on information provided by each EDB

4.76.5 **draft decision M4:** Use base year data from 2024 Information Disclosures in our final decisions, and data from 2023 Information Disclosures for our draft decisions, and

4.76.6 **draft decision M5:** For CPI forecasts, use the most recently available Reserve Bank of New Zealand monetary policy statement[103] forecasts from when the WACC was determined.

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[103] The draft decision was prepared on the basis of Reserve Bank inflation forecasts from the February 2024 Monetary Policy Statement. Given timing, they have not been updated for the May Monetary Policy Statement.

4.77 In **Attachment I** we discuss these draft decisions in more detail.

# Chapter 5 General information and how to make a submission

## Purpose of this chapter

5.1 This chapter:

5.1.1 points to other documents with information relevant to the DPP4 reset

5.1.2 advises you of our recent notice of intention to consult on potential Input Methodologies (IM) amendments

5.1.3 explains our process since the DPP4 Issues paper (2 November 2023)

5.1.4 details how to provide your views on the draft decisions in this paper, and

5.1.5 briefly describes the content of **Attachments A – J**.

## How to find other relevant information for the DPP reset

**Table 5.1 Other documents related to the DPP4 reset**

| If you are interested in: | Please refer to: |
|---|---|
| The final decisions of the Input Methodologies Review 2023 which underpin and guide the DPP decisions described in this paper | Report on the IM Review 2023: Part 4 Input Methodologies Review 2023 – Final decision (13 December 2023) |
| The statutory basis for the default price-quality path for electricity distribution businesses and the framework for DPP decision-making | Attachment A (from page 65) in the Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper (2 November 2023) |
| A detailed explanation of the context within which we are resetting the DPP4 price-quality path – including specific reference to the energy transition and the impacts of climate change | Chapter 2 in the Default price- quality paths for electricity distribution businesses from 1 April 2025 – Issues paper (2 November 2023) |
| Consultation document seeking stakeholder views on financeability for electricity distribution businesses and our approach to financeability issues in the DPP4 reset | DPP4 reset – Financeability of electricity distribution services in the default price-quality path – Issues paper (22 February 2024) |
| The information about capex and innovation which we sought stakeholder feedback on in workshops in early 2024 and late in 2022 | Forecasting and incentivising efficient expenditure for EDBs (7 November 2022)<br>Capital expenditure frameworks design (26 February 2024)<br>Innovation and non-traditional solutions allowance design (4 March 2024) |
| The process we are following in the DPP4 reset | Default price- quality paths for electricity distribution businesses from 1 April 2025 – Proposed process (25 May 2023) |

## Notice of intention to consult on a potential IM amendments

5.2 On 20 May 2024, we issued a notice of intention to consult on potential IM amendments relating to insurance entitlements and other compensatory entitlements and their treatment in relation to asset valuation, tax, and the incremental rolling incentive scheme. Further details on the potential IM amendments will be released in due course.

## How to provide your views on this paper

5.3 This section sets out the process we intend to follow for the rest of the DPP4 reset. It details the next steps of the process and provides details on how you can provide your views on the content of this paper to us.

**Table 5.2 Process followed for the DPP4 so far**

| Date | Publication/Event |
|---|---|
| **7 November 2022** | Online workshop with EDBs on the challenges of forecasting and incentivising efficient expenditure[104] |
| **25 May 2023** | Publication of the DPP4 process paper[105] |
| **23 June 2023** | Submissions on the Process paper were due and have been published on our website[106] |
| **9 August 2023** | Online knowledge sharing presentation: An introduction to the DPP[107] |
| **2 November 2023** | DPP4 Issues paper published[108] |
| **10 November 2023** | Issuance of s 53ZD notice: Information request for non-exempt EDBs |
| **19 December 2023** | Submissions on Issues paper closed |
| **26 January 2024** | Cross-submissions on Issues paper closed |
| **22 February 2024** | Preliminary version of the DPP4 financial model published |
| **22 February 2024** | Financeability issues paper published[109] |
| **26 February 2024** | Stakeholder workshop on Capex framework, written submission period followed |
| **4 March 2024** | Stakeholder workshop on Innovation and non-traditional solutions allowance, written submission period followed |
| **15 March 2024** | Submissions on Financeability issues paper closed |
| **20 March 2024** | Issuance of s 53ZD notice: Information request for non-exempt EDBs |
| **29 March 2024** | Cross-submissions on Financeability issues paper closed |

[104] Commerce Commission, "Online workshop: forecasting and incentivising efficient expenditure for EDBs", (7 November 2022).

[105] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Proposed process" (25 May 2023).

[106] Eleven submissions were provided to the Commerce Commission by 23 June 2023. They are available to view on the following Commerce Commission "Submissions due on process paper" webpage.

[107] Commerce Commission, "Online knowledge sharing presentation: An introduction to the default price-quality path", (9 August 2023).

[108] Commerce Commission "Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023).

[109] Commerce Commission "DPP4 reset – Financeability of electricity distribution services in the default price-quality path – Issues paper" (22 February 2024).

**Table 5.3 Dates for future DPP4 process**

| Date | Publication/Event |
|---|---|
| **July 2024** | Information gathering request (s 53ZD notice) issued |
| **12 July 2024** | Submissions on this paper due |
| **2 August 2024** | Cross-submissions on this paper due |
| **31 August 2024** | Information disclosure data for the year ended 31 March 2024 available |
| **By 29 November 2024** | DPP4 Final Determination and DPP4 Final reasons paper published |

## Submissions

5.4 We welcome your views on the matters raised in this paper, in this timeframe:

**5.4.1** submissions by 5pm on **Friday, 12 July 2024**

5.4.2 cross-submissions by 5pm on **Friday, 2 August 2024**.

5.5 Please note we are only consulting on the draft decisions in this paper. We are not reconsulting on the recently finalised decisions made in the 2023 IM Review.

5.6 Responses should be addressed to:

Ben Woodham, Electricity Distribution Manager

c/o infrastructure.regulation@comcom.govt.nz

5.7 Please include 'Submission on EDB DPP4 Draft decision' in the subject line of your email.

### Format for submissions

5.8 We prefer submissions in both a format suitable for word processing (such as Microsoft Word document) as well as a 'locked' format (such as a PDF) for publication on our website.

### Confidential submissions

5.9 We discourage requests for non-disclosure of submissions so that all information can be tested in an open and transparent manner. However, we recognise that there may be cases where parties that make submissions may wish to provide information in confidence.[110] We offer the following guidance.

[110] Parties can also request that we make orders under section 100 of the Commerce Act 1986 in respect of information that should not be made public. Any request for a section 100 order must be made when the relevant information is supplied to us and must identify the reasons why the relevant information should

5.10 If it is necessary to include confidential material in a submission, the information should be clearly marked, with reasons why that information is confidential.

5.10.1 Where commercial sensitivity is asserted, submitters must explain why publication of the information would be likely to unreasonably prejudice their commercial position or that of another person who is subject to the information.

5.10.2 Both confidential and public versions of the submission should be provided.

5.10.3 The responsibility for ensuring that confidential information is not included in a public version of a submission rests entirely with the party making the submission.

5.10.4 We request that you provide multiple versions of your submission if it contains confidential information or if you wish for the published electronic copies to be 'locked'. This is because we intend to publish all submissions on our website. Where relevant, please provide both an 'unlocked' electronic copy of your submission, and a clearly labelled 'public version'.

## Description of the content of the attachments to this paper

5.11 The purpose of the attachments is to provide supporting material that completes the explanation of how we reached the draft decisions in this paper.

not be made public. We will provide further information on section 100 orders if requested by parties. A key benefit of such orders is to enable confidential information to be shared with specified parties on a restricted basis for the purpose of making submissions. Any section 100 order will apply for a limited time only as specified in the order. Once an order expires, we will follow our usual process in response to any request for information under the Official Information Act 1982.

### Table 5.4 Description of attachments

| Attachments | Content |
|---|---|
| **Attachment A – Draft decisions at a glance** | Presents the full list of draft decisions. |
| **Attachment B – Capital expenditure** | Presents the capex allowances and explains how these have been determined. This includes explaining the decisions and how stakeholder views have informed those decisions. |
| **Attachment C – Operating expenditure** | Presents the components of the operating expenditure allowance. Explains the decisions and stakeholder views related to the base year, step changes and trend factors. |
| **Attachment D – Innovation incentives** | Presents the policy criteria for the Innovation and non-traditional solutions allowance (INTSA). Outlines the policy development process, and stakeholder views. Explains how the INTSA decision also promotes energy efficiency, demand-side management, and the reduction of energy line losses. |
| **Attachment E – Quality** | Presents the quality standards and incentives, normalisation approach for major events and the reference periods. Explains the decisions and stakeholder views related to the draft decisions related for all aspects of quality. |
| **Attachment F – Revenue path and wash up** | Presents the approach to starting prices and rates of change through the regulatory period. Explains our approach and stakeholder views on IRIS allowances, the revenue smoothing limit and implementation of the wash-up changes from the IM Review. |
| **Attachment G – Approach to assessing financeability** | Presents our approach to considering financeability at this reset. We outline the regulatory context and rationale for the approach we have taken, provide details on the financeability sense check we have completed, and how we have taken financeability into account when making related revenue setting decisions. |
| **Attachment H – Other matters** | Presents the other policy technical decisions that must be made for the DPP4 reset. Explains the analysis and stakeholder views related to regulatory period length, when to set the opex and capex allowances for Aurora's re-entry to the DPP in 2026, and the timeframes for CPP applications. |
| **Attachment I – Other inputs to the financial model** | Presents decisions about other inputs necessary to determine revenue allowances such as: the estimate of WACC we have applies based on the IMs, forecasts of CPI, forecasts of disposed assets and depreciation, and base-year data. These decisions largely implement approaches already defined by the EDB IMs and do not require any additional decision-making or judgment.<br><br>Please note the draft decisions detailed in Attachment I are not explained in the body of this paper as they are technical inputs only. |
| **Attachment J - Glossary of terms** | Provides a glossary of all acronyms used in this paper. |

# Attachment A Decisions at a glance

A1 This attachment presents the full list of draft decisions for the DPP4.

| Change relative to DPP3 | Unchanged | Minor change | Major change | IM review measure | New measure |
|---|---|---|---|---|---|

| # | Policy measure |
|---|---|
| **Capital expenditure (capex)** (See Chapter 3 and Attachment B) | |
| C1 | Use EDB 2024 AMP forecasts as the starting point for setting capex allowances. |
| C2 | Set the capex allowance in constant dollars based on the lower of an EDB's total forecast capex or 125% of its historical reference period capex, with an adjustment for forecast capital contributions. |
| C3 | Use a five-year historical reference period for setting capex allowances (2019 to 2023 for the draft and 2020 to 2024 for the final determination) with an additional cost escalation adjustment. |
| C4 | Include an allowance for the cost of financing, scaled in proportion to the capex allowance. |
| C5 | Include an allowance for the value of considerations for vested assets and spur assets equal to 2024 AMP forecasts. |
| C6 | Use the All-Groups CGPI forecast with an additional adjustment to escalate the constant price capex allowance to a nominal allowance. |
| **Operating expenditure (opex)** (See Chapter 2 and Attachment C) | |
| O1.1 | Apply a base-step-trend approach to forecasting opex. |
| O1.2 | Use 2024 as the base year. (2024 AMP forecasts used for the draft decision). |
| **Opex step changes** (See Chapter 2 and Attachment C) | |
| O2.1 | Consider proposed step-changes against a defined set of factors, incorporating judgement. |
| O2.2 | Step-changes should be significant. |
| O2.3 | Step-changes should be adequately justified with reasonable evidence in the circumstances. |
| O2.4 | Step-changes must not be captured in the other components of the DPP allowance. |
| O2.5 | Step-changes should have a driver outside the control of a prudent and efficient supplier. |
| O2.6 | Step-changes should be widely applicable. |
| O3.1 | Include a step-change to reflect increasing insurance costs. |
| O3.2 | Include a step-change for greater consumer engagement. |
| O3.3 | Include a step-change for low voltage (LV) monitoring and smart meter data. |
| O3.4 | Include a step-change for increasing cyber-security costs. |
| O3.5 | Include a step-change for the costs of software-as-a-service (SaaS). |
| O3.6 | Include a step-change reduction in Aurora's indicative forecasts to capture the end of its CPP spend. |
| O3.7 | Cap aggregate step-changes (in real terms) at 5% of trended opex excluding step-changes. |
| **Opex trend factors** (See Chapter 2 and Attachment C) | |
| O4.1 | Escalate all opex costs using the same cost escalator. |
| O4.2 | Escalate opex using the all-industries labour cost (60% weighting) and a producers' price (40%) indices, plus a 0.3% uplift to reflect EDB-specific inflation. |
| O5.1 | Scale growth forecast separately for network and non-network opex. |
| O5.2 | Use 2018-2024 as the reference period for scale elasticities and driver projections (2024 data available post-draft). |
| O5.3 | Forecast network opex scale growth with line length (elasticity 0.52) and ICPs (0.45). |
| O5.4 | Forecast non-network opex scale growth with line length (elasticity 0.35), ICPs (0.22), capex (0.30). |

| # | | Policy measure |
|---|---|---|
| O5.5 | | Forecast lines length extrapolated using recent growth rate trend, and irregular data adjusted. |
| O5.6 | | Forecast ICP count extrapolated using recent growth rate trend, and irregular data adjusted. |
| O5.7 | | Forecast capex based on a constant growth. |
| O6.1 | | Apply an opex partial productivity factor of 0%. |
| **Innovation, energy efficiency and demand-side management** (See Chapter 3 and Attachment D) | | |
| U1 | | Introduce an Innovation and Non-traditional Solutions Allowance (INTSA), capped at 0.6%. |
| U2 | | Incentivise energy efficiency and demand-side management incentives through the INTSA. |
| U3 | | Do not introduce a reduction of energy losses incentive. |
| **Quality standards** (See Chapter 3 and Attachment E) | | |
| QS1 | | Maintain separate standards for planned and unplanned SAIDI and SAIFI. |
| QS2 | | Retain annual unplanned reliability standards for SAIDI and SAIFI. |
| QS3 | | Retain the 2.0 standard deviation buffer for setting the unplanned interruptions reliability standards. |
| QS4 | | Maintain regulatory period length standard for planned SAIDI and SAIFI. |
| **QS5** | | Change the planned reliability buffer for the planned interruptions reliability standard to be a 100% uplift on the historic average, capped at a +/- 10% movement from the current standard. |
| QS6 | | De-weight the impact of notified planned interruptions by 50% in the assessment of compliance with planned interruption standards. |
| QS7 | | Retain SAIDI extreme event standard set at 120 SAIDI minutes or 6,000,000 customer minutes where specified. |
| QS8 | | Retain enhanced automatic reporting following a breach of a quality standard. |
| QS9 | | No new quality measures are introduced as part of the quality standards applying in DPP4. |
| QS10 | | Set interruptions quality standards and incentives for Aurora transitioning from a CPP to the DPP on the same basis as for other EDBs on the DPP. |
| QS11 | | Retain the requirement for reasonable reallocation of SAIDI and SAIFI following an asset transfer between EDBs. |
| **Quality incentives** (See Chapter 4 and Attachment E) | | |
| QIS1 | | Retain the revenue-linked quality incentive scheme for planned and unplanned SAIDI. SAIFI is excluded. |
| QIS2 | | Unplanned incentive rates are informed by the value of lost load (VOLL), discounted by (1-IRIS retention factor) to reflect expenditure incentives, and a further 10% to reflect quality standard incentives, with VOLL set at $35,374r/MWh. |
| QIS3 | | Planned incentive rates are reduced by 35% relative to the unplanned incentive rate. |
| QIS4 | | Planned 'notified' interruptions are reduced by 75% relative to the unplanned incentive rate to reflect less inconvenience to consumers. |
| QIS5 | | Incentives are revenue-neutral at the average of the reference period, also known as the target. |
| QIS6 | | The SAIDI caps (which determine maximum losses) are set equal to the SAIDI limits for planned and unplanned SAIDI. |
| QIS7 | | The SAIDI collars (which determine maximum gains) are set at 0 for unplanned and planned SAIDI. |
| QIS8 | | Cap revenue at risk at 2% of actual net allowable revenue. |
| QIS9 | | Do not implement any new incentive schemes. |
| QIS10 | | Do not make an explicit adjustment to match the duration of retention benefits between EDBs and consumers. |

| # | | Policy measure |
|---|---|---|
| **Normalisation** (See Chapter 3 and Attachment E) | | |
| N1 | | Normalisation only applies to unplanned interruptions, which are the only initiators of a major event day. |
| N2 | | Retain the normalisation approach used in DPP3, being:<br>- define a major event as 24-hour rolling periods (assessed in 30-minute blocks)<br>- the major event boundary value has been identified as the 1104th highest rolling 24-hour period for SAIDI and SAIFI over the 10-year reference period<br>- normalisation is applied on half-hour blocks, within a major event, where the SAIDI figure exceeds 1/48th of the boundary value, and<br>- treat major events by replacing any half-hour that is greater than 1/48th of the boundary value with 1/48th of the boundary value if that half-hour is part of the major event (can exceed 24 hours in duration). |
| N3 | | SAIDI and SAIFI major events are triggered independently. |
| N4 | | Set a higher boundary for very small EDBs. |
| N5 | | Retain additional reporting by EDBs for each unplanned major event in its compliance statement consistent with DPP3. |
| **Reference period** (See Chapter 3 and Attachment E) | | |
| RP1 | | Use a 10-year reference period from 1 April 2013 to 31 March 2023 to inform the parameters for unplanned interruptions reliability standards and incentives, with the period adjusted to 1 April 2014 to 31 March 2024 for the final determination. |
| RP2 | | Apply a reference period for planned interruptions of 2017 – 2023 for the draft decision, extended to 2017 – 2024 for the final decision. |
| RP3 | | Retain the cap on inter-period movement, ±5% for unplanned interruptions for both the SAIDI and SAIFI unplanned target and also apply this to the SAIDI and SAIFI unplanned limits. |
| RP4 | | Make no explicit step changes to reliability targets or incentives. |
| RP5 | | Make no explicit adjustments for instances of non-compliance contained within the unplanned interruption reference period dataset. |
| RP6 | | EDBs must record successive interruptions on the same basis they employed in responding to the s 53ZD notice. |
| RP7 | | Interruptions directly associated with an approved INTSA project are excluded for calculation of SAIDI and SAIFI values up to a cap of 0.5% of the respective SAIDI and SAIFI limit. |
| **Price path** (See Chapter 4 and Attachment F) | | |
| P1 | | Set starting prices based on the current and projected profitability of each supplier using a building blocks allowable revenue (BBAR) model and allowing for full in-period recovery. |
| P2 | | Set a default rate of change relative to CPI (X-factor) of 0%. |
| P3 | | Set alternative X-factors such that, in most cases, initial price shock is limited to 20% in real per-ICP terms, and the change between years within the regulatory period to 10% (based on the price shock and notional financeability assessments). |
| P4 | | Assess price shocks on a real revenue per-ICP basis, incorporating wash-ups and IRIS. |
| P5 | | Assess notional financeability using FFO/Debt and Debt/EBITDA ratios. |
| **Other inputs to the financial model** (These draft decisions are explained in Attachment I only) | | |
| M1 | | Weighted average cost of capital (WACC) of 7.37%. (This will be updated for the final decision.) |
| M2 | | Include an allowance for disposed assets, based on historical levels. |
| M3 | | Forecast depreciation on existing assets based on information provided by each EDB. |
| M4 | | Use base year data from 2024 Information Disclosures in our final decisions, and data from 2023 Information Disclosures for our draft decisions. |

| # | | Policy measure |
|---|---|---|
| M5 | | For CPI forecasts, use the most recently available RBNZ MPS forecasts from when the WACC was determined. |
| **IRIS** (Decision I1 is explained in Chapter 2 and Attachment D; decision I2 is explained in Attachment F) | | |
| I1 | | IRIS retention rate for capex is equivalent to the opex rate. |
| I2 | | Determine IRIS opex and capex forecasts in real terms (inflated by CPI). |
| **Revenue path** (See Chapter 4 and Attachment F) | | |
| R1.1 | | Apply a revenue cap with wash-up as the form of control. |
| R1.2 | | Forecast CPI based on the four-quarter average change in CPI between the first year of the regulatory period and the current year. |
| R1.3 | | Apply a 90% "voluntary undercharging" limit (or an alternative in some cases). |
| R1.4 | | Include a large connection contract (LCC) wash-up term in the wash-up accrual formula, to avoid recovery of LCC revenue from other customers. |
| R1.5 | | Allow EDBs to agree a reasonable reallocation of revenue following an asset transfer. |
| R2.1 | | Apply the revenue smoothing limit based on forecast net allowable revenue for the current year and CPI-adjusted recoverable costs from the prior year. |
| R2.2 | | Apply a revenue smoothing limit of 10%. |
| R3.1 | | Implement the revenue wash-up by specifying a re-run of the DPP4 financial model. |
| R3.2 | | Calculate the Y1 inflation wash-up based on the four-quarter average change in inflation between Y0 and Y1. |
| R3.3 | | Do not specify base revenue wash-up draw down amounts for DPP4. |
| R3.4 | | Calculate the time-value of money of the opening wash-up balance using one year of the DPP3 WACC and one year of a blended DPP3/DPP4 WACC (for a value of 5.25%). (This will be updated for the final decision). |
| **Other matters** (Decision X1 is explained in Chapter 2; decisions X1 – X5 are explained in Attachment H) | | |
| X1 | | Retain the current five-year regulatory period length. |
| X2 | | Include Aurora in the DPP4 expenditure and revenue setting process. |
| X3 | | Retain the CPP application timings set for DPP3. |

# Attachment B Capital expenditure

## Purpose of this attachment

B1 This attachment explains the capital expenditure[111] (capex) allowance for non-exempt EDBs and our approach for setting those allowances.

B2 Under the EDB IMs we must set a "*forecast aggregate value of commissioned assets*"[112] for each EDB so that we can set starting prices and apply the capex IRIS incentive during the DPP4 period. In practice, as explained in this attachment, we set a capex allowance which incorporates the forecast value of commissioned assets alongside other cost components.[113] The capex allowance is provided in nominal dollars, consistent with the overall approach to setting revenue paths in nominal terms.

B3 The capex allowance is an input to determining the revenues EDBs may earn; affecting their profitability, incentives to invest, and ability to deliver electricity lines services. Although the capex allowance is not at the outset the biggest contributor to the regulated revenue path, it is important because of the long-term implications for consumers, ie, once an asset is built, the cost recovery for these assets is spread over many years (both the return of assets - depreciation and the return on assets) and requirements for ongoing maintenance.

B4 The information in this attachment is organised into five sections:

B4.1 **Capex allowance for DPP4** – This section sets out the capex allowance for individual EDBs and as a total across all non-exempt EDBs.

B4.2 **How our draft decisions align with the decision-making framework** – This section explains how the draft decisions for the capex allowance align with the decision-making framework and are in the long-term interest of consumers.

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111 Under the ID definitions, capital expenditure comprises 'expenditure on assets' plus 'cost of financing' less 'value of capital contributions' plus 'considerations for the value of vested assets'.

112 Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 1.1.4(2) defines "forecast aggregate value of commissioned assets"

113 EDBs can choose to spend more or less than this allowance using the flexibility under the DPP to substitute opex and capex freely and to spend higher whilst incurring IRIS penalties.

B4.3 **Context for DPP4** – As part of the consultation on the DPP4 Issues paper, we sought feedback on emerging issues. This section sets out how we have reflected the feedback in our approach for DPP4.

B4.4 **Capex decisions** – This section sets our draft decisions and the rationale for those decisions.

B4.5 **Other regulatory tools** – This section describes the flexibility mechanisms that are available to EDBs to access during the regulatory period if their investment need is greater than provided for in capex allowances. It also sets out our preliminary thinking on future additional reporting to improve visibility and operation of the regulatory regime.

## Capex allowance for DPP4

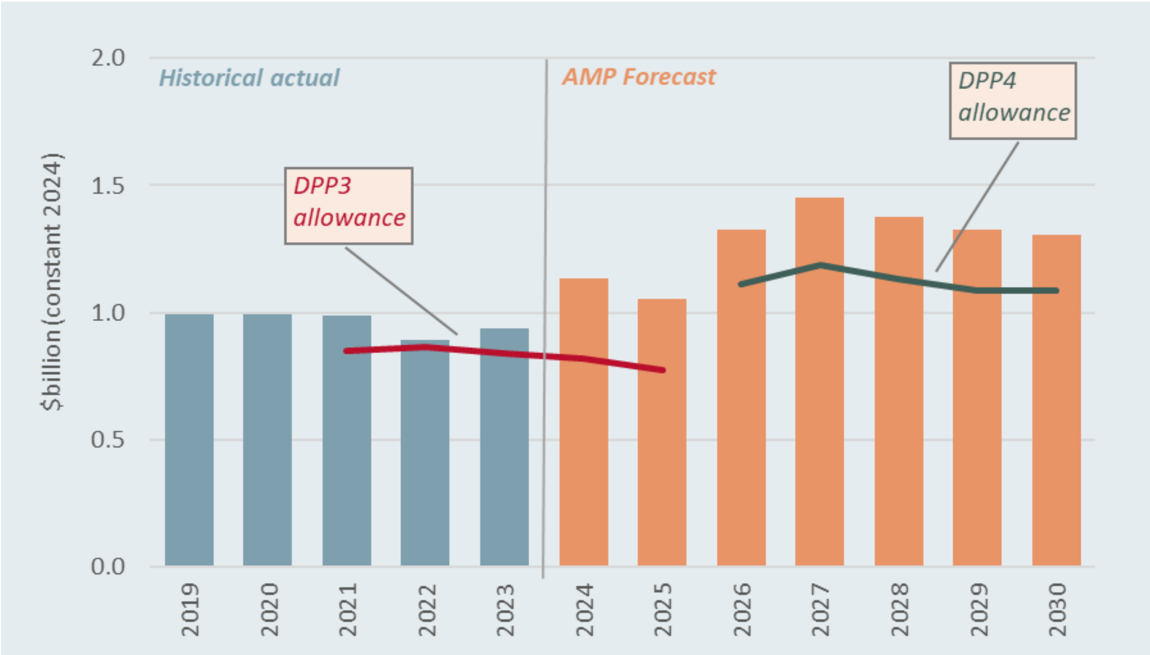
### Total capex allowance (in nominal dollars) for non-exempt EDBs for DPP4 is $6.3 billion, 17% less than forecast in EDBs’ 2024 AMPs

B5 Our draft decision includes a total capex allowance of $6.3 billion (nominal, net of capital contributions) for DPP4. The allowance is $1.3 billion or 17% less than EDBs’ 2024 AMP forecast of $7.6 billion for the DPP4 period.

B6 The allowance for DPP4 recognises that an uplift in capex is appropriate to address various needs (including to manage ageing assets, improve resilience, and support electrification) as well as to accommodate cost increases.

B7 Whilst we have set a higher allowance, we have not set it as high as forecasted in EDBs’ 2024 asset management plans (AMPs). This is in part due to our reservations about the deliverability of the large increases signalled in AMPs for DPP4, including the feasibility of such large increases ramping up over a relatively short time frame and the uncertainty in growth projections.

**Figure B1 Capex profile and DPP4 and DPP3 capex allowances[114]**




B8 Comparing between regulatory periods in 2024 constant prices, the DPP4 capex allowance of $5.6 billion is $1.5 billion or 35% higher than the DPP3 allowance of $4.1 billion.[115]

B9 The capex allowance is an initial step increase, with opportunities for EDBs to apply for higher allowances during the regulatory period as forecasts become clearer. It reflects the approach that was able to be applied under a relatively low-cost DPP, the information available to us, and the need for consumers to have confidence that step changes in investment are assessed via the appropriate regulatory tool.

[114] Capex allowances are based on forecast commissioned asset values, established net of capital contributions. DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

[115] Capex allowances are based on forecast commissioned asset values, established net of capital contributions. DPP3 allowance figures are taken from the 2019 DPP3 determination and inflated to 2024 dollars using CPI. The exceptions are Aurora, Powerco and Wellington Electricity whose allowance figures are taken from CPP and CPP-to-DPP determinations.

B10 Part 4 price-quality regulation provides a suite of flexibility mechanisms (such as reopeners, large connection contracts (LCCs), and CPPs) to meet a range of industry wide and supplier specific circumstances. We consider that for DPP4 it is appropriate that flexibility mechanisms play a more important role in funding efficient investment, than the upfront DPP4 allowance, as the additional assessment under these mechanisms are in the long-term benefit of consumers.

**The draft capex allowance is set in constant dollars, based on the lower of an EDB's total forecast capex or 125% of its historical reference period (net of forecast capital contributions)**

B11 Figure B2[116] illustrates how the DPP4 combined capex allowance across all EDBs is built up. This is explained further in the 'Capex decisions' section.

B11.1 The starting point for the capex assessment is actual expenditure on assets less capital contributions, plus the cost of financing during the reference period (2019-23 for the draft decision) in constant dollars. The historical nominal expenditure on assets, capital contributions and cost of financing are converted to constant dollars using the All-Groups capital goods price index (CGPI).

B11.2 This amount is adjusted for input price growth beyond CGPI by adding a 0.8% per annum increase to historical CGPI for each year of the reference period.

B11.3 The allowance in constant dollars is set as the lower of the EDBs' 2024 AMP forecast and the upper limit, where the upper limit is set at 125% of the adjusted historical net capex (B11.1 and B11.2), ie, an increase of 25% compared with the adjusted historical net capex.

B11.4 The resulting amount is adjusted to reflect EDBs' forecast capital contributions (for EDBs that are set an allowance consistent with the upper limit only).

B11.5 EDBs' forecast consideration of vested assets and spur assets are added.

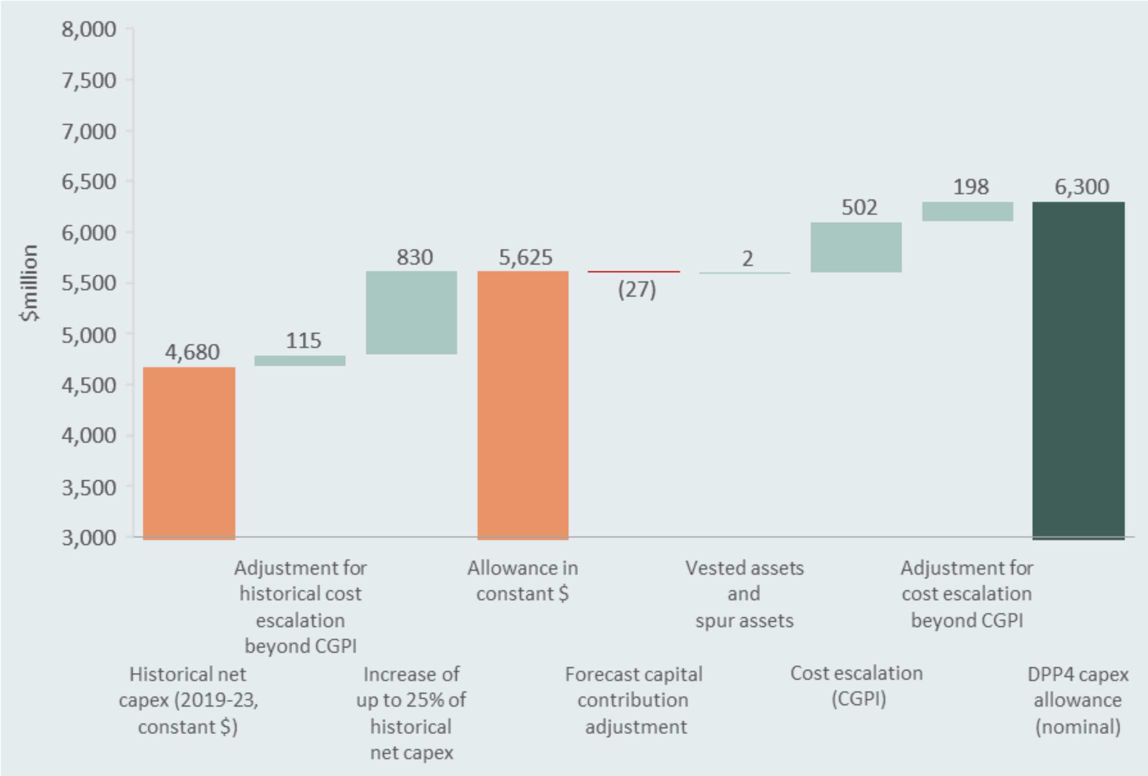
B11.6 Cost escalation is applied to provide for input price growth. The escalator is the All-Groups CGPI.

B11.7 An adjustment for cost escalation beyond CGPI is applied by adding a 0.8% per annum additional increase to forecast CGPI for each year of the forecast period.

[116] A workbook providing the breakdown of the capex allowance for each EDB will be published in early June, 2024.

B11.8 The resulting amount is the capex allowance, $6.3 billion for all EDBs combined.

**Figure B2 Components of the DPP4 capex allowance**




B12 Key differences in our approach to setting DPP4 capex allowances compared to the approach used for DPP3 are:[117]

B12.1 The draft decision provides for an increase of 25% relative to the 2019 to 2023 reference period for DPP4 (in constant dollars, net of capital contributions). The result of applying the 25% limit, whereby EDBs either get their 2024 AMP forecast or a 25% uplift (whichever is lower), is a 17% or $830m increase above the reference period capex (adjusted for historical cost escalation beyond CGPI). For DPP3 we limited increases to 20% of the reference period capex.

[117] For all EDBs combined the DPP4 allowance is 35% higher than the DPP3 allowance (in constant 2024 price terms). We note that this percentage difference is not directly comparable to the explanation of the percentages in this paragraph, which focuses on key differences in input assumptions between DPP4 and DPP3. The DPP4 draft decision reference period (2019 to 2023) only partly overlaps with DPP3 (2021 to 2025), noting that for the final decision we intend to adopt 2020 to 2024 as the reference period. The DPP4 reference period —in relation to which the maximum increase of 25% is assessed— is generally higher than DPP3 (in constant dollars). Some of the increase in DPP4 allowances compared to DPP3 is attributable to that rather than input assumptions.

B12.2 Based on evidence of higher capital goods price inflation for EDBs than in the general economy, we applied adjustments for input price growth beyond the All-Groups CGPI, which as for previous resets, continues to be our preferred cost index. The adjustment of approximately 0.8% per year to the CGPI to historical net capex and to forecast cost escalation results in an additional allowance amount of $313m ($115m adjustment to historical net capex and $198m to forecast escalation) as shown in Figure B2. For DPP3 cost escalation was a less material issue and we did not provide for adjustments.

**The capex allowance for more than half of EDBs will be equivalent to at least 90% of their AMP forecasts**

B13 The DPP4 allowance for each EDB is set out in Table B1.

### Table B1 Draft decision capex allowances for DPP4 ($million nominal)[118]

| EDB | 2026 | 2027 | 2028 | 2029 | 2030 | DPP4 Total |
|---|---|---|---|---|---|---|
| **Alpine Energy** | 32.9 | 30.8 | 27.9 | 24.9 | 29.4 | 145.9 |
| **Aurora Energy**[119] | 66.6 | 97.7 | 110.5 | 111.8 | 111.9 | 498.6 |
| **EA Networks** | 18.6 | 16.1 | 16.1 | 16.0 | 16.2 | 83.0 |
| **Electricity Invercargill** | 6.8 | 9.2 | 9.8 | 8.1 | 9.7 | 43.6 |
| **Firstlight Network** | 18.8 | 19.1 | 15.1 | 17.3 | 16.9 | 87.2 |
| **Horizon Energy** | 14.5 | 17.0 | 16.4 | 15.0 | 15.0 | 77.9 |
| **Nelson Electricity** | 2.5 | 3.0 | 3.1 | 2.7 | 2.7 | 14.0 |
| **Network Tasman** | 25.4 | 21.6 | 19.2 | 17.0 | 17.1 | 100.3 |
| **Orion NZ** | 113.6 | 139.4 | 132.6 | 139.1 | 143.0 | 667.8 |
| **OtagoNet** | 23.7 | 32.8 | 33.5 | 36.2 | 38.0 | 164.2 |
| **Powerco** | 314.9 | 337.9 | 367.2 | 375.8 | 394.3 | 1,790.2 |
| **The Lines Company** | 29.5 | 27.2 | 23.6 | 25.0 | 24.1 | 129.3 |
| **Top Energy** | 28.5 | 26.0 | 26.4 | 27.2 | 26.4 | 134.4 |
| **Unison Networks** | 73.1 | 82.8 | 80.4 | 82.8 | 101.3 | 420.4 |
| **Vector Lines** | 351.4 | 343.0 | 299.5 | 259.5 | 267.7 | 1,521.1 |
| **Wellington Electricity** | 63.3 | 98.3 | 92.5 | 93.5 | 75.3 | 422.8 |
| Total | **1,184.0** | **1,301.8** | **1,273.9** | **1,251.9** | **1,288.9** | **6,300.5** |

**Note**: The capex allowance for Vector in our draft decision package (the determination, this paper and models) reflects an adjustment for forecast capital contributions that was inadvertently applied in the modelling. The result of the error is that Vector's draft decision capex allowance states $1,521.1m when it should state $1,544.6m, in effect it is understated by $23.5m (1.5% of allowance). Instead of a capex allowance equal to Vector's 2024 AMP forecast, the allowance, in error reflects Vector's 2024 AMP forecast less an adjustment of

[118] Net of capital contributions, but inclusive of cost of financing, value of consideration for vested assets, and spur asset purchases. Note that the values in this table differ from Table 2.2.2 in the draft determination, which provides the forecast value of commissioned assets for the capex IRIS. As provided in the IMs, the values in Table 2.2.2 exclude operating leases because for IRIS purposes, operating leases are treated as opex. Table 2.2.2 in the draft determination also excludes Aurora Energy as its allowances are indicative only and subject to finalisation when Aurora Energy transitions from its CPP to the DPP in 2026.

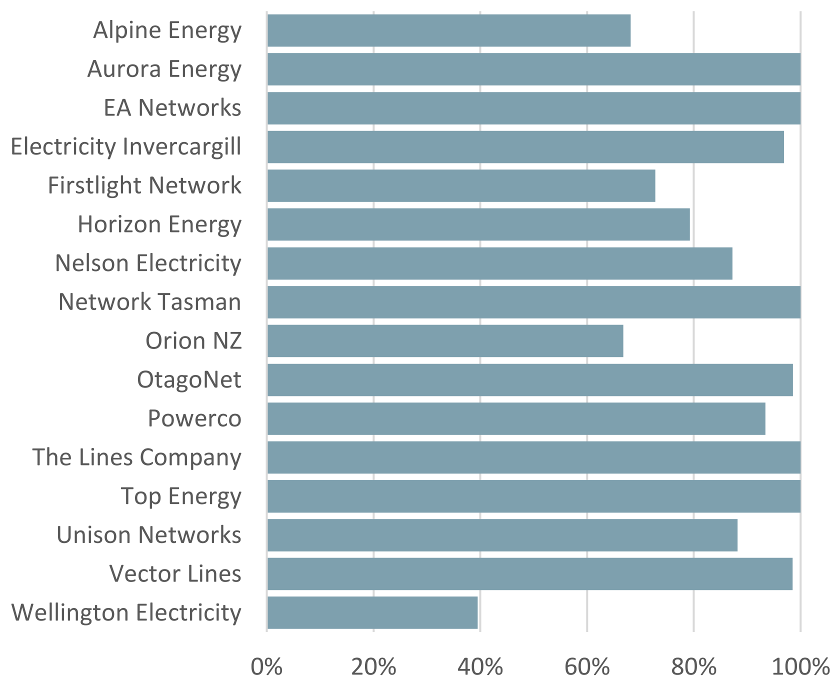
[119] The values included for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from their CPP to the DPP in 2026.

$23.5m (see Figure 2.2). We uncovered the issue with the allowance in the final stages of our quality assurance. Due to time constraints, the volume of consequential changes and the relatively small size of the error we chose not to update our draft decision documentation in light of this error.

Changes to the capex allowance have consequential impacts on revenue and opex allowances where these link to capex programme. We have not run this through the financial models with full quality assurance processes and to determine if other consequential changes are required but indicatively, we have estimated the impact would be an approximately 0.14% increase in Vector's revenue allowance. We will correct for this error in our final decision.

B14 Figure B3 expresses the DPP4 allowance as a proportion of each EDB's 2024 AMP forecast. Our draft decision means that most EDBs will have allowances that are 70% or more of their capex forecasts, which includes over half having allowances of at least 90% of their forecasts, and three EDBs with allowances of less than 70% of their forecasts.

**Figure B3 Capex allowance as a proportion of EDBs' AMP forecasts**



### How our draft decisions align with the decision-making framework

B15 In this section we explain how the draft decisions for the capex allowance align with the decision-making framework.[120] We also explain how our draft decisions are in the long-term interest of consumers, in line with section 52A of the Act.

B16 Our DPP4 decision-making framework that guides and supports our decisions for DPP4 is outlined in the DPP4 Issues paper within **Attachment A**.

### Our draft decisions are in line with the requirements of the Act and the IMs

B17 Our draft decisions for setting the capex allowances are taken with the overall objective of promoting the purpose of Part 4, in fulfilment of our statutory requirements, under section 52A of the Act.

B18 The decision-making framework requires that we apply any relevant IMs when we set price-quality paths. As noted under the 'Purpose of this attachment' section, the EDB IMs require us to set a capex allowance for each EDB.

### We have applied the low-cost principles developed in previous DPP resets

B19 Consistent with the purpose of DPP/CPP regulation, our approach for determining allowances for DPP4 have incorporated a number of low-cost principles, including:

B19.1 applying the same or substantially similar treatment to all suppliers on a DPP

B19.2 setting starting prices and quality standards or incentives with reference to historical levels of expenditure and performance, where appropriate

B19.3 where possible, using existing information disclosed under ID regulation, including suppliers' own AMP forecast, and

B19.4 limiting the circumstances in which we will reopen or amend a DPP during the regulatory period.

[120] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), Attachment A

B20 We have retained approaches from DPP3 where they remain relevant. This is the case for the use of the most recent AMPs as the starting point for setting capex allowances (**draft decision C1**), treatment of forecast cost of finance (**draft decision C4**) and value of consideration for vested assets and spur assets (**draft decision C5**). However, we have made adjustments when it comes to the reference period (**draft decision C3**) and the cost escalator (**draft decision C6**) to account for input price pressures over recent years.

B21 Our draft decision to set the capex allowance (in constant dollars) as the lower of an EDB's 2024 AMP forecast or 125% of an EDB's historical reference period (**draft decision C2**) was determined after considering section 53K (purpose of default/customised price-quality regulation), and section 52A (purpose of Part 4) and how to best give effect to these. This meant considering:

B21.1 the level of assessment that we can apply to forecast capex that is consistent with a relatively low-cost approach for setting allowances for DPP4 (see '*Set the capex allowance by capping forecast capex at an aggregate level*' section), and

B21.2 the availability of (and cost of accessing) other mechanisms to assess expenditure that is unable to be accommodated within the DPP (see '*Other regulatory tools'* section).

B22 One of the low-cost principles in the decision-making framework is limiting circumstances to reopen or amend a DPP during the regulatory period.

B23 We noted in the DPP4 Issues paper that to meet the relatively low-cost purpose of DPP regulation, we will also take into account the efficiency, complexity, and costs of the DPP regime as a whole when resetting the DPP.

B24 We anticipate that the DPP4 regulatory period will see a greater number of reopeners, as they are a relatively low-cost way to achieve an efficient outcome for areas of significant forecast uncertainty.

B25 We consider that given the high level of uncertainty the long-term benefit of consumers may be better served through an increased use of reopeners and CPPs, for expenditure which cannot be appropriately scrutinised when initially setting expenditure allowances for DPP4.

**Our draft decisions took into account the economic principles**

B26 We also have three key economic principles that we have had regard to in setting the DPP. These are useful analytical tools when determining how we might best promote the purpose of Part 4:

B26.1 Real financial capital maintenance (FCM): we seek to provide regulated suppliers the ex ante expectation of earning their risk-adjusted cost of capital (a 'normal return').

B26.2 Allocation of risk: ideally, we allocate particular risks to suppliers or consumers depending on who is best placed to manage the risk, unless doing so would be inconsistent with section 52A.

B26.3 Asymmetric consequences of over- and under-investment: we apply FCM recognising the asymmetric consequences to consumers of regulated energy services, over the long-term, of under-investment (versus over-investment).

B27 A number of submitters have raised the asymmetric consequences of over- and under-investment.

B28 Wellington Electricity stated that they consider[121] –

> …the asymmetry will increase with decarbonisation to the point that the cost of investing too early will become trivial. The environmental and long-term economic consequences of not meeting decarbonisation targets and the increasing impact of outages as customers become more reliant on electricity as their primary energy source will increase the cost difference between underinvesting (or investing too late) and over-investing (or investing too early), even further.

B29 Vector[122] and ENA[123] shared a similar view that the risks and consequences of under-investment by EDBs as a result of slower decarbonisation and less resilience in their networks in the face of extreme weather events are far more than the risk and consequences of small price increases spread over the life of the infrastructure.

B30 According to Aurora, EDBs need to invest in upgrading infrastructure ahead of increases in demand. As a result, the consequences of under-investment, or investing too late, far outweigh the impacts of investing too early.[124]

B31 However, we note that flexibility mechanisms, such as reopeners and CPPs are generally asymmetric, in that they typically are available on application of an EDB for increased allowance.

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121 Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), para 7.3

122 Vector "DPP4 Issues paper submission" (19 December 2023), p. 23

123 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 7

124 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 3

B32 The regulatory regime provides for reopeners and CPPs to provide for increased assessment of investments which cannot be appropriately scrutinised when initially setting expenditure allowances for DPP4. This protects consumers against the risk of paying for investments that do not materialise and allows consumers to engage in the appropriateness of expenditure allowances.

B33 Our approach to setting capex allowances provides for a material uplift in capex, which reflects the asymmetric consequences of over- and under-investments. However, it limits the extent of increase to reflect our allocation of risk principle that EDBs have opportunities to apply for higher allowances, through reopeners or a CPP, during the regulatory period as the need for investments becomes clearer.

B34 We consider our proposed allowances provide an appropriate balance for consumers given the evolving context for DPP4, the level of assessment consistent with a relatively low-cost regime and the availability of mechanisms to provide greater scrutiny for circumstances that are unique to individual EDBs.

## Context for DPP4

### The energy sector is in a period of change and uncertainty

B35 We are setting capex allowances within the context of an energy sector that is in a period of change and uncertainty. Where and when investment may be required by EDBs will depend on a number of factors, including:

B35.1 how government policy and consumer demand evolves. Engineering consultants, Innovative Assets Engineering (IAEngg) noted in their review of EDB's 2023 AMPs that the new growth drivers associated with decarbonisation are highly uncertain as they are influenced to a large extent by government policies and incentives[125]

B35.2 how EDBs' strategies for meeting demand for electricity lines services adapt in light of evolving market offerings to complement or substitute for EDBs' investments in network and non-network solutions

B35.3 expected improvements to investment information (eg, network risk modelling and demand forecasts); in particular, by incorporating better information on low voltage networks into investment planning, and how

[125] IAEngg "NZ EDB 2023 AMP Review Forecasting and planning assessment report" (report prepared for the Commerce Commission, 29 January 2024) . See '*Targeted reviews of 2023 AMPs confirmed that we are unable to get assurance from AMPs in a relatively low-cost way to set allowances'* section for more information on the review.

this information is reflected in renewal and growth/enhancement investment decisions, and

B35.4 further developments in industry and stakeholder views on what investments are needed, alongside developments in the national adaptation guidance and the Department of the Prime Minister and Cabinet's (DPMC) work on critical infrastructure, to improve the resilience of electricity lines services to address climate change-related risks. [126], [127]

**Growing role of non-network and distributed energy solutions**

B36 There are two broad views on how these factors shape the need for EDBs' investment over DPP4 in the provision of electricity lines services to meet consumers' energy needs. Under both views electricity lines services provided by EDBs will play a key role in enabling the electrification of New Zealand, but the quantum of additional investment in networks differs materially.

B37 One view is that to meet consumers' additional demand, a material uplift in investment is needed for network solutions to provide additional capacity. Non-network solutions have an increasing but relatively modest role.

B38 Another view, held by Rewiring Aotearoa, SolarZero and the Major Electricity Users Group (MEUG), is that the current capacity provided by distribution networks will need to be maintained and EDBs need to use distribution pricing to influence demand at a granular level (including the residential level).[128], [129], [130] Under this view EDBs' investment should largely focus on investing in renewing their existing networks because sufficient incentives exist for demand to be smoothed and shifted to time periods of available capacity, and where required additional capacity will be provided by distributed energy resources, including solar PV and batteries owned by consumers. Similar views have also been represented regarding concerns of a bias to capex risks making the energy transition more expensive than it needs to be, and that additional focus is required to ensure efficient use of existing infrastructure.

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[126] Ministry for the Environment "Aotearoa New Zealand's first national adaptation plan" (August 2022)

[127] The DPMC is progressing work to develop a new regulatory regime to enhance the resilience of NZ's critical infrastructure system, Department of the Prime Minister and Cabinet (DPMC) "Strengthening the resilience of Aotearoa New Zealand's critical infrastructure system" (June 2023)

[128] Rewiring Aotearoa "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 2

[129] Solar Zero "DPP4 Issues paper submission" (15 December 2023), p. 6

[130] MEUG in its submission to the EA on the EA's consultation paper "The future operation of New Zealand's power system

As the capex projection show, if the industry does not change course urgently there will be a large amount of capital inefficiently invested in the power system under the status quo…. New Zealanders will be lumbered with a power system that is much more costly than it needs to be… Now is the first time in history that lines pricing can be used to influence demand profile at the residential level…Lines pricing will determine the rate of growth of peak demand and the degree to which networks consider it necessary to build new infrastructure to meet growth. – Solar Zero[131]

.. today there is a systemic bias towards traditional infrastructure largely because it is seen as significantly more 'dependable'…Without a good understanding of where EDBs are in respect of non-network alternatives, we do not believe it is possible for the Commission to "give confidence that the forecast expenditure underpinning EDB price increases represents good value for money" – Rewiring Aotearoa[132]

B39 Stakeholders provided views on the importance of non-network solutions in managing and using the existing capacity of networks to potentially avoid unnecessary investment.

… we consider there should be a greater focus on demand management and that this must be integral to EDBs' forecasting… We also agree that EDBs must adapt to emerging consumer preferences and recognise the role of distributed energy resources (DER) in managing electricity peaks. As our survey research shows, there is already considerable interest from consumers in using new technologies… If the long-term interests of consumers are to be met, the Council considers demand management and reshaping the demand side of our electricity system must be given at least the same importance as investment in network infrastructure. – Consumer Advocacy Council[133]

…strongly focus on how we can better encourage EDBs… to fully optimise the use of the … distribution networks and develop non-traditional solutions, before seeking to build additional infrastructure… We consider that the current system for electricity infrastructure has a strong "bias to build" –EDBs…have continuously built "poles and wires" infrastructure to meet a relatively steady growth in demand, with assets historically sized to meet a network's peak capacity… MEUG believes that more must be done to "flatten or smooth" the demand curve, rather than continuing the practice of building networks to deal with the ever-increasing peak demand…- MEUG[134]

[131] Solar Zero "DPP4 Issues paper submission" (15 December 2023)

[132] Rewiring Aotearoa "Cross-submission on DPP4 Issues paper" (26 January 2024)

[133] Consumer Advocacy Council (CAC) "DPP4 Issues paper submission" (19 December 2023)

[134] MEUG in its submission to the EA on the EA's consultation paper "The future operation of New Zealand's power system

B40 Focusing on making better use of existing capacity in EDB networks with these initiatives instead of building networks to increase network capacity also benefits EDBs. Deferred network upgrades may mean a smaller, more manageable work programme for EDBs.

B41 However, we note that the flexibility market is still developing and may not have sufficient certainty or size to meaningfully defer EDB capex programmes. EDB investment programmes also take time to deliver and cannot be ramped up or delivered immediately. Accordingly, investment planning has to be undertaken based on an assessed likelihood of viability of alternative approaches, and the risk which arises if non-network solutions are either not available or cannot fully deliver to address network constraints.

B42 The Electricity Authority (EA) has published an open letter to EDBs on pricing reform.[135] It includes guidance on setting peak signalling prices for EDBs, and the level at which they should be set. It will be asking EDBs to reexamine the locational granularity of their network pricing, particularly if there are sections of their networks facing constraints sooner than others.

B43 The EA is currently investigating further the recommendations from the Market Development Advisory Group relating to more granular dynamic pricing for distribution networks. We note that developments such as this will help challenge the need for traditional investment in distribution networks by incentivising consumers and businesses to consider using new technologies to help better manage network congestion.

**The way that EDBs are investing continues to evolve**

B44 EDBs who are investing and operating efficiently will be planning to meet expected current and future consumer demands for service quantity and quality on a least-cost lifecycle basis. This will look different depending on the operating context and external factors that inform investment decisions such as policy settings, evolving technology and changes in consumer preferences.

[135] Electricity Authority "Open letter to distributors - distribution pricing reform" (20 May 2024)

B45 EDBs typically have visibility over their high and medium-voltage networks, but not necessarily the same level of visibility into their low voltage (LV) networks. We understand that EDBs are starting to monitor and gain visibility into their LV networks to better assist with identifying load profiles and constraints, help with network planning and provide data to inform the timing and nature of future investment decisions (eg timing of network capacity upgrades, deferring network upgrades, and implementing non-network solutions).

B46 We also understand from submissions that EDBs are needing to start capital projects earlier due to capacity constraints, making investment ahead of demand a more significant driver for forecast spend than in past AMPs.

> Electricity distributors need to invest in upgrading infrastructure ahead of the increases in demand. It is our view that the consequences of under investment, or investing too late, far outweigh the impacts of investing in network infrastructure too early. – Aurora[136]

> …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.- Powerco[137]

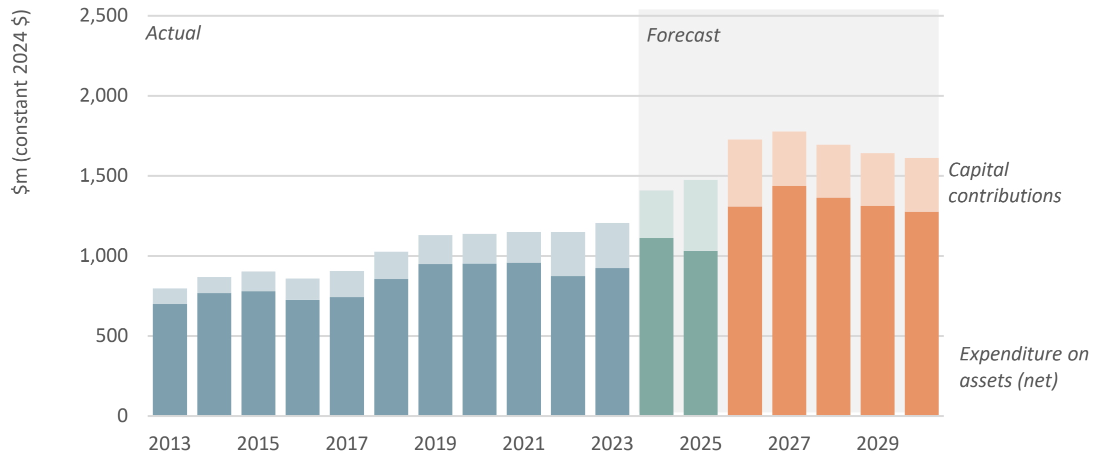
**Large capex uplifts, particularly in system growth, are signalled in AMPs**

B47 In constant 2024 dollars, EDBs have forecast to spend a total of $8.5 billion in DPP4 on assets (before deduction of capital contributions). This compares with actual expenditure on assets from 2019 to 2023 of $5.8 billion. The forecasts show that EDBs have forecast an uplift in capex for the remaining two years of DPP3 and a further increase for DPP4, as shown in Figure B4.

[136] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 3

[137] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 14

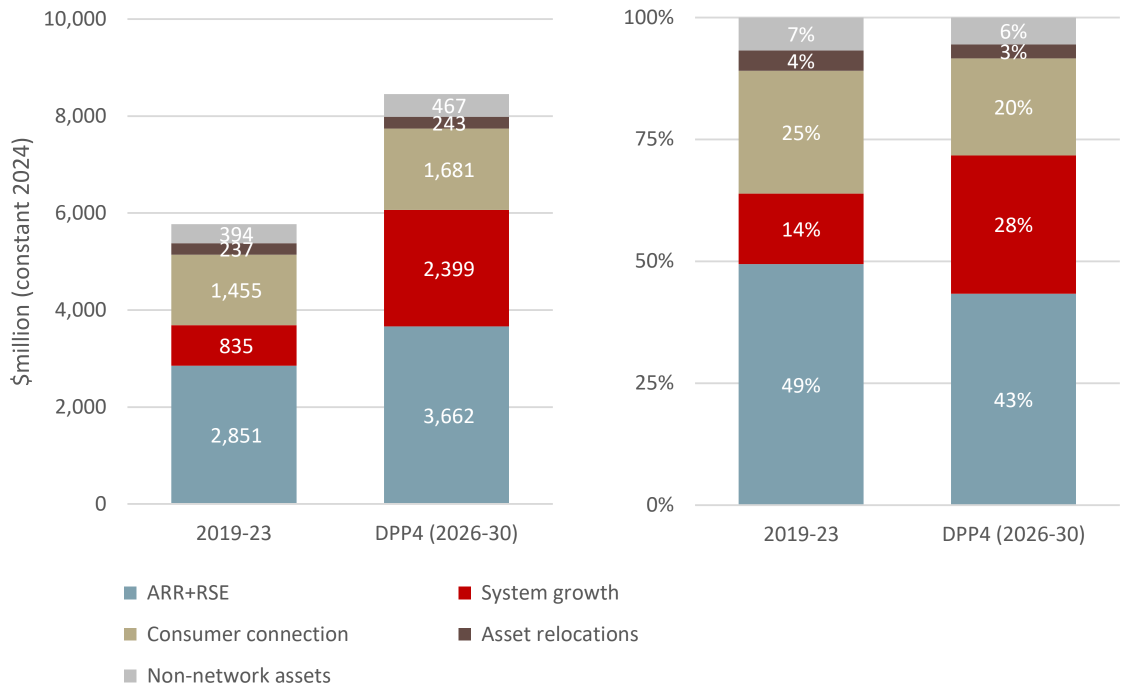
**Figure B4 Forecast and actual capex (constant 2024 dollars)**




B48 Figure B5 shows total expenditure (forecast and actual) on assets by category in constant 2024 dollars and spend as a proportion of total expenditure (before deduction of capital contributions). The forecast shows that both lifecycle renewal and system growth capex are expected to significantly increase in DPP4, with system growth forecast to have the largest increase across EDBs combined.

B49 On a proportionate basis, expenditure by asset category is forecast to remain broadly similar to historical levels for all of the categories except system growth. In constant dollar terms system growth is forecast to make up 28% of total capex (compared with 14% historically) and, due to the step increase in forecast capex, makes up $2.4 billion compared with $0.8 billion actual expenditure historically (from 2019 to 2023).

**Figure B5 Composition of capex – forecast (DPP4 period) vs actual (2019-2023) in $m and as a percentage of total capex**[138]

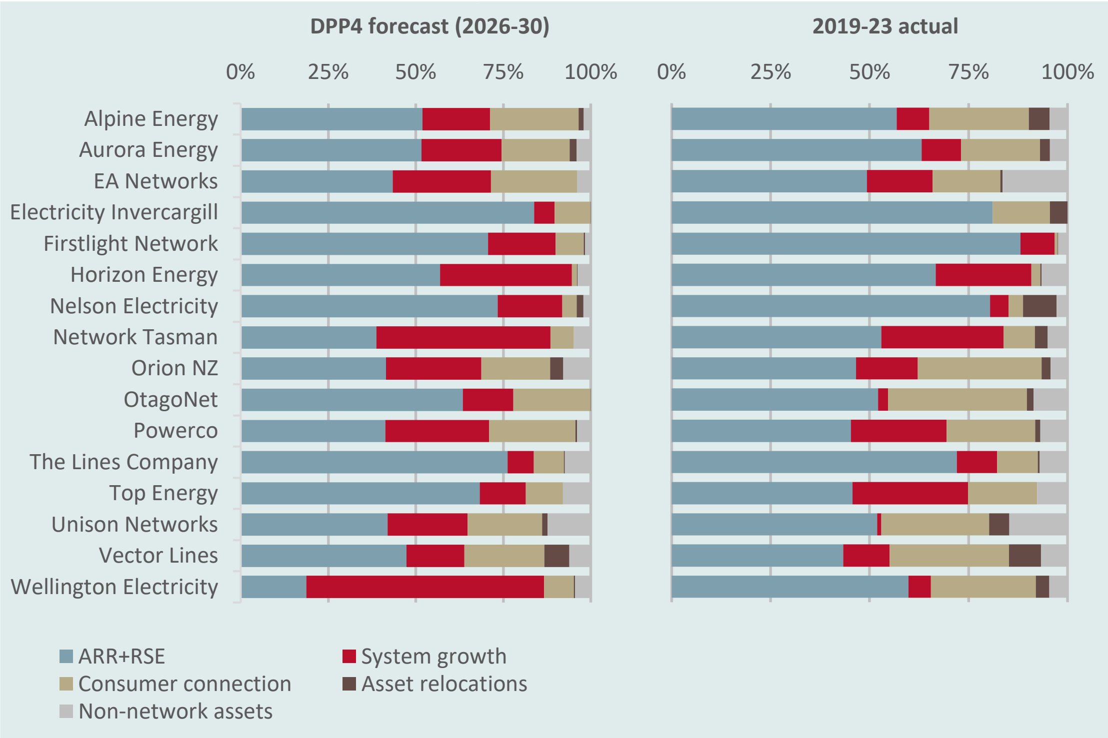



## Wide range of need across AMPs

B50 At an individual EDB level, there is wide diversity in expenditure needs. System growth capex is forecast to be a key area of investment for many EDBs, while renewal related capex – ie, asset replacement and renewal plus reliability, safety and environment (ARR + RSE) continues to be the focus for other EDBs.

[138] ARR is short for Asset replacement and renewal and RSE is short for Reliability, safety and environment

**Figure B6 Composition of forecast and actual capex by EDB** [139]

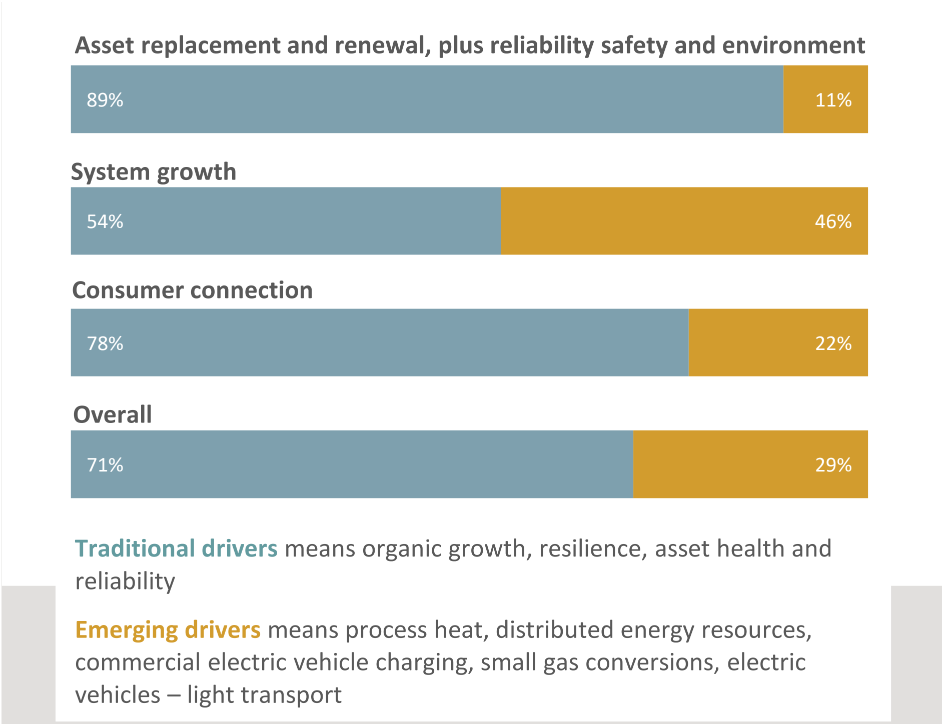



B51 EDBs with material uplifts in capex categories were asked to provide a breakdown of their draft 2024 AMP network capex forecasts by primary investment driver.[140]

[139] Total forecast capex (inclusive of capex funded from capital contributions), calculated in constant dollars

[140] Provided in response to a section 53ZD notice: Commerce Commission "Notice to supply information for 2024 DPP Reset under s53ZD" (10 November 2023) and Commerce Commission "Notice to supply information for 2024 DPP Reset under s53ZD - Attachment B and other supporting schedules" (10 November 2023)

**Figure B7 Investment drivers for different capex types**




B52 Traditional drivers continue to account for the majority of forecast in spend in aggregate, and across all categories of capex.[141] The key area of change for DPP4 is system growth where emerging drivers account for 46% of forecast spend compared with the other categories where emerging drivers overall account for no more than 22% of forecast spend.

B53 Our view is that emerging drivers are likely to be more uncertain than traditional drivers, eg, planning assumptions for electric vehicle (EV) charging stations (which is classified as emerging) are subject to greater uncertainty than planning assumptions for new residential connections (which is classified as traditional). This view is supported by IAEngg:

> Apart from business-as-usual underlying demand growth, the new growth driver arising from decarbonisation, such as process heat conversion, transport electrification and domestic gas conversion are contributing to significant demand growth forecast. The growth projections, however, are subject to a high degree of uncertainty particularly in this initial period where government and industry as a

[141] Figures reflect draft 2024 AMP figures provided in response to a 53ZD notices. Figures are approximate as they exclude forecasts from EDBs whose capex does not materially increase from historical levels. In addition, 2024 AMP forecasts may differ from draft.

whole are still coming to terms with the concrete policies and plans to achieve net zero by 2050.[142]

B54 As we explain in the 'Set the capex allowance by capping forecast capex at an aggregate level' section, our approach to setting the draft capex allowances does not rely on the distinction between emerging and traditional drivers.

B55 Given the evolving context for DPP4 and the challenges of setting capex allowances in a relatively low-cost way, within this context, it is our view that there may be some merit in shortening the regulatory period. A shorter regulatory period would allow us to consider and reflect greater certainty around drivers and other available information sooner into a new price-quality path. The length of the regulatory period is discussed further in **Chapter 2** and **Attachment H**.

## Capex decisions

B56 Our approach for setting DPP4 capex allowances, the rationale for that approach and resulting decisions are explained in this section. The six decisions that determine the capex allowance for DPP4 are as follows:

B56.1 **Draft decision C1:** Use EDB 2024 AMP forecasts as the starting point for setting capex allowances.

B56.2 **Draft decision C2:** Set the capex allowance in constant dollars based on the lower of an EDB's total forecast capex or 125% of its historical reference period capex, with an adjustment for forecast capital contributions.

B56.3 **Draft decision C3:** Use a five-year historical reference period for setting capex allowances (2019 to 2023 for the draft and 2020 to 2024 for the final determination) with an additional cost escalation adjustment.

B56.4 **Draft decision C4:** Include an allowance for the cost of financing, scaled in proportion to the capex allowance.

B56.5 **Draft decision C5:** Include an allowance for the value of considerations for vested assets and spur assets equal to 2024 AMP forecasts.

B56.6 **Draft decision C6**: Use the All-Groups CGPI forecast with an additional adjustment to escalate the constant price capex allowance to a nominal allowance.

[142] IAEngg "NZ EDB 2023 AMP Review Forecasting and planning assessment report" (report prepared for the Commerce Commission, 29 January 2024), p. 70

B57 Our decisions are cognisant that a DPP functions as part of a wider suite of regulatory tools and plays a specific role in that suite of tools (see **Chapter 1** for more information). This means that for a DPP reset, we may decide to not provide for some or all uplifts signalled in AMPs, on the basis that consumers should not face the costs of step changes in investment that have not been appropriately assessed via the appropriate regulatory tool.[143] In these circumstances, the availability of other regulatory tools (such as reopeners and CPPs) play an important role in promoting suppliers' incentives to invest.

**Draft decision C1: EDB AMPs as the starting point for setting capex allowances**

B58 In the context of a relatively low-cost regime, AMPs are the most complete information available to us, for determining capex allowances. The view that AMPs are an appropriate starting point is supported by stakeholders.

B59 EDBs are in a good position to understand the needs of their consumers and communities, and they ought to understand the health of their assets, the risks to delivering safe and reliable electricity, and what is required to manage those risks. EDBs have access to information on factors like:

B59.1 current and future demand drivers for distribution services (both the quantities of demand, and the level of quality expected)

B59.2 how to efficiently respond to this demand through conventional investment or through innovative or non-traditional approaches

B59.3 the current and future condition of their assets and the quality and safety risks these pose, and

B59.4 the costs incurred in providing these services.

B60 To the extent that capex allowances are informed by EDBs' expenditure forecasts, we are mindful that there are risks that forecasts could be set too high or too low relative to need, timing, cost or deliverability, particularly given the evolving nature of underlying drivers for investment.

B61 We note that the 2024 AMPs have been produced at a point in time and therefore reflect a range of assumptions and future scenarios. As with any forecasts that are a snapshot in time in an evolving environment, the AMPs run the risk of becoming outdated.

143 See **Chapter 1** for more about the price-quality regulatory toolkit.

**Draft decision C2: Set the capex allowance in constant dollars based on the lower of an EDB's total forecast capex or 125% of its historical reference period capex, with an adjustment for forecast capital contributions**

B62 Our draft decision is based on making three decision components, which are explained in this section:

B62.1 Set the capex allowance by capping forecast capex at an aggregate level

B62.2 Cap the increase in total forecast capex to 125% of historical reference period capex, and

B62.3 Set the capex net of forecast capital contributions.

B63 Our approach for DPP4 differs from DPP3 where we applied caps at category level before applying an overall cap of 120%. This meant that ten EDBs were capped on individual categories before the 120% overall cap was applied. The 120% cap reflected the point at which we considered the cost impact on consumers justified further assessment of expenditure and was likely to be more appropriate to assess as a CPP application.

B64 The decision to set an upper limit of 125% at an aggregate level has been made in the context of a materially larger total forecast capex value and a higher degree of uncertainty in the forecast assumptions compared with the capex forecast for DPP3.

*Set the capex allowance by capping forecast capex at an aggregate level*

B65 We have considered a range of options which we could have used to determine capex allowances for DPP4. This includes fully relying, wholly or partly, on the capex forecasts in AMPs, setting a limit on total capex, applying different limits to different categories of spend, and setting different limits for different groups of EDBs. The options can be applied at an aggregate or category level and defined in dollar or percentage terms.

B66 Given the context for DPP4 and the information that is available to us, on balance we consider a single cap applied to total capex is consistent with the relatively low-cost nature of a DPP and the high degree of uncertainty affecting expenditure forecasts at a category level.

B67 When considering which option to apply, we considered the following issues with determining DPP4 allowances:

B68 **Large uplift with ranging need.** There is a need for additional investment in distribution networks, with diverse drivers for this need that vary across EDBs (including ageing assets, demand growth to accommodate process heat electrification and expected EV uptake, and improving resilience).

B69 **Evolving environment.** Through submissions, we heard that the solutions included in EDB AMPs, particularly those with large forecast uplifts may not reflect an appropriate range of solutions, including innovative and non-traditional solutions. Some of these solutions are emerging and developing fast. The Innovation and non-traditional solution allowance (INTSA) is intended to encourage EDBs to try new things that are likely to benefit their consumers, either on their own or collaboratively. See **Chapter 3** and **Attachment D** for more about how the regime is incentivising innovation and non-traditional solutions.

> Given the substantial technological changes that are already beginning to impact the electricity industry (e.g. EV, energy efficient appliances, demand response, price responsiveness) the pattern of growth may be quite different than in the past. – Solar Zero[144]

> .. the Electricity Authority has reported that there "appears to be little progress [amongst EDBs] in establishing price signals that reward flexibility and some regression with respect to controlled hot water" , let alone the fact that large numbers of households and businesses are – today – investing in new, advanced electricity-hungry devices (such as Evs and heating/cooling equipment) that have the potential to be smartly controlled, should the price signal exist. Further, to the best of our knowledge, very few EDBs offer export tariffs that reward injections from distributed batteries at times of peak network demand , despite there being at least 4,000 distributed solar/battery installations in the country. – Rewiring Aotearoa[145]

B70 **Key demand drivers are subject to significant uncertainty.** We note that the policy and economic environment continues to be fluid and may mean that key demand drivers for forecast capex in the 2024 AMPs have changed or require updating. Our view is that given the uncertainty in key demand drivers, the DPP will be limited in its ability to accommodate the step change driven by these key drivers and that there are other mechanisms (such as reopeners and CPPs) which are more suited for assessing these changes.

[144] Solar Zero "DPP4 Issues paper submission" (15 December 2023), p. 6

[145] Rewiring Aotearoa "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 6

B71 **Limited information to understand drivers for the uplift.** Under a DPP, we apply relatively low-cost assessment of readily available information to form a view of the reasonableness of capex forecasts for allowance setting purposes. Given the context and pace of change for DPP4 and the low-cost approach to assessing AMP information, we have been unable to form a view of the reasonableness of the drivers for the uplift.

B72 The above issues are expanded on in terms of specific factors that informed our decision.

*Factors that informed our draft decision to apply an aggregate cap*

<u>Targeted reviews of 2023 AMPs confirmed that we are unable to get assurance from AMPs in a relatively low-cost way to set allowances</u>

B73 EDBs told us that the past is not a good reference for assessing future spend and that we should place a greater reliance on future focussed forecasts.[146]

B74 The DPP4 Issues paper identified that for a number of EDBs the 2023 AMPs represented a large step change in forecast expenditure. To be able to rely on forecasts contained within the AMP, particularly where there are material step-changes in forecast expenditure and historical expenditure provides less guidance on what is appropriate, having confidence in the AMPs is critical. Engaging external expert support in undertaking our review of the AMPs was intended to inform our understanding of the basis on which EDB forecasts may be used to set the DPP.

B75 As part of the independent review of 2023 AMPs, we asked engineering consultancy Innovative Assets Engineering (IAEngg), to provide a view of the elements of EDBs' forecasts that are certain and areas that have less certainty, and variations across the industry on common elements. IAEngg were tasked to identify and analyse key drivers of change, uncertainties, and variables in financial and demand forecasts and provide an opinion on the reasonableness of the variations.

[146] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023); Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025: Proposed process" (25 May 2023); Commerce Commission "Online workshop: forecasting and incentivising efficient expenditure for EDBs" (7 November 2022); Commerce Commission "Request for feedback – Expenditure forecasting by electricity distribution businesses and areas of focus for the 2025 default price-quality path reset" (15 November 2022).

B76 The independent review of the 2023 AMPs was not intended to verify expenditure forecasts and therefore does not provide an opinion on whether expenditure forecasts are reasonable. We note that the 2023 AMPs have also been superseded with the 2024 AMPs, driver information provided in response to the section 53ZD notice[147], and other economic and policy updates.

B77 The independent review of the 2023 AMPs provided some comfort that EDBs' capex forecasting approaches, as explained in their AMPs, broadly align with good industry practice but was unable to provide the assurance we needed for allowance setting purposes.

> While IAEngg can provide an opinion on the reasonableness of the forecasting approach based on assessing the quality of the forecasting model, we cannot provide an assurance of the forecasting output (volume of assets to be replaced) without examining the model inputs. In the same way, IAEngg cannot provide an opinion on the reasonableness of the expenditure forecast without access to the unit rates used to convert volumes of work into expenditure.[148]

B78 We note that the requirements for an AMP[149] differ from a CPP proposal[150] and are created for different purposes. The focus of an AMP is primarily on providing information to interested persons on asset management practices. The content and process requirements for a CPP proposal are aimed at supporting our evaluation of a supplier's expenditure proposal, including whether the proposed expenditure meets the expenditure objective.[151]

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[147] Commerce Commission "Notice to supply information for 2024 DPP Reset under s53ZD" (10 November 2023), and Commerce Commission "Notice to supply information for 2024 DPP Reset under s53ZD - Attachment B and other supporting schedules" (10 November 2023)

[148] IAEngg "NZ EDB 2023 AMP Review Forecasting and planning assessment report" (report prepared for the Commerce Commission, 29 January 2024), p. 73

[149] The requirements of an AMP are detailed within Attachment A of the Commerce Commission "Electricity Distribution Information Disclosure Determination 2012" (6 July 2023)

[150] The requirements of a CPP proposal are in Part 5 of the Commerce Commission "Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023" (13 December 2023)

[151] Expenditure objective means the objective that capex and opex reflect the efficient costs that a prudent non-exempt EDB would require to a) meet or manage the expected demand for electricity distribution services, at appropriate service standards, during the DPP regulatory period or CPP regulatory period and over the longer term; and (b) comply with applicable regulatory obligations associated with those electricity distribution services

B79 While the AMP includes requirements related to demand and related expenditure forecasts these are comparatively limited compared to what would be contained within a CPP proposal. For example, a subset of the information requirements for a CPP proposal may be met by submitting an AMP as part of a CPP proposal.[152]

B80 The final AMP review report and our view on its use in DPP4 are located on our website.[153] The review findings have been a useful input into our process for developing our approach for setting allowances, see 'Targeted reviews of 2023 AMPs confirmed that we are unable to get assurance from AMPs in a relatively low-cost way to set allowance' section for more information.

B81 We undertook a targeted review of EDB AMPs and reached similar conclusions as IAEngg. We found that forming a view on the reasonableness of expenditure forecasts for the purposes of setting allowances was not practical or possible to achieve in a relatively low-cost way. This also means that we are unable to conclude whether EDB forecasts have appropriately considered the use of non-traditional or non-network solutions to help manage demand on their networks, or whether EDB forecasts are justified and in the long-term interest of consumers.

B82 Instead, we found it more practical and useful to use AMP information to identify whether flexibility mechanisms could be used appropriately and effectively to increase allowances for investment needs that become clearer later in DPP4.

We have not been able to identify metrics and thresholds that can assess forecast capex, in a relatively low-cost way, given the context of step changes and wide-ranging needs

B83 In past resets we have used metrics and tests to assess forecast capex and set capex allowances. Given the context of change and the scale of forecast uplift in investment signalled for DPP4, we do not consider it appropriate to use metrics in the same mechanistic way as past resets.

[152] Commerce Commission "Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023" (13 December 2023), Attachment D.

[153] IAEngg "NZ EDB 2023 AMP Review Forecasting and planning assessment report" (report prepared for the Commerce Commission, 29 January 2024); Commerce Commission "Using the 'NZ EDB 2023 AMP Review' report within the DPP4 Reset" (14 February 2024)

B84 We identified a range of potential metrics for DPP4 (see Table B2) and sought feedback on these metrics at our capex workshop in February 2024[154], including on alternative approaches.

**Table B2 Metrics considered in capex workshop**

| Capex category | Metrics identified |
|---|---|
| **Total capex** | • Capex intensity trends (capex as a proportion of total capex forecast vs historical levels) |
| **Asset replacement and renewal and Reliability, safety and environment** | • Forecast vs historical spend<br>• Forecast capex vs implied (forecast) depreciation<br>• Depreciation vs depreciated asset value |
| **Consumer Connections** | • Forecast vs historical spend<br>• Forecast capex per new connection<br>• Investment driver (traditional vs emerging drivers) |
| **System Growth** | • Forecast vs historical spend<br>• Investment driver (traditional vs emerging drivers)<br>• Growth in maximum coincident peak demand<br>• Forecast capex per forecast incremental maximum coincident peak demand |
| **Non-network assets and asset relocations** | • Forecast vs historical spend |

B85 While we found the metrics useful for screening purposes, we were unable to identify approaches (including based on workshop feedback) that would allow us to get comfort about the reasonableness of capex forecasts. We did not receive any alternative analytical approaches which allow us to draw stronger conclusions on whether the expenditure proposed is reasonable.

154 Commerce Commission "Capital expenditure framework design – workshop slide deck" (19 February 2024), Slides 29-52

B86 Given the challenges outlined earlier on AMP scrutiny, our view is that the metrics we have identified are not able to effectively distinguish between forecast capex that is reasonable and forecast capex that is not reasonable. We do not consider that using a wider range of metrics would be a better approach for setting DPP4 allowances than our draft decision approach, ie, a simple assessment of forecast capex against historical reference period capex.

B87 We are open to submissions on how metrics, including metrics we set out in our capex workshop, could be used for setting capex allowances. To support submissions, *in early June 2024 we intend to publish* a workbook with metrics from the capex workshop that submitters could use to assess whether there are alternative approaches to setting capex allowances for DPP4.

Resilience is difficult to identify and separate for assessment purposes

B88 Resilience expenditure was specifically included in our DPP4 Issues paper for feedback because of the uncertainty regarding the scale of spend needed to prepare for an increasing number of severe weather and cyber security events. Our view was that recent events are likely to have changed the risks and parameters which EDBs use to assess resilience.

B89 Several submitters indicated that resilience is not a stand-alone capex project or cost category, but is instead embedded in the way EDBs design, build, operate and maintain their networks.[155]

B90 For instance, Unison indicated that its resilience work is predominantly built-in as a component of carrying out other individual work projects.[156] Similarly, Aurora indicated that investment in resilience is often integrated into its network strategies, standards, and guidelines as part of routine work.[157]

B91 PowerNet stated that[158] –

> Powernet is confident that as best as it can be, resilience planning has been, and will continue to be, reflected in our expenditure forecasts. We support the ENA submission in that resilience is not a stand-alone project or cost category, rather embedded in the design, build, and operations of our networks… Powernet, as a

155 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023),p.10; PowerNet "DPP4 Issues paper submission" (19 December 2023), p. 3; Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 14

156 Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 13

157 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 14

158 PowerNet "DPP4 Issues paper submission" (19 December 2023), p. 3

servicer of critical infrastructure is acutely aware of the need for resilient networks in an environment where the rate and scale of change is unprecedented.

B92 Vector in its 2024 AMP stated that resilience investment of around $300 million has not been included in forecasts as they continue to consult with stakeholders to determine the best value for money approach against resilience goals.[159] Vector also noted that there is value in holding more spares and inventory of key assets to respond to key weather events and global supply chain challenges. [160] We note that the current IMs enables EDBs to hold network spares as long as they are held in appropriate quantities with consideration of the reliability of the equipment and the number of items installed on the network. [161]

B93 SolarZero submitted that weather events are going to become more extreme due to climate change. [162] Therefore, new approaches are needed, and the Commission should encourage lines companies to adopt a distributed approach to resilience.

B94 Horizon pointed to the fact that resilience investment is challenging because there are multiple natural hazards that could threaten the network and there are interdependencies between infrastructure providers.[163]

B95 Powerco stated that there is increasing importance in enhancing network resilience, especially because of recent events such as cyclone Dovi and Gabrielle and the energy transition leading to increased consumer reliance on electricity.[164]

B96 In addition to submissions on the DPP4 Issues paper on this topic, we used the s 53ZD notice to collect information about how EDBs have reflected resilience in their draft 2024 AMP expenditure forecasts. [165]

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[159] Vector 2024 AMP, p. 7

[160] Vector "DPP4 Issues paper submission" (19 December 2023), p. 26

[161] Commerce Commission "Input methodologies review 2023 - Final decision - Report on the Input methodologies review 2023 paper" (13 December 2023), p227, decision AV07

[162] Solar Zero "DPP4 Issues paper submission" (15 December 2023), p. 8

[163] Horizon Networks "additional information DPP4 Issues paper submission" (19 December 2023), p. 8

[164] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 4

[165] Expenditure provided in response to the notice is grouped in terms of "primary driver" and does not necessarily represent forecast expenditure which may make an EDBs network more resilient.

B97 In response to the s 53ZD notice, two EDBs indicated that they expected to spend approximately 14% of their forecast expenditure on resilience related expenditure. Of the remaining EDBs approximately half forecasted zero expenditure where resilience was the primary driver and the other half expected to spend between 3% and 6% of forecast capex on resilience.

B98 Resilience expenditure or the portion of expenditure specifically associated with resilience is not separately itemised in EDBs AMP forecasts or AMP information. Therefore, assessing the quantum and prudency of such expenditure is difficult. This aligns with the ENA submission that “it is embedded in the way EDBs design, build, operate and maintain their networks”.[166]

B99 The feedback on the DPP4 Issues paper revealed differences in approach to resilience planning across EDBs but did not provide a clear conclusion about whether a separate assessment was needed for resilience in the capex framework or what type of adjustment was needed if any.

B100 Our assessment of the section 53ZD information and targeted review of the 2023 AMPs informed our view that there is no source for resilience expenditure information that could be assessed using a relatively low-cost approach that is a consistent with the DPP. We also note the differences in categorisation of resilience between EDBs.

B101 This conclusion is supported by the IAEngg report which attempted to assess resilience expenditure on the information available in EDBs’ 2023 AMPs. IAEngg concluded that, while it appears that all EDBs have considered planning for high-impact-low-probability events, the majority of EDBs do not itemise the expenditure they define as resilience-related. Instead, resilience expenditure has been grouped into various capex and opex regulatory categories. As such, IAEngg could not determine the reasonableness of proactive resilience expenditure given the lack of detailed information in the AMPs.[167]

B102 While resilience as an investment driver is expected to gain in importance, the form and quantum of investment for DPP4 is subject to ongoing development by EDBs. Our approach for DPP4 is to not assess resilience separately and to instead consider as part of the setting of the overall capex allowance.

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[166] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 10

[167] IAEngg 2023 AMP Review: Resilience Assessment Report, pp. 23-25

B103 For resilience projects that require expenditure beyond what is implicitly provided for in the capex allowance and meet certain criteria, EDBs have access to the new resilience reopener added in the recently concluded 2023 IM Review.

Deliverability needs to be assessed at an aggregate level

B104 Deliverability represents a risk that investment is needed but cannot be delivered due to resource constraints. The risk to consumers is that if EDBs receive allowances for projects that are not delivered, this may translate into elevated profits, not through improved efficiency but non-delivery.

B105 Deliverability is a particular concern for DPP4 given various independent reports and Transpower's independent verifier report, see the 'Deliverability of a significantly larger capex work programme' section for more detail.

B106 We expressed our concern regarding EDBs' ability to deliver their expanded work programmes while facing supply chain and labour market constraints in the DPP4 Issues paper[168] and at our capex workshop in February 2024. [169]

B107 We consider that, under a relatively low-cost DPP, it is difficult to be definitive on the scale of deliverability risk, noting that this will be different for individual EDBs and also within individual programmes. This view was also supported by Vector who stated that while an assessment of deliverability is consistent with the s52A purpose statement, it was unlikely that a highly individualised assessment of each EDB's capacity to deliver would be consistent with the low-cost objective of DPP regulation.[170]

B108 The IAEngg report noted that only a small number of EDBs appear to have clearly considered the deliverability challenge that will result from an enlarged capital programme. [171] The report further stated that –

> There is insufficient information in the AMPs for us to determine the proportion of the increased forecast expenditure that is driven by cost and the proportion driven by increased volumes of work. However, given the size of the total increase in

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[168] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023)

[169] Commerce Commission "Capital expenditure framework design – workshop slide deck" (19 February 2024)

[170] Vector "Cross-submission on DPP4 Issues paper" (26 January 2024), pp. 20-21

[171] IAEngg "NZ EDB 2023 AMP Review Forecasting and planning assessment report" (report prepared for the Commerce Commission, 29 January 2024), p. 91

forecast expenditure, it is likely that material increases in the volume of activities is forecasted.[172]

B109 AMPs do not set out the resourcing requirements (line mechanics, technicians, electrical engineers etc) to deliver the forecast plan, nor do they provide information on levels of recruitment to meet any gap between current resources and requirements over the plan period. Accordingly, in the context of industry-wide ramp-up in expenditures, we do not have visibility of industry plans to address total resource requirements. This differs from Transpower which is in the process of executing a well-developed plan to increase its workforce. The level of assessment required to assess these complexities to inform a view of the deliverability of an EDB's forecast capex programme would be inconsistent with a relatively low-cost DPP.

B110 Under a DPP, EDBs do not receive allowances for individual or category level projects. Unison, while not supporting a deliverability assessment, pointed out that:

> DPPs do not involve approval of a work programme, rather expenditure envelopes for opex and capex are included in forecast building blocks, based on a top-down approach, common to all non-exempt EDBs. Within that envelope, EDBs are free to allocate funds as required, and to respond to events that emerge during the regulatory period.[173]

B111 As such, it would be consistent to consider deliverability at an aggregate rather than at a specific programme, project or category level.

B112 Given the scale of investment forecast for DPP4 and the context for that investment, we have considered deliverability as another component of uncertainty alongside need, time and cost. We have not separated, identified or quantified adjustments for deliverability in our framework, which is consistent with how we have treated other components of uncertainty (need, timing and cost).

Issues with applying category caps compared with aggregate caps

B113 We considered setting multiple caps applied to expenditure categories or alternatively a single cap applied at an aggregate level[174], but chose not to set category caps because of:

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172 IAEngg "NZ EDB 2023 AMP Review Forecasting and planning assessment report" (report prepared for the Commerce Commission, 29 January 2024), p. 91

173 Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 11

174 For completeness we have published an alternative model which includes category caps.

B114 **Inconsistencies in classification.** Our disclosure requirements for expenditure categories require interpretation and application by EDBs about how they classify spend, particularly where there is more than one driver of expenditure. This may result in differences in how EDBs classify expenditure across different capex categories which means that setting allowances using category caps may not have sufficient rigour to place reliance on.

B115 **Unintended consequences of constraining EDBs that run cyclical programmes for different types of works.** We are aware that some EDBs run cyclical programmes for different types of works. Setting caps at category level may constrain EDBs with how they plan their programmes of work.

B116 One potential consideration with using an aggregate cap is that there are different reopeners available based on the individual capex categories, in particular there are fewer reopeners available for ARR+RSE[175] expenditure. We have addressed this risk by performing a cross check to confirm the proportion of ARR+RSE62 forecast spend that would be available for an overall cap set at a certain level. See the 'Implications for EDBs of capping expenditure at 125%' section for more detail on this.

*Cap the increase in total forecast capex to 125% of historical reference period capex*

B117 In determining an appropriate cap, we have been mindful that the DPP is intended to be 'generic' and 'sector-wide' rather than tailored to business-specific circumstances. There is therefore an element of judgement that needs to be applied when setting the cap within that context.

B118 We note that the DPP represents a base allowance. We do not set expenditure limits or restrict EDBs in their extent of spending. If EDBs forecast a need to incur additional expenditure that they may not be able to accommodate through reprioritisation of expenditure, there are other mechanisms (reopeners and CPPs) available to them that enables that expenditure to be assessed separately. We consider the additional assessment under these mechanisms instead of inclusion in the upfront DPP4 allowances is appropriate to ensure planned investments in network or non-network solutions by EDBs to provide electricity lines services are in the long-term benefit of consumers.

[175] Asset replacement and renewal and Reliability, safety and environment

B119 We consider a cap of 125% is appropriate given the need for higher capex to support electrification and respond to climate change, the wide diversity in expenditure needs across EDBs, the evolving environment, key drivers that are subject to significant uncertainty, relatively low-cost approach to assessment consistent with a DPP and deliverability challenges facing the sector. We also consider that within the context of the DPP and the availability of flexibility mechanisms such as reopeners and CPPs, a cap of 125% will promote incentives to invest while limiting EDBs ability to extract excessive profits.

*Factors that informed our draft decision to cap the increase in total forecast capex to 125% of an EDB's historical reference period*

<u>EDBs forecast need for higher allowances</u>

B120 We have evidence (see 'Context for DPP4' and 'Set the capex allowance by capping forecast capex at an aggregate level' sections) to suggest that the capex allowance for DPP4 needs to be higher and AMP forecasts are subject to greater uncertainty than past resets. This includes responding to electrification, the need to improve network resilience in response to climate change, input price pressures due to labour market and supply chain challenges and asset life cycle costs.

B121 We need to consider this when setting allowances alongside the risk of over or under forecasting, that cannot be otherwise managed by flexibility mechanisms. The applicability of these mechanisms was considered when setting the cap.

<u>Deliverability of a significantly larger capex work programme</u>

B122 As discussed in '*Large capex uplifts, particularly in system growth, are signalled in AMPs*' section, non-exempt EDBs are forecasting to spend $8.5 billion, compared with actual spend of $5.8 billion from 2019 to 2023 (in constant dollars).

B123 Total capex in constant dollars is our best available measure of the volume of work forecast by EDBs for DPP4. While DPP4 only provides funding for capex net of capital contributions, the challenge for the DPP4 period is not just about assessing need, timing and cost of investments, but also assessing how much work can be undertaken with the resources (labour and material inputs) available. It is unclear if a capex uplift of this size would be deliverable.

B124 We considered past expenditure trends to understand the scale of delivery achieved by EDBs, particularly observed step changes. Looking at historical trends, EDBs that had sustained increases in capex delivery were largely CPPs. Those EDBs would have had to plan for and implement step changes in organisational capacity and capability to be able to deliver. We were unable to infer from historical trends how EDBs as a sector would be able to deliver elevated capex work programmes when all or most EDBs individually have large programmes of work and would be competing for resources from a common pool.

B125 Our analysis of cost indices (see 'Recent input price pressures' section) show significant increases in input prices over a relatively short period of time, which may indicate shortages in the market for resources, further adding to our concerns regarding deliverability. In addition, the CGPI-Electricity distribution lines (EDB-specific CGPI) has tracked on average 0.8% per year higher than the All-Groups CGPI over the past five years.

B126 A number of external reports informed our view about deliverability:

B126.1 The Infrastructure Commission points to a constrained labour market affecting all aspects of infrastructure planning, construction and delivery, which is expected to worsen. [176]

B126.2 The New Zealand Infrastructure Strategy indicates a pipeline of infrastructure projects to the tune of about $64 billion. However, there is an estimated construction skills shortage of 118 500 workers in 2024, with shortages predicted to worsen. [177]

B126.3 The Employers and Manufacturers Association survey found that 71% of employers could not find highly skilled people, up from 40% of employers in 2022. [178] A similar survey undertaken by Kantar Public, on behalf of MBIE, found that over half of businesses (55%) struggled to find people with the right skills to fill vacancies. [179]

[176] New Zealand Infrastructure Commission. Who's working in infrastructure? A baseline report (December 2023)

[177] New Zealand Infrastructure Commission. 2022. New Zealand Infrastructure Strategy 2022-2052. NZ 30-Year Infrastructure Strategy, pp. 12, 152

[178] Employers and Manufacturers Association. Skills shortage survey. 2023. Skills-Shortage-Survey-Results-2023.pdf, p. 3

[179] Kantar Public. 2023 NZ Future of Work Survey. The future of jobs survey, p. 30

B126.4 At a regional level, the Australian infrastructure market capacity report indicates a deficit of 229 000 public infrastructure workers in October 2023. [180]

B126.5 Globally, the OECD indicates that labour shortages predate the COVID-19 pandemic. For instance, in 2019, about 55% of employers in a survey of more than 40 000 employers in 40 countries reported labour shortages. In 2022, this figure had risen to 75%.[181] The New Zealand labour market constraints appear more dire than other OECD countries, with an estimated shortfall of about 250 000 workers by 2048 across the economy.[182]

B126.6 The Transpower Independent Verifier Report and IAEngg's AMP review suggest that large sector wide and economy wide expected investment increases will likely face capacity and capability constraints. [183]

B127 EDBs told us that they have appropriate mitigations in place to manage deliverability risk or alternatively there is no risk because the increase in forecast spend is due to cost rather than quantity of work. For instance, Unison indicated that it is confident that it will deliver its work programme and that the Commission should not make judgments about the ability of individual EDBs to deliver its forecast AMPs in a DPP setting[184]. We also received submissions from a number of non-EDB stakeholders who shared our concern.[185]

B128 Despite what EDBs have said regarding their plans to recruit the workers required to deliver on their work programme, we did not get confidence that EDBs have considered the implications of resource shortages from a wider sectoral perspective.

B129 Contrary to what some EDBs have said regarding the labour market constraints easing, external reports point to on-going challenges that are likely to persist into the DPP4 period. As a result, our draft decision is to consider deliverability alongside need, timing and cost when adjusting capex allowances for uncertainty.

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[180] Infrastructure Australia. 2023. Infrastructure Market Capacity Report. Infrastructure Capacity Report, p. 64

[181] OECD. 2023. Retaining talent at all ages. Aging and employment policies. OECD Publishing. Paris. Aging and employment policies, pp. 13-14

[182] BusinessNZ. The future of workforce supply (Feb 2023), p. 43

[183] GHD Advisory Transpower RCP4 Independent Verification Report (12 September 2023)

[184] Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 11

[185] Major Electricity Users' Group (MEUG) "DPP4 Issues paper submission" (19 December 2023), p. 4

The potential influence of wider contextual developments on forecast investment needs and consideration of consumer interests

B130 We noted in our DPP4 Issues paper that the context for DPP4 continues to be fluid as EDBs respond to evolving technology, changing consumer preferences, government policies and changing economic conditions. The scale and timing of actions required to respond to these factors will not be uniform across EDBs or within an EDB's own network.

B131 As discussed in the '*Context for DPP4'* section, where, when and how much investment will be required by EDBs will depend on a number of factors that are continuing to evolve. Non-network and distributed energy solutions continue to evolve and will influence future investment decisions.

B132 For example, the IAEngg report noted that process heat conversion and residential gas to electricity conversion are two of several underlying key drivers that have put upward pressure on EDB capex forecasts. In line with the commitment to reduce greenhouse gases to net zero by 2050, the demand for natural gas is expected to decline given the transition to renewable energy. However, the rate at which gas use will decrease is uncertain and there is no clarity as to when gas use may be phased out entirely. The pace of transition away from gas is currently unclear which means the speed and extent of electrification required to support the gas transition is also unclear.

B133 We have considered the risk to consumers of capex forecasts being too high, too low or alternatively too ambitious to deliver from the uncertainty in these external drivers. This includes ensuring the incentives to innovate and invest efficiently are promoted when setting the cap, ie, uncertain or large step increases in expenditure should be assessed using the most appropriate mechanism.[186] Given the evolving context for investment, we consider it appropriate to limit the increase in forecast expenditure to 125% and expenditure beyond this to be assessed through other mechanisms when investment needs become clearer.

[186] See **Chapter 1** for more about the price-quality regulatory toolkit.

<u>Implications for EDBs of capping expenditure at 125%</u>

B134 In setting the cap, we have considered, at a high level, the implications for EDBs of having capped expenditure. EDBs have options available to them which include both managing within and outside their revenue limits. Those options include:

B134.1 operating within their revenue limits by reprioritising and substituting spend, including potential deferral of projects, noting that the price-quality path setting provides a revenue allowance, but not a cap on what can be spent ie, EDBs can substitute between opex and capex

B134.2 utilising flexibility mechanisms ie, LCCs, reopeners where these are available or CPPs (see the 'Role of flexibility mechanisms' section for more information)

B134.3 choosing to incur additional expenditure implicitly beyond that provided for in the price-path, and

B134.4 increasing the share of cost recovery directly from consumers rather than through regulatory allowances by changing capital contribution policies.

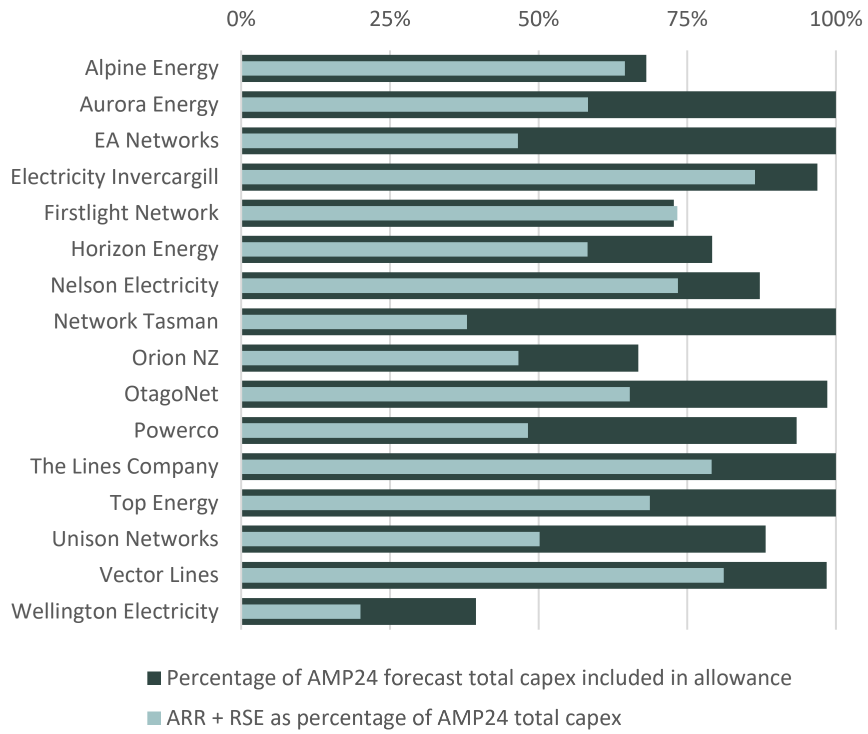
B135 As discussed in the '*Targeted reviews of 2023 AMP confirmed that we are unable to use AMPs in a relatively low-cost way to set allowances*' section, we are unable to form a view from our relatively low-cost approach to assessing the AMPs that EDBs have invested efficiently and in the long-term benefit of consumers, including whether they have appropriately considered the use of non-traditional or non-network solutions to help manage demand on their networks. As a consequence, we need to be mindful when setting the cap that it is not so high that it acts as a disincentive to invest or explore non-network solutions and innovation.

B136 The DPP has features which respond to the issue of efficient investment choices, which will continue to apply in DPP4. In particular the Incremental Rolling Incentive Scheme (IRIS) mechanism, which matches incentives between choosing an opex or capex solution and the INTSA scheme which provides incentives for EDBs to innovate. See **Chapter 3** and **Attachment D** for more detail on these incentives.

B137 In line with our decision-making framework, we have considered the implications of increased use of flexibility mechanisms by EDBs in setting the cap. As part of this we considered the availability of flexibility mechanisms for EDBs with capped forecasts by undertaking a targeted review of their 2024 AMPs.

B138 We also focussed on ensuring at a high level that the allowance, if capped at 125%, would be sufficient (see Figure B8) to enable the majority of EDBs to meet their forecast renewal-related investment needs (asset replacement and renewal and reliability, safety and environment) and provide some allowance for load related investments (system growth and consumer connection). This focus reflects that there are more flexibility mechanisms available for load-related expenditure categories and limited options for renewal-related expenditure categories.

**Figure B8 Asset replacement and renewal (ARR) and Reliability, safety and environment (RSE) capex as a proportion of capped expenditure**




B139 We consider the cap of 125% is appropriate following our high-level consideration of the implications for EDBs.

*Set the cap net of forecast capital contributions*

B140 When we set ex ante revenue allowances under a DPP or a CPP, we set revenue relating to capex allowances net of capital contributions. This approach reflects that under Part 4 price-quality regulation, we only set the maximum revenues for lines services recoverable through lines charges. Part 4 does not control revenue or monies recovered through contributions directly from consumers, which is subject to regulation by the Electricity Authority (the distribution pricing regulator).

B141 Capital contributions are a substantial funding source used by many EDBs to meet part of the requirement for expenditure on assets. Changes in the level of capital contributions can have a material effect on the level of funding available for capex.

B142 Capital contributions vary widely year-on-year, for each EDB and within each expenditure category, however, in general the portion of expenditure covered by contributions is relatively consistent over time. We note that changes in the forecast level of contributions can have a material effect on forecast capex.

B143 In our DPP4 Issues paper, we noted the significant increase in forecast funding of system growth from capital contributions by Vector, who forecast to recover all system growth costs from capital contributions in their 2023 AMP. This compares with Vector ramping up its recovery of system growth capex from capital contributions from nil in 2021, to 3% in 2022 and 45% in 2023. Historically, capital contributions by other EDBs were predominantly used to fund consumer connections and asset relocations.

B144 We have analysed forecast capital contributions and found that most EDBs are forecasting capital contributions in line with historical contributions. We note that the capex forecasts capture EDBs assumptions regarding the level of capital contributions over the DPP4 period and that this may differ from historic levels.

B145 The historical reference period has been adjusted to reflect forecast capital contribution before the cap of 125% is calculated, see Figure B9 for an illustrative example of that calculation.

**Figure B9 Illustrative example of the calculation of the cap**

| | **$million** | **Forecast (a)** | **Historical (b)** |
|---|---|---|---|
| 1 | Total capex | 100,000 | 50,000 |
| 2 | Capital Contributions | 20,000 | 5,000 |
| 3 | **Total capex, net of capital contributions** | **80,000** | **45,000** |
| 4 | Capital contributions as proportion of total capex | 20% | 10% |
| 5 | Historical capex net of forecast capital contributions (1b x (1-4a)) | **40,000** | |
| | **Capex allowance (5 x 1.25)** | **50,000** | |

B146 We are mindful that EDBs may receive windfall gains or losses if capital contribution amounts change relative to those implicit in capex allowances. An increase in monies received through contributions (that were in the allowance setting assumed to be recovered through line charges) provides for a windfall gain. A decrease on monies received through contributions represents a loss.

B147 Connection pricing (including capital contributions) was one of five key issues addressed in the Targeted Reform of Distribution Pricing: Issues Paper published by the Electricity Authority (EA) in July 2023. [187] Having considered feedback and further analysis, the EA has decided to work with industry to develop a draft Code amendment to mandate efficient connection pricing. The EA plans to release its proposal for consultation in late 2024. If the EA introduces connection pricing controls through the Code, this could lead to some EDBs changing their capital contribution policies. Final decisions on any proposed Code amendments are likely to be in the first half of 2025, ie, during the DPP4 regulatory period. Section 54V(5) of the Commerce Act 1986 enables us to accommodate Code changes from that review if asked by the EA.

B148 We are considering including additional disclosure obligations for material changes to capital contributions policies by EDBs in future consultations on ID requirements. The disclosure would include including reasons for the change and how the change better promotes the long-term benefit of consumers. This will enhance visibility of the changes to the EA and other interested persons.

**Draft decision C3: Set the allowance relative to an adjusted five-year historical reference period**

B149 Based on our analysis of historical trends and consideration of feedback from interested stakeholders, our draft decision is to use a reference period of five years, ie 2019 to 2023 for the draft, updated to 2020 to 2024 for the final decision. This five-year period reflects the higher capex profiles of EDBs post the COVID-19 period and reflects an increased focus on decarbonisation. We note the result is similar to the 10-year average.

B150 Our draft decision also includes an adjustment to the reference period of 0.8% per year, applied to the All-Groups CGPI, in response to feedback from EDBs and our own analysis of input price pressures.

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[187] Electricity Authority "Targeted Reform of Distribution Pricing: Issues Paper" (5 July 2023)

*Factors that informed our draft decision*

There is value in using a historical reference period in DPP4

B151 In past DPP resets, we have been more likely to rely on capex forecasts that:

B151.1 do not represent a material variance from historical levels of investment

B151.2 may represent a material variance in percentage terms, but less material in absolute dollar terms, and

B151.3 represent a material variance (within constraints) but the variance is appropriately supported by information in the AMP as evidenced through the AMP review and/or our analytics.

B152 EDBs have told us that unlike past resets, past expenditure is unlikely to be as relevant an indicator for future capex for DPP4.

> Our changing energy system reinforces the need for DPP4 to be forward looking and flexible, with historical information not being the appropriate reference for the nature and scale of future capex and opex. – Energy Sectors Transitions Framework[188]

> Relying on historical spending as a foundation is suboptimal when forecasting future expenditure and establishing expenditure allowances for EDBs. Increasing electrification demand, ageing asset bases, and the impacts of major weather events such as Cyclone Gabrielle are driving a level of unprecedented investment need. – First Light Networks[189]

> At the current pace of electrification and decarbonisation changes PowerNet is managing, our view is capex and opex allowances for DPP4 and future DPP's should be based on EDB 2024 AMP's and not wedded to a previous period where decarbonisation was barely on the horizon. – PowerNet[190]

B153 Other stakeholders also agreed that the past is not a good starting point for considering future spend because of the context of change and acknowledged the challenge of low-cost regulation in that environment.

> Past expenditure is not a good starting point for considering future spend, just as past philosophy and settings is not a good starting point. The electricity industry ought to be going through a major technological step change. We would hope that

[188] Energy Sector Transitions Framework (via PowerCo) "DPP4 Issues paper submission" (19 December 2023), p. 3

[189] Firstlight Network "DPP4 Issues paper submission" (19 December 2023), p. 2

[190] PowerNet "DPP4 Issues paper submission" (19 December 2023), p. 4

> future spend would be quite different because the industry will start to adopt new and better technologies and new and better ways of doing things. – Solar Zero[191]

> Low-cost regulation is difficult to achieve when there is wide disparity in the scale and density of electricity distribution business (EDB) operations or where they face different step changes in market conditions and are adopting different investment responses to those changes. – Major Electricity Users' Group[192]

B154 We consider that historical capex continues to be useful in the context of a relatively low-cost DPP. Without reference to a historical reference period, it would be difficult to understand the relative scale of change. Use of absolute or set dollar values do not work well for EDBs who have wide variability (size and nature of network, consumer base, and how they respond to drivers). Past expenditure enables us to reflect these characteristics in a relatively low-cost way and is also reflective of each EDB's baseline capacity to deliver. The use of a reference period does not require that the values are capped at historical levels and can consider changes in underlying demand or cost factors.

B155 Feedback on this view, from the capex workshop, appeared to indicate that stakeholders understood the need for this approach given the relatively low-cost nature of the DPP. There were no submissions that objected to the use of a historical reference period for assessment purposes.

Our analysis of historical trends in capital expenditure by individual EDB

B156 We analysed the historical trend in capital expenditure from 2013 to 2023 by individual EDB and identified three types of categories of trends which informed our decision to use a five-year reference period.

B157 Many EDBs showed either a steady increase or a series of step-change increases in their capital expenditure profiles. Notably, capex for these EDBs reached new levels during the period 2019 to 2023, which would support a reference period of the latest five years.

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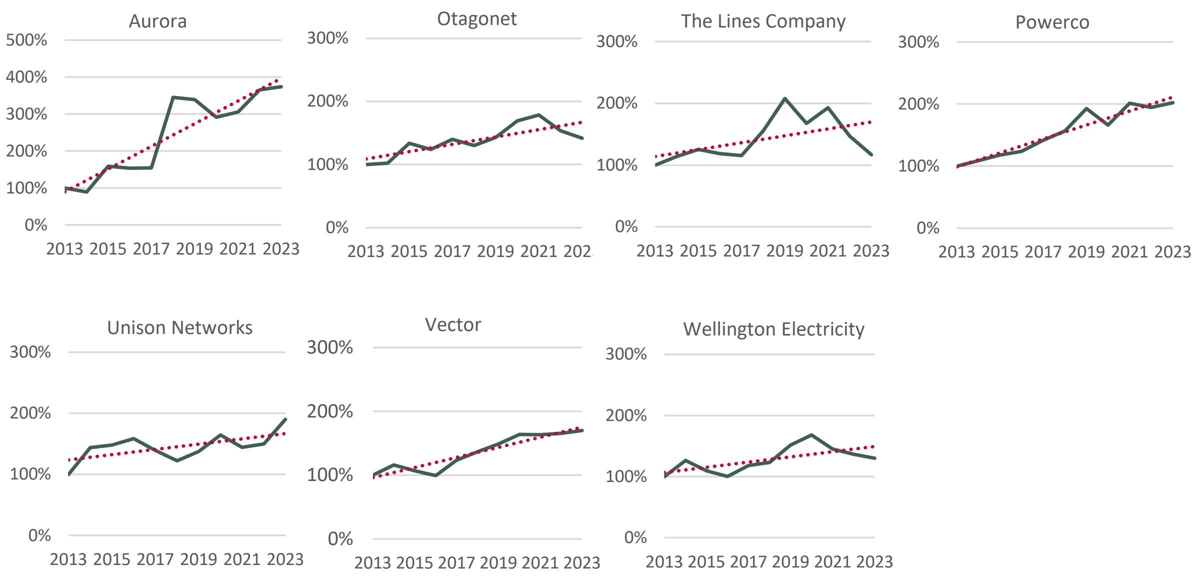
191 Solar Zero "DPP4 Issues paper submission" (15 December 2023), p. 4

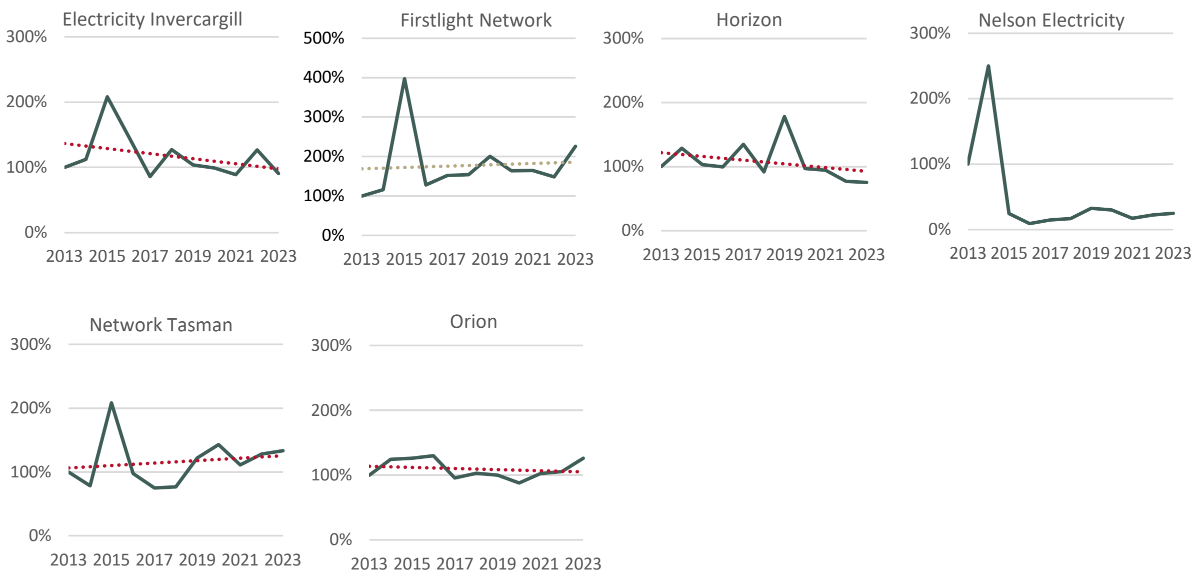
192 NZIER "EDB Default Price-Quality Path - Comment on Issues paper" (prepared for MEUG, 19 December 2023), p. 4

## Figure B10 Increasing trend in capital expenditure from 2013 to 2023



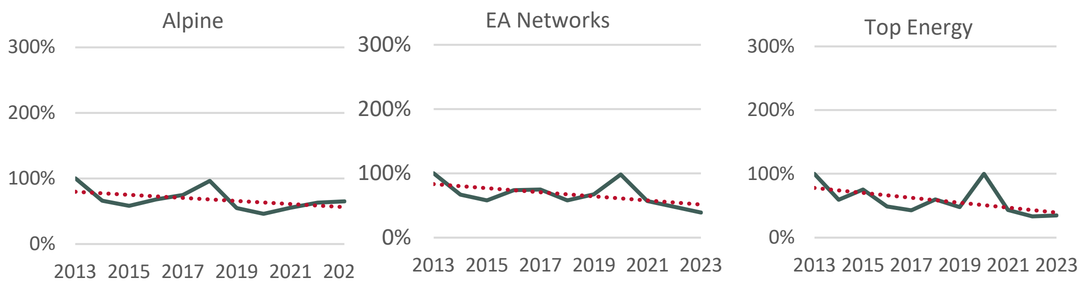

B158 Some EDBs manifested a sideways trend, which may suggest that a long-run average may be more appropriate to smooth out the volatility. However, for most of the EDBs in this category, the five-year average is similar to the 10-year average.

## Figure B11 Sideways trend in capital expenditure from 2013 to 2023




B159 A few EDBs had overall declining levels of capital expenditure. A very short reference period may penalise this category of EDBs. However, the five-year average for these EDBs turns out to be similar to the 10-year average.

**Figure B12 Downward trend in capital expenditure from 2013 to 2023**




B160 Our analysis indicates that a five-year reference period is appropriate for DPP4.

Feedback from stakeholders

B161 At the capex workshop, we presented three potential options for a historical reference period, for feedback from interested stakeholders and outlined our view that:

B161.1 three-years captures recent market challenges, emerging trends and global events like the COVID-19 pandemic and global conflicts

B161.2 five-years reflects a regulatory period and appears to minimise the extremes for individual EDBs, and

B161.3 more than five years captures more than one regulatory cycle and may provide a more normalised view of spend given the long life of assets and the lumpiness of capex profiles. Note a reference period of seven years was used in DPP3.

B162 There were mixed views on the choice of reference period:

B162.1 Most respondents (six out of eight) supported a three-year reference period, which includes the ENA[193] who suggested using a weighted rather than a simple average.

> The historical reference period used should primarily focus on the current and future cost and operating environment faced by EDBs. In practice, this means that the historical reference period should be the weighted average actual capital expenditure over the current regulatory control period (2020-2025) with a greater weighting on more recent years. – Electricity Networks Association

[193] Electricity Networks Aotearoa "Submission on Capex framework design workshop" (11 March 2024), pp.2-3

B162.2 Alpine Energy[194] submitted a preference for a longer reference period than five years because of the lumpier profile experienced by smaller EDBs.

> The short timeframe for comparison (2019-2023) used with these metrics disproportionately impacts smaller networks, like Alpine with lumpy expenditure forecasts driven by large upgrades to increase network capacity. We propose that longer reference periods are considered to as an alternative to have a "catch-all" for historic lumpy expenditure. – Alpine Energy

B162.3 Horizon Energy[195] told us that they did not have a strong preference for the reference period.

B162.4 Submitters who supported a shorter reference period tended to think that it would better represent current cost conditions.

> We believe that using data from the three most recent years offers a suitable basis for evaluating the scale of change in the DPP4 period. Data going further back may not accurately capture the evolving trends in the operating environment of EDBs. – Powerco[196]

> A more recent period will also pick up exposure to supply chain constraints which have increased material costs for EDBs across Aotearoa which are unlikely to subside over the DPP4 period. In addition, a more historical profile will not pick up emerging expenditure related to large and small connection growth, energy transition (growing cities, data centres, process heat conversion, EV uptake etc.). – Vector[197]

B163 Overall submitters who preferred a shorter period were concerned about input price pressures not being reflected adequately with a longer period.

B164 Given the lumpiness of capex, we consider it appropriate to consider input pressures separately from the choice of reference period. Based on our analysis, we consider a reference period of five-years is an appropriate reference period for capex. We have considered and responded to feedback on input price pressures in the following section.

194 Alpine Energy "Submission on Capex framework design workshop" (11 March 2024), p.3

195 Horizon Networks "Submission on Capex framework design workshop" (11 March 2024)

196 Powerco "Submission on Capex framework design workshop" (11 March 2024), p. 4

197 Vector "DPP4 Issues paper submission" (19 December 2023)

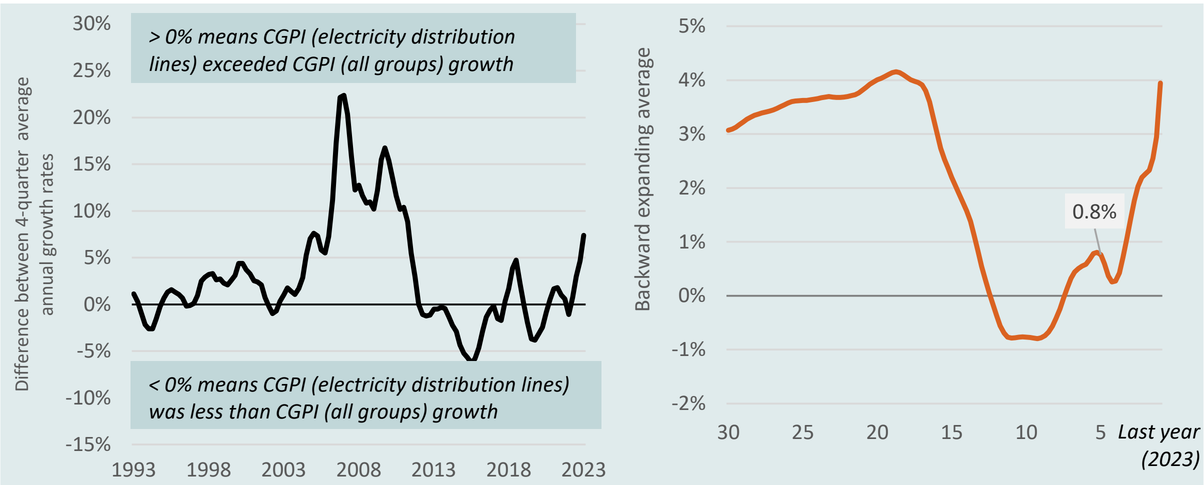
Recent input price pressures

B165 For DPP4, we are proposing to set capex allowances using a cap relative to a historical reference period in 2024 constant dollars. If the reference period capex does not appropriately reflect changes to input prices, then capex allowances may be set unintentionally low.

B166 EDBs have told us that they have experienced higher input prices in recent years and that this increase has been reflected in their capex forecasts. Our analysis of price indices and other alternative sources of evidence, confirm that some form of adjustment to the reference period is warranted.

B167 Figure B13 shows the historic average growth rate between the CGPI-Electricity distribution lines (EDB-specific CGPI) and the All-Groups CGPI. Our analysis shows that over the past five years the EDB CGPI has been tracking on average 0.8% per annum higher than the All-Groups CGPI.

**Figure B13 Difference in average growth rates between the All-Groups CGPI and the EDB-specific CGPI**




B168 We also considered alternative sources of evidence for our adjustment. The ENA provided combined data from a sample (8 of 16) of non-exempt EDBs on for the period from 2019 to 2023 on:

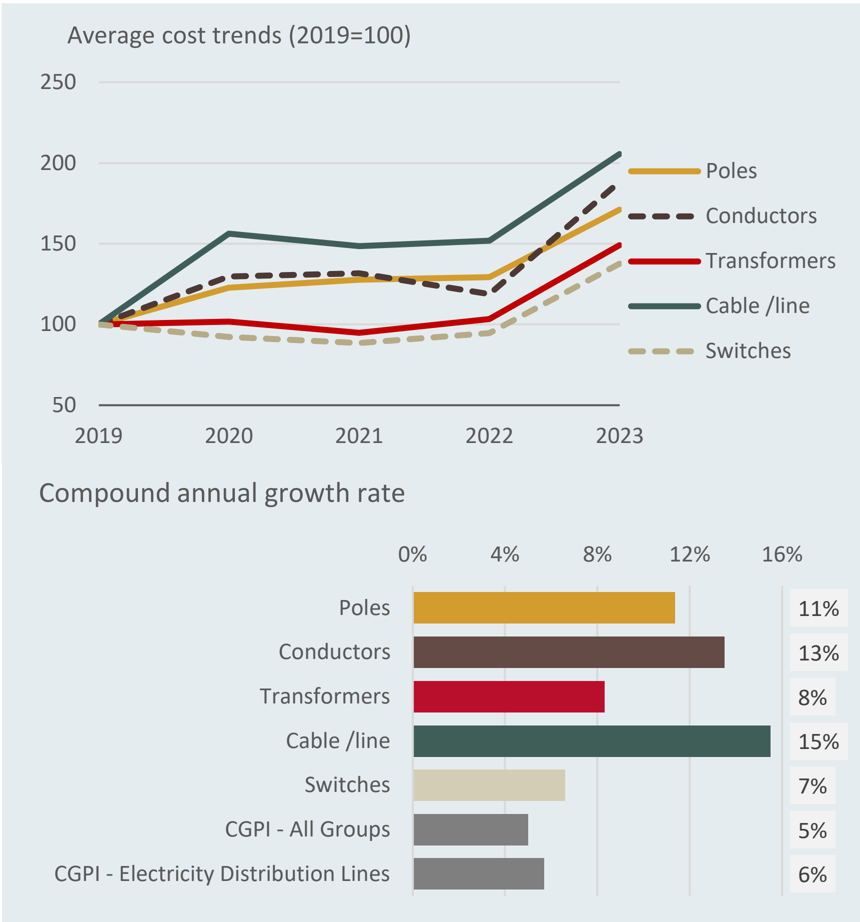
B168.1 total installed cost of five asset groupings replaced during renewal works

B168.2 asset replacement quantities for those five groupings, and

B168.3 average cost trends.

B169 Figure B14 plots the average cost trends and average annual growth rates over the period 2019 to 2023. In addition, the second chart in Figure B14 plots the average growth rates in the All-Groups CGPI and in the EDB-specific CGPI. The cost and quantity information provided by the ENA suggests average costs increased at a faster annual rate (between 7% and 15% per year) than the CGPI measures (5% and 6% per year).

**Figure B14 Average cost trends in ENA sample**




B170 Overall, given the aggregated nature of the data provided we were unable to conclude the extent to which these changes were driven by cost changes, or changes in scope of works, and the extent to which the change was consistent across EDBs or particular to certain EDBs.

B171 We have not been able to identify based on information provided whether there are particular regulatory or legislative change driven factors to the increase in input costs, such as potential increases in costs associated with traffic management requirements.

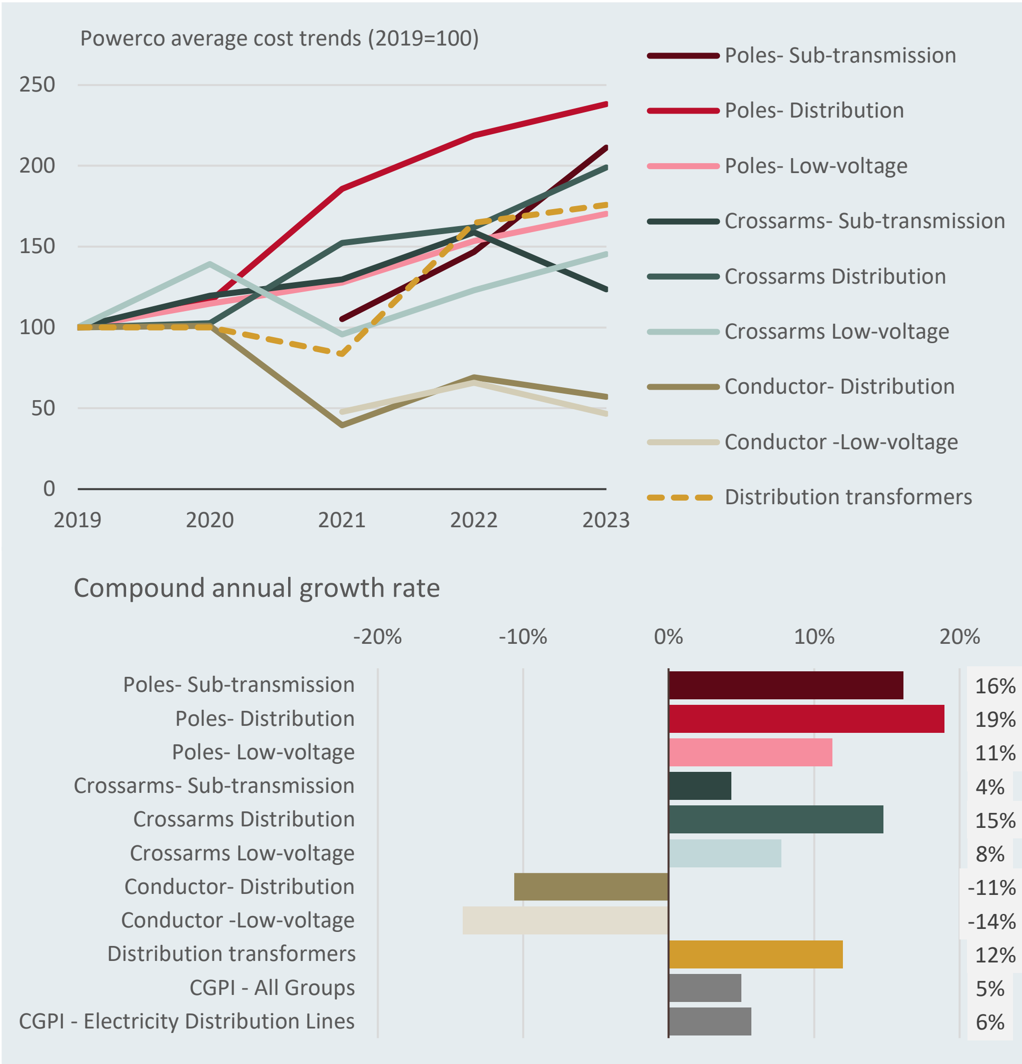
B172 To get further information we considered more granular information provided by Powerco in its annual delivery reports of its CPP and Energy Networks Consulting's Aurora CPP mid-period review report.[198], [199]

B173 Figure B15 plots the average cost trends and average annual growth rates in Powerco's asset groupings over the period 2019 to 2023. In addition, the second chart plots the average growth rates in the All-Groups CGPI and in the EDB-specific CGPI. Powerco's average costs ranged widely between a 14% decrease and a 19% increase. Pole costs increased at a similar or higher rate than in the ENA sample. The extent to which these increases reflect cost changes or changes in the scope of work is similarly unclear from the data we considered.

[198] Powerco Annual Delivery Reports: 2023, 2022, 2021, 2020, 2019

[199] Aurora Energy "CPP Mid-Period Review: Independent Expert Report" (February 2024)

**Figure B15 Average costs trends from Powerco's annual delivery report**




B174 Our review of the Aurora mid-period review report showed that while input cost inflation is a contributory factor to cost increases, there are other contributory factors such as scope, complexity and nature of work. We were unable to infer from the report by how much input cost inflation contributed to cost increases. However, the report highlights that several factors can contribute to cost changes and that it is not appropriate to assume changes in average cost are necessarily predominantly driven by changes in input costs.[200]

B175 Based on our analysis, we consider it appropriate to adjust the reference period by applying an annual adjustment of 0.8% to the All-Groups CGPI.

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200 Aurora Energy "CPP Mid-Period Review: Independent Expert Report" (February 2024)

B176 Our draft decision is to also apply the same adjustment when inflating the capex allowance into nominal dollars. Further information is located in the 'Use the All-Groups CGPI forecast with additional adjustment to escalate to the constant price capex allowance to nominal terms" section.

**Draft decision C4: Include an allowance for the cost of finance, scaled in proportion to the capex allowance**

B177 AMP forecasts include the cost of financing for the planned work programme. For DPP4, our draft decision is to retain the approach taken in past resets of including forecast cost of financing. [201] We do this by including the cost of financing in assessing AMP forecasts against the reference period, which means the cost of financing is scaled as part of the setting of the capex allowance.

B178 We are not aware of any reason to change our treatment of the cost of financing for DPP4 and welcome stakeholder views on this decision.

**Draft decision C5: Include an allowance for the value of considerations for vested assets and spur assets equal to 2024 AMPs**

B179 For DPP4, our draft decision is to include an explicit allowance for the forecast value of considerations vested assets[202] disclosed in EDBs AMP forecasts with no adjustment, given that the values are immaterial based on how the asset class is defined in the IMs. This is consistent with past resets.

B180 On occasion, Transpower has sold 'non-core' transmission grid assets (referred to as spur assets) to the EDB that connects to these assets. Our draft decision is to retain the approach we used in DPP3 for dealing with these transactions, which involved including spur asset purchases in capex forecasts, but also allows the return on/of these assets to be removed from EDB revenue if the purchase is cancelled.

B181 We are not aware of any reason to change the treatment of vested assets and spur assets for DPP4 and welcome stakeholder views on this decision.

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[201] Commerce Commission "Electricity Distribution Services Information Disclosure Targeted Review 2024 Amended Determination 2024 (Red line version 29 February). Cost of financing under ID is defined to mean the cost of financing incurred by an EDB and accumulated during the construction phase of a project that creates a new network asset, determined in accordance with clause 2.2.11(2) of the IM determination and allocated to the electricity distribution services in accordance with clause 2.1.1 of the IM determination.

[202] Commerce Commission "Electricity Distribution Services Input Methodologies Determination 2012 (Consolidated as at 23 April 2024)". Vested asset means an asset associated with the supply of electricity distribution services received by an EDB-without provision of consideration; or with provision of nominal consideration.

**Draft decision C6: Use the All-Groups CGPI forecast with additional adjustment to escalate the constant price capex allowance to nominal terms**

B182 The capex allowance needs to be expressed in nominal terms, through an appropriate cost escalation index. In DPP3, we used the New Zealand Institute of Economic Research's (NZIER) forecast of the All-Groups CGPI to escalate the capex allowance from constant to nominal dollars.

B183 Based on the feedback from submissions on the DPP4 Issues paper and analysis of other indices, including sub-indices identified as being appropriate for an EDB index, our draft decision is to use forecasts of the All-Groups CGPI to escalate the capex allowance from constant to nominal dollars for DPP4.

B184 As noted in the 'Recent input price pressures' section, a comparison of the All-Groups CGPI and EDB-specific CGPI highlights that, on average, EDBs experience higher input price inflation. Accordingly, and in recognition that energy infrastructure is likely to face higher input price inflation over DPP4, our draft decision is to add 0.8% per annum to forecasts of the All-Groups CGPI to restate capex allowances from constant to nominal terms. The 0.8% per annum figure represents the additional CGPI inflation seen by EDBs over the past five years.

*Factors that informed our draft decision*

<u>Most stakeholders supported the use of CGPI as a capex escalation index</u>

B185 We have a range of indices we could use to escalate the capex allowance, for example we could use an EDB-specific CGPI or we could use the Producers Price Index (PPI). The PPI measures movements in goods and services purchased and used by business at 'user cost' while the CGPI measures movements in the purchase and construction of capital assets (buildings, machinery, infrastructure).[203.]

B186 In our Issues paper and February 2024 capex workshop we proposed using the CGPI as the index for re-stating capex in nominal terms for DPP4. We invited interested stakeholders to provide views on this proposal.

B187 Most submitters supported the use of CGPI, because, while it may not capture the sector specific circumstances that drive EDB capex, they were not aware of any other index that would provide greater accuracy.

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203 Statistics New Zealand "Alternative frameworks for price indexes"

B188 Others suggested that more work was required to develop a customised index for the sector:

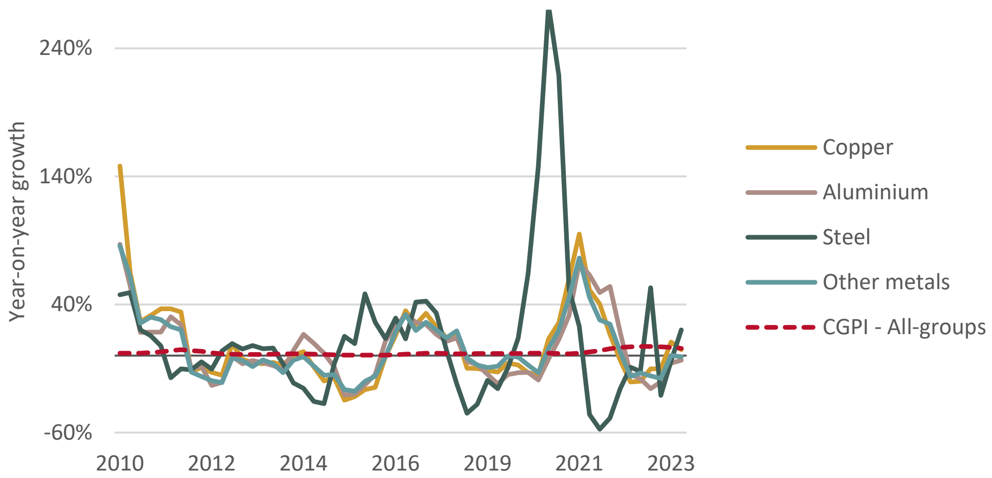
B188.1 Unison supported a more targeted, sector-specific index, that should reflect the particular pressures which the electricity transmission and distribution market in New Zealand is facing, because "an economy-wide CGPI may not capture the sector specific circumstances".[204]

B188.2 Alpine also stated that the Commission should consider a customised index,[205] while Transpower suggested that a more detailed analysis of the differences between CGPI and PPI and their application to the capex forecasts should be undertaken.[206]

Our analysis supported the use of CGPI

B189 As suggested by some submitters, we considered using sector-specific indices to escalate capex. These indices have been used previously by some EDBs under a CPP and by Transpower. However, when we compared the metals indices and the sub-indices of PPI and LCI, with the all-groups CGPI, we found the all-groups CGPI to be more stable over time, as shown in Figures B16 and B17.

**Figure B16 CGPI v Metals indices**

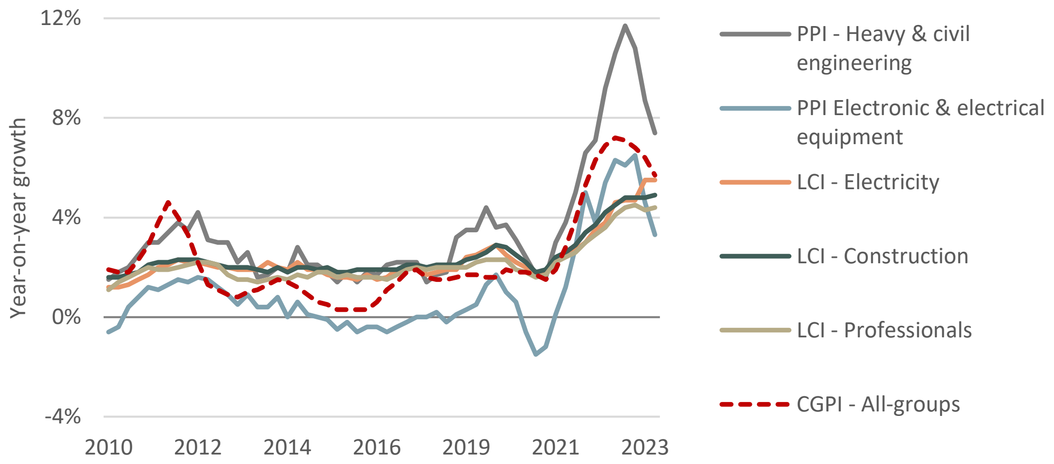



[204] Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 10

[205] Alpine Energy "DPP4 Issues paper submission" (19 December 2023), p. 3

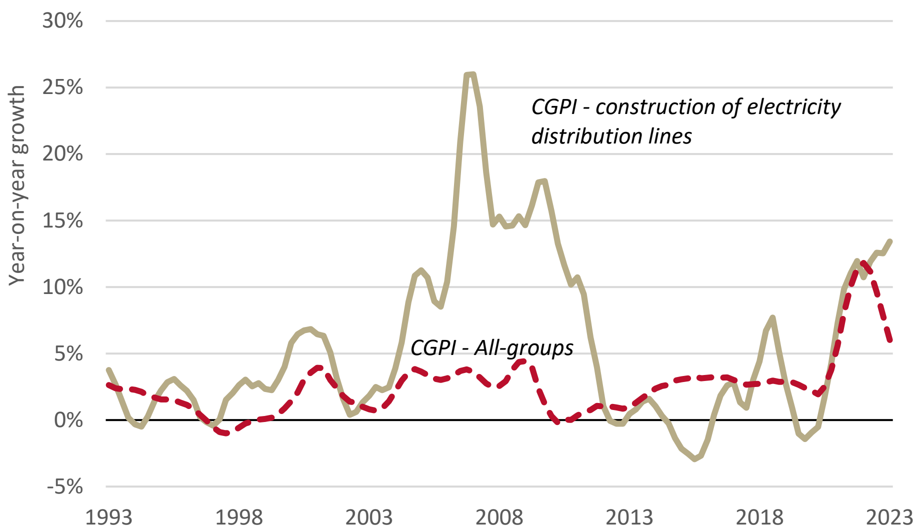
[206] Transpower "DPP4 Issues paper submission" (19 December 2023), p. 2

**Figure B17 CGPI v PPI & LCI sub-indices**




B190 We also compared the all-groups CGPI with the EDB-specific index. Again, we found the all-groups CGPI to be more stable over time, as shown in Figure B18.

**Figure B18 Annual growth rates: all-groups CGPI v EDB-specific CGPI**




B191 We considered that the use of a combination of sub-indices in Figures B17 and B18, such as LCI-construction, PPI-heavy engineering, Copper and others requires the allocation of weights, an exercise that can be prone to subjectivity and errors, rendering the indices less accurate. Also, despite being narrowly defined, it is not possible for any such indices to cover all known cost areas of EDBs.

B192 We further considered using EDBs' own implied inflation from their AMPs. We found that there is no common approach used by EDBs to escalate their input prices over the 10-year AMP cycle. The cost escalators used by EDBs in their AMPs also differ, with some as high as twice the level of CGPI and some lower. We calculated the percentage difference between the forecast capex in constant prices and in nominal terms and found that the percentage uplift for input prices implicit in the 2024 AMP forecasts ranges from around 6% to 28%.

B193 Given the complexities and volatility of narrowly defined indices, our draft decision is to use the all-groups CGPI, with an additional adjustment, to escalate capex allowances from constant to nominal terms.

## Other regulatory tools

### Role of flexibility mechanisms

B194 Flexibility mechanisms are available to be used if revenue limits need to be reconsidered during the regulatory period either because of changed circumstances during the period or, allowances that we have set excluded spend that was uncertain, insufficiently justified or identified as requiring a higher level of assessment.[207] Flexibility mechanisms help ensure that consumers can be confident that investments that were previously uncertain, insufficiently justified or unanticipated but have become more certain or justified during the period, receive the appropriate level of scrutiny via the right tool.

B195 If an EDB is faced with an investment requirement and needs to incur additional expenditure that it may not be able to accommodate within the settings of its current price-quality path through reprioritisation of expenditure, it can apply for a flexibility mechanism. The nature and circumstances of the investment(s) will determine which flexibility mechanism is appropriate, ie, either a CPP or a reopener.

B196 Reopener applications involve less assessment than a CPP proposal and, by way of general and high-level guidance, may be more appropriate in circumstances that:

B196.1 are separately identifiable or discrete

B196.2 are targeted to address a specific, rather than a general issue

[207] We use the term “flexibility mechanisms” to refer to changes which can be applied during a DPP regulatory period which includes DPP related in-period adjustment mechanisms (such as pass-through costs, recoverable costs, reopeners and LCCs) and CPPs.

B196.3 have less interdependence with the rest of the supplier's network

B196.4 are likely to affect a smaller number of consumers (especially if supported by them), and

B196.5 are not likely to require wide consultation with consumers and other stakeholders.

B197 We apply proportionate scrutiny to reopener applications. Our proportionate scrutiny principle means that the aim is to accommodate EDBs' circumstances at a level of cost and scrutiny that is commensurate with the materiality of the changes to prices or quality experienced by consumers, within the constraints of the DPP regime. Changes that would lead to material increases in prices or a material change in the quality of service should attract greater scrutiny.

B198 Reopeners are intended to be used on a justified basis in accordance with their criteria. The outcome of a reopener application is not guaranteed and is subject to a three-stage decision-making process. We consider whether the reopener trigger criteria have been met and then decide, guided by a set of consideration factors, whether the price-quality path should be amended and how the path should be amended.[208]

B199 Where an EDB considers substantial changes to the level of expenditure and potentially the level of quality it delivers are necessary, it has the option of applying for a CPP. A CPP involves proportionately greater levels of assurance, consumer consultation and regulatory scrutiny.

*Flexibility mechanisms were a key focus of the IM Review*

B200 In recognition of the changing operating environment and emerging uncertainty facing EDBs, we made changes to the suite of flexibility mechanisms in the 2023 IM Review where there was justification to do so. We:

B200.1 reviewed and made changes to reopeners, targeting situations where the forecasting uncertainty risk is highest, and

B200.2 introduced new mechanisms, ie, a large connection contract (LCC) mechanism and a new connection wash-up mechanism for EDBs on a CPP.

[208] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clauses 4.5.13(1)(a)-(d) and 4.5.15 (1)-(8)

B201 We considered the viability of a range of other potential in-period mechanisms that would allow for recovery of costs but are not reopeners and did not implement any.

B202 We concluded that the CPP regime is fit for purpose and remains appropriate where the scope and scale of individual EDB needs are more complex than DPP reopeners allow.

We reviewed and updated reopeners

B203 We introduced a new reopener, extended the scope of some existing reopeners and made changes to the reopener materiality thresholds. The net effect of these changes has made reopeners more accessible.

B204 We received a number of submissions on the DPP4 Issues paper indicating concerns about how reopeners will operate with the expected pace and volume of change.[209] Vector suggested clear reopener guidelines, and ideas to fast track the reopener application process such as the use of templates and independent verification.[210] We are alert to these concerns and are considering improvements to the reopener process as a separate workstream to the DPP4 reset. We have a number of reopener applications before us currently and expect that each reopener application will help refine and improve the reopener process for both EDBs and us. We encourage EDBs considering reopener applications to engage early with us as early guidance can help streamline the reopener application and evaluation process.

[209] PowerNet "DPP4 Issues paper submission" (19 December 2023), p. 2; Powerco "DPP4 Issues paper submission" (19 December 2023), p. 4; Vector "DPP4 Issues paper submission" (19 December 2023), pp 14, 44; Alpine Energy "DPP4 Issues paper submission" (19 December 2023), p. 3; Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 3

[210] Vector "DPP4 Issues paper submission" (19 December 2023), p. 45

B205 A number of submissions also raised the need for the scope of reopeners to be expanded.[211] Vector suggested that the scope of resilience within the Unforeseeable and Foreseeable large project reopeners should be expanded to include opex solutions.[212] The ENA stated that the DPP should include mechanisms for capex allowances such as a policy change reopener to adjust for policy changes either by the Government or regulators, that alter EDBs recovery of growth capex from connectors.[213]

B206 We note that the resilience limb of the Unforeseeable and Foreseeable large project reopeners not only includes resilience-related capex, but also consequential opex that is directly associated with resilience-related capex.[214] The price-quality path is also able to be reset (under s 54V of the Commerce Act) if allowances are materially impacted by mandatory changes by other regulators (for example, if the EA makes changes to the Code.[215]

B207 Our draft decision is to not make further refinements to reopeners, given the recent completion of the 2023 IM Review and the extent of changes made to reopeners in that review.

We considered other mechanisms in the 2023 IM Review and concluded these could not be implemented in a low-cost way

B208 We considered other mechanisms, including contingent expenditure allowances, use-it-or-lose-it allowances and quantity wash-ups in the 2023 IM Review. Broadly, we did not introduce those mechanisms because they are challenging to implement in a relatively low-cost DPP.

B209 We did not introduce:

B209.1 contingent expenditure allowances as:

B209.1.1 this would involve upfront analysis of costs at project level which is inconsistent with a relatively low-cost DPP, and

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211 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 3; Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 3; Vector "DPP4 Issues paper submission" (19 December 2023), p. 44

212 Vector “Submission on Capex framework design workshop” (11 March 2024), p. 2

213 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 3

214 Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments topic paper" (13 December 2023), paragraph 6.84 – 6.97

215 Commerce Act (1986) s 54V

B209.1.2 the cost to establish this new mechanism would likely exceed the potential benefit, given that upfront analysis is required in anticipation of the need being certain, and every possibility that the mechanism may never be triggered. [216]

B209.2 use-it-or-lose-it allowances as there was insufficient information to determine:

B209.2.1 where such an allowance would be most appropriately targeted

B209.2.2 what an appropriate magnitude or cap should be for those allowances

B209.2.3 the assessment criteria to apply that could be used to assess against

B209.2.4 how we would verify ex post that the allowance was used correctly, and

B209.2.5 how it could be applied in a low-cost manner.[217]

B209.3 quantity wash-up mechanisms as:

B209.3.1 these would likely be costly and complex to implement

B209.3.2 difficult to establish a direct relationship between the potential quantity measure to the expenditure requirement, and

B209.3.3 challenging to be designed in a way that encourages appropriate network management (does not disincentivise managing load growth or discourage flexibility solutions). [218]

B210 A number of submissions also raised the need for new flexibility mechanisms that are non-reopeners.[219] This issue was raised again in submissions at the capex workshop by Vector.[220]

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[216] Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments topic paper" (13 December 2023), pp. 198-202

[217] Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments topic paper" (13 December 2023), pp. 202-210

[218] Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments topic paper" (13 December 2023), pp. 210-214

[219] Vector "DPP4 Issues paper submission" (19 December 2023), p. 3; Unison Networks "DPP4 Issues paper submission" (19 December 2023), pp. 3-4; PowerNet "DPP4 Issues paper submission" (19 December 2023), paragraph 9

[220] Vector “Submission on Capex framework design workshop” (11 March 2024)

B211 We recognise that given the evolving context and resulting uncertainty in DPP4, other mechanisms may be of value if these could be implemented in a manner that is consistent with a relatively low-cost DPP. We are open to hearing from stakeholders if they have suggestions on overcoming the workability challenges of these other mechanisms as previously outlined, or if they have ideas for new mechanisms. We advise stakeholders to engage with the challenges and limitations identified for these mechanisms in their submissions.

B212 We note that a deliverability reopener is proposed for Transpower's fourth regulatory control period (RCP4) under the individual price-quality path (IPP). The deliverability reopener is a contingent reopener which Transpower can apply from year two of the regulatory period to unlock further revenue if it can meet certain predetermined triggers relating to workforce uplift targets required to deliver the work programme.

B213 The proposed Transpower deliverability reopener is intended to be a low implementation effort reopener with a streamlined assessment process. This is because the evaluation of the quantum of expenditure would have already been completed at the time of the IPP reset by both us and in most cases, by a verifier. This deliverability reopener is further discussed in the Transpower IPP draft reasons paper.[221]

B214 A Transpower IPP is similar to a CPP, involving a higher level of scrutiny by us, supported by verification by a verifier. In an IPP and a CPP, we evaluate whether the expenditure proposed by the EDB/Transpower is consistent with what would and could be delivered by a prudent supplier, ie, that the expenditure is needed, at the right time and that it reflects efficient costs. A deliverability reopener is appropriate in the case of an IPP or CPP if there are deliverability concerns, as prudency and efficiency of expenditure can and has already been established.

[221] Commerce Commission Transpower's individual price-quality path for the regulatory control period commencing 1 April 2025: Draft Decisions Attachment E - Deliverability expenditure" (29 May 2024), paragraphs 4.6- 4.18

B215 In a DPP reset, the relatively lower level of scrutiny means we are unable to tell whether the expenditure is needed, at the right time and at the right cost. These uncertainty aspects need to be established first before considering if proposed expenditure can be delivered, hence a deliverability reopener would not be appropriate for a DPP. If an EDB applies for a CPP however, a deliverability reopener similar to Transpower's deliverability reopener would be appropriate and able to be implemented through an IM amendment under a CPP.

CPPs are fit for purpose and appropriate given the extent of scrutiny required for individual circumstances of EDBs

B216 A few submitters expressed concerns on CPPs being resource-intensive for EDBs and our ability to process and evaluate CPPs.

B217 Horizon considered reliance on CPPs to manage uncertainty increases the risk of not meeting future needs. Its view was that a CPP is an option only for larger EDBs and that it should be used to handle exceptions that the DPP could not accommodate and not to unreasonably limit known, necessary expenditure.[222]

B218 Powerco stated that multiple CPPs can be avoided if agile in-period adjustments were enabled.[223] Unison had a similar view that multiple CPPs can be avoided if reopeners were more flexible, specifically if the 'programme of work' definition was clarified and made more flexible. [224]

B219 We concluded in the 2023 IM Review that CPPs are fit for purpose. Since CPPs are designed to better meet the particular circumstances of an EDB, the information provided must be able to support the required scrutiny. We note that even though our starting point for all CPPs is that they should be full scope, EDBs can apply for CPP IMs to be modified, exempted from or varied.[225] We apply proportionate scrutiny in our assessment approach ie, the scrutiny that an element of a CPP proposal receives is commensurate with the potential impact of that element on price and quality.

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222 Horizon Networks "Submission on Capex framework design workshop" (11 March 2024) , paragraphs 53, 57

223 Powerco "DPP4 Issues paper submission" (19 December 2023), p. 4

224 Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 10

225 Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments topic paper" (13 December 2023), paragraphs 4.16-4.21

**Large connection contracts are a new addition to the DPP/CPP regime**

B220 The 2023 IM Review introduced the large connection contracts mechanism as an alternative optional mechanism to a reopener for large new customer-initiated connections.

B221 The LCC is available to address large connection forecast uncertainty in situations where:

B221.1 the connection expenditure has not been provided for in DPP allowances

B221.2 the size of the connection is at least 5 megawatt (MW) and exceeds either 1% of the EDBs forecast net allowable revenue (FNAR) for the regulatory period or $5 million for Vector and Powerco, and $2.5 million for all other EDBs, and

B221.3 the connecting party seeking a connection to the EDB's network enters into a contract directly with the EDB, is prepared to fund the costs of the connection under that contract and agrees that the terms and conditions of the contract (including pricing) are reasonable.

*We signalled during the 2023 IM Review that we would propose how LCCs would be monitored and implemented*

B222 In the 2023 IM Review we said we would as part of the DPP4 reset process, consult on the wash-up formula and compliance statement requirements that apply to an LCC.

B223 We considered how LCCs would be taken into account in the setting of DPP4 allowances as per our capex framework and how they would be applied during DPP4. This is discussed in the following paragraphs.

<u>We propose potential LCCs are not factored into DPP4 capex allowances given these are challenging to identify</u>

B224 For expenditure to be eligible for future LCCs during DPP4, it must not already have been provided for in DPP allowances. This means potential LCCs would need to be clearly identifiable and then excluded from capex allowances. In the DPP4 Issues paper, we said we would consider the potential uptake of the new LCC mechanism when setting capex allowances for EDBs.

B225 With the timing of the IM Review final decisions published in December 2023, the requirement of identifying LCC-eligible connection expenditure was not known in time to be reflected in the AMP 2023 or the response to the November 2023 s 53ZD notice.

B226 In the February 2023 capex workshop, we asked EDBs to, through submissions, confirm if they had included potential LCCs in forecasts and if not, whether they could provide this information to us. The response to this request was mixed:

B226.1 Wellington Electricity provided a list in its 2024 AMP

B226.2 Unison and Horizon stated that no potential LCCs have been identified

B226.3 Alpine noted one potential LCC

B226.4 Orion confirmed that it has not included potential LCCs in forecasts due to commercial sensitivity but are able to share this directly with us

B226.5 Powerco noted that its forecasts incorporate implicit LCC connection expenditure and it would not be practical to produce a list of potential LCCs, and

B226.6 Vector commented on the impracticality of producing a list and expressed concern that the LCC will be redundant to EDBs who have not disclosed eligible expenditure.

B227 We propose that for DPP4 draft allowances, identifying potential LCCs for the purposes of excluding from DPP4 allowances is not possible and due to the lack of information. We encourage EDBs who have identified potential LCCs to voluntarily share that information with us on a confidential basis. Because the LCC mechanism is optional, EDBs whose connection expenditure forecasts include certain potential LCCs can treat these as they would any other connection expenditure.

<u>We propose different approaches for EDBs with capped forecasts and EDBs with uncapped forecasts to determine LCC eligibility for LCCs which arise during DPP4</u>

B228 For LCCs which arise during the DPP4 regulatory period, we set out guidance below for EDBs on how to self-assess against the criterion of "expenditure is not implicitly or explicitly provided for in DPP allowances".

B229 We propose that given the overall challenge in identifying and verifying potential LCCs, that we apply a principled approach to determine the LCC criterion of “expenditure is not implicitly or explicitly provided for in DPP allowances”.

B230 We propose:

B230.1 for EDBs with capped forecasts, we assume that that LCC-eligible connection expenditure has not been implicitly or explicitly provided for in DPP allowances, and

B230.2 for EDBs with uncapped forecasts, the LCC criterion is applied, ie, they will be required to provide evidence to prove that DPP allowances did not implicitly or explicitly provide LCC-eligible connection expenditure.

B231 We may see a higher volume of potential connection expenditure reopeners for EDBs with capped forecasts because they will have allowances that are less than their forecasts. It is more likely for those EDBs that any LCC-eligible connection expenditure might also have been capped because of the overall cap being applied. We consider that the proposed approach for EDBs with capped forecasts is appropriate and reasonable given these circumstances.

B232 The overall cap is not applied for EDBs with uncapped forecasts, which means their allowances will be in line with their forecasts and are more likely to include LCC-eligible connection expenditure. Those EDBs would be required to prove as per the LCC criterion that their LCC-eligible connection expenditure has not been explicitly or implicitly provided for in the DPP. We consider that most EDBs with uncapped forecasts should be able to produce this evidence using information they used to develop their AMP forecast for consumer connections. EDBs with uncapped forecasts whose connections are fully funded upfront by connecting parties should also be able to provide evidence to fulfil this LCC criterion relatively easily.

<u>The wash-up formula will be amended to enable us to verify the validity of LCCs and to require the future return of any LCC-ineligible revenue</u>

B233 The mechanism to monitor that LCCs are being used as they should is via the wash-up provisions. We may check whether revenue reported as LCC revenue by the EDB is "valid" LCC revenue (revenue received from qualifying LCCs -projects that meet the LCC criteria as defined in the IMs) or revenue that should have been recorded as revenue recovered under the DPP. Where an EDB reports LCC revenue that turns out not to be from a qualifying LCC, the wash-up provision enables the over recovery of revenue to enter the wash up balance to be returned to consumers.

B234 The amended IMs from the 2023 IM Review reflected how the wash-up formula should be amended to take into account LCC revenue. We propose updating the wash-up formula defined in the draft DPP4 determination to align with these amended IMs to reflect the changes required for the monitoring and future return of LCC-ineligible revenue. We discuss implementation of IM amendments to the wash-up in **Attachment E**.

<u>We propose requiring EDBs to provide information for the Annual Compliance Statement in respect of the wash-up so we can verify the validity of LCCs</u>

B235 During a DPP, an EDB is required to provide a written annual compliance statement that states that it has complied with the requirements to calculate wash up amounts using the methodology specified in in the DPP determination. It is also required to include supporting information for all components of the wash-up amount calculation.

B236 We propose including in the DPP4 determination a provision for EDBs to supply additional information (as part of supporting information for the Annual Compliance Statement in respect of the wash-up) to allow us to verify the validity of LCCs.[226] For each new LCC actual revenue reported, we propose requiring supporting information to confirm that the LCC criteria has been met.

B237 Given the potential commercially sensitive nature of this information, we propose providing the option for EDBs to disclose this information confidentially to us.

*We propose collecting additional information to better understand how LCCs are working*

B238 Orion and Alpine in submissions on the DPP4 Issues paper, raised concerns that the 5MW threshold for LCCs is too high. We consider that reviewing the MW threshold now is premature. This threshold was set as part of the 2023 IM Review decisions and was set to balance the need to limit the LCC mechanism to large connections that would otherwise require a reopener and to have it at a level that some connections are able to meet the threshold. As the LCC is a new mechanism, we can review the threshold in future when we have been able to observe how the LCC is operating in practice.

B239 We see value in, and are considering, collecting information to monitor the uptake and workability of LCCs, assess whether the LCC mechanism is working as anticipated and provide visibility and transparency to stakeholders on LCC contracts.

[226] Commerce Commission [Draft] Electricity Distribution Services Default Price-Quality Path Determination 2025 [2024] clause 11.6 (b)

**Additional reporting to improve visibility and operation of the regulatory regime**

B240 We are considering future additional reporting in a range of areas. Though our current intention is to define policy post DPP4 final decisions, we consider it beneficial to set out our preliminary thinking to capture any initial feedback that stakeholders may have.

B241 We are considering additional reporting by EDBs:

B241.1 for greater visibility and transparency of EDBs' planned work programmes and progress against those plans (Annual Delivery Report)

B241.2 to assist with reopener applications (prioritised lists of projects and programmes), and

B241.3 for better visibility of any changes in capital contributions policies.

*Intent to consider annual delivery reports*

B242 Deliverability has been a key factor that has influenced how we have set capex allowances for DPP4. As discussed earlier under the 'Deliverability of a significantly larger capex work programme' section, we did not get confidence that EDBs have considered the implications of resource shortages from a wider sectoral perspective.

B243 Given that EDBs are likely to face deliverability challenges, we consider that there is value in the use of Annual Delivery Reports (ADRs). ADRs are an accountability mechanism that enables interested stakeholders to monitor delivery progress of EDBs' work programmes, particularly where these are elevated. While ADRs do not directly address the risk that non-delivery results in elevated profits, increased visibility of work programme delivery may reduce the likelihood of this. ADRs would work as a reputational driver for EDBs to deliver on investments they have been funded for.

B244 Our early view is that the ADR would consist of a schedule of clearly described projects and programmes of work, categorised in terms of estimated cost, timing and region/location. EDBs would indicate progress made towards delivery, reasons for any variances/deferrals as well as anticipated risks and mitigation measures.

B245 At this stage, we are not proposing to include ADRs for DPP4. We expect EDBs should already be considering how they communicate with their consumers on how they are spending their money and what they are delivering for consumers. We will further consider the role of ADRs and may introduce them if we think the value for consumers exceeds the cost of producing it for the businesses.

B246 We are interested in stakeholder views on what data would be the appropriate baseline against which the ADR would be assessed.

B247 For previous CPPs there has been a plan produced which has been reported against, alternatively reporting could be against the AMP used to set the DPP, or an AMP produced post DPP decisions.

*Most stakeholders consider there is value in additional reporting*

B248 At the capex workshop in February 2024, we discussed the idea of additional reporting requirements in the form of ADRs for EDBs with elevated work programmes and asked stakeholders for their views regarding our proposal. This included seeking feedback on alternative suggestions that would achieve similar outcomes and implementation or workability concerns or suggestions.

B249 While most submitters appreciated the need for ADRs and other reporting requirements, they also raised concerns regarding the potential cost of meeting those requirements.

> …the existing DPP compliance reporting requirements, combined with the Commission's information disclosure regime (which incorporates AMP reporting requirements), provide more than sufficient information for interested parties (including the Commission) to assess EDBs' delivery of their work programme. – Electricity Network Association[227]

B250 Horizon acknowledged that consumer, and the Commerce Commission, confidence could be improved through greater understanding and transparency of how EDBs are spending against their DPP allowances but believes this can be achieved through existing means of information disclosure.[228]

B251 Orion pointed out that the DPP is a low-cost regime and this should be reflected in the reporting requirements, which should be targeted and avoid the risk of inefficient duplication if EDBs are already reporting on these areas through other channels.[229]

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[227] Electricity Networks Aotearoa "Submission on Capex framework design workshop" (11 March 2024), p. 3

[228] Horizon Networks "Submission on Capex framework design workshop" (11 March 2024), p. 8

[229] Orion "Submission on Capex framework design workshop" (11 March 2024), p. 16

*Intent to consider future additional reporting on capital contribution policies*

B252 We are also considering additional reporting for material changes to capital contributions policies by EDBs. We are interested in reasons for any changes to policies and how the changes better promote the long-term benefit of consumers. This will enhance visibility of the changes to the EA and other interested persons.

*EDBs with capped forecasts to prepare prioritised lists of projects and programmes*

B253 We have set draft capex allowances on a total capex basis using EDB AMP forecasts and not on a detailed project and programme basis.

B254 As noted earlier, we consider there are likely to be circumstances during DPP4 where EDBs may need to apply for reopeners for expenditure it had forecasted in an AMP but are unclear whether it has been provided for within a capped capex allowance.

B255 The reopener criteria within the IMs have different requirements regarding identification of whether expenditure has been included with some clauses requiring identification of whether expenditure had been "explicitly or implicitly provided for in the DPP".[230] For example, the foreseeable large project reopener requires that:

> the project or programme was foreseeable for the DPP regulatory period, however:
> the project or programme was not provided for in the EDB's forecast net allowable revenue, despite the project or programme being included in the forecasts used by the Commission for setting the DPP to which the reopener event relates.[231]

[230] Assessment of this is required for the Catastrophic event and Change event reopeners.

[231] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 4.5.10 (1)(i)(ii)

B256 While the risk event reopener requires at clause 4.5.11(c) that:

> (c) when the DPP was determined, the need to remedy the deterioration-
>
> (i) was considered and the Commission decided not to provide for it in the DPP because it was not sufficiently certain as to timing;
>
> (ii) was considered and the Commission decided not to provide for it in the DPP, but a new event has changed the circumstances that existed at that time; or
>
> (iii) could not reasonably have been foreseen by a prudent EDB; [232]

B257 Our approach to setting capex allowances within this draft decision does not provide detail of what expenditure has been provided for at a project or programme level, which may make application of these provisions more challenging.

B258 Accordingly, EDBs who have a capex allowance which is below their AMP forecast, who consider they may need to apply for reopeners, will need to create a prioritised list of projects and programmes which would outline how they intend to spend their capex allowances during the period.

B259 Having this prioritised list will enable identification of what has been provided for by the DPP and aid assessment of whether EDBs have "appropriately reviewed and reprioritised" expenditure which is required within clause 4.5.13(1)(c)(iii) of the EDB IMs.[233]

B260 At this stage we consider the prioritised project listing will be required to enable assessment of reopener applications for EDBs with capped forecasts. We may further consider requiring a prioritised project listing all EDBs through ID, including consideration of alignment with existing project and programme reporting required in AMPs.

B261 We think that ADRs and prioritised project lists would also be helpful to inform our approach for future DPP resets as these will likely provide better insights to support confidence in future EDB forecasts.

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[232] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 4.5.11 (1)(c)

[233] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023)

# Attachment C Operating expenditure

### Purpose of the attachment

C1 This attachment outlines and explains the rationale for our draft decisions on forecasting opex allowances for the DPP4 period and responds to stakeholder submissions on these issues.

C2 This attachment covers draft decisions for:

C2.1 The use of the base-step-trend approach to forecasting opex

C2.2 Choice of the base year

C2.3 The decision-making framework for opex step changes

C2.4 The approval and decline of specific opex step changes requested by EDBs

C2.5 Cost escalators for forecasting input cost increases

C2.6 Scale growth trend factors

C2.7 Reference period and methodology aspects of scale elasticities, and

C2.8 The application of a partial productivity factor.

### High level approach to operating expenditure

***Draft decision O1.1****. Apply a base-step-trend approach to forecasting opex.*

C3 Our draft decision is to retain the base-step-trend approach to setting opex allowances for DPP4. The general approach is shown below, where *opex(t)* is the opex allowance for year *t*:

$$
\begin{aligned}
\text{opex}(t) = \; & \text{opex}(t\text{-}1) \times \\
& (1+ \Delta \text{ due to scale growth}) \times \\
& (1+ \Delta \text{ due to cost escalation}) \times \\
& (1+ \Delta \text{ partial productivity for opex}) \pm \\
& \text{step changes}
\end{aligned}
$$

C4 Year one of the regulatory period (2026) is a special case where the reference year is the base year. As in DPP3, the DPP4 draft base year is Year four of the previous period (ie, 2024) and the deltas above applied for Year one account for this interval being two years not one.

C5 As we noted in the DPP4 Issues paper[234] and as stakeholders reinforced in submissions, we are setting DPP4 opex allowances in a changing and uncertain environment. However, we consider that the draft changes to components of the base-step-trend approach can account for this uncertainty without needing to change the overall approach.

C6 The base-step-trend approach is based on identifying an EDB's current level of operating efficiency, then making reasonable adjustments to represent what a prudent and efficient EDB would be expected to spend over the regulatory period.

C7 It is appropriate to forecast opex in this way because opex largely relates to recurring activities. As such, the expenditure is likely to be repeated, and can be expected to be influenced by certain known and predictable factors. While this is the same general approach used in the previous DPP resets, our draft decision includes changes to ensure it remains fit for purpose in a faster-changing context.

C8 The DPP4 forecasts that result from our draft decisions are presented in Table C1. The overall opex time series resulting from our use of the base-step-trend model is presented in Figure C1.

[234] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), pp. 17-23.

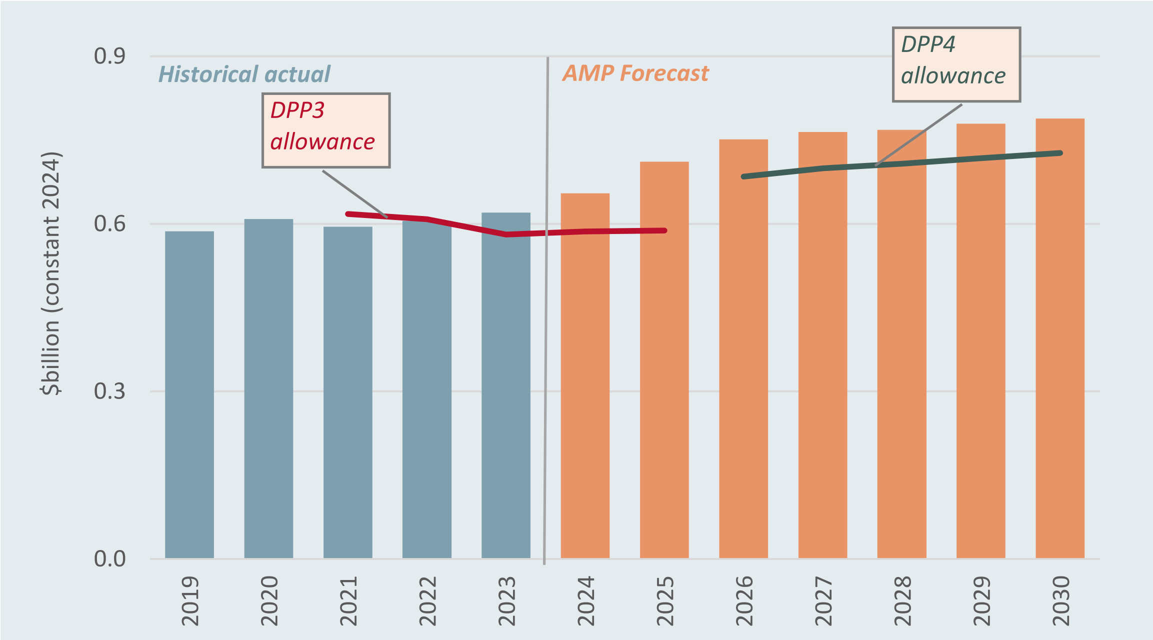
**Table C1 DPP4 opex allowances ($m, nominal)**

| EDB | 2026 | 2027 | 2028 | 2029 | 2030 | DPP4 total |
|---|---|---|---|---|---|---|
| **Alpine Energy** | 33.1 | 34.2 | 35.3 | 36.6 | 37.9 | 177.1 |
| **Aurora Energy**[235] | 47.6[236] | 55.8 | 57.6 | 59.6 | 61.7 | 282.3 |
| **EA Networks** | 18.6 | 18.9 | 19.2 | 19.6 | 20.0 | 96.2 |
| **Electricity Invercargill** | 7.0 | 7.2 | 7.4 | 7.7 | 7.9 | 37.2 |
| **Firstlight Network** | 16.7 | 17.1 | 17.6 | 18..1 | 18.6 | 88.2 |
| **Horizon Energy** | 14.0 | 14.0 | 14.4 | 14.9 | 15.5 | 72.8 |
| **Nelson Electricity** | 2.5 | 2.5 | 2.6 | 2.7 | 2.8 | 13.1 |
| **Network Tasman** | 16.7 | 17.3 | 17.9 | 18.5 | 19.2 | 89.6 |
| **Orion NZ** | 89.4 | 93.0 | 96.8 | 101.7 | 105.8 | 486.8 |
| **OtagoNet** | 11.2 | 11.7 | 12.1 | 12.6 | 13.1 | 60.6 |
| **Powerco** | 134.3 | 138.9 | 145.1 | 150.6 | 157.2 | 726.0 |
| **The Lines Company** | 18.8 | 19.3 | 19.9 | 20.5 | 21.1 | 99.5 |
| **Top Energy** | 26.0 | 26.7 | 27.4 | 28.2 | 29.0 | 137.3 |
| **Unison Networks** | 57.2 | 60.3 | 61.6 | 64.4 | 67.4 | 310.9 |
| **Vector Lines** | 188.3 | 195.5 | 203.0 | 211.1 | 219.6 | 1017.5 |
| **Wellington Electricity** | 43.7 | 45.1 | 46.6 | 48.2 | 49.9 | 233.5 |
| **Total** | **724.8** | **757.4** | **784.6** | **815.0** | **846.7** | **3928.6** |

[235] The figures for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from their CPP to the DPP in 2026.

[236] The value for 2026 here is the allowance from Aurora's CPP.

**Figure C1 Opex time series (constant 2024 figures)**




**What we heard from stakeholders**

C9 A key theme in submissions was the need to either revise or replace the base-step-trend approach to deal with a faster-changing and more uncertain environment for consumers and distribution networks over DPP4.

C10 Aurora noted the scale of change, but reinforced the uncertainties involved:[237]

> The pace and scale of change during the DPP4 regulatory period is uncertain. The Commission has an important role to play in managing this uncertainty; capex allowances need to be appropriate to support growth and opex allowances need to include sufficient step changes so distributors can meet the changing demands of consumers and stakeholders.

C11 Opex allowances of themselves cannot manage uncertainty. However, the uncertainty Aurora highlights has informed our draft decision for a more flexible approach to assessing step changes (given that allowing some step change is a least-regrets option) and the balance of factors that led to our draft decision of a 0% productivity factor.

[237] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 3.

C12 Beyond how we set opex allowances, specific uncertainties (such as transmission charges or the impact of general inflation) are better dealt with through pass-through costs and a wash-up mechanism, or may justify the future use of reopeners rather than an up-front opex allowance (such as vegetation management changes).

C13 In its submission, Horizon expressed scepticism about the use of reopeners to manage uncertainties:[238]

> In the context of decarbonisation, there are going to be more step changes in OPEX and CAPEX. In particular, if EDBs acquire flexibility services using OPEX, and that OPEX is later dropped due to additional investment in the network (CAPEX).
>
> The Commerce Commission's proposed solution for these types of step changes is to utilise the reopener process. Horizon Networks is concerned that this approach to managing uncertainty in the DPP regime will result in a higher cost to consumers through the manual processes to handle reopeners, or through EDBs choosing CAPEX because the process of deferring CAPEX through OPEX may not be efficient.

C14 While we accept that over-reliance on reopeners may drive an increase in regulatory costs, we consider our draft decision (where more certain changes have been dealt with via opex allowances, and reopeners or CPPs will deal with less certain or more significant changes) strikes a balance between regulatory burden, cost impact on consumers, and the benefits of regulatory flexibility.

C15 Alpine Energy supported retention of the base-step-trend approach in general, but noted that significant adaptations would need to be made:[239]

> Alpine Energy is generally supportive of the Commission's base-step-trend approach used to forecast opex allowance. We also think it is logical for the Commission to use the penultimate year of DPP3 as the base year for DPP4. As network maintenance spend is largely driven by maintenance standards, we believe base-step-trend is a logical approach. Whilst we encourage consistency in approach, we strongly believe the approach needs to be adapted to reflect current and future workload and cost structures.

[238] Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 13.

[239] Alpine Energy "DPP4 Issues paper submission" (19 December 2023), p. 7.

C16 Alpine highlighted the difficulties of forecasting non-network opex using historical data, given changes in customer behaviours and expectations.[240] We agree that overall the dynamics affecting non-network opex are more complex, as reflected in our draft decisions to change non-network scale drivers and allow step changes all relating to non-network opex.

C17 Similarly, ENA submitted that were we to retain the base-step-trend approach, changes to the step and trend elements would be necessary:[241]

> ENA would like to see the Commission make greater use of EDBs AMP forecasts in setting opex allowances.
>
> ENA understands the Commission's preference for the retention of the base-step-trend approach. If due and proper consideration is given to step changes and the drivers of growth in opex, it can be an acceptable alternative to the use of EDB AMP opex forecasts.

C18 Powerco identified four potential issues with the base-step-trend methodology were we to retain it unaltered:[242]

> Like any forecasting model, the base-step-trend approach exhibits shortcomings that demand careful consideration. For instance:
>
> > 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.
> >
> > The criteria for step changes can present significant evidence challenges.
> >
> > Network scale factors might not encompass all the key drivers of network opex.
> >
> > 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.

C19 We address these challenges in the sections below on the elements of the methodology.

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240 Alpine Energy "DPP4 Issues paper submission" (19 December 2023), p. 7; and, Vector "DPP4 Issues paper submission" (19 December 2023), pp. 2 and 9.

241 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 11.

242 Powerco "DPP4 Issues paper submission" (19 December 2023), p. 17.

C20 While the Consumer Advocacy Council accepted there may be reasons for overall cost increases, it highlighted the need for scrutiny:[243]

> The Council agrees the reasons behind these cost increases, and whether they were warranted, requires investigation. Scrutiny of EDBs' costs is essential in order to ensure consumers can have confidence that regulatory settings are providing appropriate checks on lines companies' expenditure.

C21 We agree with the importance of scrutiny, both to ensure consumers and other stakeholders have confidence and to ensure EDBs' forecasts are prudent and efficient. The importance of this scrutiny is behind our decision to retain our use of the base-step-trend approach, and our decision to place a cap on the level of step changes provided for. A high level of cost increase justifies the more detailed engagement, verification, and scrutiny in a CPP.

C22 SolarZero went further, and fundamentally questioned the relevance of a historically-based approach to opex:[244]

> Opex should not be thought about as it has in the past. Using a base-year approach is no longer relevant. Opex needs to increase substantially if the hump in capex is to be reduced and the power system optimised.

C23 We do not agree with SolarZero's assertion that a base-year approach is no longer fit for purpose. As shown in Figure C1, opex has historically been stable in real terms, and we consider an EDB's current opex spend a reliable indicator of its network's near-future needs given their current level of realized efficiency.

C24 However, we do acknowledge that there may be opportunities for opex to act as a substitute for capex as EDBs adopt innovative approaches to managing network demands. As discussed in Chapter 2, we consider the capex savings that can be made by doing so should provide the main incentive and source of funding for EDBs to undertake these approaches, and that where this substitution is insufficient to capture long-term capex savings, the INTSA mechanism discussed in Attachment D is available.

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[243] Consumer Advocacy Council (CAC) "DPP4 Issues paper submission" (19 December 2023), p. 3.

[244] Solar Zero "DPP4 Issues paper submission" (15 December 2023), p. 7.

### Draft decisions for opex base year

***Draft decision O1.2**: For opex base year data in draft decision financial models, use 2024 opex forecasts from EDBs 2024 AMPs.*

### Nature of the decision

C25 **Draft decision O1.2** As part of the base-step-trend approach we must specify the 'base year' for opex data. This sets the level from which opex steps and trends are then applied.

### Draft decision

C26 We have used 2024 opex forecasts from EDBs' 2024 AMPs for base year opex data in the DPP4 draft decision financial models. This is a change in approach from the DPP3 draft decision, where we used the latest available actual opex data, and the current equivalent of which would have been 2023 actuals reported under information disclosure (ID).

C27 To calculate DPP4 final prices, our draft decision is to retain the approach in DPP3 to use actuals from year four of the prior regulatory period, meaning base year opex data would be 2024 ID data. The use of year four as the base year for the final decision is necessary to ensure consistency with the opex IRIS IMs.

C28 The reason for **decision O1.2** is to improve the accuracy and therefore usefulness of the draft opex allowances in the DPP4 draft prices compared to where we expect them to land in DPP4 final prices.

### Analysis

C29 EDBs' 2024 AMPs point to strong growth in opex through the end of the DPP3 period and into DPP4. Across non-exempt EDBs, 2023 ID actuals are on average 9% lower than 2024 opex forecasts in 2024 AMPs (on a constant dollar basis).

C30 This decision reflects a preference to not have this difference flow into opex allowances in the DPP4 draft prices. While these are forecasts, and we do anticipate changes in 2024 actuals compared to 2024 forecasts, we consider it is better on balance to make this adjustment in going from DPP4 draft prices to DPP4 final prices than the alternative, which would be a much larger adjustment from 2023 actuals to 2024 actuals.

### Draft decisions for opex step change decision-making framework

C31 This section discusses our draft decisions on changes to the decision-making framework for assessing opex step changes.

C32 In DPP3, each suggested opex step change was assessed against five criteria, which all had to be satisfied for the step change to be accepted. The five criteria were that the step change must:

C32.1 be significant

C32.2 be robustly verifiable

C32.3 not be captured in the other components of the DPP allowance

C32.4 be largely outside the control of the EDB, and

C32.5 in principle, be applicable to most, if not all, EDBs.

C33 For DPP4, we have reassessed the above decision-making framework. Our draft decisions include amendments to respond to submitter feedback on the DPP4 Issues paper, to ensure DPP4 decisions are appropriate within the current industry context, and to test whether the previously applied framework remains fit-for-purpose and is incentivising the right behaviours for EDBs.

*O2.1: Consider proposed step changes against a defined set of factors, applying judgement*

**Nature of the decision and problem definition**

C34 A strict application of the decision-making framework previously used for opex step changes would lead to a step being declined if it did not meet all five criteria sufficiently. If the cost does arise during the regulatory period, the EDB then has to decide whether to avoid the cost altogether (possibly to the disadvantage of consumers), trading it off with another opex cost, or to incur negative IRIS incentives. An overly stringent application could consequently disincentivise spending that would have been in the long-term benefit of consumers.

C35 Alternatively, a framework that is relaxed too far and does not apply criteria with enough checks increases the risk of allowance being provided for costs that might not eventuate in the five-year period. This would have the impact of resulting in an underspend and would be captured as an efficiency under IRIS. In this situation, consumers would not see all of the underspend returned to them, which would have been the efficient outcome.

**Draft decision**

C36 Our draft decision is to change the opex step change decision-making framework to one that uses factors that inform judgment, rather than criteria that all must be met.

C37 The factors used to assess step changes, and to discuss them in more detail below, are whether the step change is:

C37.1 Significant (**O2.2**)

C37.2 Adequately justified with reasonable evidence in the circumstances (**O2.3**)

C37.3 Not be captured in the other components of the DPP allowance (**O2.4**)

C37.4 Have a driver outside the control of a prudent and efficient supplier (**O2.5**)

C37.5 Be widely applicable (**O2.6**).

### How the decision is aligned to the decision-making framework for the DPP

C38 This decision aligns with the decision-making framework for the DPP, specifically to better promote the purpose of Part 4.[245] Amending the criteria to factors means there is more discretion to ensure EDBs can sufficiently maintain and invest in their businesses and networks for the long-term benefit of their consumers.

### What we heard from stakeholders

C39 A number of submissions stated that they felt the opex step change criteria were too stringent. [246] They stated that step changes were denied that eventuated to opex costs over the DPP3 period, resulting in IRIS penalties for the EDBs.

C40 Aurora Energy in their submission stated: [247]

> The Commission's criteria for assessing opex step changes during the DPP3 reset process resulted in genuine expenses such as cyber security, insurance uplifts, traffic management cost increases, and digitalisation being excluded from opex allowances. This has led to distributors incurring IRIS penalties when implementing critical and prudent opex projects which are in the long-term interests of consumers. This is not a sustainable approach to employ in DPP4, especially if the Commission considers applying productivity factors to future opex allowances.

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[245] Commerce Act 1986, section 52A.

[246] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p.11.; Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 13.; Powerco "DPP4 Issues paper submission" (19 December 2023), p.19.; Network Tasman "DPP4 Issues paper submission" (19 December 2023), p. 5.; Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 18.; Vector "DPP4 Issues paper submission" (19 December 2023), pp. 31-33.; Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), pp. 27, 34.; FlexForum "DPP4 Issues paper submission" (19 December 2023), p. 9.

[247] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 4.

C41 Horizon Networks stated they were:[248]

> .. concerned that the criteria are too rigid and incentivise EDBs to avoid additional OPEX, even if there are long-term consumer benefits.

C42 Unison noted that:[249]

> ..the criteria (intentionally) do not respond to uncertainty, and as evident in DPP3, this makes EDBs disproportionately vulnerable to IRIS penalties for prudent and efficient business operations.

**Analysis**

C43 For this decision, we considered two options:

C43.1 Option 1: Status quo: keep the decision-making framework as criteria, all of which a proposed step change must meet to be approved.

C43.2 Option 2: Instead of criteria, the test will require consideration of five factors, which will be applied using judgement.

C43.2.1 This means a step change would not technically have to satisfy all five factors to be approved, if on balance enough factors were satisfied and approving the step change would give effect to the Part 4 purpose.

C43.2.2 This approach will be applied in line with the proportionate scrutiny principle. Step changes that will have a more significant impact on consumer bills (if approved) will have to clearly satisfy multiple factors.

C44 We consider that the key advantages / benefits of Option 1 (status quo) are:

C44.1 Consistency between reset periods – maintaining the status quo from DPP3 will ensure consistency for EDBs when providing information for step changes to be assessed.

C44.2 Level of certainty in decision making – having defined criteria that the step change must meet helps to create an objective approach to approving/declining each step.

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248 Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 13.

249 Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 18.

C44.3 Will help give effect to the Part 4 purpose by limiting step changes to those with a high level of certainty to the cost and the benefit to consumers.

C45 We consider the key disadvantages / risks with Option 1 (status quo) are:

C45.1 Significant opex costs are declined that eventuate over DPP4 – applying an approach that is too strict could see opex step changes declined for minor/technical reasons. This could result in IRIS not providing for full compensation for legitimate opex step changes. This provides an incentive on EDBs to cut opex spending in other relevant areas, or avoid spending opex in favour of capex. This would not be in the long-term interests of consumers.

C45.2 Risks not giving effect to s52A(1)(a) and (c) – that EDBs would not have incentives to innovate and invest to promote competitive market outcomes, and it would limit EDBs' expectation to earn a normal return.

C45.3 May incentivise high number of reopeners or CPPs – creating higher costs for EDBs, which would not be in the long-term interests of consumers.

C46 We consider the key advantages / benefits to Option 2 are:

C46.1 Increased flexibility to account for different context between DPP3 and DPP4.

C46.2 Ability to approve a step change that might have previously been declined for minor reasons, following the application of strict criteria.

C46.3 Will help give effect to the Part 4 purpose by providing greater flexibility to fund expenditure that better reflects efficient costs in a changing environment. This will be in the long-term benefit of consumers.

C47 We consider the key disadvantages / risks to Option 2 are:

C47.1 Less certainty for EDBs – this option risks inconsistency between decisions and could receive criticism from EDBs if the rationale for each step change decision is not robust or consistent enough.

C47.2 Increases the risk of providing for a cost that does not eventuate if not enough of the factors are considered / scrutinised. This would have the implication of not giving effect to s52A(1)(d), which requires the Commission to ensure EDBs are limited in their ability to extract excessive profits. Given the current financial pressures facing consumers, uncertain decisions that will impact electricity bills will further add to financial hardship already faced by some consumers. EDBs noted in submissions that they are aware about maintaining their social licence to make necessary investments in this reset.

**Conclusions**

C48 In considering and balancing the benefits and risks for either option, we consider that Option 2 would best give effect s52A and s53K of the Act and most appropriately address the context within which DPP4 is being set.

C49 Amending the criteria to factors means that there is more flexibility in the opex determination allowance process to ensure that EDBs can make opex spending decisions that promote the long-term benefit of consumers.

C50 To mitigate the risk of opex costs being provided for that do not eventuate, we are proposing to apply a proportionate scrutiny principle. Step changes that will have a more significant impact on consumer bills if approved will have to clearly satisfy multiple factors.

**Table C2 Comparison of DPP3 and DPP4 approach to assessing opex step changes**

| DPP3 'Criteria' | DPP4 draft 'factors' |
|---|---|
| Significant | Significant (O2.2) |
| Robustly verifiable | Adequately justified with reasonable evidence in the circumstances (O2.3) |
| Not be captured in the other components of the DPP allowance | Not be captured in the other components of the DPP allowance (O2.4) |
| Be largely outside the control of the EDB | Have a driver outside the control of a prudent and efficient supplier (O2.5) |
| Be applicable to most, if not all, EDBs | Be widely applicable (O2.6) |

*O2.2: Step changes should be significant*

**Nature of the decision**

C51 In DPP3, the step change needed to be material enough to justify the evidentiary burden on EDBs and the effort to assess its validity. In DPP3 we also considered a step change to be significant if allowances were insufficient to cover the cost without a step change.

**Draft decision**

C52 In DPP4, we are proposing to retain the 'significance' factor.

**What we heard from stakeholders**

C53 Only two submissions discussed the application of the significance factor. PowerCo suggested that "*in evaluating the significance of a step change, the Commission should consider the potential impact on consumers of rejecting or approving the request".*[250] WE* asked for the Commission to provide a threshold for what will be considered 'significant', to enable the EDB to decide if it is worth providing the information for the step change or not.[251]

**Analysis**

C54 Retaining the significance factor is important to help maintain the incentives to improve efficiencies and the relatively low-cost way of setting the default price-quality path.

C55 New operating expenditure that is not a significant increase to the current allowance is expected to be managed by the EDB. This approach maintains the incentives for EDBs to innovate or find efficiencies to better manage those operating costs and receive the benefits from IRIS. Not providing for every small increase in operating expenditure also achieves a balance between a more heavy-handed regulatory approach and the low-cost regulatory approach expected for a DPP. In addition, we consider that natural variability within opex costs will mean that small increases can also be 'averaged' out via small decreases in cost elsewhere.

C56 Section 53K of the Act describes the purpose of the default price-quality path regime as providing a relatively low-cost way of setting price-quality paths. Requiring an opex step change to be 'significant' gives effect to this purpose by ensuring that the Commission and EDBs are not spending too much resource providing and assessing information for all operating costs that might eventuate.

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[250] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 19.

[251] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 35.

C57 To balance the need for the DPP to be responsive to circumstance in a relatively low-cost way and the need to apply proportionate scrutiny to expenditure, the significance factor is complemented by our draft decision (O3.6, discussed further below) to cap the total level of step changes relative to overall opex.

**Conclusions**

C58 Retaining the significance factor is important for giving effect to the Part 4 purpose and maintaining a relatively low-cost way of setting the default price-quality path.

C59 We clarify that in applying the significance factor, it will be assessed with proportionate scrutiny. In applying that principle, a smaller step change with clear drivers and an objectively assessable cost may be appropriate to include, whereas a change of similar magnitude with less certain drivers and costs that are more difficult to estimate with certainty (without substantial analysis) may not be. Similarly, if the step change is for a significant cost (and therefore impact on consumer bills), then a higher level of scrutiny will be applied to the evidence and information provided against the other factors.

C60 In addition, we clarify that by nature of the Part 4 purpose, as outlined in section 52A of the Act, the impact on consumers is already inherent in the decision-making process. Applying the decision-making framework is a mechanism to ensuring that decisions on opex step changes are giving effect to the purpose outlined in section 52A and that a decision to decline or approve is for the long-term benefit of consumers.

*O2.3: Step changes should be adequately justified with reasonable evidence in the circumstances*

**Nature of the decision**

C61 In DPP3, the second criteria applied was whether the step change was 'robustly verifiable'. For a proposed step change to be robustly verifiable, the evidence EDBs provided must be such that we could establish whether the key elements of the criteria have been met with sufficient confidence. In particular, this includes knowing with reasonable certainty the costs involved.

C62 The stringency of this criteria was critiqued the most in submissions on the DPP4 Issues paper, noting it was difficult to provide sufficient evidence for a step change unless that cost occurred at the right time prior to the reset of the default price-quality path. The impact of this was declined step changes eventuating over DPP3, resulting in IRIS costs for EDBs and consumers or EDBs having to delay spend until the next reset.

**Draft decision**

C63 Our draft decision is that the second factor is amended to be that a step change should be adequately justified with reasonable evidence in the circumstances.

C64 This is intended to be less stringent than 'robustly verifiable', with some flexibility included for step changes that are either less significant, or sufficiently satisfy enough of the remaining factors.

**What we heard from stakeholders**

C65 The 'robustly verifiable' criteria as applied in DPP3 was the most commonly critiqued in the submissions received on the DPP4 Issues paper. There was a consensus that this criterion was too strict, as it required the cost to eventuate at the right time for EDBs to be able to provide quotes or invoices to support the step change.

C66 Aurora stated: [252]

> In particular, the criterion to 'be robustly verifiable' is overly onerous and not practically workable. This is evidenced by the Commission's decision to reject a step change for cyber security costs in the DPP3 reset due to a lack of information. In practice, for a spend category to meet the robustly verifiable criteria the need would have to arise at the exact time of the DPP reset. In the case of cyber security this need was foreseen at the time of the DPP3 reset, however the amount of the spend required only became clearer during the regulatory period – forcing distributors to either delay spend and risk the security of their networks, or sacrifice a fair shareholder return by incurring IRIS penalties.

C67 PowerCo advocated for: [253]

> …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."

**Analysis**

[252] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 11.

[253] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 19.

C68 Providing evidence to support a level of certainty that the new operating cost will occur within the regulatory period, and the amount for the cost, remain important aspects to the assessment of step changes. Relaxing this factor too far would risk spend being approved that either does not eventuate or is significantly less than what was provided for.

C69 It is also important to acknowledge that 'robustly verifiable' evidence may not always be available, even if there is reasonable certainty that the cost will eventuate within the DPP. A strict application of the requirement for evidence can limit the types of step changes that could be approved.

C70 To balance the benefit of certainty of spend for consumers against the flexibility to provide for necessary costs over a five-year period, we are proposing the 'robustly verifiable' criterion is amended.

C71 The wording aims to reflect that robust evidence will still be required for significant step changes, or where circumstances mean that evidence is available. On the other hand, it aims to provide for some discretion on costs that EDBs are certain will eventuate but are only able to provide evidence-based quotes or estimates at this time.

**Conclusions**

C72 We consider the change to this factor will appropriately address the concerns raised in submissions on the DPP4 Issues paper, while ensuring any step changes approved will be for the long-term benefit of consumers.

*O2:4: Step changes must not be included elsewhere in the expenditure allowance*

**Nature of the decision**

C73 To prevent EDBs from being remunerated twice for the same cost, and consumers paying twice for the same benefit, we assess whether the cost may be captured elsewhere in the regulatory allowances.

**Draft decision**

C74 Our draft decision is for no change for this factor, requiring that a step change must not be included elsewhere in the expenditure allowances.

**What we heard from stakeholders**

C75 No submissions critiqued this factor as applied in DPP3. Wellington Electricity stated that they agreed with this factor, as "it is important to ensure that EDBs are not remunerated twice for a new cost."[254]

**Analysis**

C76 This is a fundamental factor to prevent perverse outcomes and unnecessary costs to consumers. Any amendment to this factor would undermine the Part 4 purpose and would lead to perverse outcomes for consumers.

O2:5: Step changes should have a driver outside the control of a prudent and efficient supplier

**Nature of the decision**

C77 In DPP3, the step change had to be outside the control of the supplier. It was not sufficiently clear that this was referring to the driver of the cost, and as such we have received feedback from EDBs that this criterion should be relaxed for DPP4.

**Draft decision**

C78 Our draft decision is that the wording of this factor is amended to state the step change should be due to a driver outside the control of a prudent and efficient supplier.

**What we heard from stakeholders**

C79 A small number of submissions requested that this factor is relaxed in DPP4, noting that a strict application of the factor could lead to a step change being declined that would benefit consumers if technically the choice around the spend was within the control of the supplier.

C80 Wellington Electricity also noted that:[255]

> This criteria only makes sense with the 'a prudent and efficient EDB' caveat. Many decarbonisation-related cost increases could be avoided but at higher long-term costs or at the cost of not meeting ERP obligations. We suggest changing the title of the criteria to 'Outside the control of a prudent and efficient distributor'.

**Analysis**

[254] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 36.

[255] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 36.

C81 As discussed in the DPP4 Issues paper, this criterion is not so strict as to only cover events that are completely beyond EDB control, but rather focuses on whether a prudent and efficient EDB could not avoid undertaking the activity that gives rise to the cost.

C82 The reason we do not consider expenditure drivers that are directly under EDB control is because EDBs are able to choose how to spend their allowed revenue and may reprioritise within their regulatory allowance in order to undertake discretionary activities. This criterion aims to give effect to the purposes of Part 4 that suppliers have incentives to improve efficiency and share the benefits with consumers, consistent with sections 52A(1)(b) and (c).

C83 For clarity, there may be situations where a step change is appropriate where the cost is entirely within the control of the EDB, but there are wider environmental/contextual factors driving the costs for EDBs. For example, access to metering data becoming increasingly important with changes to the way consumers interact with the electricity network.

**Conclusions**

C84 To clarify the intent of this factor, the wording of our draft decision reflects that a step change should be due to a driver outside the control of a prudent and efficient supplier.

*O2:6: Step changes should be widely applicable*

**Nature of the decision**

C85 In DPP3, step changes were required to be applicable to most, if not all, EDBs. The purpose was to align the assessment of step changes to the low-cost principle in s53K of the Act.

C86 This factor was critiqued in the submissions on the DPP4 Issues paper, stating that it should be relaxed to provide for a step change that applies to a group of EDBs.

**Draft decision**

C87 Our draft decision is that this factor is amended to assess whether a step change is widely applicable.

**What we heard from stakeholders**

C88 A few submissions proposed this factor should be relaxed when being applied in DPP4. They stated that there are some step changes that will satisfy all other factors but will only apply to a small number of EDBs.

C89 Wellington Electricity stated:[256]

> We disagree with this criteria as some cost step changes only apply to a smaller group of networks (but not the majority) and where that spend is outside the control of a prudent and efficient EDB.

C90 Vector noted in their submission that some EDBs may be more advanced in certain areas than other, and a strict application of this factor would have the effect of "hold[ing] those EDBs back".[257]

C91 PowerCo expressed support for a relaxation of this criteria to be allow for a step change that applies to a 'group' of EDBs:[258]

> "Assessing 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."

**Analysis**

C92 We agree with the views expressed in the submissions on the DPP4 Issues paper. While in general, to maintain the relatively low-cost nature of the DPP, step changes should be applicable to most EDBs, there may be some circumstances where a step change that clearly satisfies the other factors but only applies to a group of EDBs could efficiently be assessed.

C93 For example, a group of suppliers in a particular region of New Zealand may consider that they are increasingly susceptible to the impact of adverse weather events and likely to incur more resilience-related expenditure relative to DPP3. In this scenario, even though the step change is not relevant to all EDBs on the DPP, it may be still efficient for us to assess a step change application for the affected group of EDBs.

C94 The relaxation of this factor for appropriate step changes will help to ensure step changes that will be for the long-term benefit of consumers are approved. As noted by Vector, there may be some circumstances where a group of EDBs are more seeking to increase an operating spend in an area for which other EDBs do not yet have the capability.

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[256] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 37.

[257] Vector "DPP4 Issues paper submission" (19 December 2023), page 32-33.

[258] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 19.

C95 For example, some EDBs have gained access, or are gaining access to, low voltage (LV) data, and as such are also increasing their spend on the software for data analytics and human resource in that area. Other EDBs are still in the process of acquiring access to the data, and therefore their spend related to analytics may be delayed until DPP5.

C96 Allowing for step changes across a group of EDBs who share some common factor may also help avoid a high number of CPPs, thereby avoiding an increase in the regulatory cost of the regime overall.

**Conclusions**

C97 We consider it is appropriate to amend this factor, to require assessment of whether the step change is 'widely applicable'.

**Draft decisions for opex step changes**

C98 The below section outlines the draft decisions on individual step changes that were suggested through submissions on the DPP4 Issues paper, or directly from EDBs following an informal information gathering process.

C99 The first half of this section discusses the step changes we are proposing to approve for DPP4. The second half discusses the step changes we are proposing to decline.

C100 For clarity, approved step changes have a trend factor applied in subsequent years where appropriate, in the same manner that the base opex is trended forward.

C101 All step changes have been assessed using the draft decision proposed decision-making process outlined above, meaning that each step change was considered against the following five factors, applying judgement. The step change should be:

C101.1 Significant (**O2.2**)

C101.2 Adequately justified with reasonable evidence in the circumstances (**O2.3**)

C101.3 Not included elsewhere in the expenditure allowance (**O2.4**)

C101.4 Have a driver outside the control of a prudent and efficient supplier (**O2.5**)

C101.5 Be widely applicable (**O2.6**).

*O3.1: Include a step change to reflect increasing insurance costs*

**Description of the step change**

C102 EDBs have experienced insurance premiums that have risen steeply in the last one to two years. They have stated that this rise has been significantly above inflation, and as such are asking for a step change in opex to reflect this recent trend.

**Alternatives considered**

## Use of an insurance-specific escalator

C103 Compared to a trend factor (a specific insurance escalator), our draft decision is that a step change can more easily and more accurately capture recent and near-future increases driven by extreme weather events, where it is uncertain whether that trend of increase will continue over the whole DPP period. As part of their analysis of cost escalators, Principal Economics provided a forecast insurance cost index, that we will use to inform the step change we include.

## Insurance as a pass-through cost

C104 The IMs allow us to specify additional pass-through costs in addition to those already listed in the IMs at a DPP reset.[259] The criteria for inclusion are:[260]

> (3) For the purpose of subclause (1)(b), the cost in question must -
>
> (a) be -
>
> (i) associated with the supply of electricity distribution services;
>
> (ii) outside the control of the EDB;
>
> (iii) not a recoverable cost;
>
> (iv) appropriate to be passed through to consumers; and
>
> (v) one in respect of which provision for its recovery is not otherwise made explicitly or implicitly in the DPP or, where applicable, CPP; and
>
> (b) come into effect during a DPP regulatory period or, where applicable, CPP regulatory period.

[259] Commerce Commission "Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.2(1)(b), p. 98.

[260] Commerce Commission "Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.2(3), p. 99.

C105 Insurance costs do not meet the criterion in (b): while the increases are new, the underlying cost is not. As noted below we also consider the control criterion in (a)(ii) is difficult to meet.

C106 Outside these criteria, and IM amendment would be required to give effect to this option.

C107 The Commission considered whether insurance should be treated as a pass-through cost during the 2023 IM Review.[261] In retaining the status quo of insurance being treated as ordinary opex we noted:

C107.1 the importance of retaining incentives for suppliers to manage their risks efficiently – including through the types of insurance they hold,[262] and

C107.2 that in a DPP context, it is not practical or low-cost for us to do a detailed assessment of risks for specific supplier's circumstances.

C108 To ensure suppliers who take active steps to reduce their insurance costs (such as through better information about their exposures, balancing the options of market, captive, or self- insurance, and choosing what risks to insure) are rewarded we consider an ex ante allowance remains the best approach – even in circumstances where forecasting changes in level is challenging.

### Analysis of the step change against the proposed decision-making factors

C109 **Significant:** We consider the insurance step change is significant. The ENA in their submission on the DPP4 Issues paper stated that EDBs' insurance expenditure has increased by 63% over the past five years.[263,264]

C110 **Adequately justified with reasonable evidence in the circumstances:** Some EDBs have supported their forecasts with quotes from their insurance providers. We have also a forecast for EDBs where no information was provided, from Principle Economics.

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[261] Commerce Commission "Input methodologies review 2023 - Final decision - Report on the Input methodologies review 2023 paper" (13 December 2023), see paragraphs 17.13 – 17.21 for the full reasoning, p. 183.

[262] Commerce Commission "Input methodologies review 2023 - Final decision - Report on the Input methodologies review 2023 paper" (13 December 2023), paragraph 17.18.

[263] This is in part supported by information disclosure data: where insurance spend by EDBs has increased 57% in nominal terms between 2019 and 2023, albeit only 30% in real terms.

[264] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 12.

C111 **Not included elsewhere in the expenditure allowance:** As explained above, we have decided not to account for the uplift in insurance costs through an insurance-specific escalator or as a pass-through cost. The step change will provide for the increase above their base spend and inflation.

C112 **Have a driver outside the control of a prudent and efficient supplier:** The driver of recent significant insurance increases has been mostly driven by increased severity of weather events. A prudent and efficient EDB would ensure their network is appropriately insured, at a level that is appropriate for consumers to pay.

C113 **Be widely applicable:** The increases are being seen across all EDBs, however some EDBs have greater increases due to the extent of their existing coverage, and their specific risk exposures.

**Conclusion**

C114 Our draft decision is that a step change for insurance costs is applied to all EDBs. We consider it satisfies all of the above factors, and maintaining an appropriate level of insurance cover is in the long-term interests of consumers. Where EDBs have not provided us with insurance forecasts, we have applied our own based off their information disclosures and the Principal Economics forecasts.

*O3.2: Include a step change for greater consumer engagement*

**Description of the step change**

C115 Some EDBs have indicated that they are looking to increase their spend on consumer engagement due to their increase in capex.

**Analysis of the step change against the decision-making factors**

C116 **Significant:** The amounts put forward as a step change for this category by EDBs were significant enough to justify its consideration as a step increase.

C117 **Adequately justified with reasonable evidence in the circumstances:** Numbers provided were signalled to be from market research on salaries.

C118 **Not included elsewhere in the expenditure allowance:** The requested amounts were for new personnel hire, and therefore that cost will not be currently captured elsewhere in the expenditure allowance.

C119 **Have a driver outside the control of a prudent and efficient supplier:** We expect prudent and efficient EDBs to be undertaking sufficient consumer engagement, particularly where there is significant growth occurring at a cost to consumers.

C120 **Be widely applicable:** This step change could be generally applicable across all EDBs, however currently only applies to a few.

**Conclusion**

C121 Our draft decision is that a step change for consumer engagement is accepted for all the EDBs who applied for it, namely: EA Networks, Orion, PowerCo, Vector and Wellington Electricity. Given the scale of changes over the next decade, and increasing opportunities for energy consumers to be more active participants in energy markets via distributed energy resources (DER) and demand response, we consider allowing for better informed engagement with consumers should improve overall outcomes. While a small number applied for the step at this stage, we considered there was enough supporting evidence from the other factors to accept the step change.

*O3.3: Include a step change for low voltage (LV) monitoring and smart meter data*

**Description of the step change**

C122 This step change has three components – the cost for the access low voltage network data, the cost for the software for storage and analysis, and the costs of additional staff for assessment and application of the analysis.

C123 Not all EDBs have indicated the need for spend on software storage and analysis or an increase in staff numbers to undertake the analysis. In those cases, or where EDBs have not provided information for this step change, we have only approved the cost for access to the low voltage network data.

**Analysis of the step change against the decision-making factors**

C124 **Significant:** The cost to acquire the data, have the right software for analysis and resource to undertake and apply the analysis is significant enough to justify assessment of this step change. This cost has also been significant enough that most EDBs who applied for this step change had identified a need for this work during DPP3, but deferred it to seek sufficient additional revenue under DPP4 to cover its cost.

C125 **Adequately justified with reasonable evidence in the circumstances:** Where available, EDBs have provided quotes or current prices from the companies from whim they are looking to purchase the smart meter data. Software costs are said to be based off licence fees (where applicable), and salary figures are stated to be from market research.

C126 **Not included elsewhere in the expenditure allowance:** For most EDBs this is a completely new activity and expense. For those with some of the costs within their base year, we have only accepted the step beyond their base expenditure and above inflation trend.

C127 **Have a driver outside the control of a prudent and efficient supplier:** The evolution of the electricity sector towards flexibility services and DER means that access to LV data will be crucial for EDBs. This driver is clearly outside the control of the EDB, and a prudent and efficient EDB would be looking to spend to support flexible solutions and demand-side management in the future.

C128 **Be widely applicable:** This step change is generally applicable to all EDBs.

**Conclusion**

C129 Our draft decision is that a step change related to the cost of accessing LV network data is approved for all EDBs. Where EDBs have provided information to support expenditure for software and analysis (including personnel), we have also approved that as part of this step change.

C130 We understand there is a possibility of work being completed by the EA that would make access to LV data more readily accessible.[265] We will stay connected with the EA on the progress of this work. If this were to occur during DPP4, we would consider a section 54V reopener after a Code amendment to modify the allowable revenues in response.

*O3.4: Include a step change for increasing cyber-security costs*

**Description of the step change**

C131 EDBs have indicated that their cybersecurity costs are likely to increase significantly. This is reflective of the increasing external cyber threat, the transition of EDBs towards cloud-based systems, and the type of information/data that EDBs may be storing on behalf of their consumers (LV 5-minute data). EDBs have noted the importance of ensuring their network is secure, especially as they begin to develop flexibility capabilities.

**Analysis of the step change against the decision-making factors**

[265] Electricity Authority "Delivering key distribution sector reform: Work programme" (16 October 2023), pp. 13-14.

C132 **Significant:** EDBs have provided evidence to support a significant increase in cyber-security costs in recent years.

C133 **Adequately justified with reasonable evidence in the circumstances:** EDBs have provided current costs and quotes from their cyber-security providers to support their step change request.

C134 **Not included elsewhere in the expenditure allowance:** Current spend will be captured in the base year, however there is evidence to support that the increases are above inflation.

C135 **Have a driver outside the control of a prudent and efficient supplier:** Cyber-security threats are outside of the EDBs control. We expect a prudent and efficient EDB to maintain an appropriate level of security, especially as they start to gain access to LV network data.

C136 **Be widely applicable:** This step change is widely applicable to most EDBs for this reset.

**Conclusion**

C137 Our draft decision is to approve a step change for increased cyber-security costs for all EDBs who sought it, namely: Alpine Energy, EA Networks, Electricity Invercargill, Network Tasman, Orion NZ, OtagoNet, Unison, Vector and Wellington Electricity. Ensuring a safe and secure system, especially while holding consumer information, will be increasingly important for consumers in the transition towards flexibility services.

*O3.5: Include a step change for the costs of software as a service (SaaS)*

**Description of the step change**

C138 EDBs have indicated that they are looking to transition their current IT systems (accounted for as capex) to cloud-based ‘Software as a Service’ systems. For example, Horizon has indicated that they are looking to replace their finance and accounting systems with a SaaS ‘solution’. This step is to recognise the costs associated with licensing or subscription fees, set up/implementation costs, and personnel/FTEs to monitor and administer the new systems.

**Analysis of the step change against the decision-making factors**

C139 **Significant:** Shifting systems towards cloud-based solutions is coming at a significant opex cost for EDBs – both initial installation costs and then ongoing subscriptions.

C140 **Adequately justified with reasonable evidence in the circumstances:** The relevant EDBs have provided quotes and estimates to support the proposed expenditure.

C141 **Not included elsewhere in the expenditure allowance:** Where current systems are treated as assets, they will be included in the RAB. As these systems are replaced, we will ensure the capex allowance reflects this to ensure there is no double-counting.

C142 **Have a driver outside the control of a prudent and efficient supplier:** We expect a prudent and efficient EDB to upgrade systems overtime to find efficiencies in operation.

C143 **Be widely applicable:** A large number of EDBs submitted they were seeking to move to SaaS solutions during DPP4.

**Conclusion**

C144 Our draft decision is to approve a step change for Software as a Service costs for all EDBs who sought it, namely: Alpine Energy, Electricity Invercargill, Firstlight, Horizon Energy, Network Tasman, Orion NZ, OtagoNet, Top Energy, Unison and Wellington Electricity.

*O3.6: Include a step change to account for the end of Aurora's CPP investment programme*

**Description of the step change**

C145 Aurora is currently subject to a CPP that will end on 31 March 2026. This CPP included a significant uplift in opex of enable delivery of Aurora's investment programme. With the CPP coming to an end, we consider that a $3.5m reduction in opex is justified to avoid one-off CPP costs being locked in for future periods.

C146 The expenditure allowances we are forecasting for Aurora as part of the DPP4 reset are indicative only – to provide Aurora and other stakeholders an idea of what a DPP allowance would look like, so Aurora can consider whether a further CPP is necessary. Before Aurora's current CPP finishes on 31 March 2026, we intend to undertake a determinative assessment of their future opex needs, as we did for Powerco when it transitioned onto DPP3.

C147 For an explanation of how we have treated Aurora in the DPP4 process generally, see **Attachment H**.

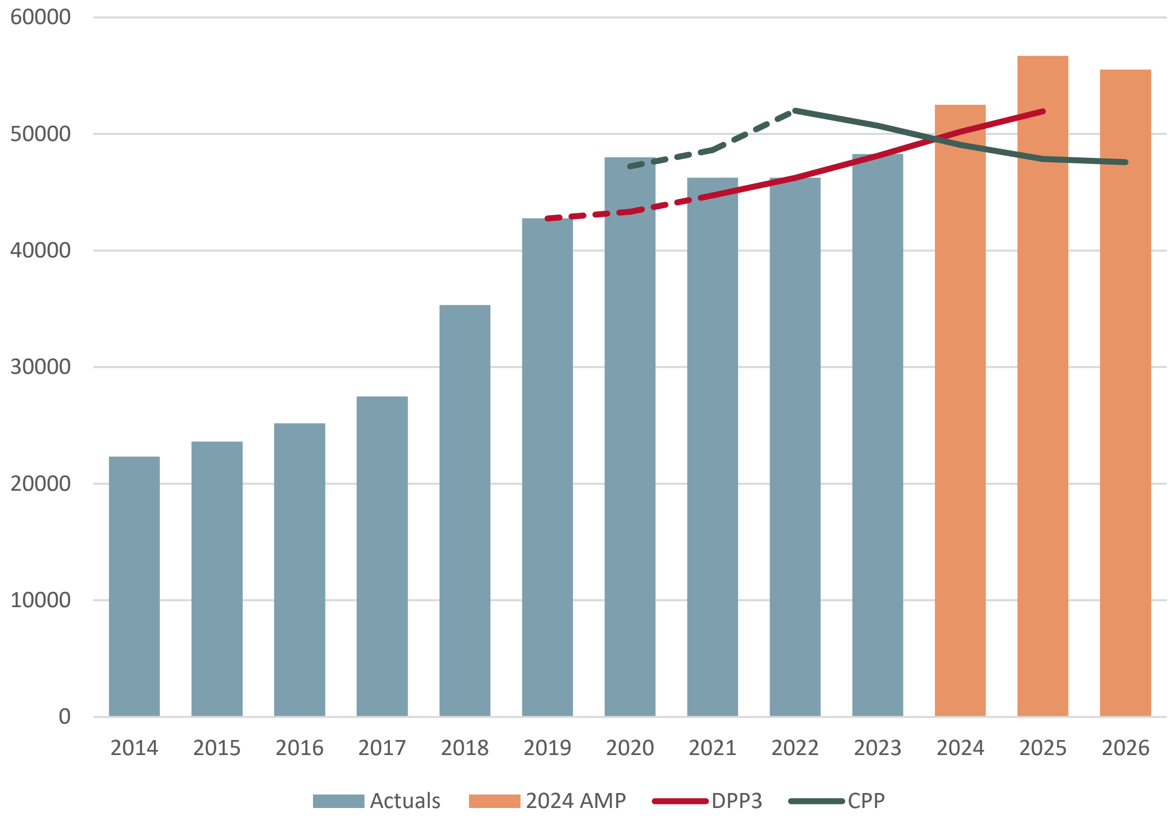
**Analysis of the step change**

C148 As this is a transitional adjustment we are proposing, rather than a proposal from stakeholders, we have not applied the general framework above.

C149 This step change is to account for the reduction of opex over the course of Aurora's CPP. To use Aurora's current estimated level of spend as a base would risk "locking in" for DPP4 a current level of spend above what is prudent and efficient.

C150 As shown in Figure C2 below, Aurora's opex allowance under its current CPP reduces over the remaining years in the CPP period (2024 through 2026). On the other hand, Aurora's actual and AMP forecast opex indicate that its CPP programme has ramped up more slowly than anticipated. As a proxy for these combined effects, we have used Aurora's CPP forecast for 2024 as a proxy for an eventual landing point, and proposed a corresponding reduction.

**Figure C2 Aurora opex ($000, nominal)**




**Conclusion**

C151 Our draft decision is to apply a base year adjustment in our calculation of Aurora's indicative DPP4 opex allowance. Aurora's base year opex will be its 2024 AMP opex forecast less $3.5m.

*Step changes that we have declined for the draft decisions*

C152 In addition to the step changes above, we have declined other proposed step changes. These proposed step changes and the reasons for our draft decisions to decline them are set out in Table C3 below.

### Table C3 Analysis of step changes that we have declined for the draft decisions

| Description of proposed step change | Analysis and reason for declining |
|---|---|
| **Decarbonisation** related step change for operating costs related to investment to deal with process heat conversion. This step change was mentioned in a submission on the DPP4 Issues paper to account for the incremental opex increases related to the ongoing nature of newly created assets. | There was insufficient evidence provided to properly assess the first two factors (significance and adequately justified with reasonable evidence). We have also proposed a capex driver is included in the trend factors for setting the opex allowance, which should cover this increase. |
| **Distribution system operation** capability. This step change was suggested in submissions on the DPP4 Issues paper and was to cover investment or spend by EDBs in DPP4 to prepare for, or have the capabilities to be, a distribution system operator. For some EDBs, this might look like investment in IT capability. | There was insufficient evidence received to properly assess the first two factors, or evidence to provide enough certainty that EDBs will incur these costs during DPP4. |
| Operating costs related to the **renewal of an ageing asset portfolio**. This was suggested in a submission on the DPP4 Issues paper. | There was insufficient evidence to properly assess the first two factors for this step change. This step change is also likely to be captured by the capex 'driver' in our non-network opex trending. |
| Operating costs relating to **routine and corrective maintenance and inspection**. This was suggested as a possible step change in the DPP4 Issues paper. | There was insufficient evidence received to determine the size of the step or whether it is above the base year expenditure with inflationary increases. |
| Operating costs to **support increasing capex** driven by increasing demand on the electricity network. | Operating cost increases correlated with increased capex are now being included in our scale growth trend factors. See paragraph C215 for a more detailed discussion on the decision to include a capex 'driver' in our non-network opex trending. |
| Three EDBs retendering their **Field Service Agreements** during DPP4 have requested a step change to account for the above-inflation uplift in costs expected under the new contracts. | While this step presents a possibly significant increase in opex for the three EDBs retendering soon, there is a strong argument that should be captured through the application of trend factors. The onus will be on the EDBs in response to the draft decision to adequately prove that the increases will be significantly above inflation, and that it remains appropriate for them to accept such a tender compared with alternative options. |
| **Resilience** related operating expenditure. From submissions on the DPP4 Issues paper and information provided following an informal information request this related to the clearance of out of zone trees, or programmes related to better targeted and identifying high risk zones for clearance.[266] | Five EDBs requested this step change. For three of these, insufficient information was provided at this stage to properly assess the step change and how it would be above current base year spend plus inflation.<br>The remaining two EDBs requested allowance for a larger programme to better identify and target areas of high risk. There was insufficient time to properly assess these steps due to the significance of the spend requested. The size of the step change requested suggests it may be better accounted for through a CPP, or through a resilience reopener. |

[266] On 18 May 2024 the Hon Simeon Brown announced amendments to the Electricity (Hazards from Trees) Regulations 2003, which are expected to be Gazetted in September 2024. The amendments are to make it easier for lines firms to take action to remove vegetation from obstructing local powerlines. If the amendments are Gazetted, they may be taken into account for the DPP4 final decisions.

| Description of proposed step change | Analysis and reason for declining |
|---|---|
| **Workforce** requirements related to network growth. A small number of EDBs in the response to our informal information request provided information for a step change related to increases in their workforce. | Increases in workforce related to system growth (capex) will be captured in the capex driver in the trend factors. For Powerco's submission, the magnitude of the step requested would require it to be assessed via a CPP. |
| Operating costs related **to service interruptions and emergencies**. Firstlight requested a step change to respond to anticipated outage increase in the short term. | There was insufficient evidence provided to support this step change and the reasons behind why an increase in outages is expected. In addition, the quality incentives within the regime should provide for some improvement in SAIDI and SAIFI. We would require more information to properly assess this proposed step change and to ensure the costs are not included elsewhere in allowances. |
| Workforce related step changes not linked to system growth. We received two similar step change requests for **workforce hires related to ESG** (environmental, social, governance) reporting functions. | This step was not widely applicable, and there was insufficient evidence provided to properly assess factors two and four (adequately justified and due to a driver outside the control of a prudent and efficient supplier). On balance, the step change did not satisfy enough of the factors with clear evidence as to the drivers of the step. |

**Table C4 Summary table showing the approved step changes by EDB**

| Step | Alpine Energy | Aurora Energy | EA Networks | Electricity Invercargill | Firstlight | Horizon Energy | Nelson Electricity | Network Tasman | Orion NZ | OtagoNet | PowerCo | The Lines Company | Top Energy | Unison | Vector | WE* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Insurance** | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| **Consumer Engagement** | | | ✓ | | | | | | ✓ | | ✓ | | | | ✓ | ✓ |
| **LV Monitoring** | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| **Cybersecurity** | ✓ | | ✓ | ✓ | | | | ✓ | ✓ | ✓ | | | | ✓ | ✓ | ✓ |
| **SaaS** | ✓ | | ✓ | ✓ | ✓ | ✓ | | ✓ | ✓ | ✓ | | | ✓ | ✓ | | ✓ |
| **CPP-specific costs** | | ✓ | | | | | | | | | | | | | | |

*O3.7: Apply an aggregate cap to total step changes equal to 5% of opex*

**Problem Definition**

C153 As outlined under section 53K of the Act, the purpose of the default price-quality path is to provide a relatively low-cost way of setting price-quality paths for suppliers. The relatively low-cost approach means that we are unable to undertake a detailed assessment for all proposed costs under a DPP process.

C154 To ensure we are promoting the long-term benefit of consumers, costs that would lead to a significant increase in allowable revenue (and likely consumers' electricity bills), should have the appropriate scrutiny applied to them before approval. The impact of this it that for some EDBs, the level of increase to their allowance they are seeking would reach a point where it would be better suited to the scrutiny and analysis that can be applied under a customised price-quality path.

**Draft decision**

C155 Our draft decision is to apply a 5% cap to the level of increase from approved opex step changes in DPP4.

**Analysis**

C156 Since opex has a direct impact on revenues (it is available to be fully recovered within the five-year period), we suggest a 5% cap is appropriate and proportionate to the 125% cap applied to capex (for reference see figure C5 below).

C157 It should also be noted that the scale trends applied for the opex allowances should also account for some of the costs not fully accounted for through the step change process, for businesses who will have the 5% cap applied.

C158 **Table C5** below shows the percentage increase of opex step changes for each EDB, and which would meet the 5% threshold.

**Table C5 Impact of applying an aggregate 5% cap on opex step change increases**

| EDB | Uncapped steps (DPP4 total, $000 2024 real) | Total opex net of steps (DPP4 total, $000 2024 real) | Steps as a % of total | Capped step | Impact of cap (% of total opex) |
|---|---|---|---|---|---|
| **Alpine Energy** | 14,835 | 151,880 | 9.8% | 7,594 | -4.77% |
| **Aurora Energy** | 5,027 | 272,902 | 1.8% | 5,027 | |
| **EA Networks** | 6,935 | 82,561 | 8.4% | 4,128 | -3.40% |
| **Electricity Invercargill** | 2,479 | 31,890 | 7.8% | 1,595 | -2.77% |
| **Firstlight** | 4,151 | 75,645 | 5.5% | 3,782 | -0.49% |
| **Horizon Energy** | 2,347 | 63,201 | 3.7% | 2,347 | |
| **Nelson Electricity** | 255 | 11,556 | 2.2% | 255 | |
| **Network Tasman** | 2,292 | 78,330 | 2.9% | 2,292 | |
| **Orion NZ** | 24,392 | 417,223 | 5.8% | 20,861 | -0.85% |
| **OtagoNet** | 4,411 | 51,947 | 8.5% | 2,597 | -3.49% |
| **Powerco** | 16,705 | 636,792 | 2.6% | 16,705 | |
| **The Lines Company** | 621 | 88,983 | 0.7% | 621 | |
| **Top Energy** | 5,112 | 118,529 | 4.3% | 5,112 | |
| **Unison Networks** | 24,779 | 266,495 | 9.3% | 13,325 | -4.30% |
| **Vector Lines** | 29,331 | 886,558 | 3.3% | 44,328 | |
| **Wellington Electricity** | 14,678 | 200,204 | 7.3% | 10,010 | -2.33% |

### Draft Decisions for opex Scale Growth

C159 This section discusses the first of our three trend factors: changes in opex with scale growth. Our draft decisions are to retain our econometric modelling approach to scale trends from DPP3, with updates and refinements.

C160 As an EDB grows, the cost of maintaining and managing its network can also be expected to grow. As in DPP3, we quantify the relationship between cost growth and scale growth using elasticities, which give the percent change in cost for a given percent change in scale. We do this by fitting econometric regression models to log-transformed opex variables with log-transformed explanatory variables.[267]

[267] The use of log-transformed variables means that the model coefficients are elasticities.

C161 Our approach to calculating opex scale growth trends involves multiplying together:

C161.1 Elasticities from our econometric modelling to select which factors we use to model opex scale growth, and

C161.2 Forecast growth rates for these factors over the DPP4 period.

C162 The results of applying the approach detailed in the rest of this section is that for DPP4 draft decisions we have calculated opex scale trends as below, with elasticities summarised in Table C6:

C162.1 Network opex (*NO*) growth:

$$\Delta\%(NO) = 0.45\ \Delta\%\ (ICP) + 0.52\ \Delta\%\ (lines)$$

C162.2 Non-network opex (*NNO*) growth:

$$\Delta\%(NNO) = 0.22\ \Delta\%\ (ICP) + 0.35\ \Delta\%\ (lines) + 0.30\ \Delta\%\ (capex)$$

C162.3 Here Δ % means percent change per annum, *ICP* is average total ICP count over a year, *lines* is total circuit length for delivery, and *capex* is Expenditure on Assets.

**Table C6 DPP4 draft elasticities for opex scale growth**

| Opex category | Elasticity to ICP growth | Elasticity to lines length growth | Elasticity to capex |
|---|---|---|---|
| **Network opex (decision O5.3)** | 0.45 | 0.52 | n/a |
| **Non-network opex (decision O5.4)** | 0.22 | 0.35 | 0.30 |

**Data**

C163 Our econometric analysis used information disclosure (ID) data provided by EDBs. Adjustments were made for earlier operating lease accounting treatments in the same way as in DPP3.

C164 Prior to fitting econometric models, we de-trend data for inflation effects, and cast the nominal ID dollar amounts to a constant dollar basis using cost escalators derived from Stats NZ inflation indices. Following the same approach as in DPP3, we have applied a 60/40 split of all industry LCI and PPI indices for opex data, and all groups CGPI for capex data.

C165 All input data is published alongside this report, bundled with our model fitting analysis (R code) and collated ID data is available on the Commission website.[268]

*Approach to opex scale growth analysis*

C166 In order to reach the results above we needed to make methodology choices and model selections. This process involved considering multiple factors, addressed one at a time with iterations to check the impact of later choices on earlier choices.

C167 Our approach was informed by a review by Cambridge Economic Policy Associates (CEPA) conducted ahead of our DPP4 Issues paper[269] and by the Frontier Economics report provided by ENA[270]. We acknowledge the usefulness of this review and report, and in the sharing of model fitting analysis (R code) between parties.

C168 In general, our model selection follows the process outlined by Frontier: first consider base model variables, then assess the inclusion of additional capex and time variables, and then apply iterative model outlier exclusion and robust clustered standard errors for final fitting of preferred models. Our draft decision elasticities are the model coefficients in the final model fits.

C169 We also examined and made choices on the reference period (ie, date-range) of input data, and data quality treatments in the form of both input data filtering and an iterative model outlier exclusion process applied at the model fitting stage.

C170 Our general process to make choices and draft decisions was as follows:

C170.1 Choose reference period / input data date range. Initially based on expected models and reassessed after final model selection based on reference period chosen.

C170.2 Decide level of opex aggregation. Uncontroversial, and not sensitive to data quality and reference period, with no iteration required.

C170.3 Choose and apply input data filtering approach.

C170.4 Choose preferred model selections for base variables.

C170.5 Choose preferred models including possible additional variables (capex, time).

[268] Information disclosure data is available as our Information disclosed by electricity distributors webpage.

[269] Results and insights from this review fed into Attachment D in: Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper " (2 November, 2003)

[270] Frontier "Opex econometric modelling" prepared for Electricity Networks Aotearoa (9 January 2024)

C170.6 Choose whether to apply iterative model outlier exclusion based on preferred model specifications.

C170.7 Generate final elasticities for preferred models with outlier exclusions and cluster robust standard errors.

C171 Our approach and conclusions are generally consistent with those from the CEPA and Frontier analysis. Key differences are:

C171.1 Our choice of a reduced reference period in order to better predict future trends (2018-2023, compared to CEPA and Frontier using all data 2013-2022 released with our DPP4 Issues paper) and application of the iterative outlier model exclusion method on this reduced data set, has resulted in some differences in elasticities.

C171.2 While we do not disagree with any of the technical findings in the Frontier report, we do draw different conclusions for model selection based on other factors. We have not included a time variable in our models.

*O5.2: The reference period for our econometric analysis is 2018-2023*

**Problem definition**

C172 Our regression analysis requires choice of the reference period or date range of data for modelling opex scale trends. For DPP3, this was regulatory years 2013-2019.

**Draft decision**

C173 For DPP4 draft decisions we have used a reference period 2018 – 2023. For DPP4 Final decisions, ID data from 2024 will also be available and we will assess whether to include this data or not.

**Alternatives considered**

C174 We considered an extended data range (2013-2023) by adding all available ID data to the DPP3 reference period, and we also considered later start years to shorten this range. We did not consider data prior to 2013 as this was excluded from DPP3 on data quality grounds.

**Analysis**

C175 There is a trade-off here between recency and model quality.

C175.1 More recent data may provide better estimates of the strength of the trends that are more likely to continue in the near future. This goes to a point raised in submissions of past trends not necessarily reflecting trends in DPP4 due to future changes in cost drivers through the anticipated electrification transition.[271]

C175.2 A too-short reference period could reduce model fit quality due to an increased sensitivity to variability or noise in the data. Generally, the more data there is in a regression, the better the statistical properties of that regression.

C176 Our choice of 2018-2023 reference period results from consideration of data quality, and three related quantitative approaches to assess model stability and potential changes in trends within the wider date range:

C176.1 A Chow test (an econometric test for evidence of structural breaks) provided statistical support for a change in non-network opex elasticities over time with 2018 the best indicated break year.[272] This change is statistically significant, albeit small in magnitude. No clear evidence for a break was observed in network opex elasticities.

C176.2 As a direct variation on the Chow test, we added a 'dummy variable' to network and non-network opex models, allowing us to return separate elasticities either side of a 'break year'. This showed no significant change in network elasticities, but evidence of a small and gradual change in non-network elasticities, with slightly higher lines elasticity and slightly lower ICP elasticity as the first year in the date range was increased.

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[271] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 29.

[272] This analysis was initially made with the DPP3 models, where both network and non-network opex were modelled with ICP and lines length. It was then reconfirmed by iteration using our preferred models, including capex as a cost driver of non-network opex.

C176.3 To examine this more closely, we fit models over a sliding date range (ie, from 2013-2023 through to 2021-2023). Results showed a smooth change in elasticity values for non-network opex as the date range is shortened, and lower accuracy if the period is too short. There is a less clear change in network opex elasticities, but improving model fit quality as earlier years with noisier data are omitted.

C177 The quality of ID data has improved over time. Irregularities in reported ICP and lines data – meaning outliers or abrupt changes in trends - do tend to be more prevalent in the earlier years, 2013-2017.

C178 These observations all point to overall smooth changes rather than clear breaks in data quality or modelled elasticities. While they don't pinpoint a definite start year for the reference period, Chow test results for non-network opex models do support 2018 as the first year to use.

C179 Our draft decision is that the reference period for DPP4 scale trend modelling is all ID data years available from 2018. This eliminates noisier earlier data while providing sufficient data for reliable model fitting of recent trends. It will also result in seven years of ID data available for DPP4 final model fitting, the same number of years as in DPP3.

**Stakeholder views**

C180 There were no submissions on the specific topic of reference period. There were more general comments that our overall approach includes the assumption that trends from the past will be good predictors of future trends and can only forecast cost driver relationships present in historical data, and may therefore not be well suited to capturing changes in cost drivers through an energy transition.[273]

C181 Our draft decision on the reference period is strongly informed by the view that, within our approach and subject to having enough data to not compromise the quality of model fits, future scale growth trends are most likely to be accurately predicted by trends fitted to recent data.

**Choice of data quality treatments**

C182 Attention to data quality is an important consideration in any regression analysis.

[273] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 29

*Our approach*

C183 We have addressed data quality at the input and model-fitting stages of this work. First, we have excluded irregular data at the input stage. This involved inspection of ICP and lines data over time for each EDB to identify data years in which ICP or lines data (or both) clearly departed from trend for that EDB. As our models fit data from all 29 EDBs over six years, we have simply removed these data points to remove their influence on model fits, rather than the alternative of detailed examination to adjust them in an appropriate way. This results in the exclusion of 25 data tuples (ie, "rows of data") from 17 EDBs out of 174 data points.

C184 Ultimately, assessed on our final models, this does not affect our model selection and results in only small changes in the calculated elasticities (changes in the order of +/- 0.01). We retain this step as appropriate in-principle with no cost to retain.

C185 Secondly, using the same approach as in DPP3, we have applied an iterative process to remove outliers from our model fits. This involves fitting an initial model, applying four outlier tests to all data points, removing all data points failing 3 or more of these tests, and re-fitting the model to the reduced data set. This process is iterated until all data points fail at most two of these tests. The outlier tests are DFITS, Cook's distance, Welsch-Kuh distance, and leverage.

C186 We comment below on the effect that this step has on our final model fitting. We have chosen to apply our iterative model outlier exclusion process for network and non-network models.

**What we heard from stakeholders**

C187 In their analysis, CEPA and Frontier both applied the iterative model outlier exclusion approach in the R code we published alongside the DPP4 Issues paper.[274]

O5.1: Scale growth forecast separately for network and non-network opex

**Problem definition**

C188 We need to decide what level of disaggregation in opex we use as the dependant variable(s). For DPP2 and DPP3 this was a split into network and non-network opex.

[274] We initially published our analysis as R scripts in a zip file, alongside the DPP4 Issues paper "DPP4_Issues_Paper_Opex_Modelling.zip" (13 November 2023). In response to a query, we later published a clarifying note "DPP4 Issues paper – opex modelling note" with one additional R script "ReEstimates with tables" (8 December 2023).

**Draft decision**

C189 Our draft decision is to retain the split for opex into network opex and non-network opex and model their scale trends separately.

**Alternatives Considered**

C190 In terms of aggregation, we have considered:

C190.1 using total opex, and

C190.2 breaking network and non-network expenditure into one or more subcategories.

**Analysis**

C191 We are unaware of any issues or concerns with the split into network and non-network opex, used in the DPP2 and DPP3 resets. This topic was noted in the DPP4 Issues paper, without suggestion of any change from the DPP3 approach, and we received no comments or suggestions of alternatives.

C192 Aggregation up into total opex was discounted on the basis that the current approach allows for better accommodation of the different cost drivers across EDBs with a wide range of geographical size and population density.

C193 The question of further disaggregation (into sub-categories of network and non-network opex) was examined by CEPA in their review ahead of our DPP4 Issues paper. As proposed in that paper, we support retention of the DPP3 approach, noting that during DDP3 various further-disaggregated models were rejected relative to the aggregated (network and non-network opex) models on the basis that the aggregated models had better explanatory power in terms of adjusted R-squared. The additional data post-2019 does not shift this finding.

*O5.3 and O5.4: Network and non-network opex models and elasticities*

**Nature of the decisions**

C194 For network and non-network opex we must now select the independent ('cost driver') variables and determine their elasticities through econometric model selection and fitting.

C195 We present these draft decisions side by side, as the process and considerations were the same.

**Draft decisions**

C196 Our **draft decision O5.3** is to forecast network opex scale growth with line length (elasticity 0.52) and ICP count (elasticity 0.45).

C197 Our **draft decision O5.4** is to forecast non-network opex scale growth with line length (elasticity 0.35), ICP count (elasticity 0.22) and capex (elasticity 0.30).

**Alternatives Considered**

C198 In terms of scale factor drivers, we have considered different combinations of the following variables, from ID data:

C198.1 total circuit length (km)

C198.2 ICP count (average number of total ICPs in the reporting year)

C198.3 annual energy delivered (MWh)

C198.4 maximum coincident peak demand (MW), and

C198.5 capex (Expenditure on Assets) ($000).

C199 And as a result of feedback in submissions we have also considered:

C199.1 ratcheted (ie, cumulative annual maximum) coincident peak demand (MW) and energy delivered (MWh), and

C199.2 a ‘time’ variable (year).

C200 Our draft decisions on opex aggregation and scale factor variables were based on a model selection process, informed by the CEPA review and by the Frontier Economics report provided by ENA.[275]

C201 We first considered base model variables, then capex and time, and then applied iterative model outlier exclusion to our preferred models.

C202 In our model selection, we looked at three things when comparing the results of our econometric analysis:

C202.1 explanatory power of the model primarily using the adjusted R squared metric, also root mean squared error (RMSE); and AIC and BIC where models have the same number of data points

[275] Frontier “Opex econometric modelling” prepared for Electricity Networks Aotearoa (9 January 2024)

C202.2 statistical significance of coefficients for model variables (p-values based on value estimates and standard errors), and

C202.3 whether the relationship between the independent and dependant variables makes sense in terms of the way EDBs manage their networks (for example from engineering and economic perspectives), rather than being a modelling artefact or coincidence (sense checks of coefficient size and sign).

C203 In addition to these technical factors, we also considered the wider context of the other components in setting opex allowances in this reset. We discuss this below with respect to capex and time variables in particular.

*Analysis*

C204 Our start point from DPP3 was to use ICP and lines as explanatory variables for both network and non-network opex and to consider variations by substituting or adding other variables to determine the 'base variables'. We then considered additional variables.

C205 The performance of our DPP3 forecasts using models with ICP and lines was reviewed CEPA and included in our DPP4 Issues paper.[276] These models tended to underestimate actual opex spend in the DPP3 period but that there may be reasons other than model misspecification for this, for example in the choice of opex cost escalation index.

C206 Nevertheless, the results below from our model selection comparison confirm that ICP and lines provide the best 2-variable model fits for both network and non-network opex.

C207 Stakeholders have in the past and in DPP4 submissions suggested other variables should be used on the basis that they considered these to be actual drivers of opex now or in the future.[277]

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[276] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper ", (2 November 2023) , Attachment D, p. 92-96.

[277] For example, Wellington Electricity "DPP4 Issues paper submission" (19 December 2023) p. 29-31.

C208 We agree that peak load and total energy delivered may be good predictors of opex. However, the results of modelling by ourselves, CEPA and Frontier concur that using both ICP and lines provides the best 'base models' assessed by explanatory model fits to past data, and that substituting or adding other variables is not supported on this basis.[278]

C209 Tables C7 and C8 below show the model fit coefficients and fit metrics for a range of network and non-network model specifications. In addition to ICP and lines, we show model fit results for including ratcheted peak demand (MW) and ratcheted delivery (GWh). Ratcheted here means the cumulative annual maximum of these values, and annual values are summed over sub-networks where an EDB reports for two or more sub-networks.

C210 Neither network or non-network models are improved by adding or substituting either ratcheted peak or ratcheted delivery. Results for models (8) and (9) in Tables C7 and C8 show that when adding ratcheted peak and energy variables to ICP and lines models, the coefficients for these terms are not statistically different from zero: their standard errors are greater than their estimated values.

C211 Our data contains strong positive correlations between candidate scale growth variables. Growth in ICP count overall leads to increased peak demand and energy delivered. The incremental change in lines length with ICP growth may depend on the mix of infill vs. network extension, but in general the overall levels of lines and ICP count are strongly correlated, albeit with different proportionality for different EDBs.

C212 In our case, the elasticities found for models with only ICP and lines variables will include contributions from other correlated drivers. That is, the elasticities above are not the pure elasticities for ICP and lines length, but also capture the effect of other correlated variables. It is not that we are discounting these alternative variables; their effects are implicitly captured in the elasticities for ICP and lines. If they could provide better or additional explanatory power, they would emerge in the models with best fits, but they don't.

[278] Frontier "Opex econometric modelling", prepared for Electricity Networks Aotearoa (9 January 2024), p. 19.

C213 Frontier considered both peak demand and ratcheted demand (as a better measure of network capacity than annual peaks, which can be subject to weather-dependent peaks) but they found no alternative model specification with ratcheted peak demand that performed better than using ICP and lines.[279] We have confirmed this result.

C214 We conclude that ICP and lines are the best 'base models' for both network and non-network opex models. Beyond this choice, we have considered two specific extensions: to add capex to the non-network opex model, and to add a time variable to both network opex and non-network opex models.

[279] Frontier "Opex econometric modelling" prepared for Electricity Networks Aotearoa (9 January 2024), p. 19.

## Table C7 Comparison of network opex base models[280]

| | (1) lines+icp | (2) lines+peakR | (3) lines+delR | (4) lines+del | (5) icp+peakR | (6) icp+delR | (7) icp+del | (8) +peakR | (9) +deliveryR | (!0) +delivery |
|---|---|---|---|---|---|---|---|---|---|---|
| **Opex category** | network | network | network | network | network | network | network | network | network | network |
| **(Intercept)** | -0.281 | 1.952*** | 1.574*** | 1.768*** | 0.759 | 1.799*** | -0.003 | -0.219 | -0.098 | -0.328 |
| | (0.187) | (0.228) | (0.209) | (0.298) | (0.685) | (0.511) | (0.466) | (0.455) | (0.379) | (0.306) |
| **lines** | 0.561*** | 0.621*** | 0.559*** | 0.842*** | | | | 0.560*** | 0.552*** | 0.560*** |
| | (0.040) | (0.042) | (0.046) | (0.038) | | | | (0.040) | (0.043) | (0.040) |
| **icp** | 0.426*** | | | | 0.718*** | 0.419*** | 0.837*** | 0.416*** | 0.388*** | 0.432*** |
| | (0.033) | | | | (0.113) | (0.111) | (0.047) | (0.077) | (0.076) | (0.042) |
| **peak_rat** | | 0.369*** | | | 0.100 | | | 0.011 | | |
| | | (0.034) | | | (0.112) | | | (0.074) | | |
| **delivery_rat** | | | 0.416*** | | | 0.407*** | | | 0.045 | |
| | | | (0.038) | | | (0.110) | | | (0.080) | |
| **delivery** | | | | 0.000*** | | | 0.000 | | | 0.000 |
| | | | | (0.000) | | | (0.000) | | | (0.000) |
| **Num.Obs.** | 149 | 149 | 149 | 149 | 149 | 149 | 149 | 149 | 149 | 149 |
| **R2** | 0.943 | 0.932 | 0.933 | 0.902 | 0.867 | 0.878 | 0.867 | 0.943 | 0.943 | 0.943 |
| **R2 Adj.** | 0.942 | 0.931 | 0.932 | 0.901 | 0.865 | 0.876 | 0.865 | 0.942 | 0.942 | 0.942 |
| **AIC** | 4.0 | 31.0 | 28.5 | 84.9 | 130.5 | 118.0 | 131.0 | 6.0 | 5.7 | 6.0 |

280 Comparison of base models for network opex. Model (1) with ICP and lines has the best model fits (highest adjusted R squared, lowest AIC and BIC) and has statistically significant coefficients (denoted ***). Numbers of paratheses are standard errors in the coefficients. Model (1) is not improved by either substitution or addition of either of peak or delivery variables. Here *peak_rat* refers to ratcheted peak demand (MW) and d*elivery_rat* refers to ratcheted delivery (total energy delivered, MWh). All models fit to the same data, after excluding irregular input data, but without any model outlier exclusion.

| | (1) lines+icp | (2) lines+peakR | (3) lines+delR | (4) lines+del | (5) icp+peakR | (6) icp+delR | (7) icp+del | (8) +peakR | (9) +deliveryR | (!0) +delivery |
|---|---|---|---|---|---|---|---|---|---|---|
| **BIC** | 16.0 | 43.0 | 40.6 | 96.9 | 142.5 | 130.0 | 143.0 | 21.0 | 20.7 | 21.0 |
| **RMSE** | 0.24 | 0.26 | 0.26 | 0.31 | 0.36 | 0.35 | 0.37 | 0.24 | 0.24 | 0.24 |
| • p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001 | | | | | | | | | | |

**Table C8 Comparison of non-network models[281]**

| | (1) lines+icp | (2) lines+peakR | (3) lines+delR | (4) lines+del | (5) icp+peakR | (6) icp+delR | (7) icp+del | (8) +peakR | (9) +deliveryR | (10) +delivery |
|---|---|---|---|---|---|---|---|---|---|---|
| **Opex category** | nonnetwork | nonnetwork | nonnetwork | nonnetwork | nonnetwork | nonnetwork | nonnetwork | nonnetwork | nonnetwork | nonnetwork |
| **(Intercept)** | 0.553* | 3.706*** | 3.126*** | 3.415*** | 1.278* | 1.485** | 0.616 | 0.788 | 0.508 | 0.452 |
| | (0.241) | (0.295) | (0.279) | (0.399) | (0.631) | (0.487) | (0.430) | (0.584) | (0.487) | (0.394) |
| **lines** | 0.283*** | 0.362*** | 0.295*** | 0.681*** | | | | 0.281*** | 0.285*** | 0.282*** |
| | (0.051) | (0.055) | (0.062) | (0.051) | | | | (0.052) | (0.055) | (0.052) |
| **icp** | 0.599*** | | | | 0.710*** | 0.624*** | 0.814*** | 0.559*** | 0.608*** | 0.610*** |
| | (0.042) | | | | (0.104) | (0.106) | (0.043) | (0.099) | (0.097) | (0.054) |
| **peak_rat** | | 0.523*** | | | 0.086 | | | 0.042 | | |
| | | (0.044) | | | (0.103) | | | (0.094) | | |
| **delivery_rat** | | | 0.571*** | | | 0.176+ | | | -0.011 | |
| | | | (0.050) | | | (0.105) | | | (0.103) | |

[281] Comparison of base models for non-network opex. Model (1) with ICP and lines has the best model fits (highest adjusted R squared, lowest AIC and BIC) and has statistically significant coefficients (denoted ***). Numbers of paratheses are standard errors in the coefficients. Model (1) is not improved by either substitution or addition of either of peak or delivery variables. Here *peak_rat* refers to ratcheted peak demand (MW) and d*elivery_rat* refers to ratcheted delivery (total energy delivered, MWh). All models fit to the same data, after excluding irregular input data, but without any model outlier exclusion.

| | (1) lines+icp | (2) lines+peakR | (3) lines+delR | (4) lines+del | (5) icp+peakR | (6) icp+delR | (7) icp+del | (8) +peakR | (9) +deliveryR | (10) +delivery |
|---|---|---|---|---|---|---|---|---|---|---|
| **delivery** | | | | 0.000*** | | | 0.000 | | | 0.000 |
| | | | | (0.000) | | | (0.000) | | | (0.000) |
| **Num.Obs.** | 149 | 149 | 149 | 149 | 149 | 149 | 149 | 149 | 149 | 149 |
| **R2** | 0.900 | 0.878 | 0.873 | 0.812 | 0.879 | 0.881 | 0.879 | 0.900 | 0.900 | 0.900 |
| **R2 Adj.** | 0.898 | 0.876 | 0.871 | 0.810 | 0.878 | 0.879 | 0.877 | 0.898 | 0.898 | 0.898 |
| **AIC** | 78.8 | 107.9 | 114.2 | 172.1 | 106.1 | 104.0 | 106.6 | 80.6 | 80.7 | 80.6 |
| **BIC** | 90.8 | 119.9 | 126.2 | 184.1 | 118.2 | 116.1 | 118.6 | 95.6 | 95.8 | 95.7 |
| **RMSE** | 0.31 | 0.34 | 0.35 | 0.42 | 0.34 | 0.33 | 0.34 | 0.31 | 0.31 | 0.31 |

- $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

### Capex variable

C215 In our DPP4 Issues paper we identified that adding capex as an explanatory variable to models with ICP and lines improved the explanatory power of non-network opex (NNO) models with a statistically significant elasticity. For network opex, the effect was too small to resolve with statistical significance.

C216 Here ‘capex’ refers to Expenditure on Assets, the quantity reported in ID data.

C217 In the DPP4 Issues paper we raised the possibility of including capex as a driver of non-network opex and asked for submissions on whether this reflected a relationship expected to apply for EDBs in practise. The business sense was overall supported in submissions, including Orion who noted:[282]

> In terms of how Orion runs its business we agree that a relationship can exist between nonnetwork opex and network capex.
>
> […]
>
> Orion submits that we support the Commission’s conclusion that forecast capex as a driver of nonnetwork opex could improve opex forecasts.

C218 Frontier provided analysis supporting the proposal in our DPP4 Issues paper to add capex as an explanatory variable for non-network opex, but not for network opex.[283]

C219 Tables C9 and C10 below compare model fits when adding capex and time variables to our base models with ICP and lines terms, after filtering input data to the reference period 2018-2023 and filtering out irregular input data.

C220 The model metrics in Table C9 show that our base network opex model (model 1) is not improved by adding a capex variable (model 2). The model with capex does not improve the adjusted R squared (for which larger is better) and it increases the AIC and BIC (for which smaller is better).

C221 Model (2) here has a small negative coefficient for capex (-0.037) but this is less than its standard error (0.046). In other words, this coefficient is not statistically different from zero, and any capex-effect is too small to resolve.

[282] Orion “DPP4 Issues paper submission” , (19 December 2023) p. 11.

[283] Frontier “Opex econometric modelling” prepared for Electricity Networks Aotearoa (9 January 2024), p. 9.

**Table C9 Comparison of network models adding capex and time variables**[284]

| | (1) lines+ICP | (2) +capex | (3) +time | (4) +capex+time |
|---|---|---|---|---|
| **Opex category** | network | network | network | network |
| **(Intercept)** | -0.281 | -0.327+ | -51.065* | -55.944* |
| | (0.187) | (0.196) | (23.598) | (23.913) |
| **lines** | 0.561*** | 0.581*** | 0.559*** | 0.589*** |
| | (0.040) | (0.047) | (0.039) | (0.047) |
| **ICP** | 0.426*** | 0.451*** | 0.426*** | 0.462*** |
| | (0.033) | (0.044) | (0.032) | (0.044) |
| **capex** | | -0.037 | | -0.055 |
| | | (0.046) | | (0.046) |
| **year** | | | 0.025* | 0.028* |
| | | | (0.012) | (0.012) |
| **Num.Obs.** | 149 | 149 | 149 | 149 |
| **R2** | 0.943 | 0.943 | 0.945 | 0.945 |
| **R2 Adj.** | 0.942 | 0.942 | 0.944 | 0.944 |
| **AIC** | 4.0 | 5.4 | 1.3 | 1.9 |
| **BIC** | 16.0 | 20.4 | 16.4 | 19.9 |
| **RMSE** | 0.24 | 0.24 | 0.24 | 0.23 |
| • p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001 | | | | |

C222 Table C10 compares non-network opex models, adding capex and time variables to our preferred base model. It shows that adding a capex term in model (2) is supported. It does improve the fit metrics: adjusted R squared increases, and AIC and BIC decrease. The capex coefficient is also statistically significant.

[284] Network opex regression model outputs. Column (1) shows results for the base model with network opex modelled (with log-transformed variables) as network opex ~ lines + ICP, and other model add capex, time or both capex and time to this model specification. Rows gives coefficient values, with standard errors in brackets underneath. Standard fit metrics are included in the lower rows.

**Table C10 Comparison of non-network models adding capex and time**[285]

| | (1) lines+ICP | (2) +capex | (3) +time | (4) +capex+time |
|---|---|---|---|---|
| **Opex category** | nonnetwork | nonnetwork | nonnetwork | nonnetwork |
| **(Intercept)** | 0.553* | 0.824*** | -73.654* | -55.902+ |
| | (0.241) | (0.240) | (30.182) | (29.488) |
| **Lines** | 0.283*** | 0.164** | 0.280*** | 0.172** |
| | (0.051) | (0.058) | (0.050) | (0.057) |
| **ICP** | 0.599*** | 0.457*** | 0.598*** | 0.469*** |
| | (0.042) | (0.054) | (0.041) | (0.054) |
| **Capex** | | 0.220*** | | 0.202*** |
| | | (0.057) | | (0.057) |
| **Year** | | | 0.037* | 0.028+ |
| | | | (0.015) | (0.015) |
| **Num.Obs.** | 149 | 149 | 149 | 149 |
| **R2** | 0.900 | 0.909 | 0.904 | 0.911 |
| **R2 Adj.** | 0.898 | 0.907 | 0.902 | 0.909 |
| **AIC** | 78.8 | 66.1 | 74.7 | 64.3 |
| **BIC** | 90.8 | 81.1 | 89.7 | 82.3 |
| **RMSE** | 0.31 | 0.29 | 0.30 | 0.29 |
| • p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001 | | | | |

C223 Model (2) adding capex now attributes some of the variance in non-network opex to movements in capex which was previously attributed in model (1) to movements only in lines and ICP count. This does result in the lines coefficient in this model having a minor reduction in statistical significance (here to p < 0.01 **).

C224 It is not surprising that adding capex reduces the other elasticities. Capex is strongly correlated with lines and ICPs, as larger networks overall have larger-cost capex programmes. In general, omitting a significant variable from a model (ie, leaving out capex in model (1)) will result in higher coefficients for any variables which are included in the model and are positively correlated with the omitted variable.

285 Non-network opex regression model outputs. Column (1) shows results for the base model with network opex modelled (with log-transformed variables) as non-network opex ~ lines + ICP, and other model add capex, time or both capex and time to this model specification. Rows gives coefficient values, with standard errors in brackets underneath. Standard fit metrics are included in the lower rows.

C225 Informed by submissions, the statistically significant positive correlation we find here between non-network opex and capex plausibly makes sense from economic and business operation perspectives. The actual underlying relationship here may depend on the nature of work undertaken, varying by EDB, and may include time lags. But within the context of a low-cost DPP approach applied across the overall regulatory period, we are satisfied to model the capex and non-network opex values from the same year.

C226 One might also expect a substitution effect to exist between increased capex spend and decreased network opex (ie, increased major works is correlated with reduced maintenance cost). However, as shown in Table C9 and discussed above, any such effect in our data is too small to resolve.

C227 Our decisions on including a capex variable are therefore:

C227.1 for network opex, to not add a capex variable, as a statistically significant effect is not resolved, and model fits do not improve, and

C227.2 for non-network opex, to add a capex variable to the ICP and lines model, as this does improve explanatory power, the capex coefficient is statistically significant, and the nature of the relationship can be considered to make sense economically.

**Time variable**

C228 We also considered adding a time variable to network and non-network models, as suggested by Frontier and supported by results showing improved model fits.[286]

C229 As shown in Tables C9 and C10 above, we confirm Frontier's results that network and non-network model fits are both improved by adding a time variable (*year*) with a coefficient of about 0.03. As we have not log-transformed the year variable, this suggests a roughly 3% pa increases over time for network and non-network opex.

C230 In contrast to the inclusion of a capex term, which as above reduced other elasticities, the addition of a time variable made almost no change to the other elasticities - compare models (1,3) in Tables C9 and C10. Unlike adding the capex term, adding a time term *is* explaining variance in the data which is not explained with the other model terms.

[286] Frontier "Opex econometric modelling" prepared for Electricity Networks Aotearoa (9 January 2024)

C231 This analysis and result are somewhat consistent with what's described as a productivity loss in the recent CEPA draft paper regarding the evolution of industry productivity.[287] The methodology and definition of costs differ slightly but not fundamentally, and the time effect differs by magnitude but not direction.

C232 A choice to include an unattributed time term in DPP4 forecasts involves more than just its observation in past data. While our scale trend approach *does* include modelled elasticities for ICP, lines length and capex growth, these are identified factors with genuine relationships to cost growth which we can assume without great loss of accuracy to apply over the DPP4 period. The same is not true for a 'time' variable even if it does point to unmodelled costs.

C233 DPP4 opex allowances already capture actual incurred cost levels through opex levels in the 2024 base year (2024 AMP forecasts for draft prices, and 2024 actuals proposed for DPP4 final prices). All costs captured in the base year level, even those uncaptured in our econometric models, with be carried forward over each year in the DPP4 period. Our draft decisions also include acceptance of several step changes, compared to only a pass-through cost for FENZ levies in DPP3. Therefore, without understanding what the observed time effect actually relates to, including it in our scale growth trends would risk double counting for costs captured in the base year level and step changes.

C234 Considering these factors, our draft decision is to not include a time trend in our opex scale trends forecasts. Doing so would inappropriately mix scale growth and cost-escalation elements of the overall trend growth in opex. Time is neither a driver of costs *per se*, nor a measure of network scale growth. Including an explicit time term would risk double counting of costs increases already captured in base year opex and step changes.

C235 However, this work has informed our draft decisions. Given the impact of recent increases in input costs on EDBs and the prospect of future increase over-and-above general inflation, we have in draft **decision O4.2.** included an EDB-specific inflation differential in addition to forecasts of economy-wide labour and producer-price inflation.

[287] CEPA "EDB Productivity report: A report prepared for the Commerce Commission" (26 March 2024).

*Model fits and elasticities after outlier exclusion*

C236 Our final step to determining elasticities is to fit models with our iterative model outlier exclusion method. Results are shown in Table C11. As discussed above, this has little impact on the elasticities for network opex, but it does result in changes to the non-network elasticities. At this stage we also apply robust standard errors, clustered by EDB.

**Table C11 Proposed opex elasticities for DPP4 draft decisions**

| | Network | Non-network |
|---|---|---|
| **(Intercept)** | -0.189 | 1.048** |
| | (0.264) | (0.354) |
| **lines** | 0.519*** | 0.354*** |
| | (0.049) | (0.078) |
| **icp** | 0.451*** | 0.216** |
| | (0.049) | (0.076) |
| **capex** | | 0.302*** |
| | | (0.084) |
| **Num.Obs.** | 145 | 137 |
| **R2** | 0.939 | 0.950 |
| **R2 Adj.** | 0.938 | 0.948 |
| **Std.Errors** | by: edb | by: edb |

- p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001

Final opex models, with robust standard errors (clustered by EDB), iterative model outlier exclusion, and irregular input data excluded from data 2018-2023.

C237 The effect of applying the iterative model outlier exclusion process on our preferred network model is to remove only 4 data points, with changes to elasticities which are smaller than their standard errors.

C238 Applied to our preferred non-network model, it results in changes to the ICP, lines and capex elasticities that are greater than their standard errors. Based on inspection of the excluded data, we accept these changes as the result of correct application of this method, rather than an artefact.

C239 The iterative model outlier exclusion removed 12 data tuples (EDB-year combinations) in our non-network model fit. All years of data are excluded for two EDBs (each of which also had one year excluded at the data input stage) and one year of data is excluded for another two EDBs.

C240 Graphical inspection of the 12 data tuples excluded offers an explanation. Data from our reference period displays less overall noise than when we include data from earlier years (ie, 2013-2017). This reduction in noise appears to have increased the number of points failing outlier tests. In particular, the points for the two EDBs with all data excluded clearly lie away from the general arc of data points from other EDBs. We consider these to be legitimate outliers from the overall trend, and that excluding these points provides a more robust model, given our aim is to determine industry-wide elasticities.

C241 The standard errors in the model fits in Table C11 result from robust standard error estimation, with data clustered by EDB. As discussed in the DPP4 Issues paper, this is appropriate for out data where data are clearly clustered by EDB, and results in an increase to standard error estimates but no change to the model coefficient (ie, elasticities).[288] The size of these standard errors indicates that an appropriate precision to specify these elasticities is two decimal places, as reflected in Table C6.

C242 Our proposed elasticities for DPP4 draft decision for network opex (ICP: 0.45 and lines: 0.52) are very similar to those used in DPP3 (ICP: 0.4514 and lines: 0.4727) with a slight increase in lines elasticity. This is consistent with our observations of weak evidence for structural change in network open models with changes in reference period.

C243 Our proposed elasticities for the DPP4 draft decision for non-network opex are not directly comparable with DPP3 non-network elasticities (ICP: 0.6520, lines: 0.2188) due to the addition of the capex term, and to the observed difference in the iterative model outlier exclusion process removing more data points when applied to our proposed DPP4 draft decision reference period.

**Considerations of including capex as a ‘cost driver’ of non-network opex**

C244 In the context of capex increasing in DPP4, we do see merit in selecting the non-network model which seeks to separate the highly correlated lines and capex effects. This would lead to opex allowances better reflecting the overall costs to EDBs to undertake larger capex programmes. In a similar way, should capex programmes reduce then with all other things being equal, we would expect small reductions in the scale growth rate of non-network opex.

[288] Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper” (2 November 2023), pp. 101.

C245 We are also mindful of the appearance that this could be seen to incentivise higher capex forecasts to increase non-network opex allowances, but we do not consider this a material concern in practise. The capex growth trend which is multiplied by the non-network opex-to-capex elasticity above is derived from DPP4 allowances (after any caps are applied) rather than AMP forecast values. The overall level of opex is more sensitive to other factors than this, for example base year opex.

C246 In practise, the decision to include a capex term in the non-network opex model here results in a higher opex scale growth trend for all but two EDBs. The counterfactual here is the overall opex trend using the same network opex model, but the non-network opex model fit without a capex term. Of those with a higher trend, the average increase due to including the capex term is +0.4% pa Two EDBs with reduced capex spend compared to the capex reference period see a reduction in their opex scale growth trend compared to this counterfactual.

Alternatives considered

C247 In response to submissions, we did consider using one extensive variable (ie, a size metric being one of ICP or lines length) and one intrinsic variable reflecting customer usage (eg, peak or energy delivery per ICP). Conceptually, this approach might be more responsive to capturing future changes in cost drivers. However, taking this approach would require the use of a model which performed worse at explaining recent past trends compared to our preferred models, and a potential additional loss of forecast accuracy from difficulties in accurately forecasting these variables. We discounted this on the basis that our proposed approach provides a more reliable forecast of opex scale growth trends.

*O5.5, O5.6 and O5.7 Draft decisions on forecasting scale growth factors*

**Problem definition**

C248 The scale trend approach requires forecasts for the underlying growth rates of the scale factors: ICP count, total lines length and capex (Expenditure on Assets).

C248.1 We have reviewed our approach to ICP and lines forecasts, and

C248.2 Capex is a new scale variable, requiring a new method.

**Draft Decisions**

C249 **Draft decision O5.5:** Forecast lines length extrapolated using recent growth rate trend, and irregular data adjusted.

C250 **Draft decision O5.6:** Forecast ICP count extrapolated using recent growth rate trend, and irregular data adjusted.

C251 **Draft decision O5.7:** Forecast capex based on a constant growth.

C252 That is, for DPP4 draft decisions we have forecast opex scale factor growth rates over the DPP4 period (% pa) as follows:

C252.1 ICP count and total lines length growth rates are forecast from recent trends in ID data subject to adjustments for data quality, and

C252.2 capex average growth rate is the compound average growth rate (CAGR) equivalent to the uplift in the total expenditure on assets allowed in DPP4 compared to the reference period actuals, when applied between the mid-point years of the reference period and the middle year of the DPP4 regulatory period.

C253 For lines, this retains the approach used in DPP3. For ICP count, this is a change from our previous approach where we mapped Stats NZ forecasts of household growth to EDB regions. For capex this is a new method.

**Alternatives Considered**

C254 As alternatives, we have considered:

C254.1 No alternative for lines length

C254.2 Household growth or EDB’s own forecasts for ICP growth, and

C254.3 Average annual change rates implied by approved capex allowances.

**Analysis**

## ICP and lines

C255 For lines length, we have no plausible alternative to a method based on recent actual ID data. In DPP3 we calculated the average annual growth rate from reported total lines length from the five years 2015-2019, using 2015-2018 for the DPP3 draft decision.

C256 Our draft decision is to retain this approach for DPP4, with attention to data quality. When fitting a small number of points (here 5 per EDB for their recent trend) the average trend can be sensitive to data irregularities. Left untreated, such irregularities could result in a fitted trend which is clearly not a reasonable estimate of the expected lines and ICP growth rates over the DPP4 period.

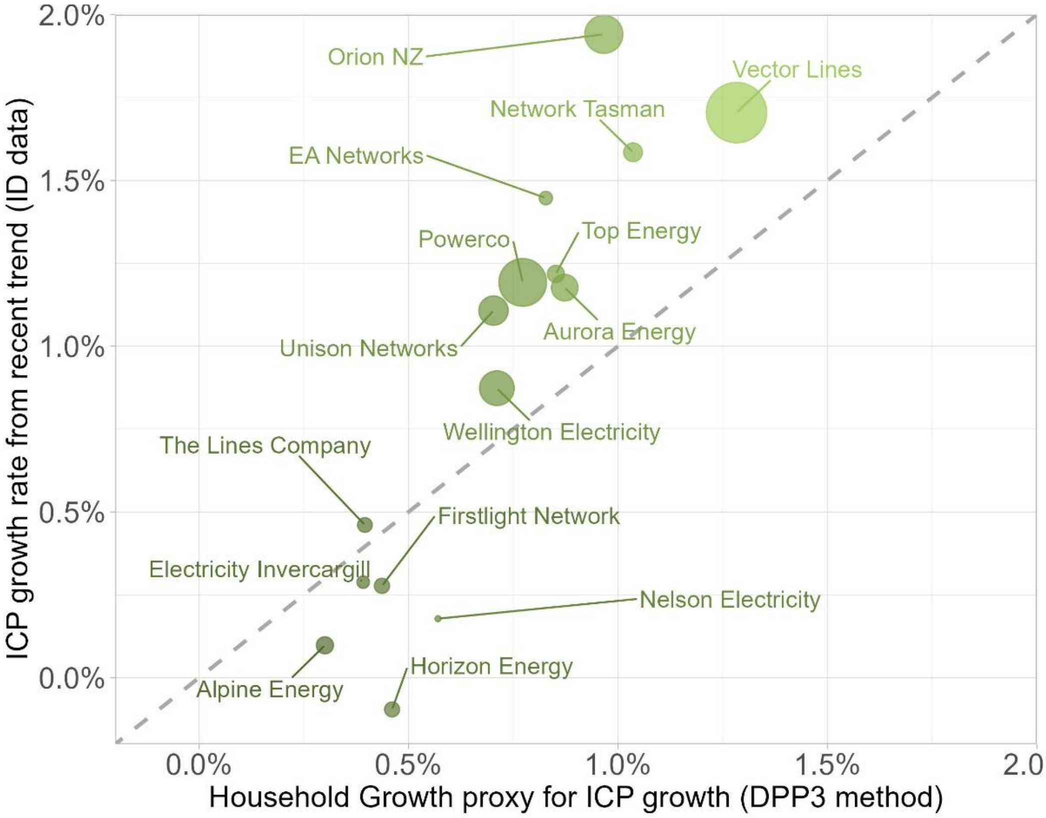
C257 Following a review of ID data, we have made some adjustments to ID lines and ICP data solely for the purpose of this trend fitting. These adjustments are detailed in a DPP4 draft decision model workbook.[289] Adjustments were made only in cases where not doing so would have resulted in forecasts clearly and significantly different from prevailing trends in the data, and as such would have been unreasonable predictors of future growth rates. We intend to revisit these adjustments for DPP4 final decisions as 2024 ID data and other information becomes available.

C258 For ICP growth in DPP3 we used a similar trend approach, applied to Stats NZ forecasts of household growth by region. We have changed our approach based on a review of the results of this approach compared to the recent actual trends in ICP growth from ID data, and also from ICP growth forecasts in EDB AMPs.

C259 Figure C3 below compares the average ICP count growth rates using the DPP3 method based on StatsNZ HHG (x axis) with an approach using the recent trend in ICP ID data (y axis). The size of the points reflects the number of ICPs, so Vector is the largest.

[289] See 'Opex-feeder-circuitlength-ICP-capex-DPP4' file in DPP4 modelling workbooks.

**Figure C3 Comparison of household growth and ICP growth**[290]




C260 If the HHG and ICP trend results aligned, all points would lie on the dotted diagonal line. Instead, points above this line indicate recent actual growth (2020-2023) above predictions from the 2018-2023 HHG forecasts, and conversely for points below the line.

C261 Actual recent growth in all of the Big Six largest EDBs has been above the HHG predictions. For example, Vector ICPs have been growing at about 1.7% pa but the HHG model results in a 1.3% pa increase. Conversely, the HHG model has over-estimated actual growth predominantly for smaller and lower-growth networks.

C262 We find the HHG forecasts to be a biased estimator of actual growth in ICP numbers, and that recent ICP trends are likely a better predictor of the DPP4 period growth rates.

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290 OtagoNet is not shown. Its recent trend is an off-scale 4.0% pa due to growth in its Lakeland Network, and its HHG-derived estimate is +0.5% pa.

C263 The implication of this change is a net increase in opex scale growth, with most EDBs having an increase in ICP growth rate, but some having a small reduction to be in line with their recent actual growth rates. The magnitude of the overall increase is about 0.1% pa.

## Capex

C264 ICP count and lines length tend to increase reasonably steadily with time in response to demographic pressures, and the trend approach above is appropriate. Capex allowance profiles however are not necessarily smooth over time, reflecting a range of factors including EDBs commissioning of "lumpy" projects (such as new substation builds or major IT projects). It is not uncommon for AMPs to have higher capex forecasts earlier in a regulatory period and to then decrease in later years. As such, it is more appropriate to consider the change in capex on an aggregate basis, not year-on-year.

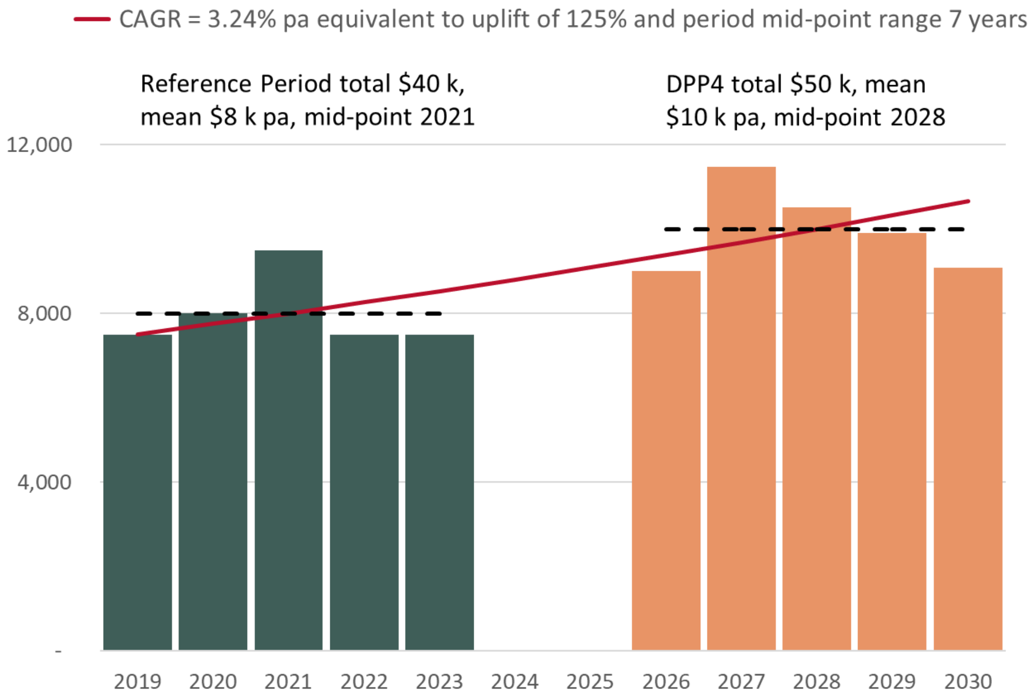
C265 We refer to the DPP4 capex allowance setting process, in which the total capex allowances have been set with consideration to the total capex in a reference period.[291] For DPP4 draft decisions, the reference period for capex is the five years 2019-2023, proposed to be updated to 2020-2024 as 2024 actuals are available. For DPP4 draft prices, we have capped the total DPP4 capex at 125% (on a constant dollar basis) of the total capex in the 5-yr capex reference period while retaining the year-to-year shape from EDBs' AMP forecasts.

C266 Following this, we have calculated a compounding average growth rate (CAGR) equivalent to this uplift. Figure C4 below illustrates this calculation, using made-up numbers (in constant $2024 terms). The total capex spend in the reference period is $40m and the allowance for DPP4 is $50 m, corresponding to a capex increase capped at +25%. The CAGR required to match this growth over the 7-year period between the mid-point of the reference period and mid-point of DPP4 is in 3.24 % pa.[292]

[291] **Attachment B**, refer *'Draft decision C2: Set capex allowance in constant dollars by limiting the total increase in forecast capex to 125% of historical level (net of forecast capital contributions)'* section.

[292] In this case, CAGR = (125%)^(1/7) -1 = 3.24%

**Figure C4 Capex CAGR equivalent to allow capex uplift**




C267 For the DPP4 draft decision, we have applied this method per EDB, using actual reference period expenditure on assets, and allowed DPP4 expenditure on assets values (after the application of the 125% cap).

C268 We intend to update these growth rates at DPP4 final decisions, using the same approach revisited for updates to final DPP4 expenditure on assets and any change in reference period.

C269 As an alternative, we considered referencing the growth rate in capex to one particular year, for example the opex base year. We discounted this on the basis that the year-to-year variability in capex spend would make it inappropriate to reference changes over the DPP4 period to a single value.

*Stakeholder views*

C270 No submissions or stakeholder views have been expressed on this topic. None of the submissions supporting the inclusion of a capex term as a driver of non-network opex considered the question of how to calculate the average annual growth rate in capex required to apply this change.

*Results*

C271 The results of applying the methods above are shown in Table C12. This shows the ICP, lines and capex growth forecasts, and for the elasticities above, the corresponding scale growth trends in network and non-network opex.

**Table C12 Scale factor growth and scale cost growth[293]**

| EDB | Circuit Length | ICP | Capex | Network Opex | Non-Network |
|---|---|---|---|---|---|
| **Alpine Energy** | 0.30% | 0.72% | 3.24% | **0.48%** | **1.23%** |
| **Aurora Energy** | 0.84% | 1.19% | 1.37% | **0.97%** | **0.97%** |
| **EA Networks** | 0.93% | 1.42% | -5.94% | **1.13%** | **-1.14%** |
| **Electricity Invercargill** | 0.26% | 0.30% | 3.24% | **0.27%** | **1.13%** |
| **Firstlight Network** | -0.03% | 0.25% | 3.24% | **0.09%** | **1.01%** |
| **Horizon Energy** | 0.33% | 0.43% | 3.24% | **0.37%** | **1.18%** |
| **Nelson Electricity** | 0.12% | 0.18% | 3.24% | **0.14%** | **1.05%** |
| **Network Tasman** | 0.68% | 1.68% | 3.17% | **1.11%** | **1.56%** |
| **Orion NZ** | 1.04% | 1.94% | 3.24% | **1.41%** | **1.76%** |
| **OtagoNet** | 0.05% | 3.15% | 3.24% | **1.45%** | **1.68%** |
| **Powerco** | 0.82% | 1.20% | 3.24% | **0.97%** | **1.52%** |
| **The Lines Company** | 0.31% | 0.48% | 1.55% | **0.38%** | **0.68%** |
| **Top Energy** | 0.57% | 1.21% | -1.11% | **0.84%** | **0.13%** |
| **Unison Networks** | 0.10% | 1.10% | 3.24% | **0.55%** | **1.25%** |
| **Vector Lines** | 0.88% | 1.70% | 3.24% | **1.23%** | **1.66%** |
| **Wellington Electricity** | 0.49% | 0.89% | 3.24% | **0.66%** | **1.34%** |

C272 In Table C12 there are many EDBs with a capex growth rate of 3.24%, indicating EDBs whose capex allowances have been capped at a 125% of capex in the reference period.

C273 Table C12 also shows negative capex growth rates for EA Networks and Top Energy, reflecting reduced capex allowances compared to the reference period.

[293] Summary of (a) Scale factor forecasts (% pa) for circuit length (‘lines’), ICP (average number of ICPs per year) and capex (expenditure on assets); and (b) resulting scale trend growth of network and non-network opex after combining with the elasticities in Table C6.

**Draft decisions on cost escalation trends**

C274 Within the base-step-trend opex model, trend factors are intended to capture continuing and broadly predictable changes in forecasting EDB opex.

C275 The purpose of cost escalators is to account for real input price increases beyond a prudent and efficient EDB's ability to avoid.[294] This is consistent with promoting s52A, as in competitive markets we would expect unavoidable input price increases to be reflected in the final prices that consumers pay (though counterbalanced by productivity improvements). In addition, there is no efficiency incentive benefit to exposing EDBs to inflation risks that they cannot reasonably control.

C276 Using too general of an index (eg, the consumer price index (CPI) or all industries indices) may miss structural supply and demand effects that EDBs and their supply chains are exposed to.

C277 An index that is too specific (eg, sub-sector indices, EDBs' own implied inflation in their AMPs) risks undermining efficiency incentives by passing on costs that result from EDBs' own cost management; and/or undermining limits on excess profits by passing on unreasonably high forecasts with limited scrutiny.

C278 Therefore, the level of aggregation on how to group opex for escalation and the choice of escalators are the two main aspects of our analysis for cost escalation.

*Level of aggregation (Decision O4.1)*

**Problem definition**

C279 In deciding how to escalate costs, we need to determine how to group opex for escalation purposes, and whether different categories of expenditure have different input cost drivers.

**Draft decision**

C280 We propose to apply the same cost escalators to all opex.

**Alternatives considered**

C281 In addition to all opex, we have also considered:

C281.1 escalation for non-network and network opex, and

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[294] "Real price effects" refers to changes in input prices net of overall CPI inflation.

C281.2 carving out subcategories (notably insurance) to be escalated separately.

**Analysis**

C282 Using a different mix of indices for different categories could be justified where we have evidence that both:

C282.1 the inputs required for different categories of expenditure differ significantly, and

C282.2 the relative proportions of those categories change materially over time or between suppliers.

C283 As noted further below, we lack detailed information about the kinds of input costs (labour, materials, services etc.) that make up EDB opex. As such, we do not know whether the drivers of network and non-network opex are sufficiently different to justify different escalators.

C284 More importantly, the relative proportion of these categories has been reasonably static over time: with network opex comprising between 39-41% of opex each year since 2014, and non-network 59-61%. In this stable context, at an industry-wide level, differences in drivers could be accommodated with a different weighting of the indices in the escalator basket, rather than with multiple baskets.

C285 Between EDBs, there is a greater level of variation (as low as 27% and as high as 61% on average), which could justify the added complexity of applying separate escalators across categories. However, in the absence of further information about input costs mix, we do not consider this approach appropriate.

C286 For insurance costs, we have used forecast information provided by Principal Economics to inform the size of the step changes we have included, rather than escalating this cost separately.[295]

**Stakeholder views**

C287 In its submissions on the DPP4 Issues paper, Horizon noted the different drivers of different opex elements:[296]

> "…different OPEX elements will have different drivers. For example, cybersecurity and insurance costs have escalated out of line with other elements of OPEX. Any

[295] These forecasts were applied where EDBs did not provide supplier-specific forecasts of opex.

[296] Horizon, "Submission on DPP4 Issues Paper" (19 December 2023), p 11.

EDB-specific index should include a mix of escalators that reflect the mix of OPEX costs faced by EDBs."

C288 Multiple submitters supported a separate treatment for insurance costs.[297] As noted, we have addressed increasing insurance costs as a step change.

*Choice of escalators*

**Problem definition**

C289 The cost of the inputs (labour, materials, and services) EDBs require to deliver the outputs expected of them changes over time. Our goal is to identify the elements of this change that are beyond the EDB's control (economy or sector-wide).

C290 In a higher and less predictable inflation environment, where different categories of inputs may be subject to different supply constraints or demand pressures, these real prices effects can have a material impact on EDB profitability. If we don't reflect these input price increases this would not be consistent with the financial capital maintenance (FCM) principle, and EDBs might not expect to earn an ex ante fair return.

**Draft decision**

C291 We propose retaining the 60/40 split of all industry LCI and PPI indices, but applying a 0.3% uplift to both to reflect historic higher inflation in the electricity, gas, water, and waste sector that we consider is likely to persist in the medium-term.

**Alternatives considered**

C292 As alternatives we have considered:

C292.1 retaining the use of the all-industries indices unadjusted, and

C292.2 applying an EDB-specific basket of cost escalators.

[297] See DPP4 Issues paper submissions from: Aurora, p. 11; ENA, p.15; Horizon, p. 11; Orion, pp. 11-12; Powerco, p. 17; and Transpower, p. 16.

**Analysis**

C293 The most material source of differences between forecast and actual cost escalation over the DPP3 period has been general inflation (represented by CPI). To insulate consumers and EDBs from CPI inflation risk, in the 2023 IM Review we introduced a “real IRIS”, where efficiency incentives are measured against expenditure adjusted for out-turn CPI.

C294 Because of this, the choice of escalator is less material than under the nominal IRIS approach, as it only captures the “real price effect” (RPE) changes relative to general inflation. Nonetheless, RPE that reflect EDBs efficient forecast costs still have a material impact on both efficiency and profitability outcomes.

C295 Historical evidence (see Figure C5 below) highlights the differences that can occur over the short to medium term between economy-wide and sectoral inflation.

C296 The +0.3% uplift we have proposed is based on the average difference between the EGWW LCI (shown in red) and the all industry LCI (shown in blue) over the past five years.

C297 Given the lack of information about breakdown of EDB-specific cost drivers (such as particular input like information technology or traffic management services, or particular categories of labour) we have not been able apply a more targeted approach.

**Figure C5 Comparison of all-industries LCI and EGWW LCI change[298]**

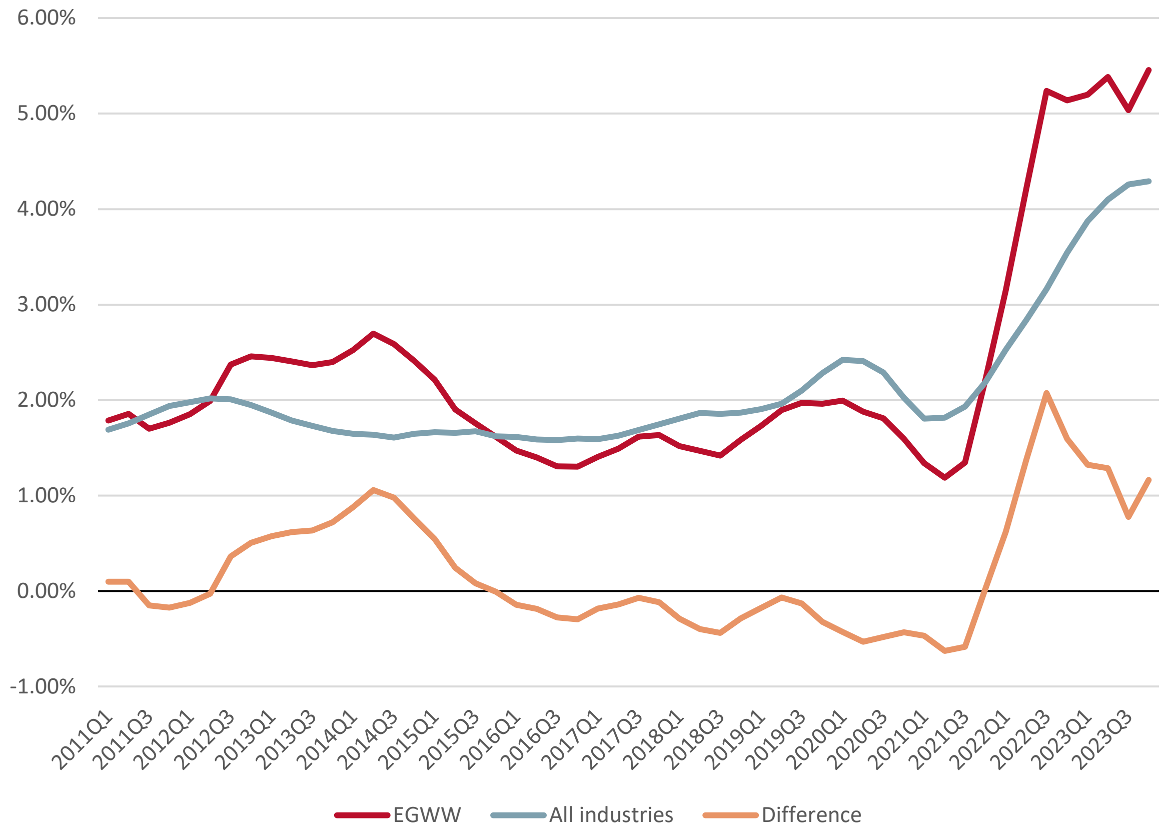


**Table C13 Proposed forecast cost escalators**

| Index | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| **CPI** | 2.3% | 1.9% | 2.0% | 2.0% | 2.0% | 2.0% |
| **LCI RPE** | 0.7% | 0.2% | -0.1% | -0.2% | 0.0% | 0.0% |
| **PPI RPE** | 0.4% | 0.4% | 0.3% | 0.3% | 0.4% | 0.5% |
| **EGWW uplift** | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% |
| **Blended LCI/PPI** | **3.2%** | **2.5%** | **2.3%** | **2.3%** | **2.5%** | **2.5%** |

[298] Four-quarter average change, per StatsNZ.

### Stakeholder views

C298 The ENA expressed tentative support for retaining the all-industries approach, while noting its shortcomings:[299]

> [T]he Commission's use of a 60/40 mix of percent changes in Labour Cost Index (LCI) all-industries and Producers Price Index (PPI) input indices may not accurately reflect the movement in EDBs' opex costs.
>
> However, to ENA's knowledge, there is no alternative approach that would deliver greater accuracy without introducing more complexity into an already complex opex trending process. Therefore, ENA's initial view is that the current approach is not inappropriate
>
> […]
>
> ENA's view is that the current LCI/PPI is broadly appropriate. While there are a myriad of potential options and weightings, there is no magic bullet. ENA therefore suggests that the current approach be retained.

C299 Similarly, Wellington Electricity submitted:[300]

> Sector inflationary increases have risen faster than the all-sector cost escalators. Inflation adjustments using the all-sector inflation aren't capturing all cost increases.
>
> […]
>
> We are concerned that the all-sector measures might not capture the higher electricity sector inflationary costs driven by high demand for labour, materials, and equipment. However, we agree that the proposed PPI and LCI forecast are probably the best available.

C300 Powerco and Unison supported using or exploring an EDB-specific escalation approach.[301] No submission provided proposed cost groupings that would better match EDB input costs.

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299 Electricity Networks Aotearoa (ENA) "Submission on DPP4 Issues paper" (19 December 2023), pp. 12 and 15.

300 Wellington Electricity "Submission on DPP4 Issues paper" (19 December 2023), pp. 28 and 31-32.

301 Powerco "Submission on DPP4 Issues paper" (19 December 2023), p 15; and Unison "Submission on DPP4 Issues paper" (19 December 2023), p. 15.

**Draft decision on opex partial factor productivity**

**Problem definition**

C301 Productivity is a measure of volume of outputs for a given set of inputs. Total factor productivity (TFP) captures the volume of outputs that cannot be explained by the use of inputs (a residual). Opex partial factor productivity (PFP) is the part of the TFP explained by a reduced set of inputs, in our case those captured by opex.

C302 The core of the base-step-trend opex approach is that cost is revealed through the continued application of our PQ and ID incentives. Suppliers' current level of operating efficiency captured by the base year is projected forward based on known factors, either step or trend factors, beyond the suppliers' control.

C303 The opex PFP helps ensure that suppliers do not face incentive penalties or rewards (via the IRIS) for changes in operating efficiency that are explained by changes in sector-wide or economy-wide improvements or declines in productivity, rather than based on their own individual performance.

C304 This draft decision on opex PFP will inform the draft opex allowances we determine for each supplier, which in turn will help determine revenue allowances for the DPP4 period. As productivity applies across all opex, and all opex is recovered in-period, this is one of the most directly material DPP decisions.

**Draft decision**

C305 We have proposed applying an opex PFP of 0%.

**Alternatives considered**

C306 In addition to the opex PFP of 0%, we also considered whether recent trends in PQ-regulated EDB productivity and changes to our cost-escalation, scale factor, and step change decisions justified a forecast increase in productivity.

**Analysis**

C307 Within the base-step-trend opex model, cost escalation, scale factors and partial productivity are the three trend factors we are proposing to capture continuing and broadly predictable changes in forecasting EDB opex.

C308 Unlike other trend factors we have not attempted to develop a reliable and objective way of forecasting productivity. In part, this is because the productivity factor can create a circularity, where lower productivity leads to higher allowances, which feed through to future resets.

C309 At the same time, we consider our forecasts should reflect economy and sector-wide improvements, to ensure the base-step-trend approach delivers an efficient baseline. The decision is ultimately an exercise in judgment, informed by context, historical evidence, and other decisions within the DPP.

C310 In DPP3, we determined an opex productivity factor of 0%, based on historical trends in the distribution sector (both domestically and in other jurisdictions) and in comparable sectors.[302] We did not undertake a full historical productivity study.

C311 In DPP2, we determined an opex productivity factor of -0.25%, based on a historical study of productivity in the EDB sector undertaken by Economic Insights, which applied a similar methodology to a recent study we commissioned from CEPA. [303]

C312 In our analysis to inform our draft decision for DPP4, we have considered the evidence from:

- C312.1 the results from CEPA's study of historic productivity changes
- C312.2 comparisons to other similar sectors of the economy and the economy as a whole
- C312.3 recent studies in other jurisdictions, and
- C312.4 the potential impact of other DPP4 decisions.

C313 We have also highlighted factors which – if weighted differently in exercising judgment – could support a higher or lower productivity factor.

C314 In this analysis, we have most heavily weighted:

- C314.1 the trends in some comparable infrastructure sectors and overseas (and tentatively in the domestic EDB sector), supporting a positive productivity factor, and
- C314.2 the future prospect of opex-capex substitution driving higher overall productivity but lower opex productivity, supporting a negative productivity factor.

C315 The overall findings from the evidence are summarised in Table C14 below.

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[302] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision" (27 November 2019), para 5.65-5.69 and A149-A166.

[303] Economic Insights "Electricity Distribution Industry Productivity Analysis 1996-2013" (24 June 2014); and CEPA "EDB Productivity report: A report prepared for the Commerce Commission" (26 March 2024).

C316 Overall, we consider these factors broadly balance out.

**Table C14 Summary of evidence for higher or lower opex partial factor productivity**

| Factors that support a higher opex PFP | Factors that support a lower opex PFP |
|---|---|
| Evidence from trends in Australian EDB performance. | Opex-capex substitution improving capital (and total productivity) at the expense of opex productivity. |
| Recent (DPP3) trends in PQ-regulated EDB opex productivity. | Medium-term (ex 2008) trend in PQ-regulated and ID-only opex productivity. |
| Accepting step changes in costs that would otherwise present as declines in productivity (SaaS capex replacement, insurance, cybersecurity). | Unaccounted for step changes with insufficient evidence (resilience, regulatory costs, digitalisation). |
| Accepting step changes that may drive future productivity gains overall (LV monitoring, SaaS system upgrades). | Scale factors (lines, ICPs) that have shown a faster historical decline than broader models. Excluding time as a scale factor. |
| Using an EDB-specific opex cost escalator. | |
| Incentives to improve efficiency resulting from innovations under the INTSA scheme. | |

*Evidence from the CEPA productivity study*

C317 Our primary source of evidence is the draft results from the recently released historical productivity study undertaken by CEPA.[304] As noted above, we do not consider it appropriate to simply project a historical figure forward. Nonetheless, historical information can shed light on the productivity changes it is realistic to expect over the next five years.

C318 Figure 1 below shows the change in opex productivity for PQ-regulated EDBs since 2008 (the start of the study period), across all the output specifications analysed by CEPA. We consider it most appropriate to focus on Model 1 (lines and ICPs) as this matches our proposed scale factors for DPP4 regarding network models. In terms of broad trends, model choice does not materially impact any conclusions, as they show a similar pattern:[305]

[304] CEPA "EDB Productivity report: A report prepared for the Commerce Commission" (26 March 2024).

[305] The significant exception being Model 5, which incorporates reliability as well as ICPs and lines. This model shows a sharp decline between 2022 and 2023 not present in other models. We do not consider it appropriate to include a reliability factor, as this risks rewarding (with future higher opex) declines in reliability. CEPA also note that it is difficult to properly account for reliability in the analysis, so this model should be treated with caution, see CEPA "EDB Productivity report: A report prepared for the Commerce Commission" (26 March 2024), p. 8-9 and p. 34-36.

C318.1 an overall decline (averaging -1.1% per year) since the start of the study period

C318.2 a comparatively slower (-0.5%) decline over the DPP0 and DPP1 periods (2008-2015)

C318.3 a sharp decline (-2.2%) over DPP2 (2016-2020), and

C318.4 a flattening trend (+0.2%) over DPP3 (2021-2023).

**Figure C6 PQ-regulated EDB opex partial productivity - draft CEPA study**

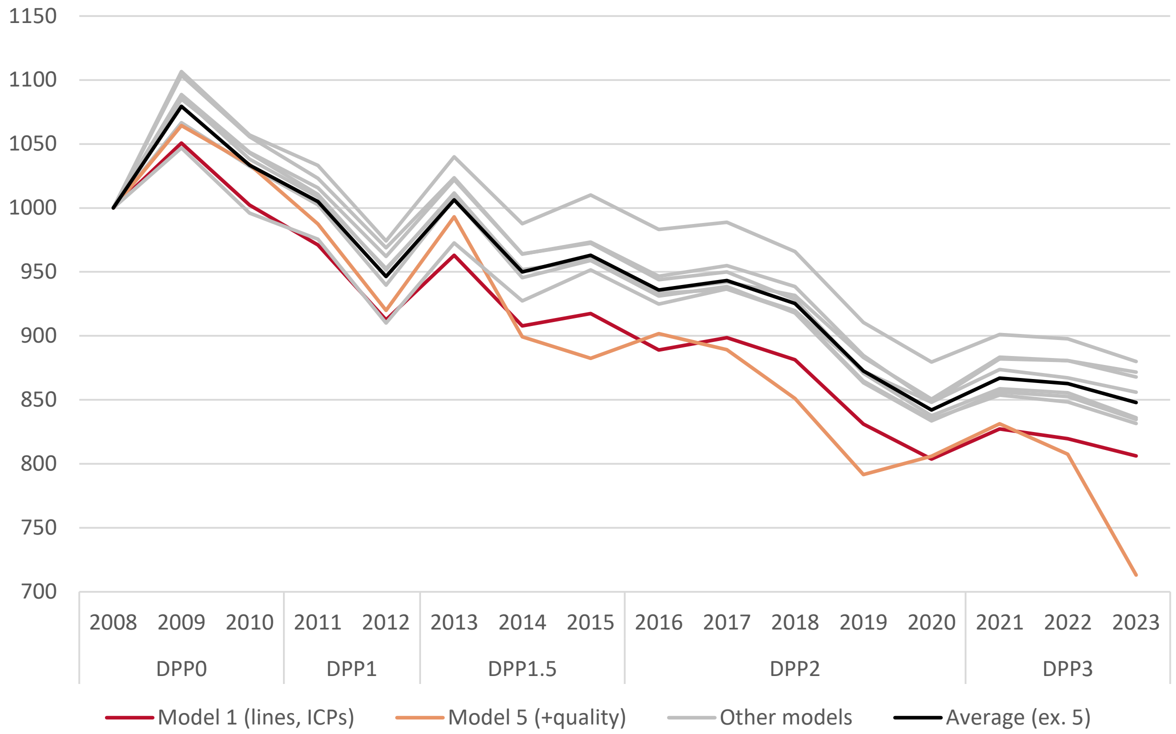
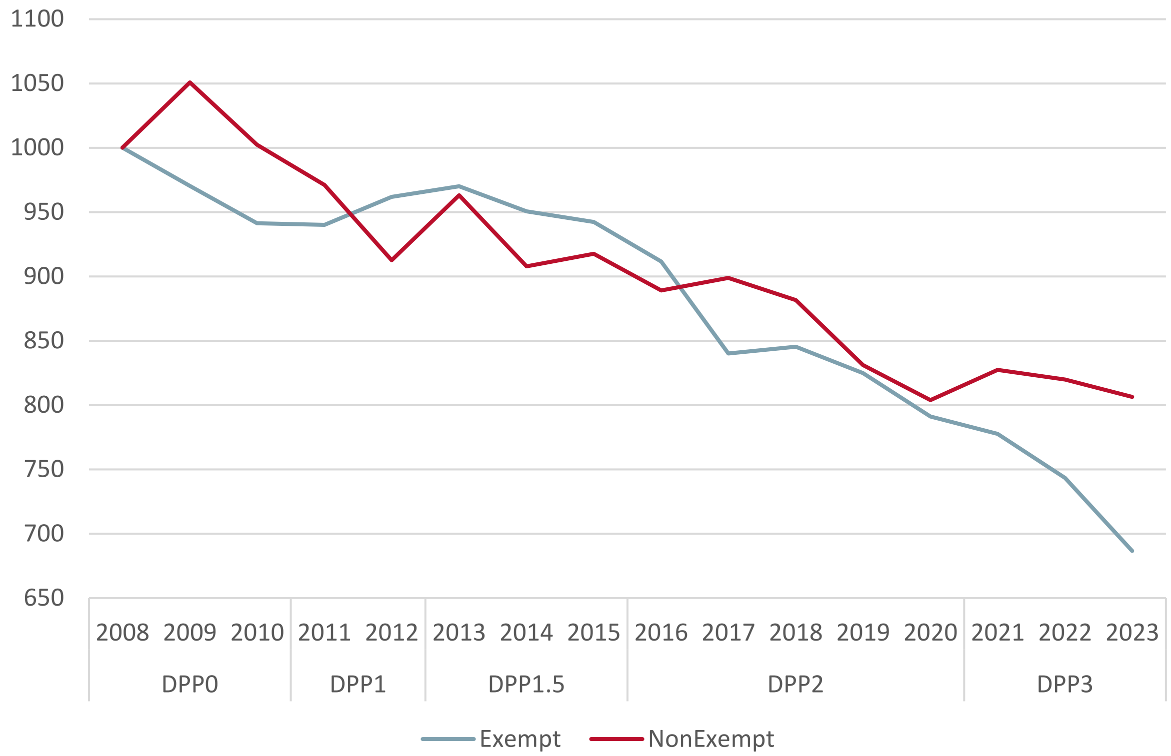
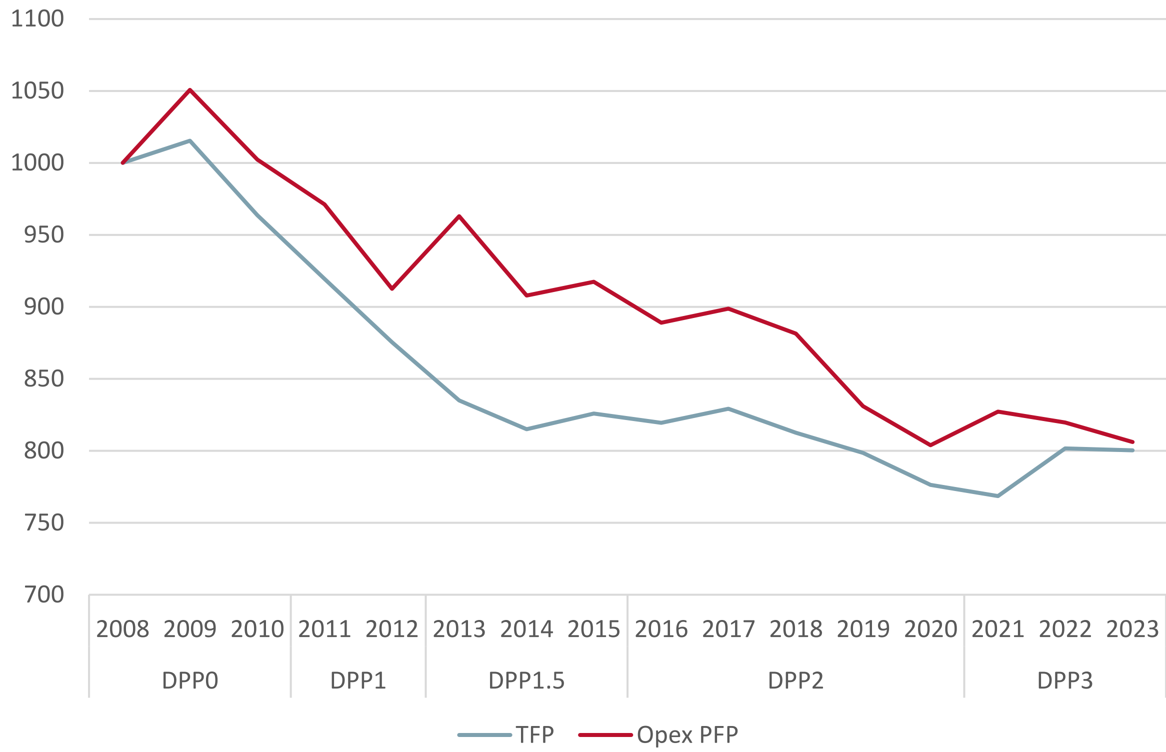


**Figure C7 PQ-regulated EDB opex partial productivity – draft CEPA study**




C319 However, the more recent trend suggests these factors may be slowing. This is especially the case (as shown above in Figure C8) for PQ-regulated EDBs who are subject to the cost-control incentives created by PQ-regulation (over DPP3 when a 0% PFP was applied).

**Figure C8 PQ-regulated TFP vs opex PFP (Model 1) - draft CEPA study**




C320 We have also considered the relationship between opex PFP and TFP, because our goal is to promote improvements in overall efficiency. A focus on opex PFP exclusively (with a reducing opex allowance) risks creating or reinforcing a bias on EDBs' part towards capital investment.

C321 Since 2013 and coinciding with the DPP1.5 mid-period reset (the first to apply a building-blocks methodology), TFP for PQ-regulated EDBs has broadly flatlined, while opex productivity has declined. This dynamic could continue – or intensify – as a greater proportion of capital expenditure becomes substitutable with opex (eg, system growth capex and demand response opex).

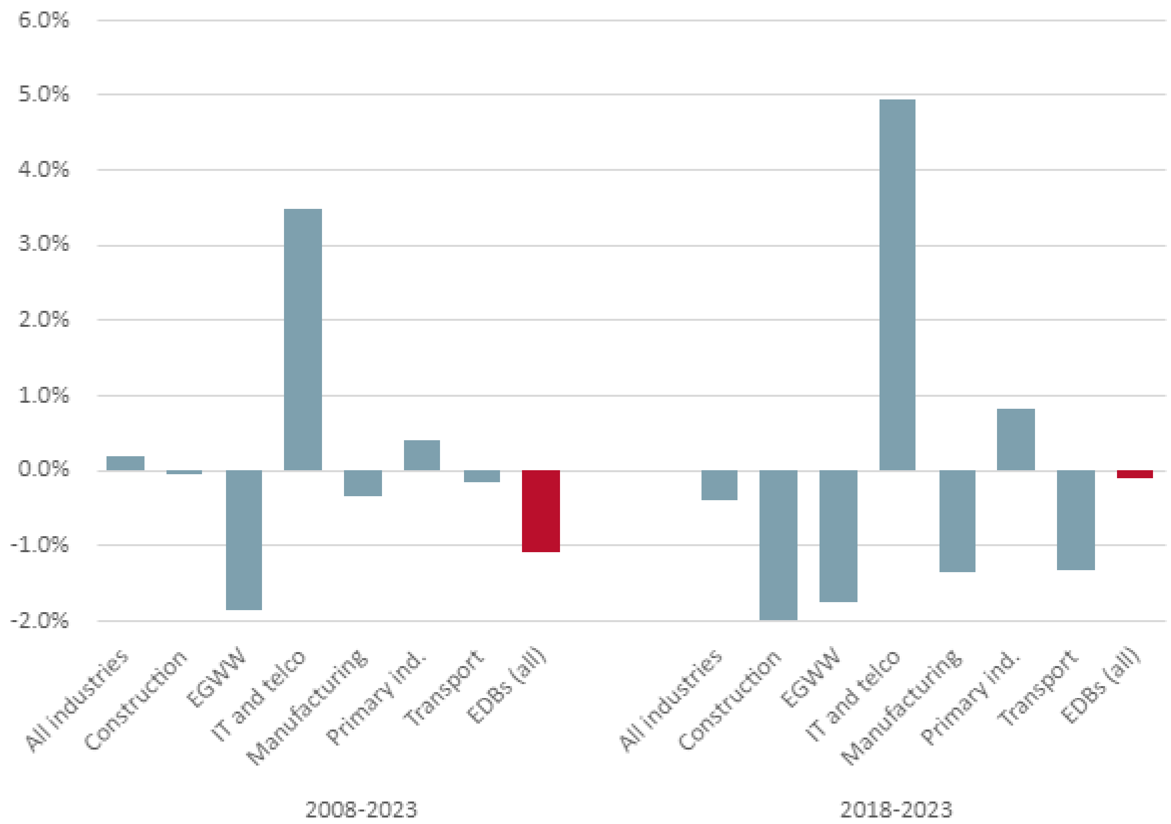
*Comparisons with other sectors*

C322 Total factor productivity for the EDB sector has declined while productivity in the overall economy has modestly increased over the medium term (CEPA's study period, 2008-2022, +0.2% overall vs -1.1% for EDBs). However, in the short term, both total factor productivity for the EDB sector and overall economy have declined (our scale factor reference period, 2018-2023, -0.4% overall vs -0.1% for EDBs).

C323 The clear outlier is the IT and telecommunications sector, which has experienced continued technology improvements and infrastructure rollouts (such as the fibre UFB program and 5G wireless). While historically this differs from the EDB sector, the prospect of innovations in the use of distributed energy resources and smart-grid technology (that multiple submitters have emphasised and that the INTSA mechanism is intended to incentivise) may mean improvements in EDB productivity may be seen in the future.[306]

C324 The TFP trend for EDBs is consistent with the overall electricity, gas, waste, and water (EGWW) sector which includes EDBs, other horizontal infrastructure services, and energy generation/production and retailing.

**Figure C9 Average change in industry TFP 2008-2023 – StatsNZ[307]**




[306] For example: Counties Energy, pp. 1-2; Drive Electric, p. 8; FlexForum, p. 3; and Rewiring Aotearoa, p. 4.

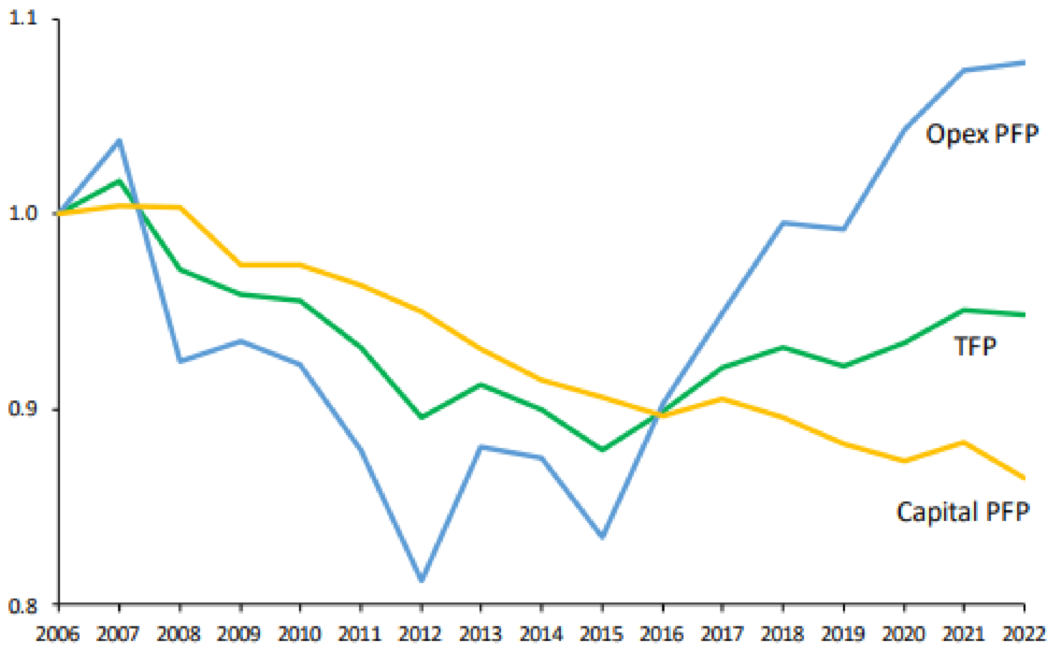
[307] EDB data sourced from CEPA draft productivity study, all other data from StatsNZ multifactor productivity series. "All Industries" series covers what StatsNZ refer to as the "Former measured sector": industries where it is possible to measure output independently from input, and excludes mainly non-market industries. Short-term figures for transport are distorted by COVID-19 disruptions.

*Comparisons with overseas jurisdictions*

C325 The Australian Energy Regulator (AER) publishes annual benchmarking reports that include sector-wide productivity analysis. As shown in Figure C10, Australian EDBs experienced a similar decline in opex productivity up to 2015 but have seen a sharp improvement since then. Caution should be exercised in comparing with the results from the CEPA study. The AER's model incorporates quality, and this variable drives much of the long-term productivity improvement.[308]

C326 While there are differences between Aotearoa's and Australia's operating and regulatory environments, the improving trend Australia has experienced suggests that declining productivity is not inherent to electricity distribution as a sector.

**Figure C10 Australian electricity distribution productivity trends [309]**




*Other DPP4 decisions*

C327 The most directly relevant draft decisions are others within our approach to opex forecasting. We have also considered decisions on capex and innovation allowances.

[308] See: AER "Annual Benchmarking Report Electricity distribution network service providers" (23 November 2023), page 24.

[309] AER "Annual Benchmarking Report Electricity distribution network service providers" (23 November 2023), p. 25.

*Step changes*

C328 We have proposed step changes for costs such as LV monitoring and smart meter data, Software-as-a-service (SaaS) adoption, and insurance costs. Submitters have highlighted these and other new costs as driving the apparent decline in EDB productivity.[310]

C329 As we propose dealing with these items as step changes, we consider this does not necessitate a future declining trend in productivity and supports neutral or positive settings.

C330 Moreover, some of the activities that drive these costs (better use of data and analytics) could drive overall improvements in productivity on a dynamic view. Again, this supports a positive productivity factor.

*Scale trends*

C331 For opex scale growth trend modelling, out draft decision is to retain the ICP and line-length drivers of network opex scale growth, and to retain these and add a capex driver for non-network opex scale growth. We have not included a time variable in either case. For consistency, this suggests the results from Model 1 in CEPA's analysis (which has declined more sharply than other, broader models) should be weighed more heavily when forecasting productivity. Additionally, the decision not to include a time variable in our forecasts relies on an independent decision on future productivity.

C332 These factors would support a lower productivity factor.

*Cost escalation*

C333 We are considering an EDB-specific set of cost escalators for DPP4. As these escalators are modestly higher than the economy wide trend in labour and input price inflation, this approach would support a higher productivity factor (as the escalator rather than the productivity residual captures this growth).

*Innovation and non-traditional solutions allowance (INTSA)*

C334 Our draft decision to adopt a strengthened and broadened INTSA scheme may mean:

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[310] Aurora "Submission on DPP4 Issues Paper", pp. 17-18; Wellington Electricity "Submission on DPP4 Issues Paper", p. 32; Unison "Submission on DPP4 Issues Paper", p. 8.

C334.1 additional spend on new activities that would otherwise appear as declining productivity in the short term will instead be funded via INTSA, and

C334.2 over the longer-term, the innovations this scheme supports may drive improvements in EDB productivity (including opex productivity).

C335 Again, both these factors would support a higher productivity factor. However, the impact from innovations will likely not affect the DPP4 period and – especially where non-traditional solutions to capacity constraints are adopted – may have a stronger impact on total factor productivity than opex productivity.

**What we heard from stakeholders**

C336 We note that stakeholders have provided submissions on CEPA's draft report. From a DPP4 reset perspective, we will treat these as submissions on the draft decision.

C337 In terms of model choice, Aurora noted in its submission that the choice of output measures in our productivity analysis may exclude relevant factors:[311]

> We also have concerns that the Commission's historic measures of productivity that focus on kWh and number of ICPs supplied are overly simplistic as they do not consider the growing service expectations of consumers, technology trends and the increased costs involved in maintaining a social 'license to operate'. Over the past decade distributors have seen numerous cost increases that are not reflected in historic measures of productivity.

C338 Similarly, Wellington Electricity also note:[312]

> … the Commission will be providing an updated partial productivity trend. Our early analysis using the traditional productivity measures shows that most networks are becoming less productive. Subjectively we think this is because EDBs are incurring new unavoidable costs that do not improve the core network efficiency measures but are expected as part of a network's social license.

C339 In our view, the changes to the study undertaken by CEPA to broaden the range of input specifications deals with some of these concerns, and as noted above the broad trend across all models is similar. More importantly, the out of trend-factors submitters cite are better dealt with via step changes where there is clear evidence of an increase in costs incurred.

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[311] Aurora "Submission on DPP4 Issues Paper", p. 18; supported by Unison "Cross-submission on DPP4 Issues Paper", p. 8; and Orion "Cross-submission on DPP4 Issues Paper", pp. 16-17.

[312] Wellington Electricity "Submission on DPP4 Issues Paper" (19 December 2023), p. 32.

C340 In terms of time period, the ENA cautions against overreliance on the most recent trends:[313]

> ENA notes that the past five years have witnessed a once-in-a-century pandemic that shut down economies and has had long-lasting and broad-ranging consequences. These consequences have increased EDB opex costs. ENA looks forward to engaging with the Commission and its consultants to discuss the drivers of EDB productivity and efficiency, the lingering impacts of the COVID-19 pandemic, and other exogenous factors that have shaped cost and output movements over DPP3.

C341 In terms of opex PFP and TFP, Vector highlighted: [314]

> …adopting dynamic efficiency rather than static efficiency as a means of reviewing suppliers' productivity performance.

## Conclusion

C342 On balance, we propose to apply an opex PFP of 0%. This is based on the evidence from both factors supporting a higher PFP and a lower PFP, as well as our consideration of matters raised in submissions on the DPP4 Issues paper.

[313] ENA "Submission on DPP4 Issues Paper", (19 December p. 14.

[314] Vector "Cross-submission on DPP4 Issues Paper" (26 January 2024), p. 13.

# Attachment D Innovation and section 54Q incentives

## Purpose of the attachment

D1 This attachment outlines and explains the rationale for our draft decisions to help incentivise innovation and the uptake of non-traditional solutions for the default price-quality path (DPP).

D2 This attachment covers the following:

D2.1 **draft decision I1** to set the Capex retention factor at 33.18%;

D2.2 **draft decision U1** to introduce an Innovation and non-traditional solutions allowance (INTSA) scheme, capped at 0.6% of maximum allowable revenue (MAR);

D2.3 **draft decision U2** to incentivise energy efficiency and demand side management incentives through the draft INTSA; and

D2.4 **draft decision U3** to incentivise the reduction of energy losses through the draft INTSA.

## High level approach to the workstream

D3 Electricity distribution businesses (EDBs) are forecasting significantly higher expenditure to support the energy transition while continuing to provide services at a quality that reflects consumers' demands. In addition, the effects of climate change are likely to continue to intensify, increasing the frequency of extreme weather events which elevate the importance of the resilience of electricity networks to these events.[315] These realities create a need, and expand the opportunity, for innovative approaches to meet these challenges.

D4 On the technology front, the cost and performance of relevant technology is likely to continue to fall and improve, respectively.[316] Technologies include solar photovoltaic (PV), batteries, electric vehicles, and other smart grid-related technologies such as control software and sensors. These technologies offer the opportunity to improve the productivity and efficiency of electricity lines services.

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[315] See 'The challenges the draft decisions aim to address', for further discussion of resilience and meeting consumer demands.

[316] For recent analysis, see for example Rewiring Aotearoa "Electric homes report" (March 2024).

D5 Innovation and non-traditional solutions (NTS) are already incentivised within the regime's baseline settings, consistent with our obligation under s 52A(1)(a) of the Commerce Act to promote incentives to innovate. The primary means for this within the baseline settings are where the regime provides incentives for innovating or for implementing NTS that have the potential to result in a cost saving (IRIS) or improve quality performance (QIS).[317]

D6 More specifically, EDBs have flexibility and are incentivised to substitute between capital expenditure (capex) and operational expenditure (opex) solutions where it results in a cost saving. They therefore have flexibility to prioritise their expenditure for innovative or NTS projects when it is in the long-term benefit of consumers to do so (and to the EDBs advantage). **Decision I1** in this attachment demonstrates an example of the regime's baseline incentives that encourage EDBs to innovate and invest in solutions that reduce the overall cost to consumers.

D7 However, we recognise that in some instances, non-exempt EDBs may still lack strong enough incentives to innovate or implement NTS.[318] The draft INTSA is an additional incentive to those already provided for in the DPP baseline settings. As such, the draft INTSA would not be the sole source of funding for innovative or NTS projects that an EDB may wish to undertake; these can still be funded through approved expenditure allowances.

D8 Our intention for the draft INTSA is to provide EDBs with an additional incentive to trial new solutions through the DPP4 period to find alternative ways to adapt their networks to decarbonisation trends, resilience expectations and changing consumer preferences. The total value of the INTSA is a significant increase from what was offered by the Innovation Project Allowance (IPA) in DPP3. However, this has been managed with careful consideration for the impact on consumer bills within the DPP4 period.

D9 Innovative and NTS projects are by nature uncertain, which may mean that some projects undertaken by EDBs through an INTSA will be unsuccessful in achieving their desired outcomes. Despite this, by requiring EDBs to provide us with a closeout report that we will publish for all completed projects - regardless of their level of success - there will be valuable lessons to be learned.

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317 For a list of ways in which the regime incentivises innovation, see Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), paragraph 6.6.

318 See paragraphs D22-D26 for further expansion of our view for the scope of when existing incentives may not be sufficient.

D10 We expect the sector, consumers, other electricity market participants and regulators will be able to use these lessons from a greater number of completed innovative and NTS projects over the course of the DPP4. This growing body of shared learnings should help to inform our process when reviewing the innovation incentives in future DPP resets. Additionally, our expectation is that towards the end of the period, if EDBs **are** able to deliver NTS as part of business as usual (BAU), **this may result** in expenditure allowances for DPP5 being adapted to account for this shift.

D11 We considered a more ambitious option, which could either be an alternative or a complement to the draft INTSA. We outline this option from paragraph D125. While this option is not part of our draft decision, we welcome stakeholders' views on it, and whether it should be part of our DPP4 final decision.

D12 The draft INTSA scheme interacts with multiple other decisions and areas of the regime where:

D12.1 In terms of opex allowances, the draft decision is for low voltage data to be approved as a step change for DPP4 for all EDBs.[319] We expect this to be particularly useful for testing and implementing NTS and may aid other INTSA projects.

D12.2 We expect some EDBs to use an INTSA to trial innovative and/or NTS projects (especially flexibility services) that would, if successful, enable capex to be deferred or permanently replaced with a more efficient opex solution.

D12.3 Our draft decision is to include a requirement in the ex ante INTSA application process for EDBs to signal whether they intend to apply a specific exclusion from the quality standards where outages are directly associated with the project. See **Attachment E** (decision RP7) for this draft decision, and paragraphs D102-D105 of this attachment for discussion of how this is proposed to be implemented from the INTSA perspective.

D13 We also note that there are further interactions that an INTSA may have with factors outside of the regime. For example, the charging and connection standards for electric vehicles led by Energy Efficiency and Conservation Authority (EECA), as well as industry codes, standards and guidance led by the Electricity Authority.[320]

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319 See Attachment C, decision O.3.3.

320 For example, distribution pricing, including capital contributions. See Electricity Authority "Distribution pricing" webpage, accessed 12 April 2024.

D14 Lastly, we acknowledge that EDBs are regionally and operationally diverse, with the 16 non-exempt EDBs each on their own path of innovation and readiness to trial/implement NTS. The draft INTSA has been designed with this in mind – to promote the long-term benefit of consumers across Aotearoa New Zealand.

**Draft decisions for innovation and section 54Q incentives**

D15 Section 52A(1)(a) of the Act requires us to ensure suppliers of regulated goods and services have incentives to innovate and invest, including in replacement, upgraded, and new assets. The Act also states, under section 54Q, that we must provide incentives, and avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management as well as to reduce energy losses.

D16 We consider that draft decision U1, to introduce an INTSA, capped at 0.6% of EDB DPP4 MAR, should further promote s 52A(1)(a) and provide incentives for section 54Q. As such, we have addressed draft decisions U2 and U3 in the policy of draft decision U1.

*Draft decision U1: Introduce an innovation and non-traditional solutions allowance, capped at 0.6% of DPP4 MAR*

**Problem definition**

D17 EDBs are natural monopolies, which means we cannot rely on competition to provide incentives for them to seek efficiencies through innovation.[321] As such, the DPP's baseline settings are designed to incentivise EDBs to find more efficient ways of doing things that result in cost savings or improvements to the quality of service provided. Similarly, EDBs have the flexibility to reprioritise expenditure into projects that might produce one of these outcomes as they see fit.

[321] R Poudineh, D Peng and S R Mirnezami "Innovation in regulated electricity networks: Incentivising tasks with highly uncertain outcomes" (2020) Competition and Regulation in Network Industries, 21.

D18 We introduced the IPA at the DPP3 reset with the rationale that the existing baseline incentives for innovation may be insufficient to capture all the benefits of innovation.[322] In this context, the IPA was introduced so that we could further incentivise innovation that might not necessarily be captured by the regime's baseline tools – using a relatively low-cost mechanism. We considered that on balance, more expenditure on innovative practices by EDBs would likely be in the long-term interest of consumers.[323]

D19 The IPA was implemented in the DPP3 determination as a recoverable cost with the following criteria:[324]

D19.1 is targeted for expenditure on innovative projects;[325]

D19.2 requires at least 50% contribution from the distributor;[326]

D19.3 is limited to the amounts calculated as the higher of 0.1% of our forecast of allowable revenue (excluding pass-through and recoverable costs) or $150,000 over DPP3; and

D19.4 requires a report from an independent engineer or other suitable specialist that the planned expenditure on the project meets the set of criteria for it to be considered an innovation project and potentially benefits consumers.

[322] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), paragraph 4.56.

[323] *Ibid*., paragraph 4.56.

[324] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), paragraph F3.

[325] Innovation project means a project that is focussed on the creation, development or application of a new or improved technology, process, or approach in respect of the provision of electricity lines services in New Zealand.

[326] The contribution from the EDB should be treated as capital or operating expenditure of the contributing EDB, while any capital expenditure treated under this mechanism as a recoverable cost would not enter the regulated asset base.

D20 In November 2023 we amended the IPA approval criteria to remove the requirement for an engineer/specialist report to be received prior to commencing an IPA funded project. We have since had one successful IPA application from Vector.[327] Prior to this amendment, Orion had applied for the IPA but were unsuccessful.[328] Of the $5.645m available under the DPP3, $750k has been funded by consumers so far[329], and we are expecting further IPA applications before the end of the period.

D21 In December 2023, the Input Methodologies (IM) Review 2023 published a final decision for the IPA to be renamed and broadened to include applications by EDBs for innovative, as well as NTS projects.[330] This has given more scope and flexibility to design a wider range of schemes for innovation and NTS as part of a DPP.

D22 When considering how to apply the IM Review to design and implement an INTSA, including whether we should implement an INTSA at all, we first had to determine the scope for what an INTSA should aim to achieve. We have surmised that an INTSA as a recoverable cost should provide for additional funding for projects:

D22.1 that are **riskier than BAU**, and wouldn’t otherwise happen; and/or

D22.2 **that are riskier than BAU, but where EDBs are unlikely to otherwise result in any financial benefits** and/or **benefits accrue entirely to third parties** (such as when benefits that are expected in future regulatory periods are not realised).

D23 Some innovation and NTS are likely to involve higher risk than BAU network solutions. If a new approach is not successful, the EDB might need to fall back to a BAU solution to address the network issue. This could result in an overspend against an EDB’s DPP allowances, or a worsening quality performance against the quality standards and incentives. In this context, we have heard from EDBs that a key barrier to them progressing projects is internal inertia driven by these risks/concerns.

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327 Commerce Commission “Vector PRISMED innovation project allowance – application” (23 December 2023).

328 Commerce Commission “Commission response to Orion’s Innovation Project Allowance Application” (28 March 2022).

329 Because the project expenditure that is recoverable for IPA projects is 50%, roughly $750k has also been funded by Vector.

330 Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), Chapter 6b.

D24 In combination with 'riskier than BAU', we consider there are projects where there are no incentives in the regime for EDBs to undertake if additional costs are incurred, but those costs are not offset by explicit financial benefits. This may be because those benefits are not realised until a later regulatory period when they are entirely captured by consumers, or they accrue entirely to third parties. In these instances, the EDB would not share in potential efficiency gains, but there may be potential benefits to consumers, and therefore it may be in consumers' interests that these projects take place.

D25 Wellington Electricity highlighted an example of this problem in detail in its submission to the IM Review process and issues paper.[331] Wellington Electricity provided an example where opex (for flexibility services) is substituted for capex spend that is deferred into the next regulatory period. Wellington Electricity considered the EDB is penalised by the regime for the opex overspend but not rewarded for the capex saving because a DPP reset occurs. We note that IRIS does not penalise (or not provide incentives) for all inter-regulatory period expenditure. In most instances EDBs are rewarded for making efficiency gains or cost savings.

D26 There are other possible instances where an innovative or NTS project does not currently provide financial benefit to the EDB, and yet does so for consumers. We are interested to hear feedback on other examples of innovative or NTS projects that may result in no accrued benefits to EDBs, but accrue entirely to consumers or third parties.

**Draft decision**

D27 Our draft decision is to introduce an INTSA, capped at 0.6% of DPP4 MAR and with the following design characteristics:

[331] Wellington Electricity "Submission on IM Review Process and Issues paper and draft Framework paper" (11 July 2022), p. 14.

**Table D1 DPP4 draft INTSA characteristics**

| Criteria type | INTSA policy criteria |
|---|---|
| **Project type – what the project is for** | An innovative or non-traditional solutions project that fits within the three eligibility criteria:<br>1. relates to the supply of electricity lines services;<br>2. promotes the Part 4 purpose of the Act; and<br>3. must be riskier than business as usual (BAU) for the non-exempt EDB such that the non-exempt EDB would not carry out the project if it could not recover some or all of the forecast costs of the project from the non-exempt EDB's INTSA.<br>Where an EDB wishes to seek approval for a share of project expenditure that is more than 75% of the project costs (up to a cap of 100% of project costs), it must demonstrate how the project is unlikely to otherwise result in any financial benefits to the non-exempt EDB. |
| **Approval timing** | Ex ante |
| **Expenditure approved** | Forecast |
| **Share of expenditure approved (%)** | Up to 75% for all projects that are riskier than BAU for the EDB<br>Up to 100% for all projects where it is unlikely to otherwise result in any financial benefits to the EDB (such as when benefits are not realised in future regulatory periods) |
| **When and on what conditions approved expenditure is received** | Expenditure may be recovered upon completion of project |
| **Maximum permissible expenditure** | 0.6% of EDB's DPP4 maximum allowable revenue (MAR) over the regulatory period for one or more projects |
| **Supporting evidence** | Project specific information |
| **Sharing learning** | Close out report must be sent to the Commission within 50 days of project completion |
| **Penalty/reward mechanism** | None 332 |

D28 The individual EDB allocations for our draft maximum permissible expenditure (at 0.6% of EDB's DPP4 MAR) are set out in Table D2 below.

[332] This is with respect to an explicit penalty/reward mechanism specified as a part of the INTSA. Expenditure incurred undertaking an eligible INTSA project would still be subject to IRIS. See Commerce Commission "Input Methodologies Review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), topic 5e.

Table D2 DPP4 draft INTSA values ($m)

| EDB | DPP4 MAR | INTSA value |
|---|---:|---:|
| **Alpine Energy** | 384,699 | 2.3 |
| **Aurora Energy**[333] | 818,724 | 4.9 |
| **EA Networks** | 301,132 | 1.8 |
| **Electricity Invercargill** | 108,106 | 0.6 |
| **FirstLight Network** | 230,693 | 1.4 |
| **Horizon Energy** | 191,151 | 1.1 |
| **Nelson Electricity** | 42,452 | 0.3 |
| **Network Tasman** | 233,311 | 1.4 |
| **Orion NZ** | 1,487,457 | 8.9 |
| **OtagoNet** | 244,148 | 1.5 |
| **Powerco** | 2,529,715 | 15.2 |
| **The Lines Company** | 289,054 | 1.7 |
| **Top Energy** | 362,572 | 2.2 |
| **Unison Networks** | 929,757 | 5.6 |
| **Vector Lines** | 3,588,280 | 21.5 |
| **Wellington Electricity** | 768,258 | 4.6 |
| **Total** | **12,509,509** | **75.4** |

D29 Our intention for the draft INTSA is to design a simple scheme and supplement it with published guidance to minimise the administrative burden of the application and approval process. As part of this guidance, we intend to publish a voluntary 'Project Eligibility Assessment' (PEA) template which EDBs can choose to fill out (or use their own form) in submitting an INTSA proposal to us. We intend for the PEA to contain the baseline information likely required for us to process an application.

[333] Figures for Aurora Energy are indicative only. They will be finalised when Aurora Energy transitions from their CPP to the DPP in 2026.

D30 Our draft decision is to provide an automatic quality standards exclusion up to a cap of 0.5% of the respective SAIDI and SAIFI limits for approved INTSA projects. We propose interruptions directly associated with one or more approved INTSA projects are excluded from the calculation of SAIDI and SAIFI assessed values, up to the 0.5% cap.

D31 An example of how this new process is intended to operate is set out below:

D31.1 An EDB identifies a project that it considers may fit the three INTSA eligibility criteria. It then completes a PEA template, or similar document.[334] As part of this process, the EDB will:

D31.1.1 determine which share of project expenditure that is recoverable is approved (either up to 75% or up to 100%) that it considers its project is fit for;

D31.1.2 set out the purpose of the project and the steps the EDB intends to take to achieve that purpose;

D31.1.3 set out the outputs and expected benefits for consumers of the project for each disclosure year the EDB intends for the project to take place until it has been completed (ie, project outputs delivered);

D31.1.4 set out the forecast costs for each year until the project has been completed (ie, project outputs delivered);

D31.1.5 provide sufficient information to enable us to assess whether the EDB's project will meet the three eligibility criteria, and whether the project or programme is unlikely to otherwise result in any financial benefits to the EDB; and

D31.1.6 explain whether the EDB anticipates applying an automatic quality standards exclusion and, if so, what the cause or causes of the interruptions are.[335]

[334] Our draft decision is that the PEA is not a legally binding document, it will be published as an optional guidance template. EDBs will be welcome to use an alternative method of demonstrating their project's eligibility.

[335] See paragraphs D102-105 for further discussion of our draft decision to include an automatic quality exclusion.

D31.2 The EDB will submit this PEA, or other document, as part of its 'INTSA proposal' to us for approval, when we will publish the proposal on our website. The EDB may likewise publish its proposal on its own website.[336]

D31.3 We will assess the EDB's INTSA proposal and decide whether the proposal meets the eligibility criteria. We may determine if more information is needed, which is likely to be where the project is fully funded by consumers, or of high value and/or complexity. For instance, for some projects, it may be appropriate for EDBs to submit an independent expert report to supplement the proposal, though this is not a strict requirement.[337] If we are satisfied that the project meets the three eligibility criteria, we will also determine which share of project expenditure is recoverable, which depends on whether the project is unlikely to otherwise result in any financial benefits to the non-exempt EDB. We will inform the EDB in writing if the project is approved. We will publish our response and the EDB's approved proposal on our website.

D31.4 With approval granted, the EDB can undertake the project as specified in its proposal, confident that it can recover the forecast approved expenditure upon completion of the project, ie, on delivery of the outputs for the relevant project. When the project has been completed, the approved forecast costs will enter the washup balance for that year as an actual recoverable cost. This is intended to be the case even where the project and forecast costs are approved in DPP4, but the project is completed in a subsequent DPP regulatory period (or under a CPP).

[336] Our draft decision is not to make this a legal requirement, although we encourage EDBs to publish their proposals on their websites when they submit them to the Commission.

[337] Our intention is that this is an exception at the EDB's discretion, and not a rule. The PEA guidance is intended to help streamline applications for approval in a standardised form.

D32 Within 50 working days of completing a project, the EDB must complete a closeout report and send this to us. Our expectation is that the closeout report is comprehensive and captures whether and how the project's purpose and expected benefits were achieved (and if not, why not), and general lessons learned such that the report supports the implementation of similar projects by other EDBs or third parties. For example, an EDB could share all relevant data (eg, open-source data) from fully funded projects that are not confidential. Similarly, we would also expect that any relevant impact on quality or performance would be highlighted. If the project did not achieve its expected outputs, benefits, or purpose, the closeout report should explain why that is the case. The EDB will send its closeout report to us which we will publish on our website.[338]

**How the decision is aligned to the decision-making framework for the DPP[339]**

D33 **Better promote the purpose of Part 4**. For the reasons outlined at paragraphs D22 to D25, our draft INTSA scheme should better promote the section 52A(1)(a) to (c) limbs of the purpose of Part 4 by providing further incentives to innovate and invest, improve efficiency and provide services at a quality that reflects consumer demands, and share with consumers the benefits of efficiency gains.

D34 In particular, the draft INTSA would help incentivise EDBs to carry out projects:

D34.1 that are **riskier than BAU**, and wouldn't otherwise happen; and/or

D34.2 **that are riskier than BAU, but where EDBs are unlikely to otherwise result in any financial benefits** and/or **benefits accrue entirely to third parties** (such as when benefits that are expected in future regulatory periods are not realised).

D35 **Better promote section 54Q.** For the reasons outlined at paragraphs D132 to D150 draft decision should better promote section 54Q by providing an INTSA scheme that better incentivises demand-side management, energy efficiency, and reduction of energy losses projects that meet the INTSA project criteria.

[338] Similar to when the EDB submits its proposal to the Commission, we encourage the EDB to publish its close out report on its own website, although this will not be a legal requirement.

[339] For the decision-making framework, see Commerce Commission "Default price- quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), Attachment A.

**What we heard from Stakeholders**

D36 There have been two key consultation opportunities to date for stakeholders to provide input into our processes for designing an INTSA scheme. These are through submissions to the DPP4 issues paper (including cross submissions), and during our innovation and non-traditional solutions workshop, including via submission on the workshop presentation and questions. We have also engaged with some stakeholders through bilateral meetings, before and after the workshop.

## DPP4 issues paper

D37 In the DPP4 issues paper we asked stakeholders to submit feedback on two key consultation areas:

D37.1 whether the regimes baseline incentives may be insufficient to support innovation (such that an innovation scheme was necessary),;[340] and

D37.2 on our proposed principles and characteristics that we considered should provide the fundamental basis for any INTSA scheme.[341]

D38 In addition to responses for these two consultation areas, feedback from submitters overall focused on the IPA and flexibility services, which we provide our response to later in this section. We also asked for feedback on our proposals for energy efficiency and demand side management, and for reduction of energy losses (section 54Q), which will be discussed at draft decisions U2 and U3 in this attachment.

D39 Many submitters to the DPP4 issues paper confirmed that the baseline incentives in the DPP may not be sufficient for innovation where the benefits go to third parties or are not likely to be realised by the EDB in future regulatory periods. For instance, Horizon Networks submitted:[342]

> Horizon Networks agrees that the baseline incentives are insufficient to support innovation and there is a need for an innovation scheme to enable EDBs to explore opportunities and try new ways of doing things. The existing innovation scheme is not doing enough to incentivise EDBs to try new things, as EDBs are only rewarded under limited circumstances and when the innovation is a success.

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[340] Commerce Commission "Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), see consultation question 22, p. 224.

[341] *Ibid*., consultation question 23, p. 224.

[342] Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 18.

D40 Wellington Electricity submitted on how in some instances, innovation may not be incentivised:[343]

> Where the primary benefit of the innovation is the customers and EDBs do not expect to recover their share of the innovation costs via the IRIS or quality incentives. The current IRIS issue of not being able to substitute opex and capex across regulatory periods exacerbates this.

D41 We recognise that there should be further incentives for innovative or NTS projects for DPP4, which is why we have designed our draft INTSA as such. Part of our draft decision is to allow some projects a 100% share of project expenditure that is recoverable. This should help support projects that fit the criteria as outlined above by Wellington Electricity.

D42 We received general support from stakeholders on our proposals for principles and characteristics for an INTSA. Some stakeholders suggested amendments or entirely new principles and characteristics. Our draft decision does not modify or add any new principles, but it does contain an additional new characteristic to those set out in the DPP4 issues paper.[344]

D43 SolarZero disagreed with our proposed principles saying:[345]

> The proposed key principles (I20) do not reflect that the industry needs to go up the learning curve rapidly. For example, a new solution may only be riskier than BAU because the industry does not have experience in applying that solution – once the industry has learnt how to do it, the solution becomes reliable. The language and fundamental underpinnings of the key principles in I20 need to change. They need to reflect a learning and innvotion [sic] paradigm.

D44 We acknowledge SolarZero's description of one of the drivers of 'riskier than BAU'. In practice, the 'riskier than BAU' criterion will likely have a subjective element to it that will depend on the circumstances of the project. For example, if the industry has no experience in delivering a project, then it may well be 'riskier than BAU'. However, our intention is that once a project has been successfully delivered with INTSA support, the EDB will have the confidence to roll the technology or process out across their business, as incentivised by the DPP's baseline settings. At that point, the project would be unlikely to be 'riskier than BAU'.

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343 Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 67.

344 See paragraphs D108-D111 for explanation of this new characteristic.

345 SolarZero "DPP4 Issues paper submission" (15 December 2023), p. 11.

D45 The few suggestions made for new principles were either inconsistent with the IM Review decision or reiterated aspects of our proposed principles. For example, Contact submitted a proposed additionality principle: [346]

> However, we propose an additional principle that considers whether the innovation project could be offered by non-regulated parties, as will be the case for some non-network solutions. In those cases, we recommend that innovation support should be provided by other parts of government so that it is open to all potential suppliers. Including these types of projects within the DPP would make the allowance exclusive to distribution companies creating a competitive imbalance, which could limit rather than enhance innovation.

D46 In practice, we do not provide funding, but instead set the maximum revenue that non-exempt EDBs may recover from consumers (without penalty) for supplying a regulated service. In this context, our mandate is limited to electricity lines services, and under Part 4 of the Act, with other areas of government responsible for the wider energy system.

D47 Many suggestions from stakeholders about the scheme characteristics could already be accommodated under the characteristics that we proposed in the DPP4 issues paper. For example, some stakeholders submitted that a requirement for an INTSA be to share the learning from projects.[347] We agree, and as such introduced a new characteristic 'sharing learning' which is a core feature of our draft decision for the INTSA.

D48 Some stakeholders also suggested that we should provide a process or guide for how to make an INTSA application. Both Electra and Wellington Electricity submitted on this idea, with Electra submitting:[348]

> We encourage the Commission to release an innovations and non-traditional solutions allowance process or a guide as part of the DPP4 reset. The lack of an understood process makes it uncertain when non-exempt EDBs will recover the innovating costs and when not. Over time, the Commission's views will be established as non-exempt EDBs apply for the allowance, and their projects are accepted or rejected, as the case may be, but this precedent will take time.

D49 Wellington Electricity submitted:[349]

> Providing guidelines and examples to support the application of the final scheme. We are applying for allowances for two innovation projects under the current scheme and we found the Vector example and feedback from the Commission on

[346] Contact Energy "DPP4 Issues paper submission" (15 December 2023), p. 2.

[347] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 68.

[348] Electra "DPP4 Issues paper submission" (19 December 2023), p. 4.

[349] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 70.

> our interpretation of the process very useful. We believe that robust guidelines and examples would reduce/eliminate the risks associated with expost applications and reduce application timelines and costs.

D50 We have taken this feedback into consideration for when we will implement an INTSA scheme for DPP4. It is our intention to release guidance for how to apply for the INTSA scheme, including a PEA template before the DPP4 period begins.[350]

D51 Aside from the two key consultation areas, much of the feedback we received from the DPP4 Issues paper was based around perceptions of the IPA that prevented it from being used to greater effect by EDBs. These included:

D51.1 the value of total permissible expenditure was too small;

D51.2 the long lag time between incurring expenditure and cost recovery;

D51.3 the time of project approval after project completion meant that EDBs had to fund projects at their own risk and that uncertainty around cost recovery is a deterrent; and

D51.4 the requirement for an independent expert report for every project regardless of its value/scale was disproportionate.

D52 For instance, Powernet submitted that: "The narrow criteria for the DPP3 innovation allowance and small expenditure allowance have not caught our attention from costs benefit perspective."[351]

D53 More specifically, Vector submitted: "…the total recoverable cost (i.e., the amount drawn down from the IPA) is limited to the greater of the 0.1% of each EDB's MAR or $150k… We recommend increasing the percentage to encourage larger projects".[352]

D54 Wellington Electricity submitted more favourably on the IPA, and said:[353]

> We think the general structure of the IPA is easy to use and is low cost. We have commissioned two expert reports verifying the projects met the innovation definition. The cost to do this was modest and our experts were able to produce them quickly. The recent changes made to the timing of when the report is needed was a significant improvement.

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[350] Please see paragraphs D29; D97-D107 for further discussion of guidance we intend to release.

[351] Powernet "DPP4 Issues paper submission" (19 December 2023), p. 14.

[352] Vector "DPP4 Issues paper submission" (19 December 2023), p. 46.

[353] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 65.

D55 This feedback on the determination amendment that changed the timing of when the independent expert report is required, is helpful for our INTSA design process. While we are not making an independent expert report a mandatory requirement by rule for the draft INTSA, we consider that we could use it as a tool to request further information for projects that are higher value or complex.

D56 Overall, the IPA has not been received by EDBs as we would have hoped when it was introduced. We have taken this feedback onboard, and it has influenced the design of the draft INTSA.

D57 We received multiple suggestions that a specific demand-side management fund or allowance could be introduced at DPP4 to incentivise flexibility services projects. For instance, as Vector submitted:[354]

> We recommend that the Commission considers a targeted innovation fund for EDBs to access expenditure related to flexibility services and/or when that payment is to a particular flexibility provider the Commission should consider this as a pass-through cost. We do not consider that the IPA or INTSA would accommodate these funds in a timely manner. Instead, the expenditures would need to be qualified as related to flexibility services or paid to a flexibility provider by an auditor through the annual information disclosure process.

D58 In the DPP, the tool that we have available for providing for such a fund as suggested by Vector falls only to the INTSA. While the IMs give us powers of significant flexibility and freedom to design an INTSA as we see fit, the INTSA is the only mechanism for which we could further incentivise flexibility (or other NTS) projects.[355] Regardless of this, we do not consider that flexibility payments meet the criteria for a pass-through cost, as they are a cost that an EDB can control.

D59 In a similar vein, the Consumer Advocacy Council (CAC) submitted that:[356]

> However, we consider there should be a greater focus on demand management and that this must be integral to EDBs forecasting.

D60 In its cross submission to the CAC, Unison submitted:[357]

> …the difficulty with the emerging flexibility market is forecasting will be inherently inaccurate as costs are not yet well understood against traditional solutions. We consider the regime can create the greater focus by genuinely strong incentives to

[354] Vector "DPP4 Issues paper submission" (19 December 2023), paragraph 127.

[355] Noting that this is a *further* incentive from those already provided for with the regime's baseline settings.

[356] Consumer Advocacy Council (CAC) "DPP4 Issues paper submission" (19 December 2023), paragraph 10.

[357] Unison "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 11.

invest in flexibility and resolving existing disincentives. This could be supported through the innovation allowance or uncertainty mechanisms.

D61 We agree with aspects from both the CAC and Unison. We consider that the draft INTSA is likely to create stronger incentives for EDBs to invest in flexibility solutions, but that these are unlikely to be at the stage where they can be accurately forecast. The draft INTSA should help support further tests, trials, and implementation of solutions (including flexibility) so that in the near future they are able to be used as BAU and can be forecast.

## Workshop

D62 In response to the workshop, requiring the dissemination of learning as a part of an INTSA scheme was suggested by some stakeholders. We agree with this sentiment and have included it as a new characteristic called 'sharing learning' in our draft INTSA design.[358]

D63 Collaboration was mentioned in feedback to the DPP4 issues paper, and also featured heavily in submissions to the workshop. Aside from Unison, all those who submitted on the workshop suggested in some way that we should consider how collaboration could feature in an INTSA. For instance, Powerco submitted:[359]

> We would be keen to further explore opportunities for formally pooling resources for innovation projects across multiple EDBs. We see that this could support better resourced initiatives with increased scope from that possible at individual EDB level. Additionally, it could facilitate the execution of projects with a higher level of professionalism and enhanced governance arrangements. With such collaboration, knowledge sharing among EDBs would be far more efficient.

D64 The Lines Company (TLC) submitted something similar:[360]

> TLC urges the Commission to encourage a collaborative and sharing approach between all parties that could contribute to an innovative and nontraditional solution project – this includes distributors working together. For example, TLC is a member of the Northern Energy Group (NEG), and it is possible that we may work with other NEG members on projects for the long-term benefit of consumers.

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[358] To see analysis of this new characteristic, see paragraphs D108-D111.

[359] Powerco "Submission on the Innovation and non-traditional solutions workshop" (19 March 2024), p. 1.

[360] The Lines Company " Submission on the Innovation and non-traditional solutions workshop" (19 March 2024), paragraph 2.

D65 We have considered how collaboration could feature in the draft INTSA. We encourage collaboration on INTSA projects, as long as all collaborating EDBs submit their own individual applications that set out their forecast share of the project's costs. In response to the above submissions, we consider that pooling resources should be viable under the draft INTSA, as long as within that pool, individual costs are clearly divided and explained by any EDB involved, in their own INTSA application.

D66 In its submission to the workshop, Orion noted two key implementation details that we consider ought to be discussed here. It submitted:[361]

> We submit that the Commission should clarify if internal resources can be charged to an allowance application or not. We submit in favour of internal costs covered where it is common practice for the business to charge across business units e.g. IT input to a project would be an example.…We submit that the Commission should clarify if contracted consultancy can be charged to an allowance application or not.

D67 We are not proposing to place conditions on the individual cost breakdown for INTSA projects. If we approve a project under the criteria, the EDB can recover the relevant project costs (which may include those mentioned by Orion) as forecast in the EDB's proposal, at the EDB's discretion, on delivery of the project outputs.[362]

**Analysis conducted**

D68 The draft INTSA has taken into consideration stakeholder feedback, the specific circumstances of the DPP4 context, international examples, and the learnings from the IPA, among other factors.

D69 Our intention with the draft INTSA design is to provide additional funding for EDBs to test and trial new ideas and technology, to improve efficiency for the long-term benefit of consumers. To do this, we have considered multiple INTSA iterations, including analysis of two key alternatives. The draft INTSA scheme is the result of judgment that aims to balance greater ambition for innovation and NTS with consumer protections and potential impact on consumer bills.

[361] Orion "Submission on the Innovation and non-traditional solutions workshop" (19 March 2024) p. 6.

[362] An EDB would allocate those costs according to the cost allocation IMs, and ensure that costs are broken down by individual EDBs for collaborative projects.

## Draft INTSA characteristics

D70 **Project type – Innovative or non-traditional solutions project that fits within the three eligibility criteria.** Rather than create a 'project type' definition that is overly prescriptive, we propose to provide three standard criteria which any (non-exempt) EDB must meet, or be likely to meet, for any INTSA project to be approved.

D71 These three criteria are:

D71.1 relate to the supply of electricity lines services;

D71.2 promote the Part 4 purpose of the Act; and

D71.3 be riskier than BAU for the EDB, such that the EDB would not carry out the project if it could not recover some or all of the forecast costs of the project from the INTSA.

D72 Where an EDB wishes to seek approval to recover an amount that is more than 75% (up to 100%) of project costs, it must demonstrate how the project us unlikely to result in any financial benefits to the EDB.

D73 These criteria should be broad enough to encompass a diverse range of innovative and NTS projects and avoid unintentionally excluding a project that should otherwise be appropriate for an INTSA. For instance, we consider that flexibility services projects, which were discussed many times in submissions to the issues paper, could be funded by our draft INTSA, provided they meet the eligibility criteria.[363]

D74 These criteria, combined with the guidance we intend to publish before the start of DPP4, should enable EDBs to apply for an array of different projects with confidence as to what is required. Our expectation is that an EDB, in its proposal and alongside further information, will justify how its project will meet the three criteria.

D75 For instance, what is riskier than BAU for some EDBs may not be so for others, owing to the diversity between EDBs regionally and operationally. In this context, an EDB could choose to support its case that a project is riskier than BAU by providing a director certificate that confirms this project would not otherwise go ahead without support from the INTSA.

[363] See paragraphs D58-D62 for this discussion.

D76 **Approval timing – ex ante.** The trade-off between ex ante and ex post approval timing balances project risk between consumers and EDBs. Ex post approval protects consumers from funding projects that may not succeed but introduces a risk for EDBs that they may not get additional funding for work already undertaken. This may deter EDBs from undertaking projects in the first instance.

D77 In contrast, ex ante approval gives EDBs confidence to proceed with projects, as they are approved before the project begins. However, ex ante approval can take time to process which can delay when a project is able to commence.

D78 Ultimately, our draft decision is to proceed with ex ante approval timing to give clarity to EDBs applying for an INTSA. We consider that the combination of the other characteristics for our draft INTSA is likely to help mitigate any unintended consequences of up-front approval.[364]

D79 **Expenditure approved – forecast**. An alternative to approving forecast project costs that we considered was approving the actual costs of the project (after the project occurs). In conjunction with ex ante approval timing, it is sensible that forecast expenditure is approved in principle as well. To approve actual costs with ex ante project approval would likely result in extra steps in the approval process, which we consider as overly burdensome for a relatively low-cost scheme such as an INTSA. We also consider that approval of forecast costs creates an incentive for an EDB to control costs once the forecast is approved.

D80 **Share of project expenditure that is recoverable – up to 75% or up to 100%.** This refers to the share (as a %) of the project expenditure that can be recovered by the EDB (which is funded by consumers). Our draft decision is that the share of project expenditure that is recoverable for any INTSA project is either up to 75% or up to 100% - based on the kind of project that is being applied for. Note that EDBs could propose projects and claim a lower share of project expenditure that is recoverable (for example, if they have a limited amount remaining in their total INTSA allowance for the DPP4 period).

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[364] Consequences of up-front approval might be that too many projects get approved that may fail to achieve desired outcomes. This consequence can be controlled more with ex post approval timing, although we consider that the other characteristics help mitigate this.

D81 An EDB who would be applying would indicate which percentage of project expenditure it considers is applicable for recovery. We would assess the project against the criteria and, if the EDB has sought a sharing of more than 75% of the forecast project costs, determine whether the relevant criterion is met to justify this (ie, the project is unlikely to result in any financial benefits to the EDB).

D82 Our draft decision is to provide for two kinds of project expenditure that is recoverable based on the scope of the INTSA, as defined at D22 – both of which are for projects that are riskier than BAU in the first instance. An EDB applying for our draft INTSA scheme with a project that is (only) riskier than BAU would be eligible for a 75% share of project expenditure that is recoverable.[365] This means the EDB shares and funds 25% of the project costs out of its core allowances.

D83 An EDB applying for our draft INTSA scheme with a project is that is riskier than BAU *and* unlikely to result in any financial benefits to the EDB would be eligible to recover up to 100% of project costs. This means the EDB shares and funds none of the project costs and consumers pay for all of the project's expenditure, which is balanced as they are likely to be the recipient of all of the benefits.

D84 We have used our judgement when deciding on a 75% cap of project expenditure that is recoverable for all projects under the INTSA in the first instance. This judgement considers international schemes, of which we have considered the Australian Energy Regulator's Demand management incentive scheme (DMIS) and Demand management innovation allowance mechanism (DMIAM), as well as Ofgem's Network innovation allowance (NIA) (see below for discussion of these two in detail).

D85 We have ultimately arrived at a 75% share of project expenditure that is recoverable to reflect that EDBs should have some skin in the game for the projects they are undertaking, as they stand to benefit (or not) from potential projects. Having some skin in the game should help to incentivise EDBs to take reasonable care in their forecast project costs, as well as when conducting the project itself to take the necessary steps to promote its success.

D86 For projects that are riskier than BAU *and* that are unlikely to result in any financial benefit for the EDB, we have concluded that a share of up to 100% of project costs that is recoverable is appropriate. Examples could be:

[365] As the 25% paid for by the supplier falls under IRIS, consumers pay approx. 92% of the costs once the IRIS sharing factor is taken into account.

D86.1 the 'inter-regulatory period issue' - which is that an EDB is not incentivised by the regime to incur costs this period that will result in greater offsetting cost savings in the next period, if consumers capture all of those cost savings.[366] Consumers on the other hand do benefit from the cost saving via lower future allowances; or

D86.2 instances where consumers, or third parties benefit from a project in the same regulatory period but the EDB does not benefit.

D87 On this basis, and to reduce the disincentive for innovative and NTS projects to not be undertaken later in the period, we consider that because they are the main benefactor, it is appropriate that consumers fund these projects purely from the INTSA.

D88 **When and on what conditions approved expenditure is received** – **expenditure may be recovered upon completion of the project.** Our draft decision is for one condition to be met before project costs can be recovered. Forecast project costs could be recovered when the project has been completed – that is outputs have been delivered.

D89 We do not consider that it would be appropriate to allow for forecast costs to be recovered before a project is completed, as this may mean we would need to implement a complex clawback mechanism if a project did not take place (or was stopped part-way through). We considered that costs could be recovered on an annual basis (for multi-year projects) but assess that, for a relatively low-cost DPP, it would be more appropriate for costs to be recovered upon completion of a project.

D90 We consider 'completion of a project' (ie, delivery of project outputs) does not necessarily have to involve the project successfully achieving its purpose as set out upfront in the project proposal. A project might be completed earlier than anticipated because an EDB found that it was not going to achieve its desired outcomes. As long as the outputs are delivered, we would still consider the project complete and the EDB could recover the approved project costs. The EDB's closeout report (see 'sharing learning') would set out the EDB's view on why the project's purpose was not achieved.

[366] Note that we do not consider this to be the only type of project that would fit these criteria.

D91 **Maximum permissible expenditure – 0.6% of EDB DPP maximum allowable revenue (MAR).** For the maximum permissible expenditure, we assess that 0.6% of an EDB's MAR is an appropriate limit; this will equate to just over $75 million in total for non-exempt EDBs. In this context, MAR is our forecast of allowable revenue for EDBs for DPP4, net of pass through and recoverable costs, and net of any washup balance.

D92 This is a significant step up from what was offered by the IPA, particularly when percentage increases in baseline revenue allowances are accounted for per EDB. Factors and analysis considered before proposing this figure, include:

D92.1 engagement with stakeholders;[367]

D92.2 international innovation schemes;

D92.3 the maturity of innovation and NTS in the sector; and

D92.4 general ambition to improve network practices and services.[368]

D93 For Instance, Vector submitted that the IPA could be improved by increasing the budget, as it currently may only be useful for tests or pilots.[369] In addition, Ofgem's NIA for their current price control period allows for between roughly 0.3% and 0.5% of allowable revenue (annually) for licensees.[370] We consider that the draft INTSA is similar in scope to the NIA, although our draft decision is to offer a greater percentage than that by Ofgem, as the UK electricity sector is more mature in innovative practice than in Aotearoa New Zealand.

D94 A further driver for this increase in the value of the INTSA over the IPA is that we consider that EDB use of innovation and NTS in general is relatively immature in Aotearoa New Zealand, as compared to other jurisdictions. While the draft INTSA is not the only tool available for EDBs to undertake these projects, we consider that offering 0.6% of MAR should better promote innovation and NTS maturity in the sector.

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[367] Particularly in bilateral engagements with EDBs to discuss specific projects.

[368] Particularly non-EDB perspectives expressed by consumer bodies, third party market suppliers and other organisations. For instance see Rewiring Aotearoa "Default Price Path 2025-2030 (DDP4) cross-submission from Rewiring Aotearoa New Zealand" (26 January 2024), whose submission demonstrates this different perspective.

[369] Vector "DPP4 Issues paper submission" (19 December 2023), p. 46.

[370] Note that this is an indicative range calculated of NIA percentage, see Ofgem "RIO-ED2 Final Determinations Core Methodology Document" (30 November 2022), calculated using tables 3 and 12.

D95 Tied to maturity, is the ambition to improve network practices from not only EDBs but also third-party interests. For instance, the CAC, Rewiring Aotearoa and SolarZero advocate for significant change in how networks are managed so that they better leverage demand side management, such as flexibility services.[371]

D96 The above factors have been assessed alongside the impact on consumer bills within the DPP4 period of different thresholds for the amount of revenue that could be made available under an INTSA. We consider that for the draft INTSA, we need to manage the drivers which are increasing the need for further funding being available in an INTSA, against bill impact to consumers.

D97 **Supporting evidence – Project specific information.** Schedule 5.3 of the DPP4 draft determination requires EDBs to submit 'sufficient information' for us to assess that the eligibility criteria have been met.

D98 To support EDBs in their applications, we intend to release both guidance for how to apply for the INTSA, as well as a document akin to the PEA which is required for Ofgem's NIA.[372] We intend to publish our own PEA which will be a standardised template EDBs can follow to help them provide us with the sufficient information needed for us to complete our approval process.

D99 The PEA will be primarily designed to help EDBs provide information that can demonstrate how the project meets the three eligibility criteria. For example, this might be an explanation for how a NTS project applies prior overseas learning to an EDB's specific geographic constraints, using a method they have not implemented before, thus making it riskier than BAU. It could then provide for other information that would assist EDBs in meeting the 'sufficient information' requirement of the draft determination and help us in our approval. Lastly, it should provide information that sets out potential quality risks associated with the project (discussed below).

D100 Information that the PEA could include, but not be limited to, might be:[373]

D100.1 project timelines (start and end dates);

D100.2 total project costs forecast;

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[371] For instance, see SolarZero "Submission: Default price-quality paths for electricity distribution businesses from 1 April 2025" (15 December 2023), p. 11.

[372] Ofgem "RIIO-2 NIA Governance Document: Version 3" (17 February 2023), paragraph 3.19

[373] Note that some of this information will be required in a project application, as set out in the DPP4 Draft determination, see Schedule 5.3.

D100.3 potential benefits;

D100.4 related projects (similar projects being undertaken nationally);

D100.5 geographic area; and/or

D100.6 challenges.

D101 In terms of project timelines, we consider that it may be beneficial for EDBs to phase potential INTSA projects (eg, with annual delivery milestones). This would also give EDBs flexibility to adapt their projects in light of unexpected results or changing information.[374] We also consider that phasing projects may be of potential benefit to consumers.

D102 Approved INTSA projects may have interruptions which are directly associated with delivery of the project. These interruptions would be excluded from the calculation of the relevant quality standards, up to a cap of 0.5% of the respective SAIDI and SAIFI limit. Application of this exclusion is discussed further within **Attachment E**, draft decision RP7.

D103 As an approved INTSA project will have interruptions excluded, it is important that the EDB has appropriately considered the risk of disruption to consumers. An INTSA proposal submitted to us will need to include any steps that the EDB has taken, or proposes to take, to reduce the likelihood or impact on consumers of any interruptions.

D104 In order to understand the potential risk of interruptions associated with the project, we are also proposing that the INTSA proposal include information which:

D104.1 identifies specific types of interruption which it considers may occur related to the INTSA asset / solution / programme which may cause an interruption. We acknowledge that dependent on the nature of the project this may be difficult to be definitive in advance. Accordingly, EDBs will be able to exclude interruptions which are not identified in the application if they are directly associated with the project.

D104.2 provides an estimate of the potential scale of interruptions which may be associated with the project.

D104.3 outlines any steps which the EDB has already taken to reduce the likelihood or impact on consumers of interruptions directly associated with the project.

[374] We do not consider these examples as exhaustive reasons for why projects may need to be adapted.

D105 We note that for the purposes of the DPP an interruption is only recorded where it is on a line that is capable of conveying electricity at a voltage equal to or greater than 3.3 kilovolts. INTSA projects which are undertaken on the low voltage (LV) network are unlikely to require disclosures unless there is a risk of creating upstream network issues.

D106 Our intention is that a PEA template be completed and included in an EDB's INTSA proposal as the main medium for its application. However, an EDB need not use our PEA template if it wishes to use an alternative method. During the approval process, and as part of meeting the 'sufficient information' requirement, the EDB could include further information or evidence (to supplement the PEA), such as an independent expert report. The need for additional evidence could be determined on a case-by-case basis and proportionate to the value and/or complexity of an EDB's project.

D107 The PEA will reflect the DPP4 draft determination but be a voluntary template that is not part of the determination. The PEA will enable EDBs to provide other information above and beyond the requirements in the DPP4 determination. The key benefit of this approach is that it allows flexibility for us to make changes to the PEA, as we gain experience of processing applications, and with feedback from stakeholders. We intend to release the PEA before 1 April 2025 (start of DPP4) and in potential collaboration with stakeholders. We welcome stakeholder views on our proposed method for introducing a PEA, as well as other supporting evidence such as the use of an independent expert report.

D108 **Sharing learning – requirement to submit a project closeout report**. The only new characteristic of the draft INTSA (from those proposed in the issues paper) that we intend to introduce is the requirement to share learning via a submitted closeout report.

D109 Within 50 working days upon completion of the project (or delivering outputs), we would require EDBs to submit to us a project closeout report. We expect this would be comprehensive and explain how/whether the project achieved its purpose and expected benefits, and if not, why. We expect this report would be of high-quality and include the EDB's insights from submitting the INTSA proposal and delivering the project outputs, which would allow others to draw on and apply those insights.[375] Such insights could include any relevant impact on network quality or performance from an INTSA project.

D110 The benefits of sharing learning by publishing a closeout report are clear: multiple parties, including us, consumers and other EDBs would gain visibility of projects that have occurred. This should promote appropriate collaboration and enable learning and knowledge sharing for the sector as a whole. This in turn can promote the Part 4 purpose by enabling more consumers to benefit from innovation in receiving services at a quality they demand.

D111 Lastly, the INTSA design – and within it – the requirement to share learning has been considered with mind to avoid introducing barriers to collaboration. For example, EDBs collaborating on a project can issue a single joint closeout report if that is the best way to support other EDBs and third parties in understanding the key costs, benefits and lessons learned. It is important to note that a group of EDBs collaborating on a project will each need to submit individual applications that set out their forecast share of project costs, though we do not intend to impose constraints on EDBs repurposing similar material in their applications.

D112 **Penalty/reward mechanism – none.** Our draft INTSA does not introduce an additional, explicit penalty/reward mechanism.[376] This is primarily because we consider that a penalty/reward mechanism is more likely to be appropriate for a CPP, due to the complexity that would be involved with instituting a design that had a penalty or reward element. The DPP is designed to be a relatively low-cost regime, and this principle might be conflicted by an INTSA with a penalty/reward mechanism.

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375 We consider that the closeout report should be able to provide lessons to others regardless of whether the project was successful or not. Others should be able to apply successes and avoid mistakes – as evidenced by the report.

376 This is with respect to an explicit penalty/reward mechanism specified as a part of the INTSA. Expenditure incurred undertaking an eligible INTSA project would still be subject to IRIS. See Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), topic 5e.

D113 Additionally, our draft INTSA design is unlikely to warrant the need for either penalties or rewards, due to its total value. Furthermore, and indicated by EDBs in our stakeholder engagement, we anticipate that an INTSA (for DPP4) is unlikely to fund projects of a scale that would necessitate a penalty/reward mechanism.

## Comparison to the IPA

D114 We have also considered how our draft INTSA decision compares to the current IPA at DPP3. We have taken IPA learnings and feedback into consideration when designing our draft decision INTSA scheme. As there have only been two applications for the IPA thus far, this provides a strong signal to us that we should examine why there has been limited uptake.

D115 Noted in the 'what we heard from stakeholders' section, we received a significant amount of feedback to the DPP4 issues paper on the IPA, despite not explicitly consulting on it. The feedback (which is explored in greater depth from paragraphs D51-D56), can be expressed briefly as the IPA protections for consumers (ex post, independent expert report, 50% share) were disproportionate to the amount of money on offer.

D116 We have taken this feedback into consideration in the design of the INTSA. We are still interested in maintaining protections for consumers but recognise that these should be proportionate. Broadly, our intention is to implement an INTSA that is more attractive in three main areas of accessibility, financial value and scrutiny:

D116.1 we have sought to improve the accessibility by making the draft INTSA ex ante and forecast costs; to provide a PEA/guidance; and we have increased the share percentage so that less risk is allocated to the EDB;

D116.2 we have sought to make the draft INTSA more financially attractive by increasing the total size of the allowance and increasing the share of project expenditure that is recoverable; and

D116.3 we sought to streamline the scrutiny process of an INTSA project with the project type definition being replaced by criteria; and requiring certain supporting evidence (including removing the need for an independent expert report for all projects).

## Consideration of international schemes

D117 In the process of designing the draft INTSA, we have undertaken research into international innovation schemes. In particular, Ofgem's NIA[377] and the AER's DMIS[378] and DMIAM.[379] These schemes and these jurisdictions were suggested to us by stakeholders and provide a good basis for which to analyse and take learnings from.

D118 We have mainly considered Ofgem's NIA, rather than their Strategic Innovation Fund (SIF)[380] because the SIF is a competitive fund, and we question whether a DPP would provide us the ability to implement something similar. We have considered the NIA in our draft INTSA design with particular regard to their share of project expenditure that is recoverable,[381] their eligibility requirements,[382] and the PEA.[383] In terms of the application process, we have drawn on the approach of having a PEA template, as well as having eligibility requirements (the project eligibility criteria).

D119 We have also considered the AER's DMIS and DMIAM. Each of these schemes were introduced to incentivise demand side management identified by the AER as a key area that they wanted to see an increase of projects in. The DMIAM is designed to test and trial new solutions, whereas the DMIS is designed to further incentivise the implementation of demand side management projects that may be more proven. For instance, the DMIS offers 50% recovery of costs whereas the DMIAM is made up of a fixed amount of $200,000 plus 0.075 percent of a distributor's annual revenue.[384] [385]

D120 We consider that our draft INTSA, in the nature of the DPP, should allow for both kinds of projects that the DMIS and DMIAM are targeted at (as well as non-demand side management projects). This information helped inform our assessment of the share of project expenditure that could be recovered under the INTSA.

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377 Ofgem "RIIO-2 NIA Governance Document: Version 3" (17 February 2023).

378 Australian Energy Regulator "Demand Management Incentive Scheme" (14 December 2017).

379 Australian Energy Regulator "Demand management innovation allowance mechanism assessment 2019–20, 2020–21 and 2021–22" (2023) <aer.gov.au>. (Viewed on 14 May 2024).

380 Ofgem "SIF Governance Document version 2.1" (17 February 2023).

381 The NIA offers 90% share of project expenditure that is recoverable for its Distribution licensees.

382 Ofgem "RIIO-2 NIA Governance Document: Version 3" (17 February 2023), p. 17-19.

383 Ofgem "RIIO-2 NIA Governance Document: Version 3" (17 February 2023), paragraph 3.19

384 Australian Energy Regulator "Fact sheet - Final decision: Demand management incentive scheme and innovation allowance mechanism" (13 December 2017), p. 2.

385 Australian Energy Regulator "Decision to approve DMIAM expenditures 2019–20, 2020–21, 2021–22" (28 July 2023), p. 5.

**Alternatives considered**

D121 We have considered multiple alternatives in the process of designing the draft INTSA. Two alternatives we examined were no scheme and a more ambitious scheme with significantly more funding available but greater protections for consumers.

## No scheme option

D122 We have considered the option of not introducing an INTSA scheme in DPP4. The main advantage of this option is that consumers would not be exposed to the risks of inefficient expenditure by EDBs on an INTSA project and the possibility that an INTSA scheme results in net costs to consumers overall. The main disadvantage of this option is that significant opportunities could be missed in the DPP4 period to unlock the potential of innovation and NTS for the long-term benefit of consumers.

D123 There is limited research and analysis about the efficacy of innovation schemes by Aotearoa New Zealand EDBs. However, an independent report for Ofgem on their low carbon network fund (LCNF) concluded that 'potential future net-benefit' was estimated at 4.5 to 6.5 times the cost of the scheme.[386]

D124 In line with promoting the section 52A(1)(a) and (b) limbs of the Part 4 purpose, it is important that EDBs innovate and adopt NTS to improve the efficiency of delivering the level of network reliability and resilience that consumers demand. While EDBs have an incentive and flexibility within the baseline DPP settings to undertake innovative or NTS, there are some circumstances where these incentives may not be enough (see 'Problem definition'). This could pose a risk that consumers miss out on some long-term benefits unless further incentives are provided by an INTSA.

## Highly ambitious option

D125 It is conceivable that the draft INTSA, while significantly more ambitious than the existing IPA, may not provide sufficient incentives to support more ambitious or transformational initiatives. This more ambitious option could work as a complement to the INTSA that we are proposing as our draft decision.

[386] Ofgem "An Independent evaluation of the LCNF" (October 2016).

D126 The essence of this more ambitious option is that it would offer a significant step change in maximum permissible expenditure together with a reallocation of risk from consumers towards EDBs (and any project partner) - it aligns rewards with risk. An outline of what the option could look like is as follows:

D126.1 **Maximum permissible expenditure**: up to 5% of MAR. This sits somewhere between the draft INTSA design (0.6% of MAR) and the MAR increase that could be expected as a result of a CPP.

D126.2 **Share of project expenditure that is recoverable**: EDB to propose. Could be greater than 100% of costs depending on the assessed probability of success and the relativity between costs and benefits. The rationale of a share greater than 100% is that the EDB bears the risk that the project succeeds or fails.[387] Therefore, the share of project expenditure that is recoverable may need to be greater than 100% in order to provide an expectation of net benefits to the EDB.

D126.3 **Expenditure approved**: forecast costs. This is consistent with the EDB bearing the risks.

D126.4 **Approval of project**: ex ante, before the project or initiative starts.

D126.5 **Supporting evidence**: ex ante, application that explains the expected outcomes and that evidences the expected net benefits to consumers. Given scale of expenditure involved, there would be a requirement of consumer consultation showing consumer support for the project. Ex post, there would be a requirement for an independent evaluation, akin to a CPP verifier, of the extent to which the project outcomes and benefits were delivered.

D126.6 **Receipt of approved expenditure**: ex post, after we would receive independent evaluation demonstrating the extent to which the project outcomes and benefits were delivered.

[387] By project success we mean that the project succeeds in delivering the intended *benefits* rather than delivering other attributes of the project such as learnings, completion to time, budget or quality.

D127 We considered whether a more ambitious option, like the one outlined above, would be more appropriate in a CPP. We concluded that, while such an option may be possible as part of a CPP, relying entirely on a CPP to make such an option available may not be appropriate. This is because CPPs involve scrutiny of an EDB's entire business rather than a specific project.[388] Therefore, an EDB that wanted to embark on an ambitious innovation or NTS initiative may be discouraged from applying to a CPP in order to get the innovation-related support required to make the initiative happen.

D128 Note that a CPP makes available to us the resources required to do a more in-depth assessment of an innovation project or initiative. This means that we can allow greater permissible expenditure with more risk allocated to consumers rather than allocating the risk to the EDB (as set out in this ambitious option). However, such level of scrutiny is not compatible with the relatively low-cost nature of DPPs. Therefore, allowing greater permissible spend in a DPP setting necessarily requires a reallocation of risk from consumers towards EDBs, in order to safeguard the long-term benefit of consumers.

D129 We welcome feedback on this more ambitious option.

**Conclusions**

D130 We welcome feedback on any part of our draft INTSA scheme, on individual characteristics or as a whole. We consider that the draft INTSA scheme is the result of finding common ground between greater ambition for innovation and NTS with consumer protections and bill increases.

Draft decisions U2 and U3: incentivise energy efficiency and demand side management incentives through the draft INTSA; and incentivise the reduction of energy losses through the draft INTSA.

**Nature of the decision**

D131 As discussed at paragraph D15, section 54Q of the Act states that we must provide incentives and avoid imposing disincentives for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses.

[388] The IM Review ruled out single issue CPPs, see Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments topic paper" (13 December 2023), from paragraph 4.31.

D132 In the context of DPP4, reducing line losses, as well as investing in energy efficiency and demand side management have the potential to provide significant benefits for consumers. We consider that EDBs are incentivised by the regime's baseline settings to invest in projects in these areas. However, we consider these projects could also be eligible for funding through the INTSA.

**Draft decision**

D133 Our draft decision is to provide additional incentives for demand side management and energy efficiency, as well as additional incentives to reduce energy losses, as part of the draft INTSA.

**How the decision is aligned to the decision-making framework for the DPP**

D134 This decision is directly aligned to the decision-making framework for the DPP because it considers how we directly promote section 54Q in a way that is consistent with promoting the section 52A(1)(a), (b), and (c) limbs of the Part 4 purpose. As we are providing section 54Q incentives as part of the INTSA, these decisions work in tandem with decision U1 to promote both the Part 4 purpose and section 54Q.

D135 This is because better incentivising energy efficiency, demand side management and reduction of energy losses is likely to provide further incentives to innovate and invest, improve efficiency and provide services of a quality that reflects consumer demands, and share with consumers the benefits of efficiency gains.[389]

**What we heard from stakeholders**

D136 At the DPP4 issues paper, we consulted on an initial approach not to introduce a specific section 54Q incentive for demand side management and energy efficiency, or to introduce a quality incentive scheme for reduction of energy losses.

D137 This was met with disagreement through submissions, although largely due to stakeholder concern about support for flexibility services (demand side management).[390] The majority of stakeholders who submitted feedback on our indicative proposal to not introduce a quality incentive scheme for energy losses agreed with that approach.

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[389] See Commerce Act 1986, Sections 52A(1), (a), (b), and (c).

[390] See paragraphs D57-D61 for discussion of submissions related to flexibility services.

D138 The CAC disagreed with our initial stance, saying:[391]

> However, we disagree with the commission's initial view (para X34) that a specific incentive for demand-side management and energy efficiency is not required. We believe this needs to be considered to help control costs and ensure EDBs are not just taking a "business-as-usual" approach… If the long-term interests of consumers are to be met, the Council considers demand management and reshaping the demand side of our electricity system must be given at least the same importance as investment in network infrastructure. EDBs have an important role to play in this shift, supporting consumers' participation in demand- side management and use of DER, as well as helping consumers understand the cost implications of different decisions about electricity use.

D139 However, the ENA agreed with our initial proposal at the DPP4 Issues paper saying that "There is no evidence of the need to support the establishment of new energy efficiency, demand-side management, and reduction of energy losses incentive schemes."[392]

D140 Aurora also agreed with our initial stance on energy efficiency and demand side management incentives, saying:[393]

> The evolution of flexibility services has somewhat superseded the demand-side management category, so we agree that there is no need for demand-side management and energy efficiency schemes in DPP4. We believe the Commission would be better served by concentrating on incentives to facilitate faster uptake of flexibility services.

D141 Some submitters have proposed that energy efficiency specifically should feature in DPP4, such as Orion who submitted that:[394]

> A well designed 54Q incentive that contemplates EDB involvement in energy efficiency of buildings, vehicles and appliances having the effect of maximising energy use, minimising energy loss and reducing customer costs as it pertains to electricity service is beneficial to the whole of system too.

D142 Others have noted their support for energy efficiency projects targeted at consumers facing energy hardship. Counties Energy submitted:[395]

> However, this improvement to the homeowner is why CEL supports energy efficiency because it does enable those in energy hardship to have a warmer drier

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[391] Consumer Advocacy Council (CAC) "DPP4 Issues paper submission" (19 December 2023), paragraphs 13; 15 and 16.

[392] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), paragraph 8.1.

[393] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), paragraph 66.

[394] Orion "DPP4 Issues paper submission" (19 December 2023), p. 23.

[395] Counties Energy "DPP4 Issues paper submission" (19 December 2023), p. 3.

home. There is no energy efficiency market in educating, and providing support, for those in energy hardship and to enable this market there should be an allowance for price non-exempt EDBs to have energy efficiency programmes for those EDBs wanting to support consumers in energy hardship. This should be an allowable expenditure up to a set percent of total distribution revenue, which CEL suggests should be around 0.1%.

D143 While Unison submitted:[396]

> If the Commission does not envisage a 'wide net' of energy efficient and demand side management solutions under its innovation and non-traditional allowance definition and criteria, another scheme should consider how to capture foreseeable and traditional ways to minimise hardship of consumers and cost-efficiently relieve constraints on a network.

D144 We sympathise, and agree in principle with Unison and Counties, to the extent that the regime would allow for us to consider energy efficiency initiatives which target hardship and/or vulnerable consumers. We consider that this may possible, but only where such projects are within the scope of the role of supplying electricity lines services.

D145 We have taken these submissions, and other feedback on section 54Q incentives, into consideration when designing the draft INTSA scheme. That is, we have designed the draft INTSA scheme with section 54Q incentives in mind, and section 54Q INTSA projects should be eligible for approval, provided they meet all the criteria.[397]

**Analysis conducted and alternatives considered**

D146 We agree with stakeholders that energy efficiency and demand side management in particular are important and should be incentivised. We also consider that an energy losses project could provide potential benefit to consumers. Where these are perhaps not explicitly incentivised within an EDBs baseline allowances, such projects are within the scope of our draft INTSA as long as they meet the other requirements.

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[396] Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 23.

[397] In particular, and firstly ensuring these projects meet the criteria of relating to the supply of electricity lines services.

D147 As discussed in the DPP4 issues paper, energy losses have remained relatively stable over 2013 to 2022, ranging from 4.5% to 4.9% with the latest three years all reporting at 4.7%[398] according to information disclosure data. Given improved LV visibility, improvements to energy efficiency of distribution transformers and the limited submissions on this issue, we are not proposing to implement a specific quality incentive scheme for the reduction of energy losses. However, we do recognise that reducing energy losses could provide benefit to consumers, which is why we consider that such a project could be provided for under the draft INTSA.

D148 Energy efficiency should be encouraged, and we recognise the inherent benefits in initiatives aimed at energy hardship for instance, although we do not consider that a stand-alone scheme for energy efficiency is needed. This is because we consider energy efficiency projects would be incentivised under the draft INTSA scheme, where such projects meet the eligibility criteria.

D149 We recognise that there may have been some merit in introducing an additional specific mechanism via the INTSA for flexibility services for instance, but on balance, we consider this would be likely to be unnecessary. Provided the INTSA is designed so that it does not unduly impede section 54Q incentive projects that should otherwise be eligible (because they are beneficial to consumers), simplicity would dictate that we have one scheme rather than multiple (particularly for a low-cost DPP).

**Conclusions**

D150 Applying section 54Q, our draft decision is to incentivise energy efficiency and demand side management incentives through the draft INTSA, and also incentivise reduction of energy losses through the draft INTSA. We consider that the draft INTSA will provide for these projects, should they fit the criteria as set out in the draft INTSA determination and explained in decision U1.

D151 We welcome feedback to these decisions, in particular if stakeholders consider that the draft INTSA would not provide for section 54Q incentive projects, and if so, why not.

[398] Loss ratio is calculated as the amount of electricity losses (GWh) / Electricity entering system for supply to consumers' connection points (GWh).

*Decision I1 Set Capex retention factor at 33.18%*

D152 Our draft decision is to set the capex incentive rate at 33.18%.[399] This would see us maintaining a capex incentive rate set equivalent to the opex incentive rate (which is a function of the WACC and the length of the regulatory period).

D153 We consider that equivalence between opex IRIS and capex IRIS is an important tool in ensuring EDBs have incentives to innovate and invest in solutions that reduce the overall cost to consumers, regardless of whether they are opex or capex, in line with the s 52A(1)(a) limb of the Part 4 purpose.

**Nature of the decision**

D154 At DPP3, we set the retention factor for the capex incentive scheme equivalent to the retention factor of opex IRIS. We set these rates equivalent to ensure that EDBs had incentives to find the most efficient solution regardless of expenditure category.[400]

D155 The draft decision to set the rates equivalent was also expected to remove barriers to innovation by making suppliers financially indifferent between opex and capex solutions, allowing suppliers to use flexibility services, or other such opex solutions, where they were cheaper than traditional poles-and-wire solutions.

D156 The topic of equivalence between capex and opex IRIS was again covered in the 2023 IM Review. Some stakeholders had expressed doubt that setting the retention factor equivalent had equalised the incentives between opex and capex. They considered equivalence important as opportunities to substitute traditional capex solutions with opex solutions, such as flexibility services, were widely expected to increase.

[399] We note that the value of the capex retention rate will change for the final decision in line with changes to the WACC between draft and final to retain equivalence with the opex incentive rate.

[400] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision reasons paper" (27 November 2019), paragraphs 6.42-6.45.

D157 As part of the IM Review, we released a staff paper demonstrating equivalence between the two incentive schemes.[401] The staff paper accompanied the EDB workshop held in November 2022. Submissions following the workshop indicated that there was growing acceptance of equivalence between the two expenditure incentives. By the conclusion of the IM Review, there was widespread acceptance of equivalence between the two expenditure incentives in most circumstances.[402]

D158 In the DPP4 issues paper, we indicated that our starting position was to retain the equivalence between the two retention factors, to ensure that EDBs were financially neutral between opex and capex solutions.[403]

**What we heard from stakeholders**

D159 Submitters such as Alpine Energy and Wellington Electricity agreed with the approach laid out in the DPP4 Issues paper to maintain the equivalence between the capex and opex IRIS.[404] Wellington Electricity submitted:

> We agree that it is important not to incentivise a preference for opex or capex. It is also important to allow EDBs to substitute capex and opex allowances if they find it is more efficient to swap what allowance expenditure is funded from. We support the approach of the opex and capex retention rates being the same. The ability to substitute capex and opex allowances will become more important as EDBs consider non-traditional solutions to building new capacity.

D160 Not all submitters agreed with the starting position laid out in the DPP4 Issues paper. Network Tasman, considered that the uncertainty surrounding forecasting warranted reducing the incentive rate experienced by EDBs submitting:[405]

> Network Tasman submits that given the uncertainty involved in forecasting expenditure for DPP4 that the Commission needs to be able to articulate explain why it considers the IRIS incentives it is providing are appropriately specified and account for the issues outlined above.
>
> Network Tasman also submits that these uncertainties have increased significantly from DPP3 to DPP4 and that the Commission should reduce the strength of the

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401 Commerce Commission "Incremental rolling incentive schemes equivalence staff discussion paper" (22 November 2022).

402 There are specific circumstances where this equivalence does not hold, namely when opex is spent in the current regulatory period to defer capex in a future regulatory period.

403 Commerce Commission "Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), paragraphs E103-E114.

404 Alpine Energy "DPP4 Issues paper submission" (19 December 2023), paragraph 17; and Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 26.

405 Network Tasman "DPP4 Issues paper submission" (19 December 2023), p. 3.

incentives provided by the IRIS mechanism. Maintaining the current incentives increases the likelihood that EDBs are unduly penalised (or rewarded) for expenditure outcomes over which they have limited control over or for forecast errors in the Commission's expenditure allowances.

### Analysis conducted

D161 As noted at D157, the decision to set the retention rates equivalent was covered in depth as part of the IM Review. By the end of the IM Review, most stakeholders agreed that there was equivalence between the capex and opex incentives in most circumstances.

D162 We continue to consider that making suppliers indifferent between capex and opex solutions is in the long-term best interest of consumers. Without this financial indifference we risk crowding out opex solutions that may reduce the overall cost of the energy transition.

D163 Many submissions on the IM Review and issues paper supported this approach. Submissions cited the importance of equivalence in encouraging EDBs to consider the best available option regardless of spend category. Opportunities for such substitutions are expected to increase as flexibility services become more prevalent.

D164 EDBs such as Aurora, Powerco, and Orion are beginning to trial the use of flexibility services to defer capex and we expect the number of EDBs investigating flexibility services to increase over the upcoming regulatory period.[406]

D165 Network Tasman suggested that we reduce the IRIS incentive rates to protect EDBs and consumers from uncertainties in forecasting for DPP4. In the context of large increases in expenditure we consider it is important that EDBs face incentives to spend efficiently and to investigate innovative solutions that lower the overall cost of the energy transition.

D166 We consider that reopeners are a more appropriate tool for managing uncertainty than lowering the incentives faced by EDBs. While there is inherently some uncertainty regarding EDB expenditure forecasts, we consider that EDBs should face consistent incentives to outperform their ex ante allowances. For expenditure that is genuinely uncertain at the time of the reset, we consider that reopeners are appropriate once uncertainties around the timing, cost or need of a project, are resolved.

[406] See Orion "Energy flexibility project a first for Canterbury" (19 October 2023).

D167 Reducing the incentive strength on capex while the opex incentive rate remains fixed would encourage EDBs to, where possible, spend capex instead of opex.[407] This behaviour would discourage EDBs from innovating with opex solutions and would place further burdens on consumers in a period where supplier revenues are expected to increase significantly.

**Conclusions**

D168 Our draft decision is to set the capex incentive rate at 33.18%, which is equivalent to the opex incentive rate. In line with promoting the s 52A(1)(b) limb of the Part 4 purpose we continue to consider that financial equivalence between capex and opex solutions is a key factor in ensuring EDBs are incentivised to choose the most efficient solution regardless of which category of expenditure it falls under. We also consider equivalence important in incentivising EDBs to innovate and find solutions that reduce the overall cost of the energy transition, regardless of expenditure type, in line with s 52A(1)(a).

[407] The opex incentive rate is a function of the WACC and retention period, both of which are set in the IMs. In the recently concluded 2023 IM Review we concluded that the opex IRIS and the method for determining the opex retention factor were fit for purpose. See Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), Chapter 5d.

# Attachment E Setting quality standards and incentives

## Purpose of the attachment

E1 This attachment explains the rationale for decisions related to setting quality standards and incentives. It also provides background analysis to those decisions and responds to stakeholder submissions on this topic area.

E2 It covers these specific areas:

E2.1 high level approach to quality

E2.2 quality standards

E2.3 quality incentives scheme

E2.4 normalisation of reliability data for major events, and

E2.5 reference periods.

### High level approach to quality

*Reasons for setting quality standards*

E3 The Commerce Act (the Act) states that every default price-quality path (DPP) must specify "the quality standards that must be met by the regulated supplier".[408] Additionally, we are permitted to include incentives for suppliers to maintain or improve quality of supply.[409]

E4 The Act explains quality standards as follows:

> Quality standards may be prescribed in any way the Commission considers appropriate (such as targets, bands, or formulae) and may include (without limitation)—
>
> (a) responsiveness to consumers, and
>
> (b) in relation to electricity lines services, reliability of supply, reduction in energy losses, and voltage stability or other technical requirements.[410]

[408] Commerce Act 1986, s 53M(1)(b).

[409] *Ibid*, s 53M(2).

[410] *Ibid*, s 53M(3).

E5 Quality standards promote outcomes consistent with competitive markets in terms of providing the level of quality that reflects consumer demand.[411]

E6 Quality standards are required to counter any incentive to under-invest created by the price-path that incentivises electricity distribution businesses (EDBs) to minimise expenditure. If there was no countermeasure then EDBs may be incentivised to reduce expenditure to a level where the quality level expected by consumers is not being met.

**Current quality settings**

E7 The principle underpinning our approach to quality standards (outlined in the issues paper) was that EDBs should at least maintain the levels of quality in network performance that they have provided historically, all else being equal. We refer to this principle as 'no material deterioration' [412].

E8 The quality standards and incentives focus on network reliability, as measured by the duration and number of outages experienced by the average customer, known as SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) respectively.[413] SAIDI and SAIFI are internationally recognised and are the most common methods of measuring reliability. We consider reliability is the most important dimension of quality to consumers, and we have the most robust historical data on reliability measured at the aggregate network level.

E9 This approach is consistent with our relatively low-cost DPP forecasting principles, in that future revenues and quality are set with reference to historical levels of performance. At the same time, our incentive arrangements (discussed in *Setting the Quality Incentive Scheme*, do allow for EDBs to within certain limits to target a different level of reliability that reflects consumers preferences.

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411 *Ibid*, s 52A(1)(b)

412 We note that climate change is being raised as a growing issue as it may be increasing the frequency and/or severity of storms. The principle of 'no material deterioration' is based on quality provided, not maintenance in the strength or integrity of the network. Accordingly, we recognise that stronger infrastructure may be required to maintain the same level of quality of service.

413 The extreme event quality standard introduced in DPP3 included a SAIDI value limit and a total customer interruption minutes limit incurred during any period of 24 hours.

E10 Significant revisions to the quality standards and incentives were made for DPP3, compared to DPP2. In the issues paper, we outlined that our position for DPP4 was to consider broadly retaining the reliability standards and incentive scheme from DPP3.[414]

E11 We consider that the quality standards and incentives are working as they should, and that there is no need to take any major departure from the current quality settings for DPP4. Accordingly, this draft decision retains most of the quality standard and quality incentive settings from DPP3 with a few targeted adjustments.

**General support to broadly maintain DPP3 quality settings**

E12 In submissions on the issues paper, there was general support to keep the principle of "no material deterioration" and to broadly maintain the quality settings determined in DPP3. For example, Electricity Networks Aotearoa (ENA) stated:

> The existing DPP quality standards have delivered the level of quality sought by consumers. There is no evidence of a desire from consumers to alter the level of service delivered by EDBs. Therefore, ENA is of the view that the current regime comprising of planned and unplanned SAIDI and SAIDI metrics should be maintained. [415]

E13 There was also general support for retaining the revenue-linked quality incentive scheme (QIS). For example: "ENA believes the Commission's current framework for quality incentives is robust and should be continued… ENA views the QIS as an appropriate mechanism for delivering outcomes that align with consumer expectations."[416] (See the section *Setting the quality incentive scheme*).

E14 There were mixed views on implementation (for example, reference periods, adjustments to data, and normalisation) that we expand on in the relevant sections in this attachment.

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[414] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), Attachment F

[415] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 16, paragraph 7.1.

[416] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023) p.18, paragraphs 8.1 and 20.

E15 We noted in our issues paper that our quality standards only apply at an aggregate network level, but that we expected EDBs to consider the needs and expectations of different consumers and consumer groups when making trade-offs about quality on different parts of their networks and to reflect these in their asset management plans (AMPs).

E16 Several submissions considered that we should have more granular quality standards (FlexForum, Manawa, Powerco, Independent Electricity Generators Association (IEGA), Vector).[417] For example, FlexForum stated:[418]

> The Commission view is that applying quality at an aggregate network level enables distributors to consider the needs and expectations of different customers and customer groups when making trade-offs about quality on different parts of their networks and to reflect these in their asset planning. This approach is no longer fit-for-purpose. To be clear, we consider households, businesses and communities are worse off due to this DPP setting because it materially reduces the level of scrutiny on distributors in managing reliability and materially reduces incentives for distributors to manage LV reliability….
>
> The Commission should commit now to introducing more granular quality standards from 2030 to expose distributors to more scrutiny.

E17 Further consideration of this point is contained in the section *Disaggregated measures of network reliability*.

### General support to maintain the principle of no material deterioration

E18 The planned and unplanned interruptions reliability standards and targets we have previously implemented are based on EDBs' historical performance as measured by the duration and frequency of interruptions (SAIDI and SAIFI) experienced by customers. These are intended to give effect to the no material deterioration principle (see the section *Reference periods and inter-period data adjustment*).

E19 The exception to this approach is the setting of the extreme event standard, which has been set at a fixed amount for all EDBs (see the section *Quality Standards*, draft decision QS7).

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417 FlexForum "DPP4 Issues paper submission" (19 December 2023), p. 9; Manawa Energy "DPP4 Issues paper submission" (19 December 2023), p. 2; Powerco "DPP4 Issues paper submission" (19 December 2023), p. 15; Independent Electricity Generators Association (IEGA) NZ "DPP4 Issues paper submission" (19 December 2023), p. 4; Vector "DPP4 Issues paper submission" (19 December 2023), p. 3.

418 FlexForum "DPP4 Issues paper submission" (19 December 2023), pp. 9-10.

E20 Our approach to setting the planned and unplanned quality standards is to base these on a historical average, with a buffer added to reduce the inherent risks due to random year-to-year volatility of SAIDI and SAIFI, and a cap on the movement between regulatory periods.

**What we heard from stakeholders**

E21 Several submissions on the issues paper (Aurora, ENA, Transpower, Vector, and MEUG) stated that we should maintain the principle of no material deterioration.[419]

E22 Some submissions gave conditional agreement:

E22.1 Wellington Electricity supported "the principle of 'no material deterioration' to unplanned outages on networks that aren't being impacted by rapid or uncertain demand growth" but considered "Networks experiencing rapid and uncertain growth may not be able to maintain 'no material deterioration' level of quality for parts of their networks where growth maybe faster than they can build new capacity."

E22.2 Together with Orion and Unison, Wellington Electricity raised concerns that financial constraints posed by DPP4 revenue/expenditure allowances would have a material impact on EDBs' ability to manage network quality.[420] We discuss this point further in the section *Some EDBs raised concerns that financial constraints affect EDBs ability to maintain network quality*.

E22.3 The Lines Company considered that:

> no material deterioration needs to be considered in the context of what TLC has control over but allows for factors outside of our control when setting quality standards. An example of this is an extreme weather year and network impacted by out-of-zone trees.[421]

E22.4 We consider extreme weather in the context of major events in the section *Normalisation of Reliability Data for Major Events*.

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419 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), pp. 12-13; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 16; Transpower "DPP4 Issues paper submission" (19 December 2023), p. 4. Vector "DPP4 Issues paper submission" (19 December 2023), p. 40; Major Electricity Users' Group (MEUG) "DPP4 Issues paper submission" (19 December 2023), p. 8.

420 Unison Networks "DPP4 Issues paper submission" (19 December 2023), p 19, Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 16; and Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 9.

421 The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023), p. 10.

Some EDBs raised concerns that financial constraints affect EDBs ability to maintain network quality

**What we heard from stakeholders**

E23 A number of submissions raised concerns that potential financial constraints posed by DPP4 revenue/expenditure allowances would have a material impact on EDBs' ability to manage network quality.

E23.1 Unison stated: "Without adequate cashflows, there will be an impact on EDBs ability to make decisions on a least cost life-cycle basis implement [sic] (which will shorten the life of and make more expensive, assets over their lives, and steadily degrade quality outcomes)". It considered that "there should be a process to consider a proportionate reduction of quality standards to match a subsequent expenditure constraint, and adjusted work programme…"[422]

E23.2 Unison also considered that: "at a time of growth, increasing climate risk to fixed infrastructure and uncertainty, the effectiveness of the QIS is reliant on access to adequate funding to resolve issues". It considered that the QIS should be agile to respond to the potential of EDBs not being adequately funded to deliver their AMPs, and where customised price-quality paths (CPPs) and reopener mechanisms cannot respond to impacts on EDB quality in a timely way.[423]

E23.3 Orion submitted "conditional agreement to the continued principle of no material deterioration and setting quality standards on a basis consistent with that established in DPP3. The condition is that if customers are willing to pay to maintain current levels and there is sufficient revenue via the DPP to maintain those levels." [424]

E23.4 Wellington Electricity stated that a consequence of insufficient investment will "mean that quality will deteriorate as demand exceeds the network capacity. If EDBs do not keep pace with demand increases, customers will experience more power cuts as networks curtail electricity use to avoid electrical equipment overloading." [425]

[422] Unison Networks Ltd "DPP4 Issues paper submission" (19 December 2023), p. 19.

[423] *Ibid,* p. 21.

[424] Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 16

[425] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 10, paragraph 6.2.

### Analysis

E24 We note that DPP regulation is a relatively low-cost regime and does not always allow analysis of the specific linkages between expenditure allowances and potential quality impacts. This would be practically challenging to undertake based on our limited information available to make that assessment.

E25 The capex allowances provided represent either the full extent of capex forecast under an EDBs AMP or a significant uplift in capex compared to recent periods. It is unclear that limiting expenditure uplifts will result in deterioration in reliability performance.

E26 Where expenditure allowances are less than forecast, EDBs have a number of options available under the regime, as outlined in **Attachment B: Capex**, *Implications for EDBs of capping expenditure at 125%*.

E27 Where EDBs have reprioritised programmes in line with DPP allowances and consider that a variation is required to reflect the realistically achievable performance they may apply for a change to the quality standards through a quality standard variation (QSV) reopener or making a CPP application.

*Assessment of breach of quality standards*

E28 In submissions on our issues paper, Wellington Electricity questioned the use of 'good industry practice' (GIP) in the assessment of a breach of quality standards, which it considers is very different to the basis of no material deterioration principle on which the quality standards are set. On its 2018 breach investigation, Wellington Electricity noted:

> …the breach investigation was assuming faster response times to an outage as 'good industry practice' but were at a level we have not needed to provide in maintaining our current levels of SAIDI and SAIFI. Applying the 'good industry practice' response times would significantly improve our SAIDI/SAIFI performance but at a significant cost increase
>
> … We ask that the Commission align the enforcement methodology with the DPP quality path to ensure EDBs can maintain the price/quality balance and they (sic) not incentivised to provide a different level of quality because of the threat of enforcement penalties.[426]

[426] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), sections 9 and 9.2.

E29 Quality standards and investigations need to be set and assessed on different bases. Assessment using GIP operates to address the concerns regarding false positives. Specific engagement on differences between historic practices which are reflected in reliability performance, and those which may have applied under GIP are best engaged on during engagement on the non-compliance.

*Some EDBs considered that quality standards should only be set within the price-quality regime*

E30 Wellington Electricity, supported by Unison and Powerco in cross submissions, suggested that new quality standards, such as those imposed through changes to the Electricity Authority's (EA) default distributor agreement (DDA) should not be set outside of the price-quality regime.[427] For example, Wellington Electricity stated:

> Recent High Cort decisions has provided the EA with the ability to impose quality targets and incentives. They are proposing two changes to the DDA with retailers which would apply higher levels of quality and significant additional cost. These quality changes must be made within the price/quality regulatory framework to ensure that customers are happy to fund the higher level of quality and that EDBs are funded to do so.[428]

E31 We note that the EA can include in the Electricity Industry Participation Code 2010 quality or information requirements for Transpower or one or more EDBs, in relation to access to transmission or distribution networks – and this is a matter for the EA to determine.[429] We and the EA engage regularly on this and other areas of overlap, including as required under s 54V of our Act.

**Quality standards**

**High level approach to quality standards**

E32 Our draft decision for setting quality standards for DPP4 is to retain the three quality standards set for DPP3, focussed on the reliability of supply. They are:

E32.1 SAIDI and SAIFI limits for unplanned outages, assessed on an annual basis

[427] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), pp. 12, 48 and 60; Unison "Cross-submission on DPP4 Issues paper" (26 January 2024), p 10; Powerco "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 3.

[428] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), pp. 47-48, section 9.

[429] Section 32(4)(a) of the Electricity Industry Act 2010.

E32.2 SAIDI and SAIFI limits for planned outages, assessed across the full regulatory period, and

E32.3 an extreme event standard for high impact and low probability events, assessed as more within the EDB control.

E33 The following table presents the draft decisions for quality standards:

**Table E1 Draft quality standards for DPP4**

| EDB | Unplanned SAIDI (1-year) | Unplanned SAIFI (1-year) | Planned SAIDI (5-year) | Planned SAIFI (5-year) | Extreme outage limit (per event)[430] |
|---|---|---|---|---|---|
| **Alpine Energy** | 121.69 | 1.1372 | 742.38 | 3.1437 | 120 SAIDI |
| **Aurora Energy** | 122.05 | 1.9675 | 1077.78 | 6.0924 | 6m CIM |
| **EA Networks** | 90.84 | 1.3110 | 1238.47 | 4.4045 | 120 SAIDI |
| **Firstlight Network** | 230.43 | 3.2346 | 1161.61 | 6.7271 | 120 SAIDI |
| **Electricity Invercargill** | 27.15 | 0.7060 | 125.94 | 0.5702 | 120 SAIDI |
| **Horizon Energy** | 184.80 | 2.2709 | 944.50 | 5.9856 | 120 SAIDI |
| **Nelson Electricity** | 18.62 | 0.4063 | 165.72 | 2.1297 | 120 SAIDI |
| **Network Tasman** | 97.73 | 1.1358 | 1019.65 | 4.4119 | 120 SAIDI |
| **Orion NZ** | 80.47 | 0.9819 | 215.41 | 0.6866 | 6m CIM |
| **OtagoNet** | 168.37 | 2.4935 | 1945.75 | 8.7119 | 120 SAIDI |
| **Powerco** | 189.27 | 2.1550 | 781.17 | 3.4964 | 6m CIM |
| **The Lines Company** | 190.55 | 3.4333 | 1245.95 | 7.8774 | 120 SAIDI |
| **Top Energy** | 399.25 | 4.8196 | 1714.83 | 7.4615 | 120 SAIDI |
| **Unison Networks** | 86.46 | 1.8737 | 688.37 | 4.9114 | 6m CIM |
| **Vector Lines** | 110.07 | 1.4034 | 643.92 | 3.1661 | 6m CIM |
| **Wellington Electricity** | 37.84 | 0.5829 | 76.66 | 0.6089 | 6m CIM |

E34 In this section, we also discuss our draft decisions to:

E34.1 retain automatic reporting obligations where an EDB contravenes a quality standard

E34.2 not to introduce any new quality measures

[430] The extreme event standard is specified in either SAIDI minute or CIM terms. CIM means customer interruption minutes, which is the sum of the total duration in minutes accumulated for each ICP for each interruption, with "m" representing millions.

E34.3 set quality standards and incentives for Aurora transitioning from a CPP to the DPP, and

E34.4 retain the requirement for reasonable reallocation of SAIDI and SAIFI following an asset transfer between EDBs.

**How the quality standards settings align to the decision-making framework for the DPP**

E35 As we discussed in *High level approach to quality*, our analysis and stakeholder views broadly support the position that the quality standard settings are fit for purpose and should largely be retained. For example:

E35.1 Our decision to retain the separation of planned and unplanned interruptions is more consistent with the purpose of Part 4 than the alternative because it avoids disincentivising investment at the most appropriate and efficient time.

E35.2 A planned standard, assessed once over the regulatory period, also gives EDBs flexibility to undertake work that will be to the long-term benefit of consumers.

E35.3 An annually assessed unplanned standard and self-reporting following contravention of any quality standard allows for more timely compliance investigations and enforcement action, which provides transparency of EDB performance and benefits consumers.

E36 We provide more detail on each of our draft decisions below. We consider these draft decisions together are likely to best give effect to the purpose of Part 4 of the Act (Part 4) and incentivise EDBs to provide services at a quality that reflects consumer demands.

*QS1: Maintain separate standards for planned and unplanned SAIDI and SAIFI*

**Problem definition**

E37 The integration of planned and unplanned interruptions into a single standard may create perverse incentives, especially where an EDB is nearing a potential compliance contravention.

**Draft decision**

E38 Our draft decision is to maintain separate standards for planned and unplanned SAIDI and SAIFI.

**What we heard from stakeholders**

E39 We received no submissions on this point in submissions on the issues paper.

**Analysis conducted**

E40 We intend to continue treating planned outages differently because they are less inconvenient for consumers as they can plan accordingly. Planned interruptions are also generally required by the EDB to perform maintenance and investment that benefits consumers in the long run.

E41 These different factors mean that separation is beneficial so that we can set the parameters of the standards differently (such as the annual limits for unplanned SAIDI and SAIFI in comparison to the five-year limit for planned SAIDI and SAIFI).

**Conclusions**

E42 Separate standards for planned and unplanned outages avoids a potential perverse incentive for EDBs to avoid network investment or maintenance which could cause inefficiency or defer investment.

## Annual unplanned interruption standard

E43 Our draft decision is to retain unplanned interruption standards:

E43.1 assessed annually for unplanned SAIDI and SAIFI (QS2)

E43.2 set with limits for unplanned SAIDI and SAIFI at 2.0 standard deviations above the reference period average (QS3)

E43.3 where the reference period is ten years (see the section *Reference Period*, draft decision RP1)[431], and

E43.4 the movement between reference periods is capped at +/-5% (see the section *Reference Period*, draft decision RP3).

*QS2: Annual unplanned interruptions reliability standards for SAIDI and SAIFI*

**Draft decision**

E44 Our draft decision is to retain annual unplanned interruptions reliability standards for SAIDI and SAIFI.

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[431] Decisions related to the reference period as signalled by "RP" are separately analysed within this chapter as they apply to both the quality standards and the quality incentive scheme

**What we heard from stakeholders**

E45 As we noted in *General support to broadly maintain DPP3 quality settings* above, submissions on the issues paper gave general support to broadly maintain the quality settings determined in DPP3.

E46 In its submission on the issues paper, Vector suggested that by not removing the annual assessment of quality standard breaches (and replacing it with the two-out-of-three-year rule used in DPP2),[432] there is a risk of false positives.[433]

> Based on Vector's experience, breach investigations are a material burden given the volume of information requested by investigations… This is warranted if there is a material issue to be worked through, but not if a breach was triggered by a false positive or if that breach is a continuation of circumstances that already have been investigated by the Commission and are actively being addressed through agreed remedial action.
>
> The Commission has suggested that adopting higher thresholds when setting the quality standard targets will help avoid false positives. However, there does not appear to have been any analysis undertaken showing that this is the case. We recommend that at a minimum, the Commission considers re-adopting the '2 out of 3 rule' approach to breaches.

E47 Powerco suggested reinstatement may be necessary to address the risk of random volatility and false positives if we alter the normalisation approach in DPP4.[434] However, we are not proposing to change the normalisation approach (see *Normalisation of Reliability Data for Major Events*).

**Analysis conducted**

E48 We consider that the removal of the two-out-of-three-year rule was appropriately assessed and considered in DPP3. The changes made in DPP3 were considered a more effective means of reducing the risk of false positives where contraventions were caused by random volatility.[435]

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[432] The 'two-out-of-three year rule' is where a breach occurs when the unplanned reliability standard is exceeded in both the current year and one of the preceding two years (as opposed to only using the current year).

[433] Vector "DPP4 Issues paper submission" (19 December 2023), pp. 41-42.

[434] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 24.

[435] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision – Reasons paper" (27 November 2019), pp. 403–405. paragraphs L29–L37.

E49 Whilst Vector have represented an issue with the annual review creating a risk of investigating a continuation of circumstances, this is no different than under the two-out-of-three-year rule as the assessment of compliance doesn't reset with preceding years considered, and there is a lower buffer for assessment.

E50 We also note that reverting to a two-out-of-three-year rule would create complexity regarding an EDBs ability to be assessed as non-compliant in the first year of the regulatory period, regardless of network performance.

E51 We have separately assessed how a two-out-of-three-year rule may have applied in DPP3 assessment periods to date in the next section*, QS3: Set with limits at 2.0 standard deviations above the reference period average.*

**Conclusion**

E52 The two-out-of-three-year rule, in contrast with an annual standard, can mean that significantly high levels of unreliability over a year are not considered to be contraventions.

E53 An annually assessed standard is simple and allows for more timely compliance investigations and enforcement action. In conjunction with our decision to set the limit at two standard deviations above the target, we consider there is limited prospect of false positives.

*QS3: Set with limits at 2.0 standard deviations above the reference period average*

**Draft decision**

E54 Our draft decision is to retain annual unplanned reliability standards for SAIDI and SAIFI, set with limits at 2.0 standard deviations above the reference period average.

**What we heard from stakeholders**

E55 We received no submissions on this point in submissions on the issues paper.

**Analysis conducted**

E56 In DPP3, we set the buffer (for the compliance limit) at 2.0 standard deviations above the historical average, which we considered together with reducing the impact of major events, provided a suitable level of protection against random volatility.

E57 The tables below show the reliability performance of EDBs in the DPP3 period to date, against the unplanned SAIDI/SAIFI limits which incorporate a 2.0 standard deviation buffer.

**Table E2 EDB performance against SAIDI limits, DPP3 regulatory period to date**[436]

| EDB | 2021 Unplanned SAIDI Assessed Value | 2022 Unplanned SAIDI Assessed Value | 2023 Unplanned SAIDI Assessed Value | Unplanned SAIDI Limit | 2021 Unplanned SAIDI Compliant? | 2022 Unplanned SAIDI Compliant? | 2023 Unplanned SAIDI Compliant? |
|---|---|---|---|---|---|---|---|
| **Alpine** | 77.48 | 89.32 | 92.94 | 124.71 | Y | Y | Y |
| **EA Networks** | 75.07 | 61.31 | 63.41 | 91.98 | Y | Y | Y |
| **Eastland/Firstlight** | 180.86 | 214.72 | 295.44 | 219.46 | Y | Y | N |
| **Electricity Invercargill** | 9.67 | 15.38 | 17.80 | 25.86 | Y | Y | Y |
| **Horizon** | 133.54 | 134.42 | 159.84 | 194.53 | Y | Y | Y |
| **Nelson Electricity** | 0 | 8.53 | 6.21 | 19.60 | Y | Y | Y |
| **Network Tasman** | 87.45 | 79.53 | 72.01 | 101.03 | Y | Y | Y |
| **Orion** | 29.70 | 52.95 | 43.37 | 84.71 | Y | Y | Y |
| **OtagoNet** | 133.2 | 141.82 | 143.82 | 160.35 | Y | Y | Y |
| **The Lines Company** | 154.74 | 159.78 | 238.94 | 181.48 | Y | Y | N |
| **Top Energy** | 300.83 | 342.68 | 513.96 | 380.24 | Y | Y | N |
| **Unison** | 44.64 | 69.40 | 75.99 | 82.34 | Y | Y | Y |
| **Vector** | 86.30 | 92.42 | 118.74 | 104.83 | Y | Y | N |
| **Wellington Electricity** | 28.414 | 25.32 | 34.92 | 39.81 | N/A | Y | Y |

[436] Powerco are not included as they have been on a CPP during the DPP3 regulatory period to date. We have also excluded Aurora Energy as they were only under the DPP3 settings for the 2021 assessment period, which had a Quality Standard Variation proposal applied.

### Table E3 EDB performance against SAIFI limits, DPP3 regulatory period to date

| EDB | 2021 Unplanned SAIFI Assessed Value | 2022 Unplanned SAIFI Assessed Value | 2023 Unplanned SAIFI Assessed Value | Unplanned SAIFI Limit | 2021 Unplanned SAIFI Compliant? | 2022 Unplanned SAIFI Compliant? | 2023 Unplanned SAIFI Compliant? |
|---|---|---|---|---|---|---|---|
| **Alpine** | 0.6354 | 0.7110 | 0.8274 | 1.1970 | Y | Y | Y |
| **EA Networks** | 0.8856 | 0.9762 | 1.1852 | 1.2826 | Y | Y | Y |
| **Eastland/Firstlight** | 2.7184 | 2.7849 | 2.6402 | 3.1525 | Y | Y | Y |
| **Electricity Invercargill** | 0.3066 | 0.3231 | 0.2444 | 0.6956 | Y | Y | Y |
| **Horizon** | 1.2797 | 1.4814 | 2.0065 | 2.3904 | Y | Y | Y |
| **Nelson Electricity** | 0 | 0.1724 | 0.1082 | 0.4277 | Y | Y | Y |
| **Network Tasman** | 0.7834 | 0.7391 | 0.7351 | 1.1956 | Y | Y | Y |
| **Orion** | 0.5026 | 0.6016 | 0.5059 | 1.0336 | Y | Y | Y |
| **OtagoNet** | 1.9435 | 2.3811 | 1.7704 | 2.4172 | Y | Y | Y |
| **The Lines Company** | 2.5500 | 2.8047 | 3.4377 | 3.2715 | Y | Y | N |
| **Top Energy** | 3.1020 | 3.9480 | 5.5000 | 5.0732 | Y | Y | N |
| **Unison** | 1.1259 | 1.4540 | 1.4327 | 1.8152 | Y | Y | Y |
| **Vector** | 1.0700 | 1.048 | 1.1940 | 1.3366 | Y | Y | Y |
| **Wellington Electricity** | 0.3733 | 0.3783 | 0.5024 | 0.6135 | N/A | Y | Y |

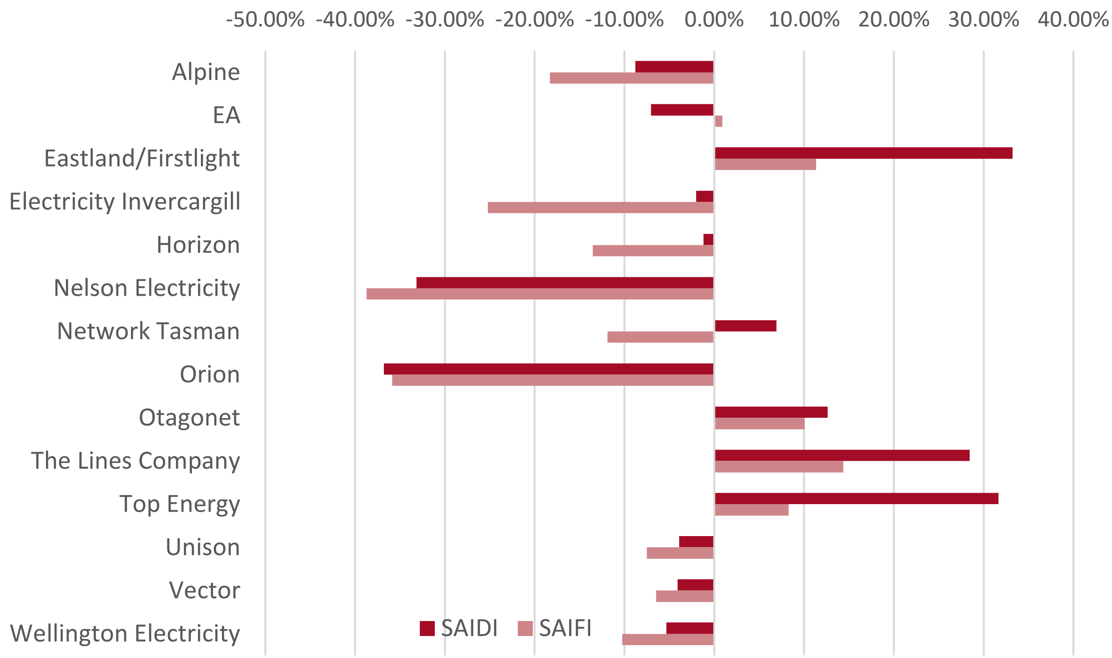
E58 The data contained in the tables above show that the 2.0 standard deviation buffer is largely working and seems to be set at the right level. This is because:

E58.1 the vast majority of disclosure years for each EDB have seen the EDB perform better than the limit, and

E58.2 EDBs who have declining performance against the unplanned target have generally been identified as being non-compliant with the quality standard.

E59 The graph below shows the average percentage variance of each EDBs' unplanned performance, from the target.

**Figure E1 Average variance of EDB unplanned performance from target, DPP3 period**




E60 We consider that using the historical mean with an additional buffer is working in capturing material deterioration in reliability. The quality standards which have applied across multiple DPPs have resulted in contraventions that investigations have shown to be, at least in part, caused by failure of those distributors to act consistently with good industry practice. Conversely, we have not found contraventions of the quality standard in the previous regulatory period to be caused only by random volatility.[437]

E61 We note that the buffer and approach to normalisation of major event days (MED) apply together to mitigate the risk of false positives.

E62 In DPP3, the application of 2.0 standard deviations was analysed to likely return the same instances of non-compliance as arose in DPP2.[438]

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[437] Note, that we are yet to conclude our analysis of instances of non-compliance for the 2023 assessment period

[438] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision – Reasons paper" (27 November 2019), p. 406. paragraphs L44 – L46

E63 We have considered how comparable the outcomes of the current approach are compared to an approach which only applied one standard deviation buffer, but had compliance assessed on a two-out-of-three-year basis, see Tables E4 and E5 below. Noting, this analysis is only indicative as these are not the standards under which EDBs were operating under.

E64 We note this indicates some instances where EDBs would be assessed as non-compliant under this approach but are compliant under DPP4 and vice-versa where an EDB would not yet be identified as non-compliant under this approach but are non-compliant under DPP4. The later may be in part due to a short time-series for application of a standard which applies over multiple years.

**Table E4 DPP3 EDB unplanned SAIDI compliance against 1 standard deviation buffer, two-out-of-three-year rule (indicative only)**

| EDB | DPP3 SAIDI Target | 1SD Buffer SAIDI Limit | 2021 SAIDI - Less than 1 SD | 2022 SAIDI - Less than 1 SD | 2023 SAIDI - Less than 1 SD | 2/3 year 1SD test compliant |
|---|---|---|---|---|---|---|
| **Alpine Energy** | 91.88 | 108.30 | TRUE | TRUE | TRUE | Y |
| **EA Networks** | 71.65 | 81.82 | TRUE | TRUE | TRUE | Y |
| **Firstlight Network** | 173.85 | 196.65 | TRUE | FALSE | FALSE | N |
| **Electricity Invercargill** | 15.39 | 20.63 | TRUE | TRUE | TRUE | Y |
| **Horizon Energy** | 144.35 | 169.44 | TRUE | TRUE | TRUE | Y |
| **Nelson Electricity** | 9.53 | 14.57 | TRUE | TRUE | TRUE | Y |
| **Network Tasman** | 74.49 | 87.76 | TRUE | TRUE | TRUE | Y |
| **Orion NZ** | 66.47 | 75.59 | TRUE | TRUE | TRUE | Y |
| **OtagoNet** | 120.02 | 140.19 | TRUE | FALSE | FALSE | N |
| **The Lines Company** | 143.04 | 162.26 | TRUE | TRUE | FALSE | Y |
| **Top Energy** | 302.16 | 341.20 | TRUE | FALSE | FALSE | N |
| **Unison Networks** | 67.81 | 75.08 | TRUE | TRUE | FALSE | Y |
| **Vector Lines** | 89.28 | 97.05 | TRUE | TRUE | FALSE | Y |
| **Wellington Electricity** | 31.20 | 35.51 | TRUE | TRUE | TRUE | Y |

**Table E5 DPP3 EDB unplanned SAIFI compliance against 1 standard deviation buffer, two-out-of-three-year rule (indicative only)**

| EDB | DPP3 SAIFI Target | 1SD Buffer SAIFI Limit | 2021 SAIFI - Less than 1 SD | 2022 SAIFI - Less than 1 SD | 2023 SAIFI - Less than 1 SD | 2/3 year 1SD test compliant |
|---|---|---|---|---|---|---|
| **Alpine Energy** | 0.9069 | 1.0520 | TRUE | TRUE | TRUE | Y |
| **EA Networks** | 1.0065 | 1.1446 | TRUE | TRUE | FALSE | Y |
| **Firstlight Network** | 2.4700 | 2.8113 | TRUE | TRUE | TRUE | Y |
| **Electricity Invercargill** | 0.4273 | 0.5615 | TRUE | TRUE | TRUE | Y |
| **Horizon Energy** | 1.8375 | 2.1140 | TRUE | TRUE | TRUE | Y |
| **Nelson Electricity** | 0.1988 | 0.3133 | TRUE | TRUE | TRUE | Y |
| **Network Tasman** | 0.9042 | 1.0499 | TRUE | TRUE | TRUE | Y |
| **Orion NZ** | 0.8371 | 0.9353 | TRUE | TRUE | TRUE | Y |
| **OtagoNet** | 1.7940 | 2.1056 | TRUE | FALSE | TRUE | Y |
| **The Lines Company** | 2.5578 | 2.9147 | TRUE | TRUE | FALSE | Y |
| **Top Energy** | 4.1328 | 4.6030 | TRUE | TRUE | FALSE | Y |
| **Unison Networks** | 1.5201 | 1.6677 | TRUE | TRUE | TRUE | Y |
| **Vector Lines** | 1.1803 | 1.2584 | TRUE | TRUE | TRUE | Y |
| **Wellington Electricity** | 0.4840 | 0.5488 | TRUE | TRUE | TRUE | Y |

## Conclusions

E65 Our draft decision is to maintain the annual unplanned interruptions reliability standards for SAIDI and SAIFI, with a 2.0 standard deviation buffer for DPP4 as it helps reduce the risk of random volatility causing breaches and allows for more timely compliance investigations.

E66 Table E6 shows the draft standards for unplanned SAIDI and SAIFI for each price-quality regulated EDB for DPP4.

**Table E6 Draft annual unplanned interruptions reliability standards**

| EDB | Unplanned SAIDI | Unplanned SAIFI |
|---|---|---|
| **Alpine Energy** | 121.69 | 1.1372 |
| **Aurora Energy** | 122.05 | 1.9675 |
| **EA Networks** | 90.84 | 1.3110 |
| **Firstlight Network** | 230.43 | 3.2346 |
| **Electricity Invercargill** | 27.15 | 0.7060 |
| **Horizon Energy** | 184.80 | 2.2709 |
| **Nelson Electricity** | 18.62 | 0.4063 |
| **Network Tasman** | 97.73 | 1.1358 |
| **Orion NZ** | 80.47 | 0.9819 |
| **OtagoNet** | 168.37 | 2.4935 |
| **Powerco** | 189.27 | 2.1550 |
| **The Lines Company** | 190.55 | 3.4333 |
| **Top Energy** | 399.25 | 4.8196 |
| **Unison Networks** | 86.46 | 1.8737 |
| **Vector Lines** | 110.07 | 1.4034 |
| **Wellington Electricity** | 37.84 | 0.5829 |

### Planned interruptions reliability standard is assessed across the full regulatory period

E67 Our draft decision is to retain planned interruption standards:

E67.1 These are assessed at the end of the 5-year regulatory period for planned SAIDI and SAIFI (QS4), with notified planned interruptions de-weighted by 50% from planned (QS6).

E67.2 Limits for planned SAIDI and SAIFI are set with a 100% uplift on the reference period average, with a cap set at +/- 10% movement from the current standard (QS5).

E67.3 We use a reference period of seven years, changed from 10 years (RP2) - see *Reference periods and inter-period data adjustment*.

E68 Table E7 shows the draft standard for planned SAIDI and SAIFI for each price-quality regulated EDB for DPP4.

Table E7 Regulatory period draft planned interruptions reliability standards (5-year total)

| EDB | Planned SAIDI | Planned SAIFI |
|---|---|---|
| **Alpine Energy** | 742.38 | 3.1437 |
| **Aurora Energy** | 1,077.78 | 6.0924 |
| **EA Networks** | 1,238.47 | 4.4045 |
| **Firstlight Network** | 1,161.61 | 6.7271 |
| **Electricity Invercargill** | 125.94 | 0.5702 |
| **Horizon Energy** | 944.50 | 5.9856 |
| **Nelson Electricity** | 165.72 | 2.1297 |
| **Network Tasman** | 1,019.65 | 4.4119 |
| **Orion NZ** | 215.41 | 0.6866 |
| **OtagoNet** | 1,945.75 | 8.7119 |
| **Powerco** | 781.17 | 3.4964 |
| **The Lines Company** | 1,245.95 | 7.8774 |
| **Top Energy** | 1,714.83 | 7.4615 |
| **Unison Networks** | 688.37 | 4.9114 |
| **Vector Lines** | 643.92 | 3.1661 |
| **Wellington Electricity** | 76.66 | 0.6089 |

*QS4: Maintain regulatory period length standard for planned SAIDI and SAIFI*

### Draft decision

E69 Our draft decision is to maintain regulatory period length standard for planned SAIDI and SAIFI.

### What we heard from stakeholders

E70 In its submission on the issues paper, Wellington Electricity stated "We do like the planned quality standard being measured over the whole DPP period as this lets us adjust the planned SAIDI 'budget' to changes in the work plan."[439]

[439] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 56, paragraph 9.6.1.

**Analysis conducted**

E71 Currently, the planned interruption standard is assessed once for the regulatory period for planned SAIDI and SAIFI standards, ie, assessment is against a five-year total. In comparison, an annual assessment for planned interruptions may incentivise EDBs to defer or bring forward work that may be less efficient for consumers.

E72 There are long-term benefits to consumers stemming from the network investment and maintenance that is associated with planned interruptions. Applying the planned quality standard over the full regulatory period allows EDBs to schedule planned work in the way that works best for their business and consumers, rather than for regulatory settings.

E73 We note that assessment once every five years creates the potential of a significant lag between the time an EDB begins significant levels of planned interruptions and the time compliance and enforcement action can be taken. It also reduces the maximum pecuniary penalty that an EDB that continues high levels of interruptions over several years will face.

E74 However, the EDB will continue to face the incentives of the QIS each year, and continual years of high interruption frequency or duration would likely be taken into account in our enforcement response.

E75 We also consider that only assessing compliance at the end of the regulatory period is justified given that planned interruptions:

E75.1 are generally less harmful for consumers, as long as they are notified of planned work, as they can plan ahead for them and make alternative arrangements if required

E75.2 are required for beneficial network maintenance and investment

E75.3 are not an indicator of current under expenditure (although may be required for historical under expenditure)

E75.4 can be driven by operating policies, such as live lines practices, and

E75.5 are exposed to our revenue-linked incentives.

**Conclusions**

E76 Given the above, our draft decision is to retain assessment of planned interruption standards for SAIDI and SAIFI across the full regulatory period.

QS5: Change the planned reliability buffer for the planned interruptions reliability standard to be a 100% uplift on the historic average, capped at a +/- 10% movement from the current standard

**Draft decision**

E77 Our draft decision is to change the planned reliability buffer for the planned interruptions reliability standard to be a 100% uplift on the historic average, capped at a +/- 10% movement from the current standard.

**What we heard from stakeholders**

E78 We received no submissions on the appropriateness or size of the buffer or any suggestions we cap the movement between regulatory periods for planned interruptions in submissions on the issues paper.

E79 We did receive submissions stating that expected increases in investment are likely to result in increased planned interruptions, these have been separately analysed in the section *Setting the QIS at the historical average.*

**Analysis**

E80 For DPP4, our draft decision is to shorten the reference period which will result in a significantly higher historical average for most EDBs (see *Reference period*, draft decision RP2). Were we to apply the 200% DPP3 buffer and then multiply by the 5-year regulatory period length, the increase in the planned interruption standard would be significant.

E81 In addition, the uptake of 'notified' interruptions as shown in Table E8, which halves the impact of SAIDI in the assessment of compliance, has incentivised behaviour that is valued by consumers. The de-weighting of notified interruptions is only applied to the assessment and is not reflected in the reference period dataset, which also has a significant impact.

E82 At this stage we are proposing to maintain the de-weighting of notified interruptions only being applied to the assessment period and not the reference period dataset. We note this application has an offsetting effect compared to the expected increase in planned interruptions with increased electrification.

E83 However, given most EDBs have already responded to the incentive, it is not clear that it needs to be maintained, and may result in windfall gains to EDBs who simply continue their DPP3 practices into DPP4. We intend to further consider in moving from draft to final whether the de-weighting should be applied to the reference period dataset where an EDB has notified interruptions.

**Table E8 Proportion of planned assessed SAIDI attributable to notified planned interruptions[440]**

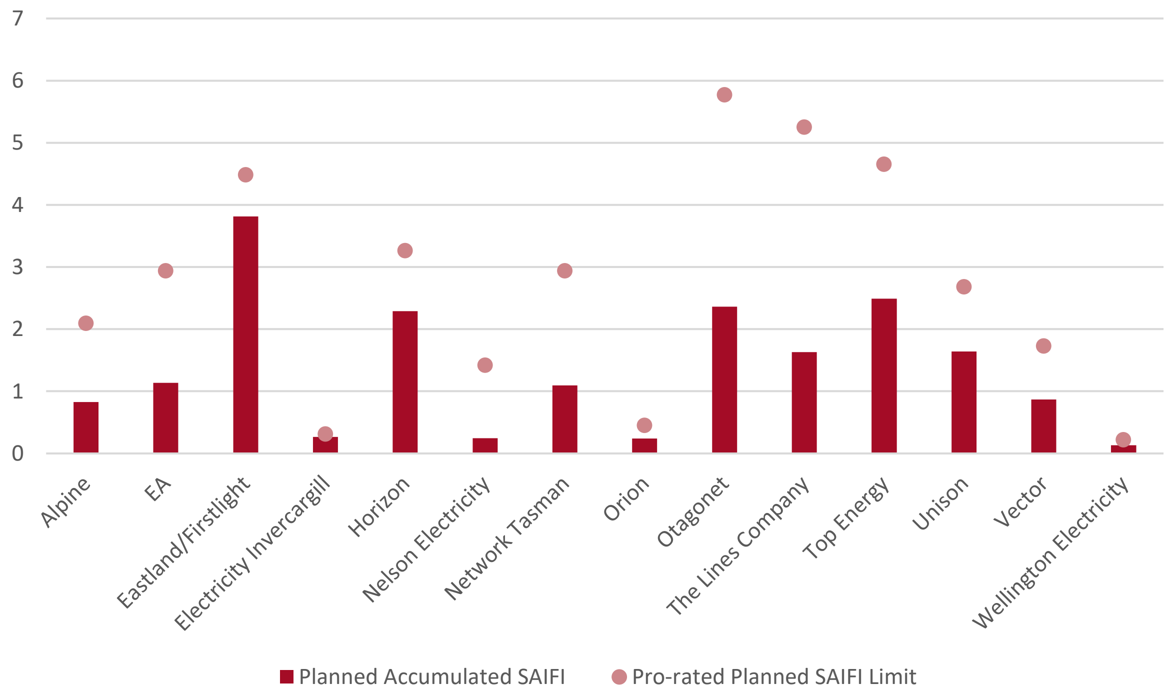
| EDB | Notified SAIDI as a % of total | | |
|---|---|---|---|
| | 2021 | 2022 | 2023 |
| **Alpine** | 0% | 17% | 60% |
| **Aurora** | 62% | 90% | 90% |
| **EA Networks** | 0% | 0% | 0% |
| **Electricity Invercargill** | 7% | 100% | 95% |
| **Firstlight** | 83% | 84% | 80% |
| **Horizon** | Not Available | Not Available | Not Available |
| **Nelson Electricity** | 100% | 100% | 100% |
| **Network Tasman** | 0% | 0% | 0% |
| **Orion** | 70% | 1% | 60% |
| **OtagoNet** | 5% | 91% | 92% |
| **Powerco** | CPP | CPP | CPP |
| **The Lines Company** | 30% | 75% | 93% |
| **Unison** | 88% | 86% | 90% |
| **Vector** | 90% | 93% | 90% |
| **Wellington Electricity** | CPP | 15% | 71% |

E84 The conservative limit and decrease in weighting of notified interruptions has resulted in all EDBs tracking to compliance for the regulatory period with the planned interruptions standard, some by a significant margin.

[440] This table shows the percentage of total planned assessed SAIDI for each EDB in the DPP3 regulatory period is attributable to interruptions being classified as "Notified" planned interruptions.

**Figure E2 Comparison of EDB accumulated planned SAIDI vs pro-rated limit, DPP3 period to date**


**Figure E3 Comparison of EDB accumulated planned SAIFI vs pro-rated limit, DPP3 period to date**



### Determining the uplift on the historical average

E85 We have shown values if the buffer was set at 200% of the historical average of a 10-year reference period and 200% and 100% of the historical average of a 7-year reference period. We see significant volatility in the limit value compared to the standard set in DPP3.

## Table E9 Draft planned SAIFI limit at different buffer settings (uncapped)

| EDB | DPP3 Planned SAIFI | Draft DPP4 Planned SAIFI at different buffer settings | | | | | |
|---|---|---|---|---|---|---|---|
| | 10-year RP, 200% buffer | 10-year RP, 200% buffer | Change from DPP3 limit | 7-year RP, 200% buffer | Change from DPP3 limit | 7-year RP, 100% buffer | Change from DPP3 limit |
| **Alpine Energy** | 3.49 | 3.48 | -0.4% | 3.59 | 2.9% | 2.40 | -31.4% |
| **Aurora Energy** | 5.54 | 8.95 | 61.6% | 11.80 | 113.1% | 7.87 | 42.0% |
| **EA Networks** | 4.89 | 5.30 | 8.2% | 5.97 | 22.1% | 3.98 | -18.6% |
| **Firstlight Network** | 7.47 | 7.82 | 4.6% | 8.14 | 9.0% | 5.43 | -27.4% |
| **Electricity Invercargill** | 0.52 | 0.86 | 65.0% | 0.96 | 84.7% | 0.64 | 23.1% |
| **Horizon Energy** | 5.44 | 8.01 | 47.2% | 9.72 | 78.7% | 6.48 | 19.1% |
| **Nelson Electricity** | 2.37 | 2.32 | -2.1% | 0.93 | -60.7% | 0.62 | -73.8% |
| **Network Tasman** | 4.90 | 5.02 | 2.5% | 5.26 | 7.3% | 3.51 | -28.5% |
| **Orion NZ** | 0.75 | 0.91 | 21.9% | 1.03 | 37.7% | 0.69 | -8.2% |
| **OtagoNet** | 9.62 | 11.29 | 17.3% | 13.07 | 35.8% | 8.71 | -9.5% |
| **Powerco** | 3.51 | 4.52 | 28.8% | 5.24 | 49.4% | 3.50 | -0.4% |
| **The Lines Company** | 8.75 | 8.65 | -1.2% | 9.62 | 9.9% | 6.41 | -26.7% |
| **Top Energy** | 7.75 | 10.51 | 35.5% | 11.19 | 44.4% | 7.46 | -3.8% |
| **Unison Networks** | 4.46 | 6.98 | 56.4% | 8.32 | 86.4% | 5.55 | 24.3% |
| **Vector Lines** | 2.88 | 4.41 | 53.3% | 5.57 | 93.4% | 3.71 | 28.9% |
| **Wellington Electricity** | 0.55 | 0.84 | 51.9% | 1.04 | 88.0% | 0.69 | 25.4% |

### Table E10 Draft planned SAIDI limit at different buffer settings (uncapped)

| EDB | DPP3 Planned SAIDI | Draft DPP4 Planned SAIDI at different buffer levels | | | | | |
|---|---|---|---|---|---|---|---|
| | 10-year RP, 200% buffer | 10-year RP, 200% buffer | Change from DPP3 limit | 7-year RP, 200% buffer | Change from DPP3 limit | 7-year RP, 100% buffer | Change from DPP3 limit |
| **Alpine Energy** | 824.87 | 972.31 | 17.9% | 1,087.51 | 31.8% | 725.01 | -12.1% |
| **Aurora Energy** | 979.80 | 1,808.63 | 84.6% | 2,405.67 | 145.5% | 1,603.78 | 63.7% |
| **EA Networks** | 1,376.08 | 1,541.19 | 12.0% | 1,767.32 | 28.4% | 1,178.22 | -14.4% |
| **Firstlight Network** | 1,290.68 | 1,251.20 | -3.1% | 1,363.34 | 5.6% | 908.90 | -29.6% |
| **Electricity Invercargill** | 114.49 | 196.97 | 72.0% | 223.05 | 94.8% | 148.70 | 29.9% |
| **Horizon Energy** | 858.63 | 1,295.12 | 50.8% | 1,642.01 | 91.2% | 1,094.68 | 27.5% |
| **Nelson Electricity** | 180.11 | 181.33 | 0.7% | 248.59 | 38.0% | 165.72 | -8.0% |
| **Network Tasman** | 1,129.14 | 1,391.65 | 23.2% | 1,529.47 | 35.5% | 1,019.65 | -9.7% |
| **Orion NZ** | 198.40 | 283.00 | 42.6% | 323.12 | 62.9% | 215.41 | 8.6% |
| **OtagoNet** | 2,114.43 | 2,596.62 | 22.8% | 2,918.62 | 38.0% | 1,945.75 | -8.0% |
| **Powerco** | 772.50 | 1,013.49 | 31.2% | 1,171.75 | 51.7% | 781.17 | 1.1% |
| **The Lines Company** | 1,331.68 | 1,645.83 | 23.6% | 1,868.92 | 40.3% | 1,245.95 | -6.4% |
| **Top Energy** | 1,905.36 | 1,999.75 | 5.0% | 1,877.76 | -1.4% | 1,251.84 | -34.3% |
| **Unison Networks** | 625.79 | 989.44 | 58.1% | 1,178.89 | 88.4% | 785.93 | 25.6% |
| **Vector Lines** | 585.38 | 960.82 | 64.1% | 1,237.99 | 111.5% | 825.33 | 41.0% |

| EDB | DPP3 Planned SAIDI | Draft DPP4 Planned SAIDI at different buffer levels | | | | | |
|---|---|---|---|---|---|---|---|
| | 10-year RP, 200% buffer | 10-year RP, 200% buffer | Change from DPP3 limit | 7-year RP, 200% buffer | Change from DPP3 limit | 7-year RP, 100% buffer | Change from DPP3 limit |
| **Wellington Electricity** | 69.70 | 114.91 | 64.9% | 143.02 | 105.2% | 95.35 | 36.8% |

E86 We note that Top Energy and Firstlight are outliers in not having a significant increase in SAIDI when the 200% buffer on a 7-year reference period is applied. This is supported by their SAIDI time series not showing a significant uplift in the last seven years.

E87 When comparing to how far under pro-rated limits most EDBs are there is limited justification for a further significant uplift for any EDB, even with an expectation of an increased capex work programme.

E88 Our draft decision is to apply a 100% buffer to the historical average, capping the change from DPP3 limit to +/- 10%.

E89 The cap will apply across regulatory periods as we consider there is value in reducing the extent of change across periods given long-term planning horizons employed by EDBs and the continued signal provided to EDBs that planned work should not be deferred to comply with a tight standard. We note this maintains a conservative setting (ie, EDBs are unlikely to breach) when applied in conjunction with the de-weighting of notified interruptions.

**Conclusions**

E90 Our draft decision is to reduce the buffer to reflect significantly increased annual average planned SAIDI and SAIFI arising from a change in the reference period, and capping the movement between regulatory periods to reduce volatility.

E91 We are proposing changes from the settings in DPP3, but overall, we consider the standard setting approach proposed provides EDBs room to increase planned interruptions, as signalled by EDBs capex forecasts within AMPs. We consider this approach balances the level of interruptions allowed to not be too excessive to consumers and maintains the incentive to deliver planned interruptions in a least impactful way through the impact of the QIS.

*QS6: De-weight the impact of notified planned interruptions by 50% in the assessment of compliance with planned interruption standards*

**Draft decision**

E92 Our draft decision is to de-weight the impact of notified planned interruptions by 50% in the assessment of compliance with planned interruption standards.

**What we heard from stakeholders**

E93 We received no submissions on this point in submissions on the issues paper.

**Analysis conducted**

E94 In DPP3, we de-weighted notified planned interruptions by 50% in the assessment of compliance with planned interruption standards. We considered de-weighting notified planned outages was appropriate as they are less inconvenient for consumers than planned interruptions because they give better opportunity for consumers to plan accordingly.

E95 The DPP3 reasons paper included considerable discussion on the value consumers place on notification of planned outages which led to changes in the quality standards and QIS settings to strengthen EDBs' incentives to give greater notification of planned interruptions by further reducing the impact of the SAIDI incentive and compliance assessment by 50%. [441]

E96 The majority of EDBs have responded positively to the incentive to notify interruptions.

**Conclusions**

E97 Together with settings in the QIS (see *Setting the quality incentive scheme*), we consider it is important that EDBs are incentivised to provide appropriate notification to consumers of planned interruptions.

*QS7: Retain SAIDI extreme event standard set at 120 SAIDI minutes or 6,000,000 customer minutes where specified*

**Problem definition**

E98 In the absence of a standard relating to extreme events, the unplanned interruptions reliability standards (with normalisation) may miss large interruption events that are caused by not applying good electricity industry practice or under-spending on network maintenance and investment.

**Draft decision**

E99 Our draft decision is to retain SAIDI extreme event standard set at 120 SAIDI minutes or 6,000,000 customer minutes where specified.

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[441] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision – Reasons paper" (27 November 2019), pp. 455-457 and 431-437.

**What we heard from stakeholders**

E100 We received no submissions on this point in submissions on the issues paper.

**Analysis conducted**

E101 The 'extreme event standard' deals with extreme one-off events, with the threshold set at the lower of either 120 SAIDI minutes or 6 million customer interruption minutes. This standard applies to events not caused by major external factors.

E102 For the purposes of the extreme event standard, major external factors means:

E102.1 natural disaster

E102.2 third-party interference

E102.3 a fire that does not originate on the non-exempt EDB's network, or

E102.4 wildlife.[442]

E103 We specified limits as we consider it was not possible to set a limit based on the reference period for each EDB for an expectation of no material deterioration because of the infrequency of such events.

E104 The standard was set at the lower of either:

E104.1 a SAIDI value of 120 minutes, whereby the extreme event standard limit will be exceeded if, during any period of 24 hours (starting on the hour or half past the hour), the SAIDI value of all unplanned interruptions that start during that 24-hour period, in aggregate, is above 120 minutes, or

E104.2 a total of six million customer interruption minutes, whereby the extreme event standard limit will be exceeded if, during any period of 24 hours (starting on the hour or half past the hour), the total duration of customer interruption minutes resulting from all unplanned interruptions that start during that 24-hour period, in aggregate, is more than six million customer interruption minutes.

[442] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper" (27 November 2019), p. 415, paragraph L81.]

E105 Whilst there have been significant events during the DPP3 period, eg, Cyclone Gabrielle, these have not been identified as extreme events as they were the result of major external factors. As such, there have been no reported instances of non-compliance with the extreme event standard during the DPP3 regulatory period to date.

E106 In the absence of a standard there may be little incentive from our regulatory settings to appropriately guard against such events as most of the impact on reliability will be removed through normalisation.

E107 We note that there may well be instances of consumer harm from large interruption events triggered by external factors like a severe storm, but which could have been significantly mitigated had the EDB applied good industry practice resulting in greater network resilience. However, we do not consider that it is possible at this stage to create a quality standard that differentiates based on the practices of the EDB without a significant level of compliance burden.

**Conclusions**

E108 It is in the long-term interests of consumers to set a quality standard relating for extreme events. Such a standard is intended to incentivise EDBs to take practicable steps to minimise the likelihood of high impact, low probability events that are within its control as well as mitigating the extent of them.

*QS8: Retain enhanced automatic reporting following a breach of a quality standard*

**Nature of the decision**

E109 In DPP3 we implemented two enhanced reporting requirements relating to:

E109.1 quality standard contravention self-reporting, and

E109.2 major event reporting.

**Draft decision**

E110 Our draft decision is to retain enhanced automatic reporting following a breach of a quality standard. We discuss our draft decisions on major event reporting in the section “Normalisation of reliability data for major events”.

### What we heard from stakeholders

E111 In our issues paper, we invited views on additional quality reporting obligations which may be beneficial to include, or revisions to improve our existing disclosure requirements.[443]

E112 There were no submissions specifically on the contravention reporting and two submissions on compliance reporting in general. Aurora considered that the quality standard reporting obligations included in the annual compliance statement are appropriate. Wellington Electricity agreed that the current reporting obligations are generally appropriate.[444]

### Analysis conducted

E113 If an EDB is non-compliant with a quality standard at the end of the assessment period, it must disclose to the Commission and publicly the information outlined in the appropriate clause of the DPP3 Determination:[445]

E113.1 planned interruption standard reporting under clause 12.2

E113.2 unplanned interruption standard reporting under clause 12.4, and

E113.3 extreme event standard reporting under clause 12.6.

E114 As no EDB has yet exceeded the planned interruption standard or extreme event standard, we have not had an opportunity to assess and consider whether the extent of information provided is appropriate, or identified any supporting information which may be beneficial to require.

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443 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), pp. 193-195, paragraphs F150-F163.

444 Wellington Electricity noted that, in their view, the exception is to planned works reporting which it suggested should change with a new quality standard (linked to future capex spend) – which we are not proposing to do. Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 58, section 9.7.

445 Commerce Commission "EDP DPP3 final determination" (27 November 2019), clause 12.

E115 However, the information required under clause 12, related to unplanned interruptions is in line with initial information requests we made for EDBs that contravened previous quality standards, and there was wide stakeholder support in submissions for the proposal.[446]

**Conclusions**

E116 We consider that self-reporting when a quality is contravened remains appropriate and such disclosures provide greater transparency and accountability of distributors for their quality performance.

*QS9: No new quality measures are introduced as part of the quality standards applying in DPP4*

**Problem definition**

E117 There are a wide range of quality of service measures which could be considered for inclusion in the regime beyond aggregate-level SAIDI and SAIFI measures. In our issues paper, we noted these include leading reliability indicators such as asset health, and consumer-centric measures such as voltage quality, customer service, and the time taken for new connections. Several submissions saw a need for more granular quality standards, such as by geographical region.

**Draft decision**

E118 Our draft decision is that no new quality measures are introduced as part of the quality standards applying in DPP4.

**Role of other tools with the regulatory regime**

E119 We consider that quality standards should align with what consumers value, be measurable, and have clarity on what an appropriate target would be such that EDBs can be influenced towards outcomes that represent value for consumers. In the absence of these conditions, new quality measures would add complexity and cost to the regime without necessarily benefiting the consumer.

[446] Orion "Submission on EDB DPP3 Reset issues paper" (20 December 2018). paragraph 54; and Meridian "2020-2025 Distribution default price-quality path – Issues paper – Meridian submission" (20 December 2018), p. 4.

E120 We consider that some aspects of network performance may be better addressed through our programme of information disclosure and performance analysis, which also helps ensure transparency and EDB accountability for its performance.

**What we heard from stakeholders, in summary**

E121 There were a wide range of views on the appropriateness of the current quality measures in submissions on our issues paper.

E122 Submissions largely supported not introducing new quality standards in DPP4 (Aurora, MEUG, Orion, The Lines Company, Vector, Wellington Electricity, ENA, Horizon),[447] although some consider there is a need for and an expectation that new quality standards will be introduced in future resets (Powerco, FlexForum, ENA).[448]

E123 Some submissions considered new measures are necessary in DPP4 (SolarZero, Drive Electric).[449]

E124 Several submissions considered that we should have more granular quality standards (FlexForum, Manawa, Powerco, IEGA, Vector).[450]

E125 The primary reasons submitters gave for not introducing new quality standards in DPP4 included that it was:

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[447] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 14; Major Electricity Users' Group (MEUG) "DPP4 Issues paper submission" (19 December 2023) p. 4; Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 17; The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023), p. 11; Vector "DPP4 Issues paper submission" (19 December 2023), p. 40; Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), pp. 58-59; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), , p. 17; Horizons Networks "DPP4 Issues paper submission" (19 December 2023), p. 15.

[448] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 25; FlexForum "DPP4 Issues paper submission" (19 December 2023), p. 10 Electricity Networks Aotearoa (ENA) (26 January 2024), p. 4.

[449] SolarZero "DPP4 Issues paper submission" (15 December 2023), p. 9 ; and Drive Electric "DPP4 Issues paper submission" (19 December 2023), p. 11.

[450] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 14; Major Electricity Users' Group (MEUG) "DPP4 Issues paper submission" (19 December 2023) p. 4; Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 17; The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023), p. 11; Vector "DPP4 Issues paper submission" (19 December 2023), . 40; Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), pp. 58-59; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023) , p. 17; Horizons Networks "DPP4 Issues paper submission" (19 December 2023), p. 15.

E125.1 not prudent (MEUG, ENA)[451]

E125.2 too early without the ability to calculate robust targets (Wellington Electricity),[452]and

E125.3 not realistically achievable and/or unnecessary (Powerco, ENA).[453]

**Analysis conducted**

E126 Our analysis considers the following additional measures of quality:

E126.1 disaggregated measures of network reliability (as opposed to retaining our aggregate whole-of-network approach to standards); and

E126.2 additional new quality measures beyond SAIDI and SAIFI (from page 330).

**Disaggregated measures of network reliability**

**Problem Definition**

E127 The aggregate nature of our standards may not adequately capture quality and customer experience across different parts of the network.[454]

**What we heard from stakeholders**

E128 A number of submissions on our issues paper considered that the aggregate nature of our standards does not adequately capture quality and customer experience across different parts of the network (FlexForum, Manawa, IEGA, SolarZero, Vector).[455] Some consider that this inhibits effective management of network performance and investment, and risks delivery of the quality that consumers demand.

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451 Major Electricity Users' Group (MEUG) "DPP4 Issues paper submission" (19 December 2023),p. 4; Electricity Networks Aotearoa (ENA) (26 January 2024), p. 4.

452 Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), pp. 58-59.

453 Powerco "DPP4 Issues paper submission" (19 December 2023), p 25; Electricity Networks Aotearoa (ENA) (26 January 2024), p. 15.

454 We note the quality standards do not cover low voltage networks as interruptions, as the "prescribed voltage electric line" is defined as those conveying electricity at a voltage equal to or greater than 3.3 kilovolts

455 FlexForum "DPP4 Issues paper submission" (19 December 2023), p. 9; Manawa Energy "DPP4 Issues paper submission" (19 December 2023), p. 2; Powerco "DPP4 Issues paper submission" (19 December .2023), p. 15; Independent Electricity Generators Association (IEGA) NZ "DPP4 Issues paper submission" (19 December 2023), p. 4; Vector "DPP4 Issues paper submission" (19 December 2023), p. 3.

E129 For example, FlexForum stated:[456]

> The Commission view is that applying quality at an aggregate network level enables distributors to consider the needs and expectations of different customers and customer groups when making trade-offs about quality on different parts of their networks and to reflect these in their asset planning. This approach is no longer fit-for-purpose. To be clear, we consider households, businesses and communities are worse off due to this DPP setting because it materially reduces the level of scrutiny on distributors in managing reliability and materially reduces incentives for distributors to manage LV reliability….
>
> The Commission should commit now to introducing more granular quality standards from 2030 to expose distributors to more scrutiny.

E130 Manawa, SolarZero and Vector advocated for more granular level quality metrics such as by geography, network characteristics, and customer grouping.[457]

E131 FlexForum suggested measuring sub-transmission assets,[458] IEGA suggested measuring at singular asset level, although ENA stated in cross submissions that this was not "practical or suitable" given the "DPP is intended to be a low cost, light touch regime".[459]

E132 In our issues paper we noted that the aggregate nature of our standards could result in individual customers receiving a service level higher or lower than they demand relative to the cost of lines services. Wellington Electricity agreed with our view and, together with MEUG, suggested that it would be sensible to review the appropriateness of the N-1 approach in future rather than as part of DPP4.[460]

E133 In Powerco's view, which is consistent with other submissions on this issue:[461]

> 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

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456 FlexForum "DPP4 Issues paper submission" (19 December 2023), pp. 9-10.

457 Manawa Energy "DPP4 Issues paper submission" (19 December 2023), p. 2; SolarZero "DPP4 Issues paper submission" (15 December 2023), p. 8; and Vector "DPP4 Issues paper submission" (19 December 2023), p. 3.

458 FlexForum "DPP4 Issues paper submission" (19 December 2023), p. 10.

459 Independent Electricity Generators Association (IEGA) NZ "DPP4 Issues paper submission" (19 December 2023), p 4, Electricity Networks Aotearoa (ENA) (26 January 2024), p. 4.

460 Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), section 9.5.7; Major Electricity Users' Group (MEUG) "DPP4 Issues paper submission" (19 December 2023), paragraph 18.

461 Powerco "DPP4 Issues paper submission" (19 December 2023), p. 24.

> not afford any form of weighting to customers' consumption levels or their varying value of supply.

E134 Powerco noted their considered importance of more granular measures in the wider industry context:[462]

> As we move to a decarbonised future, where electricity use will play an increasingly important role, these shortcomings will become increasingly acute and be particularly evident in low voltage networks, where many of the emerging changes in energy use will occur but which are currently excluded from service quality measures.

E135 Submissions consider the impacts of this shortfall include:

E135.1 inhibits effective management or well-targeted investment for service quality reasons (Powerco)[463]

E135.2 weakens incentives on EDBs to measure and manage reliability and quality performance (FlexForum)[464] and

E135.3 masks poor performance (IEGA).[465]

**Analysis**

E136 We do not intend to apply reliability measures at a disaggregated level, eg, customer segmentation or geographical region.

E137 We consider significant work would likely be required to establish and set historical standards for customer segmentation (residential/commercial/industrial) or other geographic measures (rural/urban). Information has not previously been requested to be recorded in this way and it is not clear how assets which potentially support multiple regions could be accommodated or how clearly customer segmentation could be defined on a consistent basis.

E138 Increased granularity would also reduce the impact of averaging which occurs by assessing assets on an aggregate basis and may be more exposed to random fluctuations in performance which may be difficult to account for in our normalisation processes.

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462 Powerco "DPP4 Issues paper submission" (19 December 2023), p. 24.

463 Powerco "DPP4 Issues paper submission" (19 December 2023), p. 25.

464 FlexForum "DPP4 Issues paper submission" (19 December 2023), p. 9.

465 Independent Electricity Generators Association (IEGA) NZ "DPP4 Issues paper submission" (19 December 2023), p. 4.

E139 While we see value in understanding network performance at a disaggregated level with increased electrification, we consider analysis of additional disclosures required under the Targeted Information Disclosure Review (TIDR) will improve our understanding.

E140 Quality information disclosures introduced as part of TIDR (2024) will require EDBs to disclose more granular information on SAIDI and SAIFI:[466]

E140.1 raw interruption data annually that will allow stakeholders to better assess whether EDBs are providing services at a quality that reflects consumer demands, and

E140.2 worst-performing feeder information which will make readily available information on areas of an EDB's network that are receiving a relatively poor quality of service.

E141 These disclosures will allow stakeholders to better understand EDBs performance at a granular level and may form the basis of a robust dataset in the future upon which more granular quality standards than currently exist could be based.

E142 We agree that the monitoring and transparency of low voltage (LV) power quality and reliability can help EDBs identify issues, allowing better targeting of expenditure and will be important with increased expectations regarding distributed energy resources (DER). However, it is our understanding that many EDBs do not yet have sufficient visibility of their networks to be able to collect and assess this information in a robust and consistent way. We understand this should improve with access to smart meter data, but we do not currently have a dataset upon which a quality standard could be set for LV networks.

E143 In its submission on the issues paper, Wellington Electricity confirmed:[467]

> We agree with the Issues Papers observation that any LV quality measures will be dependent on networks developing visibility of the LV networks. This will require a step change in investment to introduce this capability.

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[466] Commerce Commission "Targeted Information Disclosure Review 2024 - Electricity Distribution Businesses - Final decision- Reasons-paper",(29 February 2024), pp 83-93; Commerce Commission "Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC2" (29 February 2024), clause 2.1(g), Schedule 10(vi) and Schedule 10a.

[467] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 59.

**Conclusion**

E144 We do not intend to apply reliability measures at a disaggregated level, eg, geographical region or customer segmentation. We consider this would add unnecessary complexity and there would likely be significant work required by EDBs to establish an historical basis for such standards. We consider that newly introduced information disclosures will help provide sufficient information to improve stakeholder understanding of performance.

E145 We do not intend to introduce LV based quality standards for DPP4 as we do not currently understand that EDBs have sufficient information on the performance of their LV networks in order to set a robust standard.

**Do not introduce additional new quality measures or guaranteed service levels**

**What we heard from stakeholders**

E146 SolarZero and Drive Electric considered new measures are necessary in DPP4. Drive Electric considered those measures we identified in our issues paper - connection, installation and service levels – are important, with the desire for these measures to be regulated and used to incentivise EDBs to respond to market demand.[468]

E147 Utilities Disputes saw "significant value in collecting and sharing this information on these other measures of quality as well as introducing leading indicators.[469] It considered expanding the service measures would appear to aid in meeting the objective of providing more leading indicators and lead to better outcomes. It would also assist generally in determining the appropriate standards for consumers.

E148 Vector have proposed guaranteed standards in the past which they consider would help to better measure quality with a greater focus on customers.[470] See the section *Guaranteed service levels*.

**Analysis**

E149 Our issues paper outlined that a key aspect of introducing any new quality measures under the DPP is the clear definition and quantification of the new measures. Definitions used as part of any new quality measure need to be specified in a way that can be consistently applied across all EDBs to an auditable standard.

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[468] Drive Electric "DPP4 Issues paper submission" (19 December 2023), p. 11.

[469] Utilities Disputes "DPP4 Issues paper submission" (19 December 2023), p. 1.

[470] Vector "DPP4 Issues paper submission" (19 December 2023), p.40

E150 **Leading indicators of EDB network reliability performance**, eg, asset health, are likely to be challenging to identify and implement in a robust auditable manner. In particular, inconsistencies in EDBs' approaches to assessing and measuring such indicators may create complexities in designing a quality standard which can be audited and enforced.

E151 **New connections**: A quality measure related to the timing of new connections could be defined in relation to the time the EDB takes to provide a quote for a new connection or the time to physically provision the new connection. A well-defined measure for new connections would need to take account of variations in the size and complexity of customer connections, as well as the involvement of third parties in installation. We consider the information required to set compliance standards for new connections is yet to be developed.[471] The EA also has a planned programme of work to consider making code requirements for new connection processes.[472]

E152 **Low voltage networks**: It is increasingly important to understand power quality measures such as voltage stability as networks become platforms for two-way flows. Basic visibility of the LV system is a prerequisite to reporting accurately and dynamically on power quality measures, and targeted investment by EDBs in the LV system is required to enable this type of reporting. Collecting exhaustive information about voltage fluctuations, particularly on the LV network, would also involve significant investment in monitoring, information systems and communications.[473]

[471] We expanded requirements to capture different dimensions of quality as part of the Targeted ID Review (Tranche 1) to better reflect consumers' overall experience of quality. Quality information disclosures introduced include narrative disclosures on for "Time taken for new connections" and "Impact of new connections". Commerce Commission "Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022[2022] NZCC 36" (25 November 2022).

[472] Electricity Authority, "Network Connections Project" (8 April 2024). The Authority is adding load application processes to the Electricity Industry Participation Code 2010 (Code) as part of its Network Connection Project. There are already Code processes for distributed generation. Part 6 of the Code sets rules for applications (e.g. information disclosure by EDB and applicant, timeframes for EDBs to approve/decline applications, regulated terms if a contract is not signed, disputes resolution and maximum fees). Part 6 requires EDBs to keep records for each application (e.g. how long to process, number of extensions sought, approved/declined). There are no reporting requirements, but the Authority can request the records to determine performance.

[473] Quality information disclosures introduced include power quality (Q2), ie, narrative disclosures on practices the consumer's experience of for monitoring voltage (including any plans for improvements).

**Guaranteed service levels:**

E153 In the issues paper, we noted that the quality regime could include a guaranteed service level (GSL) scheme, where consumers who receive a service below a minimum level would be entitled to a service level payment. [474] An effective GSL scheme could enhance the incentives facing EDBs to recognise and respond to poor service levels at a more granular level.

E154 Our initial view was not to propose to introduce a GSL scheme, as we had identified potential complexities in implementing such a scheme, which included the considerable amount of work involved, how a GSL scheme would sit within a framework that includes a QIS, and how such a scheme would affect incentives for EDBs to offer a quality of service that consumers want.

E155 In submissions on the issues papers, Wellington Electricity stated:

> We agree with the Commission's concerns about the implementation of guaranteed service levels, especially difficulties including the scheme into the cost base and how it would work with existing incentives. We agree with not including it in the DPP4 for the reasons provided.

E156 Flick noted that "in our experience, most EDBs removed any obligation for service quality payments to customers when the Distributor Default Agreement was adopted." but did not make any recommendations. [475]

E157 We note recent work being undertaken by the EA in this regard.[476]

*Introduce no new quality incentive schemes (QIS9)*

E158 Our draft decision is not to introduce any new quality incentive schemes.

E159 Under s 53M(2) of the Act, we may include incentives for a supplier to maintain or improve its quality of supply, with standards being required within a price-quality path in order to have incentive schemes.

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[474] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), paragraphs F176-F179.

[475] Flick Electric "DPP4 Issues paper submission" (19 December 2023), p.2.

[476] Electricity Authority "Appendix A: Proposed Code amendment – Removal of recorded terms" (1 April 2023), paragraph 9.10.

E160 We received limited submissions on this issue, with the general consensus being that the QIS is fit for purpose at present. ENA considered the current QIS settings to be appropriate and that no other incentive schemes are necessary.[477]

E161 SolarZero's submission implied that it considers a QIS on energy efficiency is important. "A key quality indicator needs to be [included] around the efficient use of capital… One simple measure is the difference between peak and off peak demand… This measure needs to become a central part of the quality incentives framework."[478]

E162 Whilst we agree that efficient use of the network will be important during the energy transition to manage cost impacts to consumers. We consider an efficiency metric would not be appropriate to include as a quality standard, or as part of an incentive scheme. It is not clear that a decline in performance would represent a material deterioration in performance of the network, instead it could well be driven by a range of other incentives provided by entities other than the EDB, or dis-incentivise timely increases to network capacity. This could instead reasonably be a focus of summary and analysis.

**Conclusion**

E163 Our draft decision is not to introduce any additional new quality measures, a GSL scheme or any additional quality incentive schemes.

E164 Taking the above into account, we do not consider we have a robust data series on which to set new quality standards which reflect current performance, nor consumer expectations. We also do not propose introducing a GSL scheme into the quality regime due to the complexities involved.

*QS10: Set quality standards and incentives for Aurora transitioning from a CPP to the DPP on the same basis as for other EDBs on the DPP*

**Nature of the decision**

E165 Unlike starting prices, s 53X of the Act does not give us the power to determine quality standards when an EDB transitions off a CPP.

[477] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 18.

[478] SolarZero "DPP4 Issues paper submission" (15 December 2023), p. 9-10.

E166 Aurora is on a CPP for the five-year period over 2022-2026. It will transition to DPP4 when the current CPP ends in 2026.

**Draft decision**

E167 Our draft decision is to set quality standards and incentives for Aurora transitioning from a CPP to the DPP on the same basis as for other EDBs on the DPP.

**What we heard from stakeholders**

E168 Aurora considers that the application of the 10-year historic reference period "would not correctly capture recent performance levels and would therefore lead to adverse regulatory outcomes with inappropriate breach limit risks and unrealistic targets for the incentive scheme."[479] However, Aurora did not suggest the length of reference period that would be appropriate.

E169 Aurora "supports a continuation of the Aurora CPP period limits and targets, noting that the target remains ambitious, but potentially achievable toward the end of the DPP4 period with a modest investment in reliability improvement as proposed in our 2024 AMP" [480] Aurora considers that applying the CPP period limits and targets to Aurora Energy would prevent the need to address historic step changes.

**Analysis conducted - Aurora's CPP settings**

E170 Aurora's CPP application primarily focussed on improving asset health to deliver safety improvements, rather than improving reliability.

E171 Aurora's CPP differs from DPP3 in the following ways:

E171.1 A 4-year reference period from 2017-2020 was used to inform the target for unplanned SAIDI and unplanned SAIFI. The annual unplanned interruption limit was set above the limit Aurora faced under DPP3 to make it realistically achievable.

E171.2 We included a relatively large buffer between the targets and limits (deviating from DPP3). This was considered to reflect the greater range of SAIDI and SAIFI outcomes that could be expected from Aurora given its relatively low understanding of the health of its network assets.

[479] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 13, paragraph 49.

[480] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 13, paragraph 50.

E171.3 We set the limit for planned outages the same as that under DPP3, with a higher target for the duration of planned interruptions due to the large amount of asset replacement intended.

E172 The revenue-linked incentive scheme was retained for both unplanned and planned interruptions.

## Aurora's reliability performance under the CPP

E173 Aurora have complied with the unplanned and planned quality standards over the course of the CPP to 2023, as shown in the Table E11.

**Table E11 Aurora's compliance against quality limits under its CPP**

| | 2021 | 2022 | 2023 | CPP Limit (1 year) | CPP Limit (5 years) |
|---|---|---|---|---|---|
| **Unplanned SAIDI Assessed** | 85.39 | 98.45 | 106.49 | 124.94 | |
| **Unplanned SAIFI Assessed** | 1.46 | 1.50 | 1.75 | 2.07 | |
| **Planned SAIDI Assessed** | 102.73 | 124.50 | 110.34 | 195.96 | 979.80 |
| **Planned SAIFI Assessed** | 0.68 | 0.83 | 0.60 | 1.11 | 5.54 |

E174 Table E12 shows Aurora's reliability performance against the target where red cells indicate it has faced financial penalties while green cells indicate financial rewards under the QIS. For 2021, Aurora received financial rewards as the Unplanned SAIDI Assessed value was lower than the target.

**Table E12 Aurora's performance against targets under the QIS**

| | SAIDI Assessed 2021 | 2022 | 2023 | QIS Target |
|---|---|---|---|---|
| **Unplanned SAIDI Assessed** | 85.39 | 98.45 | 106.49 | 88.08 |
| **Planned SAIDI Assessed** | 102.73 | 124.50 | 110.34 | 72.16 |

## Comparison of draft DPP4 and CPP SAIDI and SAIFI

E175 Our DPP4 draft decisions are to use a 10-year reference period (2014-2023) for unplanned SAIDI and SAIFI; and a 7-year reference period (2017-2023) for planned SAIDI and SAIFI.

E176 Table E13 below shows draft DPP4 SAIDI and SAIFI values, normalised for major events (for unplanned interruptions) over the relevant reference period, compared to the CPP targets and limits.

E177 Aurora has provided feedback that it considered a 10-year reference period to be inappropriate given it does not reflect its current performance (see *What we heard from our stakeholders*). Taking this into consideration and given that Aurora's CPP had used a 4-year reference period, beginning 2017, we have considered using a 7-year reference period from 2017-2023, as well as the standard 10-year reference period to calculate unplanned SAIDI and SAIFI.

E178 Our analysis shows that applying alternative reference periods results in higher target values than the CPP, although the higher buffer used in the CPP narrows the gap between the draft DPP and CPP limits. The average for planned SAIDI and SAIFI using a 7-year reference period is more than double the CPP target.

**Table E13 Comparison of uncapped Draft DPP4 SAIDI and SAIFI targets and limits, compared with CPP**

| | | SAIDI | | | SAIFI | | |
|---|---|---|---|---|---|---|---|
| | Reference period (RP) for Draft | SAIDI Target/ Average for DPP | Buffer | SAIDI Limit (uncapped for DPP) | SAIFI average | Buffer | SAIFI limit (uncapped for DPP) |
| **Unplanned** | | | | | | | |
| CPP 4-year RP | 2017-2021 | 88.08 | 36.86 | 124.94 | 1.57 | 0.50 | 2.07 |
| DPP4 7-year RP | 2017-2023 | 113.67 | 29.48 | 143.15 | 1.70 | 0.37 | 2.07 |
| DPP4 10-year RP - our draft decision | 2014-2023 | 97.98 | 24.07 | 122.05 | 1.55 | 0.33 | 1.87 |
| DPP4 7-year RP change from CPP | | 29.0% | (20.0%) | 14.6% | 8.3% | (26.2%) | (0.0%) |
| decision | | 11.2% | (34.7%) | (2.3%) | (1.6%) | (34.4%) | (9.6%) |
| | | | | | | | |
| **Planned** | | | | | | | |
| CPP (Retain DPP3 limit, raise DPP3 target) | | 72.16 | 123.80 | 195.96 | | | 1.11 |
| DPP4 7-year RP - our draft decision | 2017-2023 | 160.38 | 160.38 | 320.76 | 0.79 | 0.79 | 1.57 |
| DPP4 change from CPP - our draft decision | | 122.3% | 29.5% | 63.7% | | | 41.7% |

### Setting DPP4 standards - unplanned SAIDI and SAIFI

E179 Our DPP4 draft decision is that the unplanned limits include a buffer of 2.0 standard deviations above the target, and regulatory period movement for both target and limit is capped at +/- 5% from CPP settings.

E180 Table E14 shows that after applying the 5% cap to the historical average, the draft targets are the same for DPP4 either using a 10-year reference period or a 7-year reference period. The limit is higher if using a 7-year reference period.

**Table E14 Aurora draft unplanned interruptions reliability standards under DPP4**

| | Reference period (RP) | SAIDI (minutes) QIS target | Limit | SAIFI (interruptions) Target | Limit |
|---|---|---|---|---|---|
| **CPP 4-year RP** | 2017-2021 | 88.08 | 124.94 | 1.57 | 2.07 |
| **DPP4 7-year RP** | 2017-2023 | 92.48 | 131.19 | 1.65 | 2.07 |
| **DPP4 10-year RP - our draft decision** | 2014-2023 | 92.48 | 122.05 | 1.55 | 1.97 |
| **DPP 10-year RP change from, CPP** | | 5.0% | (2.3%) | (1.6%) | (5.0%) |
| **Scaling adj to 5% cap inter-period** | | (5.6%) | – | – | 5.0% |

E181 The target under the CPP is lower than that under DPP4 regardless of the choice of the length of the reference period. The limit under CPP is similar to that for DPP4 using a 10-year reference period, but lower than that for DPP4 using a 7-year reference period.

E182 Aurora's CPP involved a substantial uplift in the level of operational expenditure and capital expenditure for the CPP period. In determining quality standards, we need to consider the extent to which these increases were related to improving quality standards.

E183 In its proposal for a CPP, Aurora suggested that slight reliability improvements may arise as a by-product of its safety related investments after 2024, while it forecasted considerably worse reliability over the CPP period (2022-2026).[481]

E184 Our decision on reliability measures under the CPP would mean that Aurora's consumers could expect the reliability and quality of their electricity supply to stabilise, before gradually improving over time.[482]

E185 As such, we consider it is appropriate to set standards for unplanned SAIDI/SAIFI for Aurora on the same basis as for other EDBs under DPP4, using:

E185.1 a 10-year reference period

[481] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 Final decision - Reasons paper" (27 November 2019), p. 164.

[482] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 Final decision - Reasons paper" (27 November 2019), p. 161.

E185.2 a buffer of 2.0 standard deviations above the targets, and

E185.3 a 5% cap for inter-period movement that applies to both the target and the limit.

### Planned SAIDI and SAIFI

E186 Our DPP4 draft decision is that the planned limits include a buffer of 100% of the SAIDI and SAIFI target, with regulatory period movement for the limit capped at +/-10%.[483]

E187 Table E15 shows the potential targets and limits for planned SAIDI/SAIFI for Aurora if following the same approach as for other EDBs under DPP4. Both targets and limits are higher than those under the CPP. This reflects the scale of work undertaken on Aurora's network under the CPP.

**Table E15 Aurora draft planned interruptions reliability standards under DPP4**

| | | SAIDI | | | SAIFI |
|---|---|---|---|---|---|
| | Reference period (RP) | QIS target | Buffer | Limit | Limit |
| **Annual** | | | | | |
| CPP (Retain DPP3 limit, raise DPP3 target) | | 72.16 | 123.80 | 195.96 | 1.11 |
| DPP4 7-year RP - our draft decision | 2014-2023 | 160.38 | 55.18 | 215.56 | 1.22 |
| | | | | | |
| **Standards (5 years)** | | | | | |
| CPP (Retain DPP3 limit, raise DPP3 target) | | | 619.00 | 979.80 | 5.54 |
| DPP4 7-year RP - our draft decision | 2014-2023 | | | 1,077.78 | 6.09 |
| | | | | | |
| **DPP4 change from CPP** | | | | 10.0% | 10.0% |
| **Scaling adjustment to 10% cap** | | | | (32.8%) | (22.6%) |

[483] We intend to retain clauses 9.5 and 9.6 of the DPP3 Determination which outlines how the planned interruption standard which applies for the full regulatory period is adjusted for an EDB that transitions from a CPP to a DPP during the regulatory period. The Determination for Aurora will reflect the full 5-year regulatory period but it will divide by five years and multiply by the four years Aurora will have in DPP4 to calculate the value of the planned standards that apply.

E188 We note nearly all price-quality regulated EDBs present significant increases in planned SAIDI since 2017.

E189 Therefore, our draft decision is to set standards for planned SAIDI/SAIFI on the same basis as for other EDBs under DPP4. The key parameters of the settings include:

E189.1 a 7-year reference period

E189.2 a buffer of 100% of the SAIDI and SAIFI historical average, and

E189.3 10% cap for inter-period movement of the limit.

**Other considerations**

E190 We note we have separately considered this issue for Powerco and Wellington Electricity when they transitioned off CPPs. At that time, we set quality standards and incentives for these EDBs on the same basis as all other distributors, noting that was due to the significant change in quality standards which occurred in DPP3.[484]

**Conclusions**

E191 We do not consider that Aurora is such an outlier that it requires a different reference period to be consistent with our principle of no material deterioration. Additionally, transitioning Aurora to DPP4 with the same proposed settings as apply for other EDBs avoids unnecessary complexity and meets the relatively low-cost principle of the DPP.

*QS11: Retain the requirement for reasonable reallocation of SAIDI and SAIFI following an asset transfer between EDBs*

**Problem definition**

E192 Consumers should not bear the risk of being worse-off due to an asset transfer transaction, in terms of quality of service.

**What we heard from stakeholders**

E193 There were no submissions on our issues paper on the reallocation of SAIDI and SAIFI following an asset transfer.

[484] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 Final decision - Reasons paper" (27 November 2019), p. 344.

**Analysis conducted**

E194 When an EDB engages in a transaction where it transfers assets to another entity, and this transfer results in consumers no longer being served by the transferring EDB, an adjustment needs to be made to both the transferring and receiving EDBs' quality standards and quality incentives.[485]

E195 Where this transfer occurs by way of a complete amalgamation or merger of two price-quality regulated EDBs, the input methodologies (IMs) provide for their price-quality paths to be aggregated.[486] Where the transfer affects more than 10% of an EDB's opening regulatory asset base (RAB), we may reopen the price-quality path (referred to as a 'major transaction').[487]

E196 Where a transaction is not an amalgamation and affects less than 10% of an EDB's opening RAB, the DPP determination specifies how EDBs are to adjust their revenue. To deal with these situations, which we refer to as 'transfers', we have adopted a principles-based approach to adjusting the revenue path and quality standards.

**Conclusion**

E197 Our approach is one based on the principle that, in aggregate, consumers should be no worse-off, than they would have been had the transaction not occurred.

E198 Under this approach, EDBs will have to agree an allocation for each of the parameters of the quality standards (for example: boundary values, reliability limits) and quality incentives (for example: targets and caps).

E199 We note that when demonstrating whether adjustments to quality standards were reasonable, we would look to the ICP weighted sums of SAIDI and SAIFI before and after the transactions, rather than the absolute amount of SAIDI and SAIDI.

**Setting the quality incentive scheme**

E200 The revenue-linked incentive scheme for reliability is designed to provide EDBs with incentives to consider cost-quality trade-offs in their decision making. In the absence of other adequate incentives, EDBs may be incentivised to reduce expenditure, at the expense of quality, to increase profitability.

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[485] Another entity in this case could include: another price-quality regulated distributor, an exempt distributor, or a non-distributor purchaser, who – following the completion of the transaction – becomes a distributor.

[486] Clause 3.2.1 of the IMs

[487] Clause 4.5.4 of the IMs

E201 This attachment sets out our detailed draft decisions on setting the revenue-linked quality incentives for DPP4 and responds to submissions regarding incentives we received in response to our issues paper.

*Summary of our draft decision*

E202 Retain the revenue-linked QIS for SAIDI. SAIFI is excluded.

**Incentive Rates**

E203 Unplanned incentive rates are informed by the value of lost load (VOLL), discounted by (1-IRIS retention factor) to reflect expenditure incentives, and a further 10% to reflect quality standard incentives, with VOLL set at $35,374/MWh.

E204 Planned incentive rates are reduced by 35% relative to the unplanned incentive rate.

E205 Planned "notified" interruptions are reduced by 75% relative to the unplanned incentive rate to reflect less inconvenience to consumers.

E206 Do not make an explicit adjustment to match the duration of retention benefits between EDBs and consumers.

**Incentive scheme model**

E207 Incentives are revenue-neutral at the average of the reference period, also known as the target.

E208 The SAIDI caps (which determine maximum losses) are set equal to the SAIDI limits for planned an unplanned SAIDI.

E209 The SAIDI collars (which determine maximum gains) are set at 0 for unplanned and planned SAIDI.

E210 Cap revenue at risk at 2% of actual net allowable revenue.

**New incentive schemes**

E211 Our draft decision is not to implement any new quality incentive schemes.

**Economic principles underpinning incentives**

E212 We consider that revenue-linked incentives on reliability provide incentives to manage the price-quality relationship, with appropriate settings profit maximising EDBs will be:

E212.1 encouraged to find solutions where there are net benefits, ie, Marginal Benefit (MB) > Marginal Cost (MC);

E212.2 neither encouraged or discouraged to find cost-neutral solutions to improve reliability – MB=MC for EDBs and MB>=MC for consumers; and

E212.3 discouraged to find relatively expensive solutions to improve reliability – MB<MC for EDBs and MB<MC for consumers.

E213 However, if the revenue-linked incentives are too strong, then EDBs may be encouraged to find solutions where the costs to consumers can exceed the benefit to consumers – MB>MC for EDBs and MB<MC for consumers.

*QIS1: Retaining the reliability incentives, which only apply to SAIDI*

**Problem definition**

E214 EDBs are not exposed to a consistent cost-quality trade-off of the decisions they make regarding reliability during the year, but rather focus more on the expenditure impact in addressing reliability when quality standard contravention risk is low.

E215 Reliability standards do provide an incentive on EDBs not to let quality degrade. However, they are likely most effective where EDBs are at risk of contravening the limits.

**Draft Decision**

E216 For our draft DPP4 decision, we are retaining reliability incentives; however, as per DPP3, these will only apply to SAIDI, and not SAIFI.

**What we heard from stakeholders**

E217 There was broad agreement to retain a quality-linked incentive scheme (Aurora, ENA, Horizon, MEUG, Orion, The Lines Company, Wellington Electricity and Vector).[488]

[488] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 15; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 18; Horizons Networks "DPP4 Issues paper submission" (19 December 2023), p. 17; Major Electricity Users' Group (MEUG) "DPP4 Issues paper submission" (19 December 2023), p. 4; Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 18; The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023), p. 13; Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 58, section 9.6.2. Vector "DPP4 Issues paper submission" (19 December 2023). p. 40.

E218 ENA considered the current QIS settings to be appropriate and that no other incentive schemes are necessary.[489]

> ENA views the QIS as an appropriate mechanism for delivering outcomes that align with consumer expectations…ENA believes the Commission's current framework for quality incentives is robust and should be continued. There is no evidence of the need to support the establishment of new energy efficiency, demand-side management, and reduction of energy losses incentive scheme.

E219 Aurora noted that:

> the targets need to be realistically set to ensure that the mechanism is symmetric and not just a mechanism to reduce revenue. In practice if capex and opex allowances are insufficient to fund reliability driven investments, distributors are forced to effectively decide whether to incur a quality penalty, or future IRIS penalties.[490]

E220 Wellington Electricity supported retaining the framework of the current incentives with changes to the rate.[491]

E221 EDBs have represented they take the QIS into account in various ways, eg, in making investment decisions, planning works and preparing for unplanned outages (Aurora, Horizon, Powerco, ENA, Orion and The Lines Company)[492]. For instance, Powerco considers:[493]

E221.1 potential QIS penalties are included within our Copperleaf investment optimisation tool – it shows up as financial risk

E221.2 replacement and renewal works are strategically coordinated across portfolios to minimise customer interruptions, ensure efficient delivery, and optimise QIS outcomes, and

E221.3 our asset management objectives are also strongly aligned with realising QIS benefits.

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489 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 18.

490 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 15.

491 Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 58, section 9.6.2.

492 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p.15; Horizons Networks "DPP4 Issues paper submission" (19 December 2023), p. 17; Powerco "DPP4 Issues paper submission" (19 December 2023), p. 27; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 18; Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 18; and The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023), p. 13.

493 Powerco "DPP4 Issues paper submission" (19 December 2023), p. 27.

### Analysis Conducted

E222 The revenue-linked incentive scheme for reliability is designed to provide distributors with incentives to consider cost-quality trade-offs in their decision making. In the absence of other adequate incentives, distributors may be incentivised to reduce expenditure, at the expense of quality, to increase profitability.

E223 We consider allowing EDBs to make trade-offs about the level of reliability they deliver, and ensuring consumers share in the benefits of those trade-offs, is an important element of the DPP.

E224 SAIDI is a function of interruption frequency (SAIFI) and interruption length (CAIDI). Put another way, SAIDI is the product of SAIFI and CAIDI. We therefore consider that retaining the removal of SAIFI from incentives is appropriate.

### Conclusion

E225 Our decision to retain the removal of SAIFI from the incentive scheme is driven by the following considerations:

E225.1 SAIFI will still be subject to compliance standards

E225.2 SAIFI, as well as CAIDI, are indirectly captured through SAIDI incentives, and

E225.3 SAIFI incentives may place undue priority on short-term mitigations rather than preventing long-term deterioration.

E226 We consider the QIS provides an appropriate incentive for EDBs to deliver quality outcomes that reflect consumer demands and applying only to SAIDI reduces potential duplication.

*QIS2, QIS3, QIS4: Setting the QIS incentive rates*

E227 The incentive rates determine the level of financial exposure of EDBs to a marginal change in reliability.

### Draft Decision

E228 Our draft decision is:

E228.1 unplanned incentive rates are informed by an updated value of lost load (VOLL), discounted by (1-IRIS retention factor) to reflect expenditure incentives, and a further 10% to reflect quality standard incentives, with VOLL set at $35,374/MWh;

E228.2 planned incentive rates are reduced by 35% relative to the unplanned incentive rate; and

E228.3 planned "notified" interruption incentive rates are reduced by 61.538% relative to planned interruption incentive rate (being 75% relative to the unplanned interruption incentive rate), to reflect less inconvenience to consumers.

**What we heard from stakeholders**

E229 There were a range of views on the appropriateness of the current incentive rate in the QIS scheme.

E230 Horizon considered the proposed incentive rate is appropriate.[494]

E231 ENA noted that "the fall in the incentive rate between DPP2 and DPP3 lessened the prominence of the incentive in EDBs decision-making and planning, including a reduction in the use of portable generation to shorten planned outages." [495]

E232 Orion questioned whether the incentive rates are providing a strong enough incentive. It suggests that "a stronger signal might drive some improvements if this was consistent with customer preferences."[496]

E233 Wellington Electricity considered that the VOLL-based quality incentive calculation introduced in DPP3 provides incentives that are immaterial for EDBs with low SAIDI/SAIFI. It states:

> The cost of improving quality generally outweighs the incentive rates. Under the current scheme, we are not incentivised to consider improvements. Our focus is therefore solely to ensure we do not breach.[497]

E234 Wellington Electricity suggested that:

> the $25k per MWh will need adjusting to reflect the large recent inflationary increases. The studies calculating VOLL are also old and may need updating. We also think the 10% adjustment to reflect that EDBs are already incentives (sic) to avoid a breach is arbitrary and should be removed. The VOLL should be as close as possible to the value of avoiding an outage. [498]

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[494] Horizons Networks "DPP4 Issues paper submission" (19 December 2023), p. 17.

[495] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 18.

[496] Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 18.

[497] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 56, section 9.6.

[498] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 58, section 9.6.2.

**Analysis Conducted**

E235 This section:

E235.1 identifies the rationale for VOLL and our adjustment to account for inflation

E235.2 outlines why we reduce VOLL by the IRIS retention factor to reflect expenditure incentives

E235.3 outlines why we reduce this rate to account for quality standard incentives

E235.4 identifies why planned incentive rates are reduced relative to the unplanned incentive rate

E235.5 identifies why notified interruptions incentive rate is further reduced, and

E235.6 outlines incentive rates arising from our decisions.

**Rationale for application of VOLL and accounting for inflation**

E236 VOLL is an estimate of the economic value, in dollars per megawatt hour (MWh), that a consumer places on electricity they plan to consume but do not receive because of an interruption, noting this reflects an average across customer type, location, outage duration and timing.[499,500].

E237 It is important to note that VOLL is not used as a way to profile the difference in customer preferences – it is an average that ultimately smooths over the differences between customers, and also over individual customer preferences (eg, sensitivity to interruptions at different times of the day).

E238 The rationale for introducing a VOLL based incentive in DPP3, was that previously some EDBs had been responding to the signal provided in the DPP2 Determination which provided an incentive rate which was potentially greater than the value which consumers placed on improved reliability.

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499 PwC "Estimating the Value of Lost Load in New Zealand" (March 2018)

500 We note this value is lower than comparative VoLL rates used by AER and Ofgem.

E239 The wide difference in historical performance of EDBs leads to a wide variation in quality standards and the range over which the incentives apply for individual EDBs. If a consistent revenue-at-risk percentage is used the value of the incentive varies widely and there is a potential mismatch between the cost to customers of incentive driven changes in reliability and the value customers attach to the change in reliability.

E240 We consider that it would be appropriate to increase VOLL to more accurately represent a current value for consumers for the DPP4 period.

E240.1 We consider the VOLL figure transposed for DPP3 (from Transpower's PwC recommendation) outdated, due to inflation

E240.2 If we do not automatically update VOLL in line with the treatment of revenue allowances, then we are potentially diluting incentive strength, and

E240.3 The midpoint of the regulatory period will most accurately reflect a VOLL figure that accounts for backward and forward-looking inflation.

E241 For the DPP4 draft decision, we are proposing to inflate the VOLL figure up until the midpoint of the DPP4 regulatory period (30 September 2027).

**Accounting for inflation in calculating VOLL**

E242 By adjusting for inflation using the CPI as at Q4 of each preceding year, we have estimated VOLL to be \$32,251/MWh as at Q4 2023.

E243 The formula applied is:

$$VoLL_{2004\$\,/MWh} * \frac{CPI_{Q4\,PY}}{CPI_{Q4\,2004}} = VoLL_{Present\,\$\,/MWh}$$

where:

E243.1 $VOLL_{2004\$/MWh}$ is the default figure for VOLL in 2004 dollars, set at \$20,000/MWh;

E243.2 $CPI_{Q4\ PY}$ is the CPI figure as at quarter 4 of the prior year

E243.3 $CPI_{Q4\ 2004}$ is the CPI figure as at quarter 4 of 2004 (774.2669), and

E243.4 VOLL (present) is the VOLL figure derived for the present (the output), in present year \$/MWh.

E244 For 2024, we used the forecasted annual inflation figure of CPI, of 2.5%. This is for the December quarter of 2024, consistent with the back-casting calculations of the inflation of VOLL.

E245 For 2025, 2026 and 2027, we have used a forecasted annual inflation rate of CPI, of 2%. This represents the midpoint figure for the period spanning the end of 2024 (publication of the DPP4 final determination) and the midpoint of the DPP4 regulatory period (30 September 2027).

E246 The forecasted annual inflation rate of CPI figures has been derived from the Reserve Bank of New Zealand (RBNZ), and historic CPI figures have been retrieved from Stats NZ (and inform the annual inflation rates at Q4 used in calculations).

E247 This involves using historical inflation figures to cast the VOLL figure up until Q4 2024 and using 2% thereafter to project VOLL up until the regulatory period midpoint (as 2% is the midpoint of the target range of forecasted inflation).

**Table E16 Calculation of VOLL**

| Assessment year | CPI (at Q4 previous calendar year) | Actual annual inflation rate at Q4 for calculation (%) | Forecasted annual inflation rate at Q4 for calculation (%) | Inflated VOLL ($/MWh) |
|---|---|---|---|---|
| **2023** | 1,259 | 5% | - | 32,521 |
| **2024** | 1,290 | - | 2.5% | 33,334 |
| **2025** | 1,316 | - | 2% | 34,001 |
| **2026** | 1,343 | - | 2% | 34,681 |
| **2027** | 1,369 | - | 2% | 35,374 |

### Reducing VOLL by the IRIS retention factor to reflect expenditure incentives

E248 To ensure that consumers are not overpaying for quality driven expenditure, we factor in the expenditure incentives that consumers are also sharing. Taking account of expenditure incentives, we scale back the VOLL, or incentives rates, by (1 – the IRIS retention factor).

E249 Under the IRIS, EDBs keep the value of improvements in efficiency for five years before sharing them with consumers. Under our approach, EDBs will keep the value of quality improvements or declines (VOLL) at least until the end of the regulatory period.

E250 In addition, without an adjustment consumers may pay more for investments than the value they place upon them, through the combination of IRIS and QIS payments. Consumers may have more aversion to a deterioration in reliability than they have a desire for improvements in reliability. In other words, consumers are willing to accept (WTA) a higher level of payment for lower reliability than they are willing to pay (WTP) for higher reliability.

**Reducing the incentive rate to account for quality standard incentives**

E251 In DPP3 we also considered that recognition of incentives associated with not contravening the quality standard should be factored in and set a further discount of 10%. We are proposing to retain this discount for DPP4 as we consider it is appropriate to maintain a comparatively conservative approach.

**Planned incentive rates are reduced relative to the unplanned incentive rate**

E252 We consider de-weighting planned interruptions is appropriate as they are less inconvenient, as long as customers are notified, they can plan accordingly. Planned interruptions are also generally required by EDBs to perform maintenance and investment that benefits consumers in the long run.

E253 Without a de-weighting of planned interruptions there may be a perverse incentive for EDBs to defer necessary network maintenance and investment.

E254 We do not consider removing planned interruptions appropriate. While it is less inconvenient for consumers, it is not without inconvenience. We consider it is important that EDBs are incentivised to undertake its planned interruptions efficiently and consumers are compensated accordingly. Furthermore, the standards associated with planned interruptions have a significant buffer to the historic average built in on the assumption that revenue-linked incentives are the appropriate avenue to encourage EDBs to manage its planned interruptions appropriately.

E255 We received limited response in submissions on the de-weighting of the notification mechanism for planned interruptions.

E256 Our draft decision is to weight the discounts applied to the planned interruption incentive rate, reducing this to a 35% discount from unplanned interruption incentive rate. This reflects that 24 hours' notice is required for planned interruptions may not provide sufficient time for consumers affected by the interruption to adequately plan, and the significant uptake in the "notified" planned interruption scheme.

**Application of the "notified" planned interruption incentive rate**

E257 In DPP3 we introduced "notified" planned interruptions and de-weighted the incentive rate by 75% relative to the unplanned interruption incentive rate.

E258 For the DPP4 draft decision, we are retaining the 75% de-weighting of the "notified" interruption incentive rate relative to the unplanned interruption incentive rate.

E259 The planned interruption incentive rate will bear a 35% discount from unplanned interruption incentive rate, and the "notified" interruption incentive rate will bear a further 61.538% discount from the planned rate (which renders the "notified" rate as bearing a 75% discount from the unplanned rate) (draft decisions QIS3 and QIS4)

E260 Orion stated that "The planned notification incentive was complex to implement, and it is still too early to gauge whether the benefits have outweighed the costs."[501]

E261 We consider the notification mechanism incentivises transparency and provision of adequate preparation time to affected consumers ahead of necessary network maintenance and investment that will result in a planned interruption.

E262 We consider that this mechanism is balanced, in that it provides both a sufficient financial benefit to EDBs for good practice, and adequate notice and time to consumers to prepare for a disruption to the electricity supply.

E263 In Table E17, we have detailed the proportion of planned assessed SAIDI that can be attributed to notified planned interruptions in the regulatory period to date.[502]

E264 We note that for most EDBs, there has been significant uptake and usage of the notified planned interruption mechanism, while for the minority of EDBs there has been little to no usage of the mechanism in the regulatory period to date.

E265 We are not planning on changing the criteria or definition of 'Class B notified interruption" or "notified interruption window" as we have not received any submissions on this and because we do not want to introduce costs to change systems set up to meet the requirement.

[501] Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 18.

[502] Note that we do not have 'notified' data available for Horizon, as they have not disclosed their notified SAIDI in their compliance statements for 2021-2023. We do not have 'notified' data for Wellington Electricity as they were on a CPP in 2021, and Powerco who was on a CPP from 2021-2023).

**Table E17 Proportion of planned assessed SAIDI attributable to notified planned interruptions**

| EDB | Notified SAIDI as a % of total | | |
|---|---|---|---|
| | 2021 | 2022 | 2023 |
| **Alpine** | 0% | 17% | 60% |
| **Aurora** | 62% | 90% | 90% |
| **EA Networks** | 0% | 0% | 0% |
| **Electricity Invercargill** | 7% | 100% | 95% |
| **Firstlight** | 83% | 84% | 80% |
| **Horizon** | Not Available | Not Available | Not Available |
| **Nelson Electricity** | 100% | 100% | 100% |
| **Network Tasman** | 0% | 0% | 0% |
| **Orion** | 70% | 1% | 60% |
| **OtagoNet** | 5% | 91% | 92% |
| **Powerco** | CPP | CPP | CPP |
| **The Lines Company** | 30% | 75% | 93% |
| **Unison** | 88% | 86% | 90% |
| **Vector** | 90% | 93% | 90% |
| **Wellington Electricity** | CPP | 15% | 71% |

E266 We note that the significant de-weighting of planned interruptions based on notification requirements may have promoted a focus on this initiative rather than other measures which may reduce the impact of planned interruptions, ie, the use of portable generation.

E267 We are interested in stakeholder views whether the comparative de-weighting of planned interruptions is consistent with the value which consumers place on the additional notification.

### Implication for incentive rates

E268 If we set the incentive rates with reference to VOLL using a figure of $35,374/MWh (factoring in inflation to 30 September 2027, the midpoint of the DPP4 regulatory period) so that consumer preferences are better reflected in the price-quality trade-off decisions. The outcomes are to:[503]:

E268.1 reduce the incentive rates by 66.82% to approximate a five-year retention of the benefits by EDBs; (33.18% of VOLL or $11,737.09/MWh)

[503] Note that some non-whole number percentages are rounded, up to two decimal places.

E268.2 reduce the incentive rate by a further 10% to account for the existing incentives created by quality standards (29.86% of VOLL or $10,563.38/MWh)

E268.3 for planned interruptions, reduce the incentive rate a further 35% to reflect the fact that these are generally less disruptive to consumers (to 19.41% of VOLL or $6,866.09/MWh), and

E268.4 for planned interruptions where certain notification criteria are met, reduce the incentive rate by a further 61.54% (7.47% of VOLL or $2,640.85/MWH).

E269 This informs the respective incentive rates for EDBs who will be on a default price path (DPP4):

**Table E18 Draft incentive rates for DPP4 compared to DPP3**

| EDB | DPP3 | | | DPP4 | | |
|---|---|---|---|---|---|---|
| | Unplanned Incentive rate | Planned incentive rate<br>50% of UP | "Notified" Incentive rate<br>25% of UP | Unplanned Incentive rate | Planned incentive rate<br>65% of UP | "Notified" Incentive rate<br>25% of UP |
| **Alpine Energy** | 7,879 | 3,940 | 1,970 | 15,978 | 10,386 | 3,995 |
| **Aurora Energy** | 14,279 | 7,140 | 3,570 | 26,581 | 17,278 | 6,645 |
| **EA Networks** | 5,394 | 2,697 | 1,349 | 11,694 | 7,601 | 2,924 |
| **Firstlight Network** | 2,797 | 1,399 | 699 | 5,750 | 3,738 | 1,438 |
| **Electricity Invercargill** | 2,544 | 1,272 | 636 | 5,041 | 3,276 | 1,260 |
| **Horizon Energy** | 5,397 | 2,699 | 1,349 | 10,967 | 7,128 | 2,742 |
| **Nelson Electricity** | 1,417 | 709 | 354 | 2,740 | 1,781 | 685 |
| **Network Tasman** | 6,260 | 3,130 | 1,565 | 12,958 | 8,422 | 3,239 |
| **Orion NZ** | 31,686 | 15,843 | 7,922 | 66,372 | 43,142 | 16,593 |
| **OtagoNet** | 4,339 | 2,170 | 1,085 | 9,088 | 5,907 | 2,272 |
| **Powerco** | 47,908 | 23,954 | 11,977 | 99,382 | 64,598 | 24,845 |
| **The Lines Company** | 3,827 | 1,914 | 957 | 7,370 | 4,790 | 1,842 |
| **Top Energy** | 3,283 | 1,642 | 821 | 6,567 | 4,268 | 1,642 |
| **Unison Networks** | 16,185 | 8,093 | 4,046 | 33,225 | 21,596 | 8,306 |
| **Vector Lines** | 84,519 | 42,260 | 21,130 | 167,795 | 109,067 | 41,949 |
| **Wellington Electricity** | 23,215 | 11,608 | 5,804 | 45,675 | 29,689 | 11,419 |

**Conclusion**

E270 Whilst we have broadly retained the incentive settings from DPP3 the strength of the incentive has significantly increased for EDBs, with the increase in the IRIS incentive rate, and inflation adjustment for VOLL.

E271 Further consideration of other factors which may impact the incentive rate is included within the section *Not make an explicit adjustment to match the duration of retention of benefits between EDBs and consumers*.

*QIS5: Setting the SAIDI target for the QIS at the historical average*

**Nature of the Decision**

E272 The quality target is the level of reliability performance at which the revenue impact of an EDB's performance is zero. Put another way, it is the point at which losses turn into gains and vice versa.

E273 Consistent with the no material deterioration principle, we intend to retain setting the target based on the historical average level used for setting SAIDI standards. Without better information about the level of reliability consumers demand, we consider historical reliability provides an appropriate outcome for a default path.

E274 This approach ensures that:

E274.1 where reliability improves or declines over time, the EDB faces a proportionate incentive, and

E274.2 where there is random variation in performance, over time these random variations can be expected to cancel out, leaving the EDB in a neutral position.

**Draft Decision**

E275 Our draft decision for DPP4 is that incentives are revenue-neutral at the average of the reference period, also known as the target.

E276 We note that we intend to use two separate reference periods for planned and unplanned interruptions to establish the historical average – the QIS comprises both planned and unplanned interruptions in its calculations.

### What we heard from stakeholders

E277 Powerco questioned whether the planned SAIDI quality incentive target should be raised above the historical average, as "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".[504]

E278 Wellington Electricity held similar views:

> The planned SAIDI budget is based on modest historic work programmes which do not allow us to deliver our increasing capex without exceeding the target. Our budgeted planned SAIDI reflects our increasing capex programme and is always much higher than our regulatory target. This means we always incur a penalty. Improving this would mean not delivering critical asset replacement and network reinforcement. Essentially the planned quality incentive is just a penalty. The planned quality targets should be a function of a network's work programme so that the budgets can increase in line with capex. Without this change, networks with increasing decarbonisation related work programmes will be penalised for delivering their capex and maintenance programmes.[505]

### Analysis Conducted

E279 In Table E19, we have outlined the forecasted planned interruption SAIDI by EDBs as per their 2023 ID disclosures.

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504 Powerco "DPP4 Issues paper submission" (19 December 2023), p. 27.

505 Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 56, section 9.6.1.

### Table E19 Forecasted planned interruptions SAIDI, by EDB and year

| EDB | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|
| **Alpine Energy** | 55 | 55 | 55 | 55 | 55 | 55 |
| **Aurora Energy** | 185 | 159 | 158 | 137 | 146 | 138 |
| **EA Networks** | 110 | 120 | 120 | 120 | 120 | 120 |
| **Electricity Invercargill** | 30 | 32 | 32 | 32 | 32 | 32 |
| **Firstlight Network** | 85 | 101 | 101 | 101 | 101 | 101 |
| **Horizon Energy** | 57 | 57 | 57 | 57 | 57 | 57 |
| **Nelson Electricity** | 42 | 15 | 15 | 15 | 15 | 15 |
| **Network Tasman** | 160 | 100 | 100 | 100 | 100 | 75 |
| **Orion NZ** | 13 | 13 | 13 | 13 | 13 | 13 |
| **OtagoNet** | 260 | 162 | 162 | 162 | 162 | 162 |
| **Powerco** | 93 | 94 | 90 | 91 | 90 | 88 |
| **The Lines Company** | 88 | 114 | 114 | 114 | 114 | 114 |
| **Unison Networks** | 94 | 95 | 95 | 95 | 95 | 95 |
| **Vector Lines** | 117 | 117 | 117 | 117 | 117 | 117 |
| **Wellington Electricity** | 8 | 10 | 12 | 18 | 15 | 21 |

E280 We note that despite increases in capex programmes (based on expenditure profiles) the associated planned interruptions disclosures do not generally reflect an increase in planned interruptions.

E281 We have also considered alternative approaches to estimate what forecast changes to planned interruptions could be, including establishing what a proportional increase in capex spend was compared to a historical average. These measures would be indicative at best and any adjustments to proposed capex allowances would need to be reflected in the calculation. We do not intend to implement this option.

E282 Reducing the length of the reference period for planned interruptions (from the current 10 years) to seven years will reflect the more recent step change in planned interruptions from 2018 which mitigates some of the concern on the relevance of the historical data series.

E283 We note that de-weighting of notified interruptions will potentially have a greater impact on calculation of the quality incentive than an increase in planned interruptions. We note that we are not de-weighting notified interruptions in the reference period dataset. Accordingly, the significant uptake of notified interruptions by most EDBs to date will likely more than offsetting any increase associated with an increase in planned interruptions.

E284 The quality incentive is calculated as the lessor of **revenue at risk** or

E284.1 the sum of:

A. $(SAIDI_{unplanned,target} - SAIDI_{unplanned,assessed}) * IR; and$

B. $\left(SAIDI_{planned,target} - \left(SAIDI_{B} + (SAIDI_{N} * 0.384615)\right) * 0.65\right) * IR$

E285 If the $SAIDI_{planned,target}$ is set at the historical average as intended (without accounting for notified interruptions) the de-weighting of notified interruptions will likely result in a higher likelihood of receiving an incentive payment for most EDBs, noting that not all EDBs currently apply notified interruptions.

**Conclusion**

E286 We intend to retain setting the target based on the historical average level used for setting SAIDI standards as we consider this is consistent with the no material deterioration principle.

*QIS6, QIS7: SAIDI caps and collars*

**Context**

E287 The reliability caps are the points at which no further incentive losses are applicable to the revenue-linked incentive scheme. Conversely, reliability collars are the point at which no further incentive gains are applicable.

**Draft Decision**

E288 Our draft decision is to:

E288.1 retain the SAIDI cap for the quality incentive scheme, set at the compliance standard and

E288.2 retain the SAIDI collar for the quality incentive scheme, set at zero.

**Reliability Caps**

E289 We consider that it is not consistent with maintaining quality at a level that reflects consumer demands to allow EDBs to continue to make trade-offs beyond the minimum level of reliability determined by the quality standards, so a cap above the limit is inappropriate.

E290 On the other hand, we consider that it is consistent with maintaining quality at a level that reflects consumer demands for EDBs to consider trade-offs all the way up to the limit, as this preserves the marginal incentive to improve reliability (or avoid further declines) regardless of their performance up to that point in the assessment period.

**Reliability Collars**

E291 We have previously set planned and unplanned SAIDI collars at zero, subject to a specified maximum revenue exposure. In other words, we have removed the collars in our incentive scheme. This means that financial incentives for reliability will always apply below the SAIDI limits.

E292 As reliability improves, we expect the marginal cost of further improvements will increase. Rational EDBs will look for the least-cost improvements in reliability before pursuing more expensive improvements. As SAIDI approaches zero, we anticipate that the cost of further improvement would far outweigh the conservative incentive rates we have set, and so do not consider this will lead to improvements beyond what consumers expect.

*QIS8: Capping the revenue at risk for the quality incentive scheme*

**Nature of the Decision**

E293 Revenue at risk is the total pool of incentives an EDB may gain or lose based on its performance. It can be expressed in both dollar terms and as a percentage of EDBs' total revenue.

E294 If we retain the setting of SAIDI incentive rates and the SAIDI bounds for which incentives apply explicitly, the revenue exposure to the revenue-linked incentive scheme may create an excessive level of exposure. To mitigate this in DPP3, EDBs total exposure was capped across planned and unplanned interruptions at 2% of allowable revenue each year.

**Draft Decision**

E295 Our draft decision for DPP4 is to cap Revenue at Risk at 2% of actual net allowable revenue.

**What we heard from stakeholders**

E296 We received limited specific submissions related to capping revenue at risk, though Orion submitted that they "do actively monitor [their] progress against targets, caps, collars and revenue at risk and report at Board level." [506]

E297 Vector submitted their desire to "retain revenue-linked incentives for both planned and unplanned SAIDI," and for "targets, caps, collars, incentive rate and revenue at risk [to be] set on a consistent basis with DPP3." [507]

**Analysis conducted**

E298 Table E20 illustrates the revenue at risk for each EDB as a percentage of total revenue in DPP4, with those that hit or exceed the 2% cap being highlighted.

[506] Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 18.

[507] Vector "DPP4 Issues paper submission" (19 December 2023), p.40.

Table E20 DPP4 Implied Maximum Revenue at Risk

| EDB[508] | Maximum loss | | | Maximum gain | | |
|---|---|---|---|---|---|---|
| | Unplanned | Planned | Total | Unplanned | Planned | Total |
| **Alpine Energy** | 0.7% | 1.0% | 1.7% | 1.9% | 1.0% | 2.0% |
| **EA Networks** | 0.4% | 1.7% | 2.0% | 1.4% | 1.5% | 2.0% |
| **Firstlight Network** | 0.6% | 1.1% | 1.7% | 2.3% | 0.7% | 2.0% |
| **Electricity Invercargill** | 0.3% | 0.2% | 0.4% | 0.4% | 0.2% | 0.6% |
| **Horizon Energy** | 1.3% | 1.5% | 2.0% | 4.0% | 2.0% | 2.0% |
| **Nelson Electricity** | 0.3% | 0.3% | 0.7% | 0.3% | 0.3% | 0.6% |
| **Network Tasman** | 0.7% | 1.8% | 2.0% | 2.0% | 1.8% | 2.0% |
| **Orion NZ** | 0.4% | 0.3% | 0.7% | 1.4% | 0.3% | 1.7% |
| **OtagoNet** | 0.8% | 2.4% | 2.0% | 2.4% | 2.4% | 2.0% |
| **Powerco** | 0.6% | 1.0% | 1.6% | 3.1% | 1.0% | 2.0% |
| **The Lines Company** | 0.5% | 1.0% | 1.5% | 1.9% | 1.0% | 2.0% |
| **Top Energy** | 0.7% | 1.3% | 2.0% | 2.9% | 0.7% | 2.0% |
| **Unison Networks** | 0.3% | 0.7% | 1.0% | 1.3% | 0.9% | 2.0% |
| **Vector Lines** | 0.4% | 0.7% | 1.1% | 2.2% | 1.3% | 2.0% |
| **Wellington Electricity** | 0.2% | 0.1% | 0.3% | 0.9% | 0.2% | 1.1% |

E299 The number of EDBs hitting or exceeding the 2% cap is broadly consistent with the outcome in DPP3.[509]

E300 This decision does not affect all EDBs, as the 2% cap does not bite for EDBs that have more reliable networks – whereas it bites for EDBs with generally less reliable networks. Less reliable EDBs will generally be exposed to a higher revenue at risk than more reliable EDBs. However, we consider it appropriate that the least reliable EDBs are subject to more revenue exposure, as they have the largest scope for improvements in reliability.

E301 We note that, for example, an EDB can only really achieve maximum gains as their SAIDI minutes approach zero; in practicality, this is a highly unlikely phenomenon. The 2% cap on revenue at risk only bites at the extremes; in this sense, we consider that the broad similarities between the application of the cap in DPP3 to DPP4 support its retention.

[508] Excludes Aurora - on a CPP until 31 March 2026.

[509] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision – Reasons paper" (27 November 2019), p440.

**Conclusion**

E302 We consider maintaining a cap of Revenue at Risk at 2% of actual net allowable revenue is appropriate for the QIS as it balances providing incentives to improve performance which reflect consumer demands without over-exposing EDBs to revenue fluctuations.

*QIS10: Not make an explicit adjustment to match the duration of retention of benefits between EDBs and consumers*

**Problem definition**

E303 Due to the design of the quality incentive scheme, the duration of the benefit to an EDB is a function of the reference period used to set the SAIDI target. This may not align with the period for which consumers benefit from improved performance from investments.

**Draft decision**

E304 Our draft decision is to not make an explicit adjustment to match the duration of retention of benefits between EDBs and consumers.

**What we heard from stakeholders**

E305 There were a range of views on the appropriateness of the current incentive rate in the QIS scheme which are covered earlier within the section *Setting the QIS incentive rates*.

E306 We have not received any submissions related to the potential mismatch of the duration of retention of benefits between EDBs and consumers.

**Analysis**

E307 In setting the QIS, we make an adjustment to VOLL, reflecting the fact that with the IRIS scheme in place, an EDB only bears a proportion of the costs (33% in DPP4) to better ensure that we align EDB’s incentives to the interests of consumers in higher levels of quality.

E308 However, we do not make a similar adjustment reflecting the fact that EDBs only retain the benefits of the quality incentive payment until the quality improvement is reflected in the reference data set.

E309 The benefit of an investment which improves quality is retained for different periods of time between EDBs and consumers:

E309.1 EDBs hold on to the benefit of a SAIDI improvement for 7.5 years if we maintain the 10-year reference period for unplanned interruptions, regardless of when the investment occurs during the regulatory period. This is based on the EDB receiving, all else being equal, an incentive payment for the remainder of the regulatory period, and then for a proportional part of the next two regulatory periods depending on when the investment occurred, and

E309.2 The length of time that consumers maintain the benefit will depend on the nature of the investment, with capex investments having different life spans dependent on the nature of the asset and opex based solutions may be employed which may have shorter life spans.

E310 In principle, making an adjustment to retention of benefits as we do for retention of costs would better align EDBs incentives with the interests of consumers in avoiding outages.

E311 However, we propose to not make an adjustment for the retention of benefits because:

E311.1 significant assumptions would need to be made on how long consumers may hold benefits, including around the nature of investments which EDBs might make to improve quality, and

E311.2 we are concerned that there are limitations in the calculation of VOLL and that an overly strong QIS may cause specific investments in quality improvements that exceed the willingness to pay for the affected consumers.

**Conclusion**

E312 Our draft decision is not to raise the quality incentive rate to account for the potential mismatch in the length of retention of benefits as we are not clear to the extent to which increasing the existing QIS incentive rate will align with the reliability that consumers demand and their willingness to pay.

E313 We invite submissions on how EDBs use the current QIS rate in their evaluation of quality improvement opportunities, including whether they factor in IRIS adjustments when assessing costs and/or consider the duration of the quality incentive payment.

**Normalisation of reliability data for major events**

**Nature of the decisions (or Problem definition)**

E314 SAIDI and SAIFI, particularly for unplanned interruptions, are highly variable, and are strongly influenced by major individual events. In our draft decision for DPP4, we have applied a normalisation process to historical reliability and to the way reliability performance are assessed during the DPP4 period. This applies to both the unplanned interruptions reliability standards and to the incentive scheme for unplanned SAIDI.

E315 Events beyond a certain statistical boundary are identified as major events and the underlying SAIDI is replaced with a pro-rated boundary value.

E316 Our draft decision is that we retain the approach under DPP3 to normalise reliability data for major events. Detailed draft decisions and analysis relating to normalisation approach and associated reporting requirement are provided below (**N1**-**N5**).

**How the decisions are aligned to the decision-making framework for the DPP**

E317 The purpose of identifying and normalising major events is to limit the impact of such events on the assessment of compliance with the quality standard and QIS. Reducing the volatility of these measures allows a focus on material deterioration, avoiding false positives where significant weather events drive non-compliance not deterioration in the overall performance of the network.

E318 Our proposed approach is to retain the settings from DPP3 as we consider the current settings appropriately provide incentives to provide services at a quality that reflects consumer demands.

*N1: Normalisation only applies to unplanned interruptions, which are the only initiators of a major event day*

**What we heard from stakeholders**

E319 In submissions on the issues paper, there was general support to retain the DPP3 normalisation approach, but no submissions on this specific point.

**Analysis conducted**

E320 Previous analysis indicated that of the largest periods of interruptions, around 93% of SAIDI and 95% of SAIFI were attributable to unplanned interruptions.

E321 We note that in some instances significant planned interruptions may be required subsequent to a MED. We consider the separation of planned and unplanned quality standards and the ability for EDBs to reduce the impact on quality incentives by providing greater notification to consumers appropriately addresses this issue. In addition, the reference data will include planned outages that have followed past major events, and it would be very difficult to remove such planned outages from the reference dataset.

E322 We consider that the DPP3 rationale still holds and that it is practically unlikely that planned outages will come close to meeting the MED threshold.

**Conclusion**

E323 Our draft decision is to retain the approach that normalisation only applies to unplanned interruptions, which are the only initiators of a MED. There were no specific submissions on this point in submissions on the issues paper.

*N2: Retain the normalisation approach used in DPP3*

E324 Our draft decisions are to retain the following normalisation approach, consistent with the DPP3 determination:

E324.1 normalisation applies to 24-hour rolling periods

E324.2 the major event boundary value has been identified as the 1104th highest rolling 24-hour period for SAIDI and SAIFI over the 10-year reference period

E324.3 normalisation is applied on half-hour blocks, within a major event, where the SAIDI figure exceeds 1/48th of the boundary value, and

E324.4 treat major events by replacing any half-hour that is greater than 1/48th of the boundary value with 1/48th of the boundary value if that half-hour is part of the major event (can exceed 24 hours in duration).

**What we heard from stakeholders**

E325 In submissions on the issues paper, there was general support to retain the DPP3 normalisation approach.

**Analysis conducted**

E326 We consider that maintaining the replacement of identified major events with a reduced replacement value is appropriate, given that:

E326.1 enhanced major event reporting requirements, can provide more transparency and incentives around the main cause of events

E326.2 reducing a large source of volatility may provide a clearer indication of the underlying reliability of the network

E326.3 the extreme event standard, places further onus on EDBs to take practicable steps to minimise the likelihood of high impact, low probability events that are within its control as well as mitigating the extent of them, and

E326.4 there are other incentives to manage the risk of significant outages associated with a major event such as customer complaints and reputational risk.

E327 Table E21 below shows the impact of how this normalisation has applied within DPP3.

**Table E21 Impact of major event day normalisation on SAIDI value**

| EDB | | 2021 | | 2022 | | 2023 | |
|---|---|---|---|---|---|---|---|
| | Unplanned SAIDI boundary value | Pre-normalised (total all MEDs) | Normalised (MEDs only) | Pre-normalised (total all MEDs) | Normalised (MEDs only) | Pre-normalised (total all MEDs) | Normalised (MEDs only) |
| **Alpine Energy** | 9.17 | 32.27 | 1.07 | 128.03 | 5.63 | 14.34 | 0.53 |
| **EA Networks** | 6.25 | 0.00 | 0.00 | 72.59 | 4.80 | 56.38 | 3.54 |
| **Firstlight/Eastland** | 13.10 | 18.29 | 3.27 | 158.34 | 11.37 | 1195.81 | 20.30 |
| **Electricity Invercargill** | 4.13 | 26.78 | 0.56 | 62.48 | 0.81 | 18.14 | 0.17 |
| **Horizon Energy** | 14.69 | 14.78 | 1.34 | 163.31 | 4.41 | 79.32 | 3.96 |
| **Nelson Electricity** | 8.68 | 0.00 | 0.00 | 24.15 | 0.36 | 14.33 | 0.18 |
| **Network Tasman** | 7.22 | 0.00 | 0.00 | 32.41 | 1.87 | 51.32 | 2.22 |
| **Orion** | 7.60 | 0.00 | 0.00 | 11.87 | 1.81 | 0.00 | 0.00 |
| **OtagoNet** | 11.81 | 0.00 | 0.00 | 79.31 | 8.86 | 120.59 | 8.04 |
| **The Lines Company** | 11.17 | 62.29 | 2.51 | 66.29 | 11.14 | 436.95 | 19.87 |
| **Top Energy** | 27.92 | 0.00 | 0.00 | 420.09 | 21.26 | 1330.21 | 52.52 |
| **Unison Network** | 4.48 | 37.52 | 2.56 | 21.57 | 3.66 | 1749.61 | 4.68 |
| **Vector** | 4.83 | 0.00 | 0.00 | 20.49 | 7.71 | 312.09 | 19.78 |
| **Wellington Electricity** | 2.16 | - | -- | 6.40 | 0.68 | 5.97 | 0.71 |

E328 Normalisation of major events is intended to limit the impact of the most substantial interruptions on underlying reliability data.

E329 While some major events (such as those caused by extreme weather) are somewhat beyond the control of EDBs, the degree of controllability is not always clear. The underlying performance of the network does have some effect on how well networks respond to significant events. For example, the engineering advice we have received with respect to contraventions suggests that there were operational decisions EDBs could have made to minimise the impact of external events.

E330 However, we recognise that to some extent the effects of extreme external events may be beyond the control of EDBs, and this can cause some variability in reliability performance which EDBs will not be able to eliminate. Replacing major events with the full boundary value may make the frequency of major events too large a driver of underlying reliability performance.

E331 Consistent with our position in DPP3, we still do not consider it appropriate to completely remove the major event impact for assessment purposes, or replace it with a half-hourly average, as this would completely remove variation caused by major events, regardless of the extent to which the event was outside the EDB's control.

E332 Consistent with our DPP3 decision, major events that are identified will be replaced with a pro-rated boundary value, however, only those half-hour SAIDI or SAIFI raw values that exceed 1/48th of the respective boundary value will be replaced.

E333 By identifying major events on a 24-hour basis and replacing major events with a pro-rated boundary value, the impact of major events will generally be much lower than replacing with the full boundary value. However, given that a pro-rated boundary value is still relatively large compared to a normal half-hour, EDBs would still face some exposure to the frequency of major events.

**Normalisation applies to 24-hour rolling periods**

E334 Consistent with DPP3, we consider that a major event should not be arbitrarily constrained to a fixed period–major events often do not fit neatly within a calendar day. For example, if a major storm hits an EDB at 11:00pm and results in several interruptions stretching into the following day, it would be reasonable to treat the same as a storm hitting at 12:00am. The move to a rolling window means that all interruptions are treated equally regardless of the time of day they occurred.

E335 This means that it is possible for half-hours to be normalised which are, by definition, part of the major event but some time from the initial cause of the major event. While we consider that this is not ideal, we have implemented this for practical reasons, namely, to capture major events of different profiles without adding increased complexity. However, only those half-hours that exceed 1/48th of the boundary value are normalised down. The major event boundary value has been identified as the 1104th highest rolling 24-hour period for SAIDI and SAIFI over the 10-year reference period.

**The major event boundary value has been identified as the 1104th highest rolling 24-hour period for SAIDI and SAIFI over the 10-year reference period**

E336 Our draft decision is to retain the use of the 2.3 MEDs per year expectation in the calculation of boundary values.

**Assessment of the expectation of 2.3 major event days**

E337 For DPP2, we adapted the Institute of Electrical and Electronics Engineers (IEEE)' methodology for normalisation. This methodology was based on the expectation of 2.3 MEDs per year. Over a 10-year period, this implied the 23rd highest day represented a reasonable boundary for a major event. This methodology is known as the "2.5β method", as the 2.3 expectation is derived from a multiplier of 2.5, and a β is the standard deviation of the logarithms of SAIDI data used in the study.

E338 In DPP3, we retained the use of the 2.3 MEDs per year expectation in the calculation of boundary values for EDBs.

E339 In the DPP4 issues paper, we indicated our preference to retain the normalisation methodology from DPP3. We received submissions from some EDBs indicating that the 2.3 MEDs per year statistical expectation may no longer be an appropriate value given the effects of climate change on the frequency and intensity of significant weather events.

### Stakeholder views

E340 ENA, Orion, Powerco, The Lines Company and Vector suggested that the expectation of 2.3 MEDs per year may no longer hold, given the increase in extreme weather events. Submissions suggested we should look forward, rather than backward and to check advice from the National Institute of Water and Atmospheric Research (NIWA) and other experts, as well as that we align with IEEE's approach to normalisation. [510] [511] Unison and Orion both supported Vector's submission in cross submissions.[512]

E341 Vector stated:

> The Commission must reconsider its allowance for major event days when setting quality standards. This must be done looking forward not backwards as history will not be a good predictor in this case as climate change will result in a level of major events not seen in past years. The Commission must work with weather agencies in forming its view.

E342 Powerco stated:

> We urge the Commission to engage with the IEEE to ascertain whether they are updating their normalisation standard to reflect changing climate patterns.

### Analysis conducted

E343 We undertook a review of key information the Ministry for the Environment and NIWA have made available with regards to the impact of climate change on future weather events in New Zealand.[513] [514]

E344 While NIWA has indicated that climate change will have an aggravating impact on the extreme wind speeds, they noted that this effect will not be uniform across different parts of the country.

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[510] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023) p. 17; Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023) p. 16; Powerco "DPP4 Issues paper submission" (19 December 2023), p. 24; The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023), p. 10; and Vector "DPP4 Issues paper submission" (19 December 2023) p. 3.

[511] Institute of Electrical and Electronics Engineers "IEEE 1366 Guide for Electric Power Distribution Reliability Indices"(22 November 2022).

[512] Orion "Cross-submission on DPP4 Issues paper" (26 January 2024), pp. 13-14; Unison "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 10.

[513] NIWA "Climate change scenarios for New Zealand" 2016.

[514] Ministry for the Environment "Climate Change Projections for New Zealand: Atmospheric Projections based on Simulations undertaken for the IPCC Fifth Assessment" 2016.

E345 NIWA also acknowledged that more analysis is needed to determine the extent to which climate change will affect the frequency and severity of storms.

E346 The statistical expectation of 2.3 MEDs per year was published by the IEEE in 2012; since then, the IEEE have published an updated study in 2022. In the updated study, the IEEE reaffirmed the preference of their 2012 methodology and addressed the concern regarding an increased frequency of major events:

> The β multiplier of 2.5 was chosen because, in theory, it would classify 2.3 days per year as major events. If significantly more days than this are identified, they represent events that have occurred outside the random process that is assumed to control distribution system reliability. The process and the multiplier value were evaluated by a number of utilities with different sized systems from different parts of the United States and found to correlate reasonably well to current major event identification results for those utilities. A number of alternative approaches were considered. None was found to be clearly superior to the 2.5β method. [515]
>
> As companies have used this method, a certain number of them have experienced large-scale events (such as hurricanes or ice storms) that result in unusually sizable daily SAIDI values. The events that give rise to these particular days, considered "catastrophic events", have a low probability of occurring. However, the extremely large daily SAIDI values may tend to skew the distribution of performance toward the right, causing a shift of the average of the data set and an increase in its standard deviation. Large daily SAIDI values caused by catastrophic events will exist in the data set for five years and could cause a relatively minor upward shift in the resulting reliability metric trends. [516]

E347 We agree with the preceding statement. Weather events like Cyclone Gabrielle are one-off events with a low probability of occurring; yet they push the distribution of SAIDI to the right.

> While significant study was undertaken to develop objective methods for identifying and processing catastrophic events (to eliminate the noted effect on the reliability trend), the methods that were developed, in order to be universally applied, caused for many utilities, catastrophic events to occur far too often to accept as being reasonable.[517]

E348 We interpret this statement as a statistical issue; the implication here is that it is nearly impossible to adjust the distribution of SAIDI to account for low-probability-severe-impact events, without (in turn) falsely ascribing a higher probability of occurring to those rare events.

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[515] Institute of Electrical and Electronics Engineers "IEEE 1366 Guide for Electric Power Distribution Reliability Indices" 2022, p. 31.

[516] *Ibid*, p. 29.

[517] *Ibid*

> In addition, the elimination of catastrophic events from the calculation of major event threshold caused, in some utilities, a rather large increase of days identified as MEDs in the following five years.[518]
>
> It is recommended that the identification and processing of catastrophic events for reliability purposes should be determined on an individual company basis by regulators and utilities since no objective method has been devised that can be applied universally to achieve acceptable results.[519]

E349 The IEEE considers that setting the statistical expectation of MEDs per year at 2.3 remains appropriate at present. Note that this updated study, while it retains the 2.3 expectation, broadly accounts for developments in climate change and other factors that may affect the frequency and severity of extreme weather events.

E350 We note impacts of expected volatility in underlying performance, including those attributable to climate change are considered by multiple parts of the quality regime including the length of the reference period, MED normalisation and the setting of the boundary value for quality standard non-compliance.

E351 We have received no evidence from EDBs of a quantitative nature which would support a statistical change.

E352 Accordingly, our draft decision is to retain the IEEE statistical expectation of 2.3 MEDs per year, per the IEEE's 2022 guidance.

**Application of the expectation of 2.3 major event days**

E353 To identify the trigger for what is considered a major event, we need to establish the major event boundary value. This is based on analysis of the reference period dataset for unplanned interruptions only.

E354 To determine the boundary value, we:

E354.1 use the IEEE expectation of 2.3 MEDs per year as a base

E354.2 multiply the 2.3 by 48 (half-hours per day) to reflect a rolling half-hourly assessment—which gives 110.4 half-hours per year, and

E354.3 multiply by 10 (years) to account for the length of the reference period—1104th highest half-hourly rolled 24-hour SAIDI and SAIFI over the reference period.

[518] *Ibid*

[519] Institute of Electrical and Electronics Engineers "IEEE 1366 Guide for Electric Power Distribution Reliability Indices" 2022, p. 29.

E355 From a practical application perspective this means, we:

E355.1 aggregate the raw SAIDI and SAIFI values from each unplanned interruption into half-hour blocks (rounding each interruption down to the nearest half-hour)

E355.2 sum the raw SAIDI and SAIFI values of each half-hour block with the respective SAIDI and SAIFI values of the following 47 half-hour blocks (to create a rolled 24-hour value for SAIDI and SAIFI), and

E355.3 separately identify the 1104th highest rolled half-hour values for SAIDI and SAIFI to determine the respective SAIDI and SAIFI boundary values for all EDBs.

E356 There are exceptions where there is a comparatively limited data-series due to limited circuit length size. This applies for the following networks:

E356.1 Electricity Invercargill where the 734th highest rolled 24-hour SAIDI and SAIFI values are used, and

E356.2 Nelson Electricity where the 327th highest rolled 24-hour SAIDI and SAIFI values are used.

E357 We note these values were determined based on the EDBs circuit length size compared to 1,000km, with values pro-rated down.

**Normalisation is applied on half-hour blocks, within a major event, where the SAIDI figure exceeds 1/48th of the boundary value**

E358 To normalise the dataset over the reference period, and for each assessment period, for unplanned interruptions only, we replace each half-hour with 1/48th of the boundary value if:

E358.1 that half-hour is part of any 24-hour rolled period that exceeds the applicable SAIDI or SAIFI major event boundary value, and

E358.2 that half-hour exceeds 1/48th of the applicable SAIDI or SAIFI boundary value.

**Conclusion**

E359 Our draft decision is to retain the normalisation approach that was used under DPP3. There was general support on this point in submissions on the issues paper.

*N3: SAIDI and SAIFI major events are triggered independently*

**What we heard from stakeholders**

E360 In submissions on the issues paper, there was general support to retain the DPP3 normalisation approach. No submissions were received on this specific point.

**Analysis conducted**

E361 We consider the logic which applied in DPP2 and DPP3 for SAIDI and SAIFI major events being triggered independently still holds.

E362 Major events may affect a large number of customers in an urban area for a relatively short period of time and therefore triggering SAIFI but not SAIDI; or a relatively small number of customers may be affected for a significant length of time and therefore triggering SAIDI but not SAIFI, for example a severe storm in a remote area.

**Conclusion**

E363 Our draft decision is to retain the approach under DPP3. There were no specific submissions on this point in submissions on the issues paper.

*N4: Set a higher boundary value for EDBs with a smaller dataset of interruptions*

**Nature of the decision**

E364 Smaller networks, all else being equal, can expect to have fewer interruptions relative to larger networks. This is because there is less equipment that can fail at any given time, and consequently less equipment at risk of truly experiencing a major event.

E365 In DPP3, we reduced the expected frequency of major events if an EDB has less than 1,000 kilometres of circuit length, to reflect the circuit length as a proportion of 1,000km.

**Draft decision**

E366 Our draft decision is to reduce the expected frequency of major events if an EDB has less than 1,000 kilometres of circuit length, thereby setting a higher boundary value for small EDBs.

**What we heard from stakeholders**

E367 In submissions on the issues paper, there was general support to retain the DPP3 normalisation approach but no submissions on this specific point.

**Analysis conducted**

E368 If an EDB experiences fewer interruptions than the number of major events we allow then this would result in a major event threshold of 0 for SAIDI and SAIFI, that is every interruption would be considered a major event. We do not consider that this would incentivise reliability reflecting consumer demand, especially if we were to replace major events with a daily average (also 0).

E369 Electricity Invercargill and Nelson Electricity have significantly fewer interruptions than any other non-exempt EDB. This is largely because they are much smaller networks, with a comparatively higher level of underground cables compared to overhead lines. Consequently, without modification:

E369.1 a high proportion of the interruptions that take place would be considered a major event, and

E369.2 a significant proportion of unplanned interruptions (particularly SAIDI) would be normalised out.

E370 Our draft decision reduces the expected frequency of major events if an EDB has less than 1,000 kilometres of circuit length. As outlined in Table E22, this impacts only Electricity Invercargill (665km) and Nelson Electricity (296km).

**Table E22 Reduced frequency of major events**

| EDB | 2023 Circuit length (km) | Major events (compared to 23) | 'Major half hours' (compared to 1104) |
|---|---|---|---|
| **Electricity Invercargill** | 665 | 15.3 | 734 |
| **Nelson Electricity** | 296 | 6.8 | 327 |

**Conclusion**

E371 Our draft decision is to retain the approach under DPP3. There were no specific submissions on this point in submissions on the issues paper.

*N5: Retain additional reporting by EDBs for each unplanned major event in its compliance statement, consistent with DPP3*

**Nature of the decision**

E372 We consider that when a major event is identified, there should be full transparency as to when and why the major event happened, and the impact of normalising the major event. This is important given our draft decision to replace major events with a pro-rated boundary value, rather than the full boundary value.

**Draft decision**

E373 Our draft decision is that an EDB must report for each major event in its annual compliance statement:

E373.1 the start date and time

E373.2 the end date and time

E373.3 the raw SAIDI and SAIFI values

E373.4 the normalised SAIDI and SAIFI values

E373.5 the location and equipment involved

E373.6 the event cause and response to the event, and

E373.7 any mitigating factors that may have prevented or minimised the major event.

**What we heard from stakeholders**

E374 There were two submissions on the issues paper on our reporting obligations. Aurora considered that the quality standard reporting obligations included in the annual compliance statement are appropriate. Wellington Electricity agreed that the current reporting obligations are generally appropriate. Neither submission commented specifically on major event reporting.

**Analysis conducted**

E375 We consider that increased transparency of major events is helpful to mitigate against the risk that EDB may be encouraged to trigger a major event given our decision to replace major events that are identified with a lower SAIDI and/or SAIFI value. Furthermore, increased reporting will allow us to cross-check the causes of any extreme event.

**Conclusions**

E376 Our draft decision is to retain the approach under DPP3. There were no specific submissions on this point in submissions on the issues paper.

**Reference periods and inter-period data adjustment**

*Apply a reference period to inform parameters for reliability standards and incentives*

**Nature of the decision**

E377 Any quality standards and incentives we set need to be specific to individual suppliers.

E378 To set reliability parameters for the DPP4 period, we require a baseline that informs those parameters. Without reliable external evidence about customers' preferred level of quality and without the ability to use benchmarking to identify a more 'optimal' level of reliability we intend to use the EDBs' historical performance to provide that baseline.

E379 We need to determine the reference periods for unplanned and planned interruptions, to apply to all non-exempt EDBs that will be subject to DPP4.

E380 Given changes in EDBs operating environment, network performance, and maintenance practices, the choice of reference period can have a significant impact on the parameters we set.

**How the decision is aligned to the decision-making framework for the DPP**

E381 The use of a historical reference period aligns with the principle of 'no material deterioration' and better reflects the underlying characteristics of the network than we could derive independently under a relatively low-cost framework.

**Draft decision**

E382 Our draft decision is to:

E382.1 use a 10-year reference period from 1 April 2013 to 31 March 2023 to inform the parameters for unplanned interruptions reliability standards and incentives, with the period adjusted to 1 April 2014 to 31 March 2024 for the final determination, and

E382.2 apply a reference period for planned interruptions of 2017 – 2023 for the draft decision, extended to 2017 – 2024 for the final decision.

**What we heard from stakeholders**

E383 In submissions on the issues paper, there was general support to retain a 10-year reference period updated for the most relevant information.

E384 Powerco, The Lines Company, Vector, Electricity Networks Aotearoa (ENA), Horizon and Orion all supported retaining the 10-year reference period.[520]

E385 Orion stated:[521]

> A shorter period may risk omitting periods of frequent clustered events and not take into account differing regional patterns/timings e.g., Vector's more recent spate of events versus Orion's more recent benign period. Consideration of a shorter period was made when Orion moved from their CPP to the DPP, and it was concluded that the 10-year reference period remained appropriate, and this has been true in practice

E386 Wellington Electricity submitted that it supported retaining a 10-year reference period for unplanned outages only and considered planned outages should be linked to an EDB's work programme:[522]

> We support The Issues Paper's position to maintain a 10-year reference period for unplanned outages rather than extending it to 15 years as this will better reflect the "current underlying level of reliability performance and network operation practices … we believe that planned quality targets should be a function of the capex programme rather than a historic reference period. The historic planned outage levels will be a function of the past investment focus of asset replacement and will not reflect the step change in network growth and new connections capex needed to deliver New Zealand's decarbonisation targets.

E387 Aurora and Flick both disagreed with a 10-year reference period for different reasons.

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[520] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 23; The Lines Company "DPP4 Issues paper submission" (19 December 2023) p. 10; Vector "DPP4 Issues paper submission" (19 December 2023) p. 40, paragraph 148; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023) p. 17; Horizon Networks "DPP4 Issues paper submission" (19 December 2023) p. 14; Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023) p. 16.

[521] Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023) p. 16.

[522] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 52, section 9.3.

E388 Aurora considered that:[523]

> The application of the 10-year historic DPP3 methodology to Aurora Energy would not correctly capture recent performance levels and would therefore lead to adverse regulatory outcomes with inappropriate breach limit risks and unrealistic targets for the incentive scheme. We support a continuation of the Aurora CPP period limits and targets.

E389 Flick considered that:[524]

> It is well understood that network assets are aging. Quality performance is likely to deteriorate at a faster rate as assets get towards their end of life. We suggest a 10-year reference period will hide this deterioration.

E390 We separately assessed whether it may be more appropriate for Aurora to remain on its CPP period limits and targets (see *Quality Standards*, draft decision QS10 above).

E391 We consider the current approach for setting quality standards should detect asset deterioration given it is an annual test compared to the 10-year reference period. We consider extending the reference period may include historical data which is not necessarily reflective of the current network and in some instances may be less reliable. A ten-year reference period will identify asset deterioration to extent these result in failures as would be anticipated under a “bathtub curve”. Given standards are set with regard to the ‘no material deterioration’ principle they inherently are consistent with the historic data series. We note as DPP4 progresses the reference period will progressively move to be greater than 10 years old.

*RP1: Use a 10-year reference period from 1 April 2013 to 31 March 2023 to inform the parameters for unplanned interruptions reliability standards and incentives, with the period adjusted to 1 April 2014 to 31 March 2024 for the final determination*

**Draft decision**

E392 Our draft decision is to use a 10-year reference period from 1 April 2013 to 31 March 2023 to inform the parameters for unplanned reliability standards and incentives, with the period adjusted to 1 April 2014 to 31 March 2024 for the final determination.

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523 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 13, paragraph 52.

524 Flick Electric "DPP4 Issues paper submission" (19 December 2023), p. 2.

**Analysis conducted**

E393 We consider that setting the reference period at ten years for unplanned interruptions is appropriate, as the period is:

E393.1 long enough to account for longer term weather cycles,

E393.2 long enough to mitigate year-on-year variation due to circumstances outside the EDBs' control,

E393.3 long enough in that it better reflects the operating environment of EDBs, and evens out changes, and

E393.4 best reflects the current underlying level of reliability performance, given the availability of reliable and consistent data.

**Alternative considered**

E394 We considered setting reliability parameters, where EDBs would need to adjust SAIDI and SAIFI parameters each year to reflect the latest years performance, would add a level of complexity for little added value given the volatile nature of SAIDI and SAIFI. For this reason, we considered that fixing reliability parameters for the regulatory period using data from the most recent 10 years to be a simpler approach, while still approximating the expenditure incentives.

E395 In considering extending the reference period dataset for unplanned interruptions to cover a longer period of time, for instance 15 years, there is a trade-off between more data evening out variations, but potentially being less reflective of the current network and associated interruption management approaches. The 10-year period appropriately balances this trade-off.

**Conclusion**

E396 For DPP4 our draft decision for DPP4 is to apply a 10-year reference period for establishing the unplanned interruption settings updated for the most recent information.

*RP2: Apply a reference period for planned interruptions of 1 April 2017 – 31 March 2023 for the draft decision, extended to 1 April 2017 – 31 March 2024 for the final decision*

**Draft decision**

E397 Our draft decision is to use a 7-year reference period from 1 April 2017 to 31 March 2023 to inform the parameters for planned interruptions reliability standards and incentives, extended to 1 April 2017 – 31 March 2024 for the final determination.

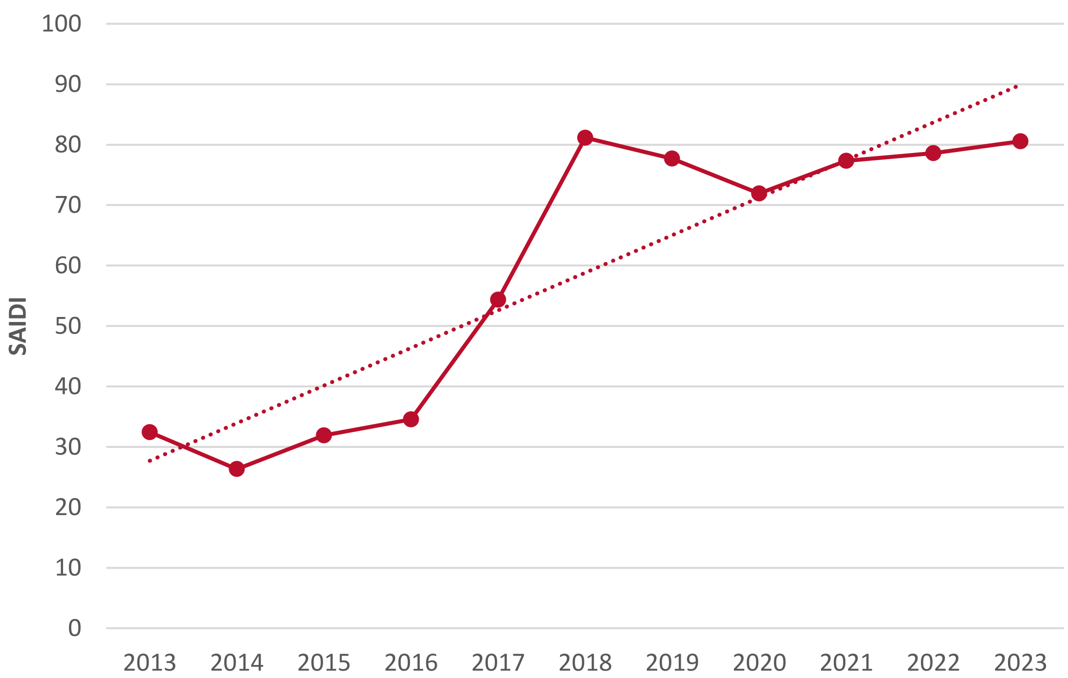
**Analysis conducted**

E398 From 2017 to 2023, we have seen a step change where planned interruptions have changed significantly across nearly all non-exempt EDBs compared to previous periods (see Figures E4 and E5). This may imply a shortening of the 10-year reference period is appropriate to more accurately reflect current network practices given planned interruptions are largely within the control of the EDBs.

E399 The significant increase on average in planned interruptions started occurring in DPP2 (2017 – 2020) before the separation of the planned and unplanned quality standard, so we do not consider there is a direct relationship between the planned interruptions settings in DPP3 and the significant increase in planned interruptions.

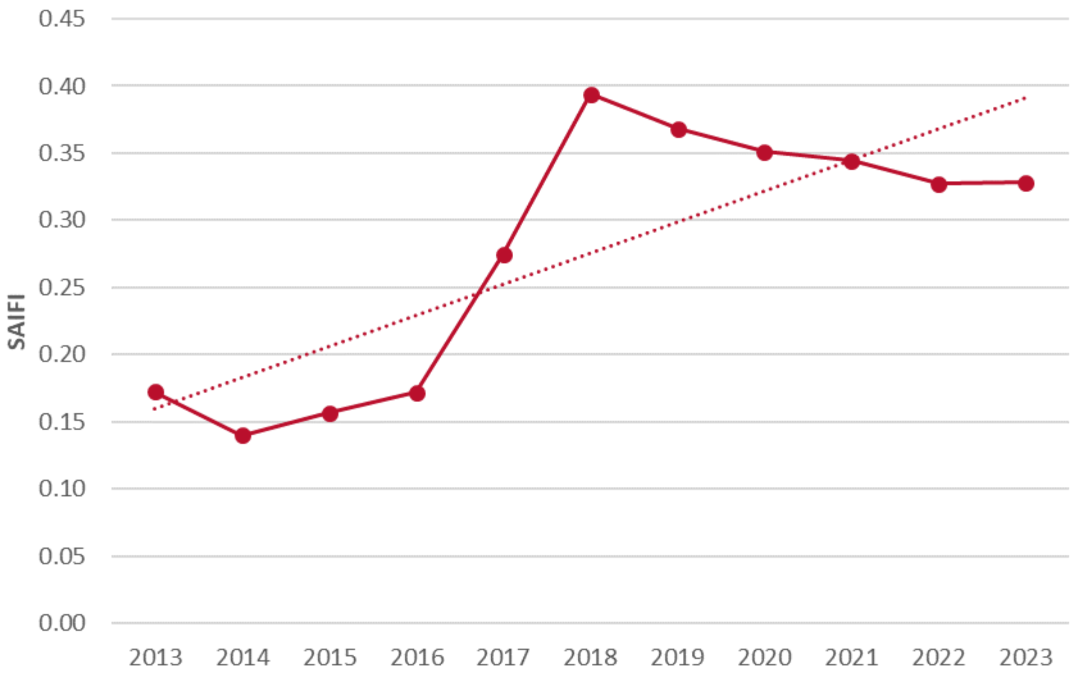
E400 We have not analysed the detailed underlying datasets to understand potential drivers as this is likely to be an extensive piece of work but consider the changes are likely to be a combination of increased planned work programmes reflecting increased investment associated with network renewals of assets reaching end of physical lives and changes in operational procedures (eg, live lines).

**Figure E4 Average planned SAIDI for non-exempt EDBs[525]**




[525] Based on Schedule 10(i) planned interruptions data required under information disclosure regulation. We note that the Information Disclosure rules have different calculations to those required under the DPP Determination, but the data represents a consistent data series.

**Figure E5 Average planned SAIFI for non-exempt EDBs**




E401 We note that EDBs have stated an increased expectation of planned interruptions means the reference period may not be as relevant for setting the target. Our ability to use a different basis, other than a historical reference period, for setting the standard was discussed earlier under *Setting the SAIDI target for the QIS at the historical average* where we noted EDBs ID did not reflect an increase in planned interruptions, and we were not well placed to estimate one in the absence of further information.

**Alternatives considered**

E402 We considered adjusting historical baselines to align with forecast capex increases, but do not have a robust dataset on which to determine an appropriate adjustment.

**Conclusions**

E403 For DPP4, our draft decision is to apply a reference period for planned interruptions of 2017 – 2023 for the draft decision, extended to 2017 – 2024 for the final decision. We consider shortening the reference period from a 10-year reference period better reflects current planned interruption practices employed by EDBs.

**Inter-period data adjustment**

*RP3: Retain the cap on inter-period movement, ±5% for unplanned interruptions for both the SAIDI and SAIFI unplanned target and also apply this to the SAIDI and SAIFI unplanned limits*

**Nature of the decision**

E404 Aside from acceptable movements within the cap-collar range where EDBs already receive rewards and penalties, we need to consider that deteriorating performance may result in more lenient standards for the next regulatory period; and improved performance may lead to stricter standards.

**Draft decision**

E405 Our draft decision is to retain the cap on inter-period change in unplanned interruptions and apply it to both the targets and limits.

**How the decision is aligned to the decision-making framework for the DPP**

E406 This setting will help to reduce the potential for significant changes in the reliability parameters without further scrutiny of whether the potential changes are consistent with consumers' long-term interests.

**What we heard from stakeholders**

E407 There was a single submission to the issues paper on this issue. Powerco supported a ±5% limit on inter-regulatory period change.[526]

> 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.

**Analysis conducted**

E408 We note that as five years (1 April 2014 to 31 March 2019) are common to both DPP3 and DPP4 reference periods, we have effectively allowed a maximum change of around 10% over 10 years (2014-2019 v 2019-2023).

E409 Table E23 shows the results of applying 5% cap to unplanned SAIDI targets for DPP4. Green cells identify reductions greater than 5% from DPP3. Red cells identify uplifts greater than 5% from DPP3.

[526] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 24.

#### Table E23 DPP3 vs Draft DPP4 5% cap applied to unplanned SAIDI targets

| EDB | DPP3 SAIDI Target | DPP4 SAIDI Average Unadjusted | DPP3 to DPP4 Movement | DPP4 SAIDI Target (capped) |
|---|---|---|---|---|
| Alpine Energy | 91.88 | 90.14 | -1.9% | 90.14 |
| Aurora Energy | 88.08 | 97.98 | 11.2% | 92.48 |
| EA Networks | 71.65 | 71.30 | -0.5% | 71.30 |
| Firstlight Network | 173.85 | 188.34 | 8.3% | 182.54 |
| Electricity Invercargill | 15.39 | 17.10 | 11.1% | 16.16 |
| Horizon Energy | 144.35 | 138.45 | -4.1% | 138.45 |
| Nelson Electricity | 9.53 | 5.84 | -38.7% | 9.06 |
| Network Tasman | 74.49 | 72.21 | -3.1% | 72.21 |
| Orion NZ | 66.47 | 48.70 | -26.7% | 63.14 |
| OtagoNet | 120.02 | 132.62 | 10.5% | 126.02 |
| Powerco | 151.96 | 166.17 | 9.4% | 159.56 |
| The Lines Company | 143.04 | 179.81 | 25.7% | 150.19 |
| Top Energy | 302.16 | 320.65 | 6.1% | 317.27 |
| Unison Networks | 67.81 | 71.10 | 4.8% | 71.10 |
| Vector Lines | 89.28 | 120.36 | 34.8% | 93.74 |
| Wellington Electricity | 31.20 | 29.96 | -4.0% | 29.96 |

E410 We consider deteriorating performance should not be rewarded with relaxed standards, consistent with the 'no material deterioration' principle.

E411 Table E24 shows the results of applying the 5% cap to determine the unplanned interruption reliability limits, which reflects that the cap will impact the setting of the limits for number of EDBs with more recent volatility in SAIDI and SAIFI performance.

#### Table E24 DPP3 vs Draft DPP4 5% cap applied to unplanned SAIDI and SAIFI limits

| EDB | SAIDI | | | | SAIFI | | | |
|---|---|---|---|---|---|---|---|---|
| | DPP3 SAIDI Limit | DPP4 SAIDI Unadj | DPP3 to DPP4 Change | DPP4 SAIDI Limit (capped) | DPP3 SAIFI Limit | DPP4 SAIFI Unadj | DPP3 to DPP4 Change | DPP4 SAIFI Limit (capped) |
| Alpine Energy | 124.71 | 121.69 | -2.4% | 121.69 | 1.20 | 1.02 | -14.9% | 1.14 |
| Aurora Energy | 124.94 | 122.05 | -2.3% | 122.05 | 2.07 | 1.87 | -9.6% | 1.97 |
| EA Networks | 91.98 | 90.84 | -1.2% | 90.84 | 1.28 | 1.31 | 2.2% | 1.31 |
| Firstlight Network | 219.46 | 237.47 | 8.2% | 230.43 | 3.15 | 3.23 | 2.6% | 3.23 |

| EDB | SAIDI | | | | SAIFI | | | |
|---|---|---|---|---|---|---|---|---|
| | DPP3 SAIDI Limit | DPP4 SAIDI Unadj | DPP3 to DPP4 Change | DPP4 SAIDI Limit (capped) | DPP3 SAIFI Limit | DPP4 SAIFI Unadj | DPP3 to DPP4 Change | DPP4 SAIFI Limit (capped) |
| **Electricity Invercargill** | 25.86 | 29.15 | 12.8% | 27.15 | 0.70 | 0.71 | 1.5% | 0.71 |
| **Horizon Energy** | 194.53 | 183.01 | -5.9% | 184.80 | 2.39 | 2.02 | -15.4% | 2.27 |
| **Nelson Electricity** | 19.60 | 14.90 | -23.9% | 18.62 | 0.43 | 0.30 | -29.0% | 0.41 |
| **Network Tasman** | 101.03 | 97.73 | -3.3% | 97.73 | 1.20 | 1.03 | -13.4% | 1.14 |
| **Orion NZ** | 84.71 | 59.84 | -29.4% | 80.47 | 1.03 | 0.76 | -26.4% | 0.98 |
| **OtagoNet** | 160.35 | 173.78 | 8.4% | 168.37 | 2.42 | 2.49 | 3.2% | 2.49 |
| **Powerco** | 180.25 | 195.72 | 8.6% | 189.27 | 2.27 | 2.12 | -6.6% | 2.15 |
| **The Lines Company** | 181.48 | 227.26 | 25.2% | 190.55 | 3.27 | 3.43 | 4.9% | 3.43 |
| **Top Energy** | 380.24 | 404.84 | 6.5% | 399.25 | 5.07 | 4.52 | -11.0% | 4.82 |
| **Unison Networks** | 82.34 | 86.81 | 5.4% | 86.46 | 1.82 | 1.87 | 3.2% | 1.87 |
| **Vector Lines** | 104.83 | 139.47 | 33.0% | 110.07 | 1.34 | 1.53 | 14.2% | 1.40 |
| **Wellington Electricity** | 39.81 | 37.84 | -4.9% | 37.84 | 0.61 | 0.56 | -7.9% | 0.58 |

### Conclusion

E412 We received only one single submission which supported the use of 5% cap on inter-regulatory period change for unplanned reliability. Our draft decision is to retain the 5% cap on inter-period movement for unplanned interruptions and apply it to both the targets and limits for unplanned reliability.

*RP4: Make no explicit step changes to the interruption data series*

### Nature of the decision

E413 We consider 'no material deterioration' to continue to be the starting point for quality standards and QIS. However, we recognise that certain factors may create a requirement to include a forecast step change to reliability parameters for quality standards and incentives as compared to the reference period, or an ability to exclude certain interruptions.

E414 For DPP4, the criteria for assessing step changes in reliability are that any changes:

E414.1 be significant

E414.2 be robustly verifiable

E414.3 be largely outside the control of the EDB

E414.4 in principle, affect the reliability of most, if not all, EDBs, and

E414.5 not be captured in the other components of our reliability parameters (reference period, normalisation methodology).

E415 We consider these criteria to be broadly appropriate, but consider similar to the application for opex these may be more appropriately considered as factors, rather than definitive criteria.

E416 We note that where reliability step changes are specific to an EDB they may more appropriately be the subject of a quality standard variation reopener, or where the investment is significant, a CPP proposal.

E417 We note that we have separately considered some potential step changes elsewhere within this document, so these are not explicitly covered within the section below:

E417.1 expectations of increases in planned interruptions where there is increasing capex spend covered under the section *QIS5: Setting the SAIDI target for the QIS at the historical average*, and

E417.2 change in recording approaches, including inconsistency of SAIFI outage recording, covered within the section *RP6: EDBs must record successive interruptions on the same basis they employ in responding to the s 53ZD notice*.

E418 As discussed in the section RP5: Make no explicit adjustments for instances of non-compliance constrained within the unplanned interruptions reference period dataset, the 'multi-count' issue which has been addressed, at least in part, by allowing EDBs to maintain a consistent reporting approach.

*RP5: Make no explicit adjustments for instances of non-compliance contained within the unplanned interruptions reference period dataset.*

E419 In the s 53ZD notice we requested EDBs to identify if there had been a material change in their policies and procedures for recording and capturing interruptions. Apart from a submission by Aurora, which was considered separately we are not aware of any changes in approach which need to be accommodated.

**Draft decision**

E420 Our draft decision is to make no explicit step changes to the interruption data series.

E421 We have noted below the analyses of how we have considered or addressed various possible step changes.

**Stakeholder views**

E422 In submissions on the issues paper, Wellington Electricity noted that if the tree regulations are finalised in time to include in the draft price path, then it would support a step change to reflect any quality impact. If they are not finalised in time, then it agrees with the proposed approach of using a reopener.[527]

E423 The Lines Company considered that lines through forestry blocks and an increase in carbon farming blocks are major concerns and an "outside the control" issue for The Lines Company.[528] However, it did not offer any further comment.

E424 Vector suggested carving out or normalising SAIDI and SAIFI minutes for bush fire risk and where emergency services prohibit access to the outage site.[529] Unison supported both carve-outs in cross submissions.

> Meanwhile as our summers get warmer the risk of bush fires has become a grave concern for EDBs. With lessons learned from the recent fires in Maui, a viable solution to avoid the spread of bush fires is to turn off the feeders that could if left on help spread them. If an EDB had to resort to this solution the impact of SAIDI would be huge. EDBs can plan as much as possible to circumvent fire damaging the network and its surrounding trees, but a bush fire is not something to take lightly when lives are at stake.
>
> The above circumstances are imminent and the if they occur will be outside control of the EDB. We suggest this is an ideal candidate for a reliability step change by carving out or normalising SAIDI and SAIFI for any instances of shutdowns in the case of a bush fire risk management.

527 Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 54, paragraph 9.5.3.

528 The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023), p. 11.

529 Vector "DPP4 Issues paper submission" (19 December 2023), pp. 3 and 41, paragraph 155-156; Unison "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 10.

E425 In submissions on the DPP4 issues paper, certain EDBs raised the concern that extreme weather events could increase in frequency and severity moving forward due to the effects of climate change. This comes after a year of significant one-off weather events, where some EDBs were extensively affected (as reflected by their non-compliance with the unplanned interruptions reliability standards).

E426 As such, they recommended that the unplanned interruptions reliability targets and normalisation method needed adjustment to account for this in DPP4. [530]

E427 Certain submitters on the issues paper suggested we should look forward, rather than backward and to check advice from NIWA and other experts. [531]

E428 Vector stated:

> The Commission must reconsider its allowance for major event days when setting quality standards. This must be done looking forward not backwards as history will not be a good predictor in this case as climate change will result in a level of major events not seen in past years. The Commission must work with weather agencies in forming its view.

E429 Powerco stated:

> 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.

E430 Unison and Orion both supported Vector's submission in cross submissions.[532]

**Analysis**

**Step changes due to changes in operational procedures**

E431 Certain step changes may arise from changes in maintenance and issue resolution processes, which may result in inconsistencies in the dataset.

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[530] For DPP2 and DPP3, we adapted the IEEE's methodology for normalisation. This methodology was based on the expectation of 2.3 major event days per year.

[531] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023) p. 17; Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023) p. 16; Powerco "DPP4 Issues paper submission" (19 December 2023), p. 24; The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023) p. 10; and Vector "DPP4 Issues paper submission" (19 December 2023) p. 3.

[532] Orion New Zealand Ltd (26 January 2024), pp. 13-14; Unison "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 10.

E432 MBIE are shortly to begin consultation on amendments to the Electricity (Hazards from Trees) Regulations 2003 with amendments expected to be gazetted in September 2024. We are unclear what the outcome of this process will be and the timing of when any change might apply. We consider this is best dealt with via a reopener, subject to the appropriate criteria being met once further clarity on the potential impact on EDBs is available.[533]

E433 We consider the above issues raised by The Lines Company (related to lines through forestry blocks and carbon farming blocks) will be considered as part of reform of tree regulations, and any adjustment is better considered following that decision.

**Bush Fire risk**

E434 We understand that it is good industry practice to turn off "auto-reclose" in times where high fire risk is identified for EDBs. The reason for turning off is to reduce the risk of a feeder fault igniting dry vegetation~~.~~

E435 We also understand that where there is an active fire that EDBs isolate power when requested by emergency services, so this does not create an additional risk for emergency service personnel.

E436 We are aware that in certain conditions, such as high winds, extreme fire risk condition, faults on feeders may increase the risk of vegetation fires. We understand that under these conditions EDBs consider turning off feeders, interrupting supply to consumers, to reduce the fire risk to communities. This is current practice in Australian high fire risk zones.

E437 We are interested in hearing from EDBs who have developed policy and implemented the processes, or are considering the approach, to understand the potential impact to customers of this approach.

[533] We note the "Change event" reopener (at clause 4.5.5 of the EDB IMs) requires that the legislative change (a) results in additional reasonable costs (whether capex, opex, or both) to respond to the changed requirement that exceed one of the thresholds specified in subclause (3); or (b) causes an input methodology to become incapable of being applied.

There is not a specific provision which provides for a reopener to the path where changes to the Regulations result in expected change in quality outcomes, but no change to costs. We consider this is practically an unlikely outcome. In the event this does occur an EDB could apply for a quality standard variation reopener.

**Emergency Services prohibiting access to outage sites**

E438 Vector submitted that we should consider carving out SAIDI and SAIFI minutes attributable to the prohibition of access to an outage site by emergency services.

E439 While these circumstances are "largely outside the control of the EDB", and affect most EDBs in principle, we note two reasons why we do not intend to make any adjustments:

E439.1 we are not aware of any changes in emergency services practices that would deviate from those seen in the current reference period, and

E439.2 adjustment would be practically difficult given most EDBs will not have this distinction recorded in their systems, making it a one-way adjustment.

**Climate Change**

E440 In the sections relating to Normalisation and Reference Period, we noted that impacts of expected volatility in underlying performance, including those attributable to climate change are considered by multiple parts of the quality regime including the length of the reference period, MED normalisation and the setting of the boundary value for quality standard non-compliance.

E441 Whilst broadly the risk of climate change will be significant on EDBs, the time period under which we are likely to see significant change compared to historical averages is uncertain. We note that the IEEE did not change their statistical expectation of 2.3 MEDs per year in its 2022 re-assessment.

E442 We consider that the impacts of climate change are outside the control of the EDBs and will affect all EDBs, though that impact is likely to be uneven based on the network configuration and geographic location.

E443 We consider that we do not have a robust approach for implementing a step change due to climate change and volatility is better accounted for within the buffer which applies for unplanned interruptions, with normalisation reducing the impact of an increased frequency of severe events.

E444 While the effects of climate change may prove to be significant, our draft decision is that no step change is applied at this time because:

E444.1 impacts of expected volatility in underlying performance, including those attributable to climate change, are considered by multiple parts of the quality regime

E444.2 climate change risk assessment and management is an evolving space. The material impact of climate change as compared to the historical average, in the forthcoming DPP4 period, is uncertain

E444.3 the IEEE considered the effects of climate change, yet in 2022 maintained the expectation of 2.3 MEDs per year

E444.4 the impact of climate change on EDBs will be uneven based on network configuration (ie, underground vs overground) and geographic location, and

E444.5 the buffer mechanism and normalisation of MEDs both provide protection against the inherent volatility presented by weather.

**Conclusions**

Our draft decision is to not make explicit step changes to the interruption data series, following our analysis on each of the possible step changes and response to submissions.

*RP5: Make no explicit adjustments for instances of non-compliance contained within the unplanned interruptions reference period dataset.*

E445 We note there are instances of non-compliance contained within the unplanned interruption reference period dataset.

E446 We consider that the 5% cap, which applies to both the unplanned interruptions reliability targets and limits, appropriately addresses the unintended consequences that deteriorating performance results in more lenient standards for the next regulatory period. This is consistent with the 'no material deterioration' principle.

E447 We considered an alternative approach of removing specific years from the reference period, but note this was not appropriate as DPP2 applied a two-out-of-three-year rule, with an associated lower standard deviation (1.0) and a different normalisation approach for MEDs.

*RP6: EDBs must record successive interruptions on the same basis they employ in responding to the s 53ZD notice.*

**Nature of the decision**

E448 A successive interruption means an interruption that follows an initial interruption that either:

E448.1 relates directly to that initial interruption, or

E448.2 occurs as part of the process of restoring supply of electricity lines services following that initial interruption.

E449 In setting DPP3 it was identified that EDBs were applying different recording practices with regards to successive interruptions, which resulted in different recording of associated SAIDI and SAIFI values.

E450 If an interruption to the supply of electricity distribution services is followed by restoration, and then by a successive interruption, some EDBs had been calculating the relevant SAIFI values based on a single interruption, rather than multiple interruptions. Other EDBs were only recognising successive interruptions after they completed certain operational practices. We refer to these practices as an 'aggregation' approach.

E451 A "multi-count" approach involves recording all successive interruptions as an additional SAIFI value if restoration of supply occurs for longer than a certain amount of time (for example, one minute).

E452 As part of the DPP4 draft decision we must decide the basis (or bases) acceptable for EDBs to recognise successive interruptions in their calculation of SAIFI values.

**Draft decision**

E453 Our draft decision is to retain the approach that EDBs must record successive interruptions on the same basis they employed in responding to the s 53ZD notice. Where an EDB provided datasets on multiple basis, we have used the multi-count dataset.

**What we heard from stakeholders**

E454 There were several submissions on the issues paper on the multi-count approach. In general, they support allowing individual EDBs to record successive interruptions using an aggregate or multi-count approach, as they deem appropriate.

E455 Confirming our understanding of the inconsistency amongst EDBs of how they record successive interruptions, Orion noted that they already record on a multi-count basis[534].

[534] Orion New Zealand Ltd "DPP4 Issues paper submission" (19 December 2023), p. 17.

E456 Submissions on the issues paper from Horizon, Unison, The Lines Company and Wellington Electricity suggest they have been calculating the relevant SAIFI values for successive interruptions based on a single interruption (an 'aggregate' approach).[535]

E457 Unison noted that a consistent approach to reporting multi-count data will require system changes and EDBs need adequate understanding of the approach to build that reporting capability.[536]

E458 Some submissions considered some EDBs would not have or be able to approximate a robust multi-count dataset to inform DPP4.

E459 ENA noted: [537]

> For some EDBs, the adoption of the multicount approach to SAIFI occurred in 2023. As a result, some EDBs do not have data sufficient for the calculation of robust multicount SAIFI thresholds for the DPP4 period.

E460 Horizon noted that it has been working on back-casting SAIFI using the multi-count approach:[538]

> Our learnings so far is that this is not a simple task and due to the techniques required to retrospectively generate a multi-count SAIFI dataset and limited historical information available will not have the evidence base required for an unqualified audit opinion

E461 Wellington Electricity, ENA and Horizon all suggested each EDB be able to take a different approach to their recording of successive interruptions.

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535 Horizons Networks "DPP4 Issues paper submission" (19 December 2023), p.15; Unison Networks Ltd "DPP4 Issues paper submission" (19 December 2023), p. 19; The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023) ,p. 11; Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 53, section 9.5.2.

536 Unison Networks Ltd "DPP4 Issues paper submission" (19 December 2023), p. 19.

537 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023),p.16.

538 Horizons Networks "DPP4 Issues paper submission" (19 December 2023), p.15.

E462 Wellington Electricity disagreed with the need for a consistent approach to measuring SAIFI as it considers comparison across different networks to be meaningless, given other factors like network density, asset age, and network design, drive the majority of differences in SAIDI/SAIFI measures. It considers a constant historical approach to measure changes in quality performance for a specific network in what is important. [539]

E463 Wellington Electricity considers the best solution is to allow EDBs to choose which method best incentivises the level of quality that customers on their networks want. Wellington Electricity supports treating successive interruptions as a single outage on the Wellington network as it incentivises it to restore power as quickly as possible, which is what Wellington customers want. Wellington Electricity state that the best way to do this is to sectionalise an outage, which will create repeat tripping and successive interruptions, and incur lower SAIDI but higher SAIFI.

E464 ENA stated: [540]

> For some EDBs, the use of the multicount approach commenced in 2023-24. For these EDBs, ENA suggests they be able to apply to have historical non-multicount data used to set a non-multicount SAIFI threshold [for compliance testing and quality incentives]. To maintain comparability with EDBs who collect and report on a multicount basis, ENA recommends that the Commission also publish a target multicount SAIFI (for those businesses transitioning to the multicount approach) and require these EDBs to report against this target.

E465 Horizon recommended: [541]

> Given that EDBs are required to produce the multi-count information in future IDs, Horizon Networks recommends that existing, audited SAIFI standards are used for setting DPP4 targets with a view to transitioning to multi-count in DPP5, where there will be sufficient, audited historic information available to make an informed decision. Horizon Networks supports reporting multi-SAIFI as part of DPP4, however, it is not possible to set a robust multi-SAIFI target for EDBs that don’t have reliable historical multi-SAIFI information.

[539] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 53, section 9.5.2.

[540] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p.16-17.

[541] Horizons Networks "DPP4 Issues paper submission" (19 December 2023), p. 15.

**Analysis conducted**

E466 In DPP3, we determined that EDBs should record successive interruptions in a manner that is consistent with that applied by them for the fourth assessment period of the DPP2 regulatory period, as represented in the information provided to us in the s 53ZD notice regarding the DPP3 reset. This was due to the inability of EDBs to adjust the historic data series to apply a consistent approach across all EDBs, and perceived difficulties in establishing systems to record on a multi count approach.

E467 This approach maintains internal consistency of assessment and whilst SAIFI values are determined on a different basis and therefore not directly comparable, there are a number of other factors which inherently drive different SAIFI outcomes – network configuration, etc.

E468 In the s 53ZD notice we issued on 10 November 2023, we asked EDBs to provide their interruptions reference dataset, and to identify whether this dataset had been prepared using a multi-count approach or an alternative basis.

E469 If an alternative basis was used to record interruptions, EDBs were asked to explain the method used.

E470 Where there was a material change to EDBs' interruption recording method that occurred between 1 April 2019 and 31 March 2023, EDBs were asked to disclose the date on which that change occurred and the nature of the change.

E471 In responding to the s 53ZD notice, several EDBs provided a reference dataset using the multi-count approach or aggregate approach, while one provided two datasets using both approaches. EDBs were largely silent on whether they could back-cast a reference dataset using the multi-count approach. Only Wellington Electricity and Horizon noted their inability, or difficulty with doing this, consistent with their submissions to the issues paper.

E472 In the issues paper we stated we would consider whether there was an appropriate proxy which could apply. Despite the request in the s 53ZD notice, we consider we have not gathered sufficient data series to determine if there is an appropriate proxy to apply, nor did we receive any submissions on proxies which stakeholders thought could apply.

E473 Wellington Electricity's submission stated it would not support using a proxy data set to move to a multi-count method, noting that approximating historic data would further degrade the operating of the quality standards by adding forecast risks into the quality targets.[542]

E474 We note that as part of recent Targeted Information Disclosure Review (TIDR) changes we will receive SAIDI and SAIFI values on 31 August 2024 produced on both bases for those EDBs who were not previously applying a multi-count approach. This could be used to establish the potential variance in values caused by the different approaches and could also be used as a proxy if the impact could be clearly identified.

E475 We intend to further consider whether a proxy is appropriate to apply to change the historic reference dataset to be more reflective of equivalent outcomes. If the multi-count approach is applied, we will consider the materiality of difference between the datasets and whether different EDBs have materially different outcomes. If neither of these values are material, then we would consider applying the proxy adjustment for the final decision and require EDBs to report on the multi-count basis. This would reduce compliance costs to EDBs as they would not have to maintain different recording approaches, as occurs under the current proposed approach. We note translating the impact of values for 2024 to a historical data series may be challenging if the values are material.

E476 Whilst we have one dataset to determine the potential size of a proxy adjustment, we consider we need a greater set of disclosures to better understand if the proxy is reasonably representative.

**Conclusions**

E477 We consider it is important that EDBs maintain a consistent recording approach with regards to successive interruptions. While different EDBs may employ their own practices, by ensuring that each EDB maintains an approach consistent with their past recording practices, we can set standards and assess their reliability consistently as well. This upholds the principle of 'no material deterioration', which underpins our quality regime.

[542] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 53, section 9.5.2.

E478 An advantage of our draft decision is that it would be relatively straightforward for EDBs to apply because it reflects their existing operational practices. We will consider whether there is an appropriate proxy adjustment (which can be used to approximate the impact of switching from an aggregate to multi-count approach) which can be applied to the data following receipt of 2024 ID information. This would enable a singe common basis for future reporting requirements under the DPP and ID.

*RP7: Exclude INTSA approved projects or programmes from assessed SAIDI and SAIFI subject to any cap for the quality standards and quality incentive scheme (QIS*)

**Nature of the decision**

E479 We consider that excluding certain interruptions from the quality standard and QIS to account for non-performance of innovative solutions may address concerns that the regime may discourage innovation.

**Draft decision**

E480 Our draft decision is to exclude outages directly associated with an approved Innovation and non-traditional solutions allowance (INTSA) project from the calculation of SAIDI and SAIFI values up to a cap of 0.5% of the respective SAIDI and SAIFI limits.

**What we heard from stakeholders**

E481 Submissions and cross submissions on the issues paper supported removing barriers to innovation and provided their views on how to adjust for the non-performance of non-traditional and innovative solutions, including further exclusions from the definition of an "interruption".[543]

E482 Unison, among others, suggested that this should include investment in energy efficiency and demand side management, eg, flexibility and DER.[544] Vector, supported by Unison in cross submissions, considered it should also cover when a network operator has issued a dynamic operating envelope (DOE) and third parties have failed to comply.[545]

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[543] Commerce Commission "Electricity Distribution Services Default Price-Quality Path Determination 2020 [2019] NZCC 21" (27 November 2019), defines the term 'interruption' under clause 4.2.

[544] Unison Networks Ltd "DPP4 Issues paper submission" (19 December 2023), p. 22.

[545] Vector "DPP4 Issues paper submission" (19 December 2023), p. 22; Unison "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 10.

E483 SolarZero considered that the Commission needs to think through how to adjust settings to more strongly encourage uptake of more cost-effective distributed energy resources and related Virtual Power Plant technologies because these are going to become more ubiquitous over the coming 5 years.[546]

E484 Views expressed include that:

E484.1 we revisit the IM decision to not introduce regulatory sandboxing

E484.2 we introduce a new outage category for non-network solutions that is excluded from quality compliance assessments and the QIS, and

E484.3 any adjustments should be temporary and linked to specific trial activities.

E485 Vector recommended "the Commission revisits its IM decision to not introduce regulatory sandboxing to cater for innovation trials which may impact SAIDI/ SAIFI."[547,548] It suggests the sandbox could be geographical and ensure consumers were onboard with a trial's purpose and potential consequences. It considers that keeping the sandbox targeted in this way for a DPP will avoid complexity and keep it low-cost.[549]

E486 Rewiring Aotearoa supported Vector's views in cross submissions, noting that it is important regulations that facilitate sandboxes do not become so overly cumbersome that there is little incentive to use them. It also generally supported "carve-outs" in respect of quality standards where it has been caused by a flexibility provider or failure to comply with a DOE. "However, the quid pro quo is that EDBs must not adopt punitive consequences for the flexibility providers in such events".[550]

E487 Several submissions (Aurora, ENA, FlexForum, Horizon, Powerco, The Lines Company) and cross submissions (Orion, Rewiring Aotearoa, Unison) suggested that we introduce a new outage category for non-network solutions that is excluded from quality compliance assessments and the QIS.[551]

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546 SolarZero "DPP4 Issues paper submission" (15 December 2023), p. 9.

547 Vector "DPP4 Issues paper submission" (19 December 2023), p. 3.

548 We note that there is no IM for quality standards or quality incentive schemes.

549 Vector "DPP4 Issues paper submission" (19 December 2023), pp. 40-41.

550 Rewiring Aotearoa (26 January 2024), p. 7-8.

551 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 15; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 18; FlexForum "DPP4 Issues paper submission" (19 December 2023), p. 9; Horizons Networks "DPP4 Issues paper submission" (19 December

E488 Wellington Electricity would not support permanently expanding the definition of an interruption to exclude interruptions relating to the non-performance of flexibility services. It states:[552]

> The quality measures, including what's counted as an interruption, should reflect customer expectations so that EDBs can manage their networks to meet those expectations. It is then an EDBs responsibility to manage the network to deliver the expected quality levels using the most efficient tools and solutions to do so. ... Excluding the non-performance of flexibility service from the interruption definition would also send the wrong incentives to flexibility providers. If EDBs pay for flexibility services, then there will also be an expectation that they should be reliable.

E489 Horizon recommended (emphasis added):

> …the DPP includes a "quality allowance" for innovative solutions, that is linked directly to the actions of the innovation and recognises that these approaches may take time to establish and understand but sets a limit beyond which the EDB will need to decide it if wishes to continue with the innovation (and wear the quality consequences) or abandon the innovation to minimise future disruption to consumers.[553]

E490 Wellington Electricity supported temporarily excluding the impact of flexibility services from the quality targets while they are being developed, but consider the innovation mechanism is a better tool that would allow application to specific trial activities. It suggests:[554]

> We suggest a specific innovation mechanism for flexibility services that includes a standard exception for all services funded by the innovation allowance to also provide an exception to exclude any SAIDI/SIFI impacts from the annual quality assessment. We support a sand box approach.

E491 On a related matter, Electra suggested:

> Such recognition could also be extended to the reliability and security of supply through reduced service during interruptions. Battery storage, for example, has the potential to enhance reliability and support the security of supply during interruptions, if not full service, then partial services. Battery storage, a non-

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2023), p. 18; Powerco "DPP4 Issues paper submission" (19 December 2023), p.27; The Lines Company Ltd "DPP4 Issues paper submission" (19 December 2023), p.13; Unison Networks Ltd "DPP4 Issues paper submission" (19 December 2023), p. 22; Orion New Zealand Ltd (26 January 2024), p. 12; and Rewiring Aotearoa (26 January 2024), pp. 7-8; Unison "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 10.

[552] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 54, section 9.5.5.

[553] Horizons Networks "DPP4 Issues paper submission" (19 December 2023), p. 18.

[554] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 54, section 9.5.5.

traditional solution, might be effective on the remote parts of our network and utilised to improve consumer experience during interruptions.

> …Under the current approach, the SAIDI and SAIFI calculation for the interruption would include those ICPs with alternative or partial supply. These ICPs contribute to the overall SAIDI and SAIFI calculation despite those ICPs not being interrupted because they can receive services via batteries.
>
> We are exploring if there is a way that the SAIDI and SAIFI calculations could take account of alternative or reduced services when calculating the interruption of SAIDI and SAIFI.
>
> We believe excluding the ICPs altogether from performance is inappropriate. While these consumers may be receiving services, these services might be at lower than standard operating levels (e.g., half the installed capacity). However, equally including these ICPs in the interruption without consideration for partial supply is also inappropriate, as these consumers would not be entirely without services.[555]

### Analysis conducted

E492 We recognise that innovative approaches to capacity constraints may include a range of potential non-traditional and innovative solutions including non-network solutions, some of which may be less proven.

E493 We understand that price-quality regulated EDBs have concerns regarding less proven solutions including:

- E493.1 an external flexibility solution provider may not deliver a contracted service
- E493.2 an internal non-network solution may not respond in an anticipated way, and
- E493.3 operational difficulties may arise with implementation of non-network solutions in practice, eg, a system established to recognise where the DER are established but the system fails to identify or forecast that it is required.

E494 In the absence of an adjustment, interruptions associated with these causes would be recorded against the EDB and have both quality standard and QIS impacts. Caution around this may create a reticence to implement these types of solutions and result in a focus on more proven established technologies, typically capex investments.

555 Electra "DPP4 Issues paper submission" (19 December 2023), p. 3.

E495 We consider that non-performance of non-network solutions should be part of normal contractual agreements. Accordingly, we would expect that risks may be allocated to the external provider where they are better placed to manage those risks. EDBs should also be reasonably aware of expected performance and taking appropriate decisions between poles and wires where they do not have confidence in solution performance.

E496 We note that carving out non-performance of flexibility solutions from assessment may not be a desirable approach in the long-term. We expect an increase in prevalence of these activities meaning in the future a lot of interruptions could be excluded. This view was supported by submissions.

E497 We consider that accommodating a carve-out from the quality standard and QIS is appropriate where it is related to something more genuinely innovative than BAU processes. We have implemented this by linking the carve-out mechanism to approved INTSA decisions.

E498 Our draft decision is that all interruptions directly associated with an approved INTSA project are excluded from the calculation of SAIDI and SAIFI values up to a cap of 0.5% of the respective SAIDI and SAIFI limits.

E499 We consider setting a cap or limit in advance is preferable to a process which provides for ex post approval for excluding interruptions during the regulatory period. Ex post approval would not necessarily reduce the perceived risk by EDBs and would increase the regulatory burden on both EDBs and the Commission.

E500 Our approach is to include additional terms “SAIDI INTSA value” and “SAIFI INTSA value” which reflect values which are removed in the calculation of compliance with the quality standard and in determining QIS values.

E501 Whilst the existing definition of interruption already has a number of exclusions, we consider it may be more appropriate to exclude any carve-out in the assessment of quality standard compliance and quality incentive values.

E502 This approach means EDBs will continue to record interruptions and will provide better visibility on the scale of interruptions being removed in assessment calculations.

E503 The cap set in advance means that regardless of the number of INTSA approved projects an EDB will have a set limit on the extent of interruptions it is able to exclude, and the value is not directly linked to the nature of the INTSA project.

E504 We have considered an alternative approach where each INTSA approved project has a specific carve-out associated with it which is established at the time of application.

E505 This approach would more directly link the exclusion to the size and associated risks related to the INTSA project and mean the INTSA carve-out is not directly linked to an EDB's past performance, which is quite variable across EDBs. It would also mean a specific cap on SAIDI and SAIFI values which are able to be excluded would not be required to be set in advance of assessing the individual projects.

E506 We intend to set the INTSA exclusion cap in advance and in aggregate as:

E506.1 this should result in lower transaction costs for EDBs and the Commission in engaging on a reasonable limit of exclusions for each INTSA application. In practice it may be challenging for an EDB to scope what a reasonable cap for disruptions may be, and for the Commission to assess the reasonableness of what is proposed

E506.2 it may encourage uptake of the INTSA mechanism as EDBs will have increased certainty on the outcome of an approved application

E506.3 setting the cap in advance establishes the size of potential exclusions and allows greater stakeholder engagement, and

E506.4 it will make the INTSA more simple, user-friendly, and practical for EDBs and us to implement.

E507 Whilst we do not intend to set specific project level exclusions, we will require information as part of an INTSA application which sets out potential quality risks associated with the project. This will ensure that EDBs have given adequate thought to the potential risks to consumers of the project. These requirements are set out within **Attachment D**, under *Draft INTSA characteristics*, paragraphs D97-D107.

E508 For the draft determination we have set the exclusion cap to 0.5% of the SAIDI and SAIFI limit with the cap applying before normalisation is applied for unplanned interruptions. Without knowledge of the types of INTSA applications we may receive, we have not tried to estimate a value, but have set the value with reference to the fact the INTSA is capped at 0.6% of maximum allowable revenue (MAR).

E509 Given the current SAIDI and SAIFI limits already include buffer amounts from the historic average, this approach is more generous than if the exclusion cap were to be set based on the SAIDI and SAIFI target. We note that the exclusion cap is applied pre-normalisation due to the complexity involved in removing interruptions associated with INTSA projects or programmes from a normalised dataset.

E510 We have not created a specific carve-out where a third-party fails to comply with a DOE as we consider this should be able to be accommodated within contractual terms. We are unclear at this stage on the potential risk in creating an exclusion of this nature due to the unclear size and risk profile. We note that interruptions are currently only recorded on prescribed voltage electric lines which are lines that are capable of conveying electricity at a voltage equal to or greater than 3.3 kilovolts.

E511 We are proposing to include requirements for reporting within an EDB's compliance statement information outlining interruptions excluded as SAIDI INTSA value or SAIFI INTSA value. In particular:

E511.1 the SAIDI value of planned interruptions excluded

E511.2 the SAIDI value of unplanned interruptions excluded

E511.3 the SAIFI value of planned interruptions excluded, and

E511.4 the SAIFI value of unplanned interruptions excluded

E512 We do not intend to implement any compliance requirement to evidence why interruptions have been assessed as being directly associated to the INTSA project within the compliance statement. Our view is this may significantly increase the compliance burden where some interruptions may have quite minimal SAIDI or SAIFI impact. However, we note that this will need to be considered as part of the audit process.

E513 Whilst not requiring disclosures by default as with any other outage amount, we will have the ability to check and challenge the validity of the reported quantum if we have concerns. The burden of proof will be on the EDB to support how the outage minutes they have excluded are directly associated with that project.

E514 As part of INTSA project close out reporting EDBs will be required to outline:

E514.1 any SAIDI INTSA values and SAIFI INTSA values relating to the project or programme

E514.2 the cause or causes of the interruptions for any SAIDI INTSA values and SAIFI INTSA values relating to the project or programme, and

E514.3 any steps that the non-exempt EDB took to reduce the likelihood or impact on consumers of the interruptions under subparagraph.

**Conclusions**

E515 In conclusion, our draft decision is to exclude all interruptions directly associated with an approved INTSA project in the calculation of SAIDI and SAIFI values up to a cap of 0.5% of the respective SAIDI and SAIFI limit.

E516 We consider removing interruptions associated with INTSA projects will reduce barriers to undertake innovative projects.

E517 Setting a cap in advance will also provide EDBs greater assurance regarding the value of interruptions which may be able to be excluded and reduce transactions costs for both EDBs and the Commission in setting individual project exclusions.

# Attachment F Revenue path

**Purpose of the attachment**

F1 This attachment explains the rationale for our draft decisions related to the revenue path. It also explains the drivers behind changes in revenue from DPP3 to DPP4 and responds to stakeholder submissions on the topic.

F2 It covers these specific areas:

F2.1 a brief overview of the components of the revenue path and how they relate to one another;

F2.2 draft changes to the revenue path, stepping through:

F2.2.1 the "building blocks" revenues that reflect our forecasts of EDBs' costs (including the cost of capital), and the factors that drive these changes;

F2.2.2 the impact of previously-accrued wash-up drawdown amounts and IRIS incentives amounts on changes in revenue allowances; and

F2.2.3 the impact of revenue smoothing decisions;

F2.3 draft decisions about:

F2.3.1 net allowable revenues;

F2.3.2 smoothing revenue increases to mitigate price-shocks to consumers while considering EDB financeability;

F2.3.3 implementation of amendments to the wash-up from the IM Review;[556] and

F2.3.4 implementation of amendments to the IMs to apply IRIS in real (CPI-adjusted) terms.

[556] Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), Attachment D.

F3 This attachment is supported by **Attachment G**, which sets out in detail the financeability analysis we have applied as a sense-check to the draft revenue path we have set.

### Overview of the revenue path

F4 This section explains the key components of the revenue path, how they operate together to regulate the revenue EDBs can recover, and the terminology we use.

### Prices vs revenues

F5 While the term used in section 53M of the Act is "prices" (hence *price*-quality path), the Act defines "prices" as including revenues, and allows us to set a revenue cap as the form of control on EDB prices. Under the EDB IMs, EDBs are subject to a revenue cap, so we generally refer to revenues in this attachment for the sake of clarity. Where we refer to 'price' or 'prices', this will generally mean the prices consumers face (or the proxies we use to estimate them).

### Controls on revenue

F6 We regulate the revenue EDBs can recover from their customers using two regulatory controls:

F6.1 the (primary) revenue path that determines the total revenue an EDB may recover from its customers and that is defined in terms of "forecast allowable revenue";[557] and

F6.2 the (secondary) revenue smoothing limit that can require EDBs to defer revenue recovery in a present-value neutral way in some circumstances. [558]

### Forecast allowable revenue

F7 The primary revenue path defined by forecast allowable revenue is made up of four parts:

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[557] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(1)(a)

[558] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(1)(b). The circumstances where the revenue smoothing limit requires deferral are not specified in the IMs and are specified in the DPP. See paras F115-164 (below).

F7.1 forecast net allowable revenue, that allows EDBs to recover forecast costs over the regulatory period;[559]

F7.2 forecasts of pass-through costs, that allow EDBs to pass on certain costs beyond their control to consumers (for example industry levies or transmission charges);[560]

F7.3 forecasts of recoverable costs, that (largely) implement regulatory adjustments such as wash-ups or incentives amounts; and[561]

F7.4 forecasts of revenue received under large connection contracts.[562]

F8 This attachment mainly focuses on our decisions on 'forecast net allowable revenue', because this is what we determine when setting a DPP.

F9 Pass-through and recoverable costs are largely determined by the EDB IMs and are largely a question of fact over the course of the regulatory period, rather than a matter about which we are required to exercise judgement.[563]

F10 Similarly, large connection contract revenue is added to the revenue path subject to the connection contract meeting the requirements set out in the EDB IMs with a wash-up to avoid other consumers bearing the cost of any revenue not recovered from the connecting party.[564]

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559 Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(3)(a)

560 Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(3)(b) and clause 3.1.2

561 Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(3)(c) and clause 3.1.3

562 Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(3)(d)

563 For certain recoverable costs, we have the discretion under the IMs to further specify requirements in a DPP or CPP determination, see for example Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.3(2) and DPP4 Schedule 2.2.

564 Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 1.1.4(2) – definition of LCC

F11 However, certain recoverable costs – the wash-up drawdown amount and the IRIS incentive amounts – will have a material impact on the revenue EDBs can earn, and a flow-on impact on price shocks for consumer and on EDB financeability. As such, we discuss the impact of these two recoverable costs on revenue smoothing decisions below.

F12 We have used the term "distribution revenue" to describe the combined total of forecast net allowable revenue and recoverable costs.

**Summary of draft decisions on forecast net allowable revenue**

F13 Under the EDB IMs and consistent with section 53P(5) of the Act, forecast net allowable revenue over the regulatory period is specified in terms of:

F13.1 "starting prices" – forecast net allowable revenue in the first year of the regulatory period;[565]

F13.2 the annual change in forecast CPI;[566] and

F13.3 an annual rate of change relative to forecast CPI, or "X-factor".

F14 The draft starting prices and draft rates for each EDB are set out in Table F1 below.[567]

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[565] Starting prices are specified in Schedule 1.1 of the draft EDB DPP4 determination.

[566] The methodology for calculating CPI is specified in Schedule 1.3(2) of the EDB DPP4 determination.

[567] As the CPI component of the change in forecast net allowable revenue is determined based on updated values each year of the regulatory period, it is not set out here. This change was made as part of the 2023 IM review.

**Table F1 DPP4 draft starting prices and rates of change[568]**

| EDB | Starting prices – FNAR in 2026 ($m) | X-factor – rate of change relative to CPI[569] |
|---|---|---|
| **Alpine Energy** | 70.2 | -2.5% |
| **EA Networks** | 45.8 | -11.5% |
| **Electricity Invercargill** | 17.0 | -9.9% |
| **Firstlight Network** | 35.7 | -10.6% |
| **Horizon Energy** | 34.1 | -3.7% |
| **Nelson Electricity** | 7.0 | -7.2% |
| **Network Tasman** | 37.0 | -9.5% |
| **Orion NZ** | 219.5 | -13.0% |
| **OtagoNet** | 33.6 | -16.4% |
| **Powerco** | 486.1 | 0.0% |
| **The Lines Company** | 48.4 | -6.8% |
| **Top Energy** | 53.0 | -13.5% |
| **Unison Networks** | 136.1 | -13.4% |
| **Vector Lines** | 580.8 | -8.5% |
| **Wellington Electricity** | 118.8 | -10.7% |

## Drivers of change in forecast net allowable revenue between DPP3 and DPP4

F15 This section discusses what is driving changes in forecast net allowable revenue in our draft DPP4 decision compared to forecast net allowable revenue in DPP3. It steps through:

F15.1 draft changes in 'building blocks revenue' (before any smoothing is applied);

F15.2 the impact of wash-up drawdown amounts and IRIS incentive amounts on 'distribution revenue'; and

F15.3 the impact of our smoothing decisions.

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[568] Aurora is currently subject to a CPP and will rejoin the DPP on 1 April 2026. As such they have been excluded from the tables in Attachment F. Decisions related to Aurora's revenue path will be made prior to their return to the DPP. See **Attachment H** for details.

[569] Section 53P(5) of the Act and the EDB DPP4 determination expresses X-Factors in 'CPI *minus* X' terms. As such, while the X-factor values presented here are negative, they will allow forecast net allowable revenue to increase at these rates.

### Overall changes in unsmoothed net allowable revenue

F16 The changes to forecast net allowable revenue we propose are driven by EDBs' current revenue allowances not covering our forecasts of their costs for the DPP4 period. Table F2 below compares (on a present-value basis) our draft forecast net allowable revenues over the DPP4 period to a counterfactual where current allowances for DPP3 are rolled-forward, as provided for in s 53P(3)(a).

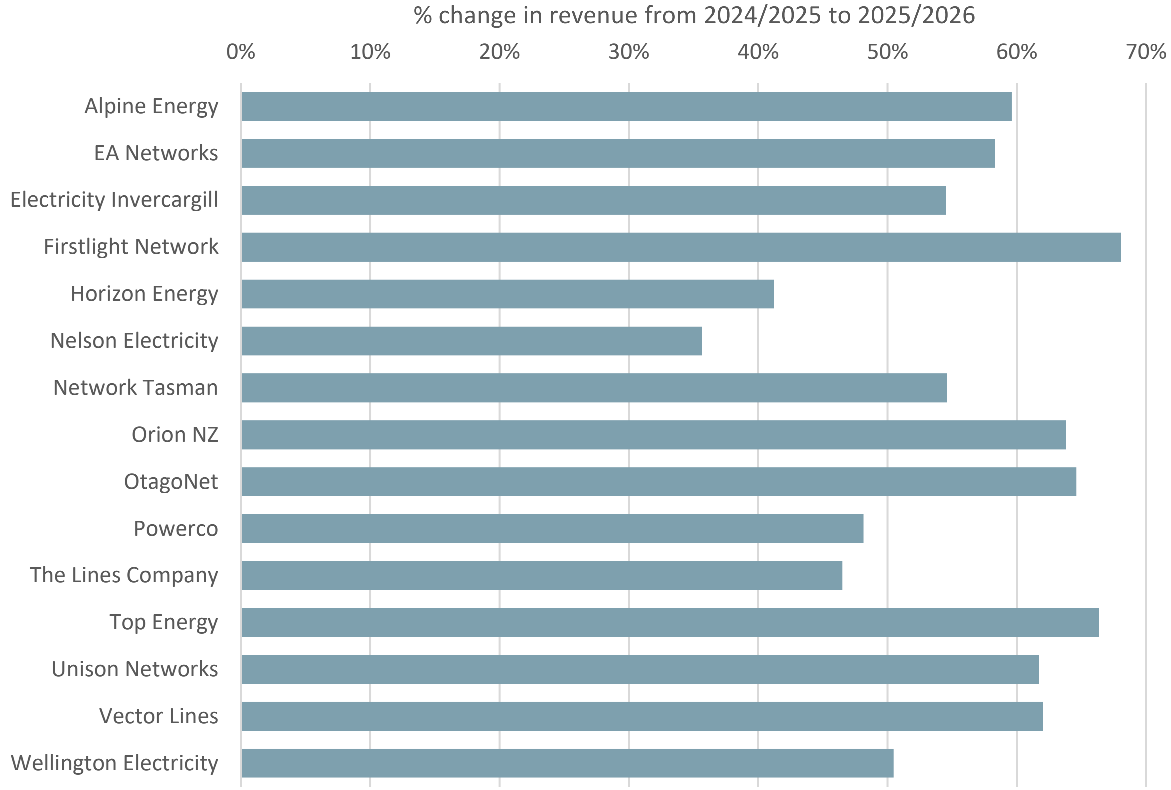
**Table F2 Draft allowance compared to roll-over scenario ($m, DPP4 NPV)**

| EDB | Draft DPP4 net allowable revenue | Roll-over scenario net allowable revenue[570] | % difference |
|---|---:|---:|---:|
| **Alpine Energy** | 319.5 | 213.3 | 50% |
| **EA Networks** | 247.1 | 166.3 | 49% |
| **Electricity Invercargill** | 88.9 | 61.3 | 45% |
| **Firstlight Network** | 189.5 | 120.1 | 58% |
| **Horizon Energy** | 158.5 | 119.6 | 33% |
| **Nelson Electricity** | 35.0 | 27.5 | 27% |
| **Network Tasman** | 192.0 | 132.3 | 45% |
| **Orion NZ** | 1218.4 | 792.5 | 54% |
| **OtagoNet** | 199.2 | 128.9 | 55% |
| **Powerco** | 2108.2 | 1516.1 | 39% |
| **The Lines Company** | 238.7 | 173.5 | 38% |
| **Top Energy** | 296.8 | 190.1 | 56% |
| **Unison Networks** | 761.2 | 501.4 | 52% |
| **Vector Lines** | 2960.3 | 1943.5 | 52% |
| **Wellington Electricity** | 631.1 | 446.8 | 41% |

F17 Figure F1 shows the (unsmoothed) change in forecast net allowable revenue between the end of DPP3 and the beginning of DPP4 that would be necessary to make up for this shortfall. Figure F2 then illustrates the drivers of this difference at an industry-wide level.

[570] In this scenario, forecast net allowable revenue in the final year of DPP3 (2025) is projected forward at CPI.

**Figure F1 Unsmoothed nominal changes in draft forecast net allowable revenue, 2025 to 2026**




F18 At an industry-wide level for the draft decision:

F18.1 changes in DPP3 CPI and other components (that primarily reflects RAB growth over the DPP3 period) contributes 26% of the change;

F18.2 the increase in the estimated cost of capital (WACC) contributes 40%;

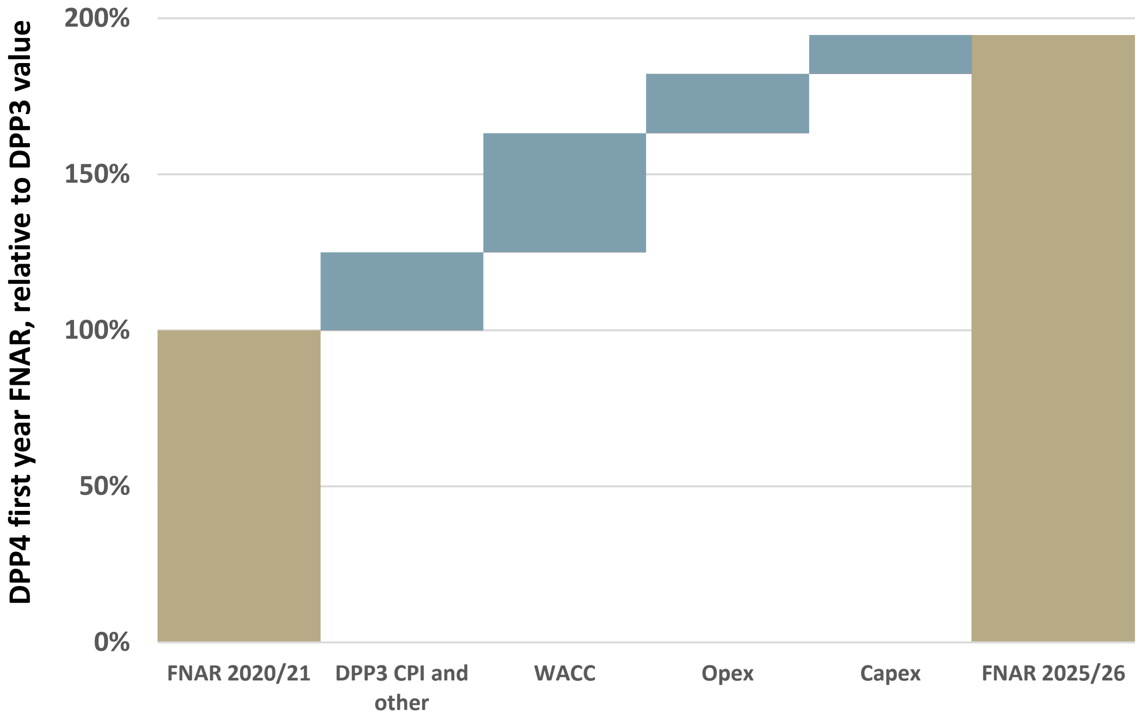
F18.3 increases in opex contributes 20%; and

F18.4 increases in capex contributes 13%.

F19 The impact of these changes varies substantially across individual EDBs, both in terms of the total level of increase and the relative contributions of each major factor.[571]

[571] Drivers for each EDB can be found in the "DPP4 MAR waterfall model" published on our website alongside this paper.

**Figure F2 Drivers of change in forecast net allowable revenues between DPP3 and DPP4**




F20 The next sections provide additional detail on the impact of DPP3 CPI and other components and the cost of capital. For details on changes in opex and capex allowances, see **Attachments B** and **C** above.

**Effect of DPP3 CPI and other components**

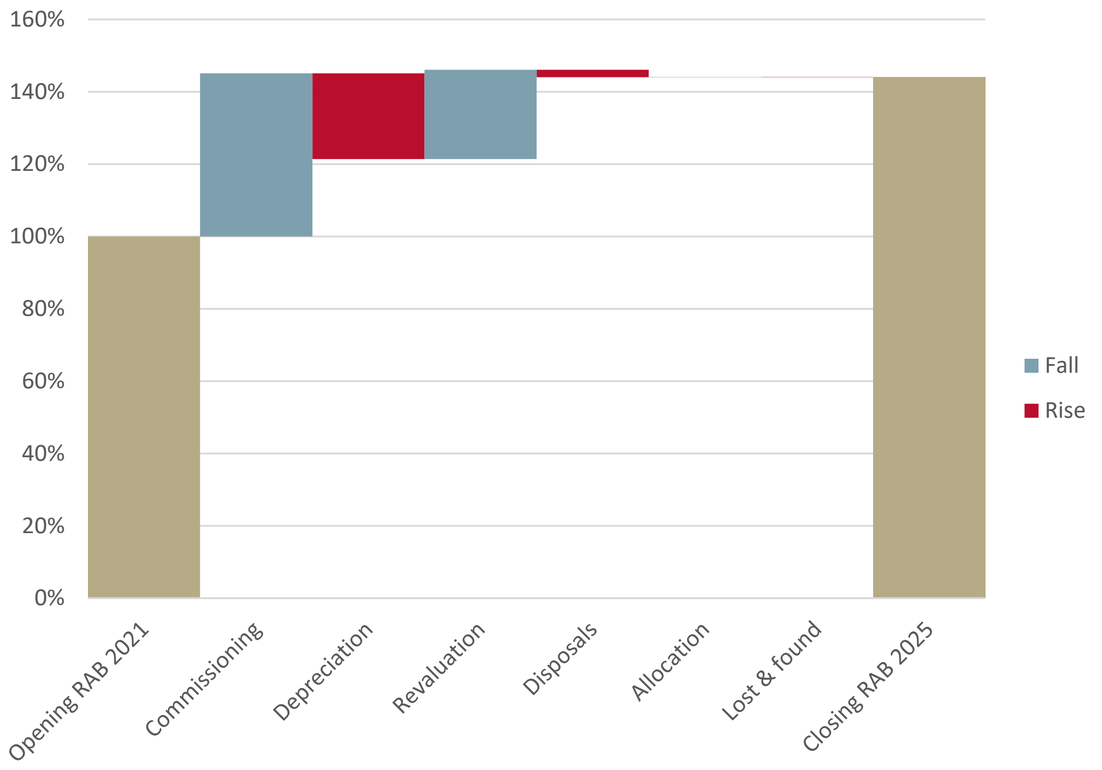
F21 This line item captures the financial starting point for our DPP4 financial model. Of these, the most material input is EDBs' (allocated) RABs and the growth in them over DPP3.[572] Drivers in RAB growth are shown in Figure F3 below.

[572] The other initial conditions relate to: tax allowances, CPI as an element of the price path, CPI for forecast revaluations, and asset disposals.

F22 As this figure shows, commissioning new assets and revaluations for inflation have contributed to most of the growth in the RAB over the DPP3 period. Actual revaluations are calculated based on actual CPI,[573] which has been elevated (and higher than forecast) over period since 2020, as illustrated in Figure F4 below.

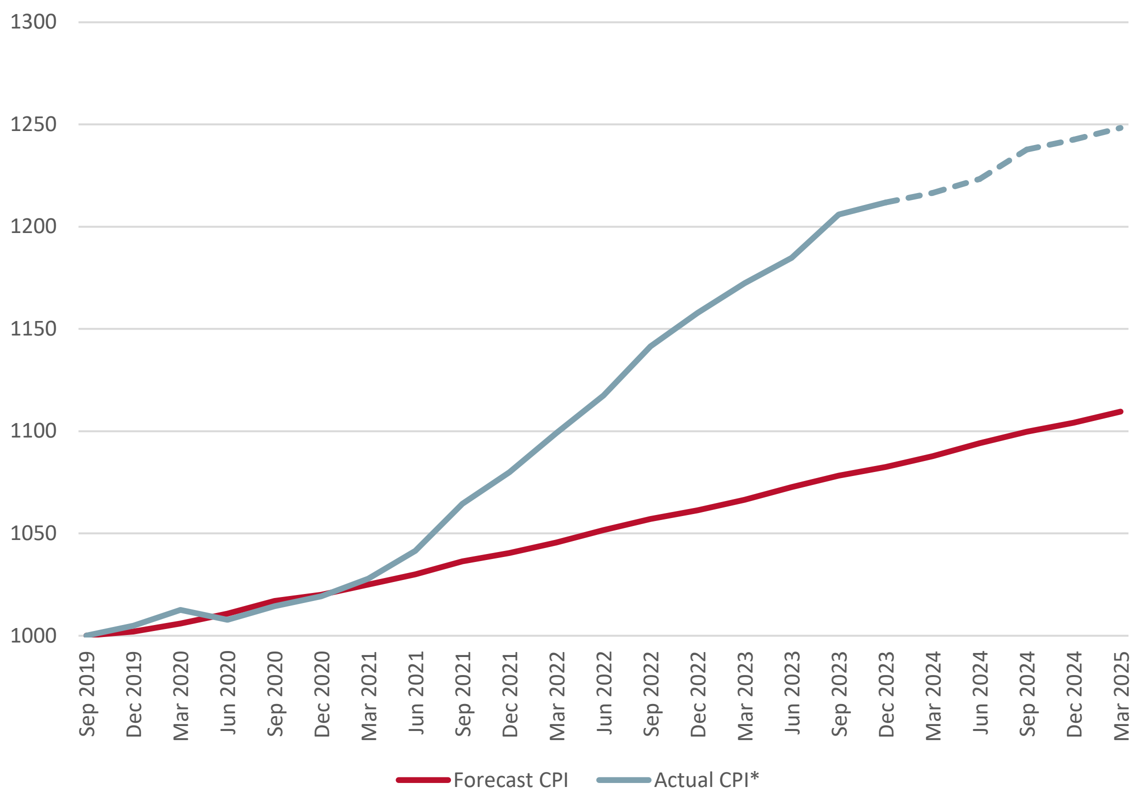
F23 Commissioning new assets reflects both an increase in real terms of the level of capex EDBs have undertaken (see **Attachment B** for analysis of capex) but is also influenced by higher capital goods input prices.

**Figure F3 Industry wide RAB growth over the DPP3 period (2021-2025)**




[573] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 2.2.9

**Figure F4 Cumulative CPI over DPP3, forecast versus actual**




* Actual CPI includes update RBNZ forecasts as of the February MPS for the quarters where StatsNZ actual data is not available.

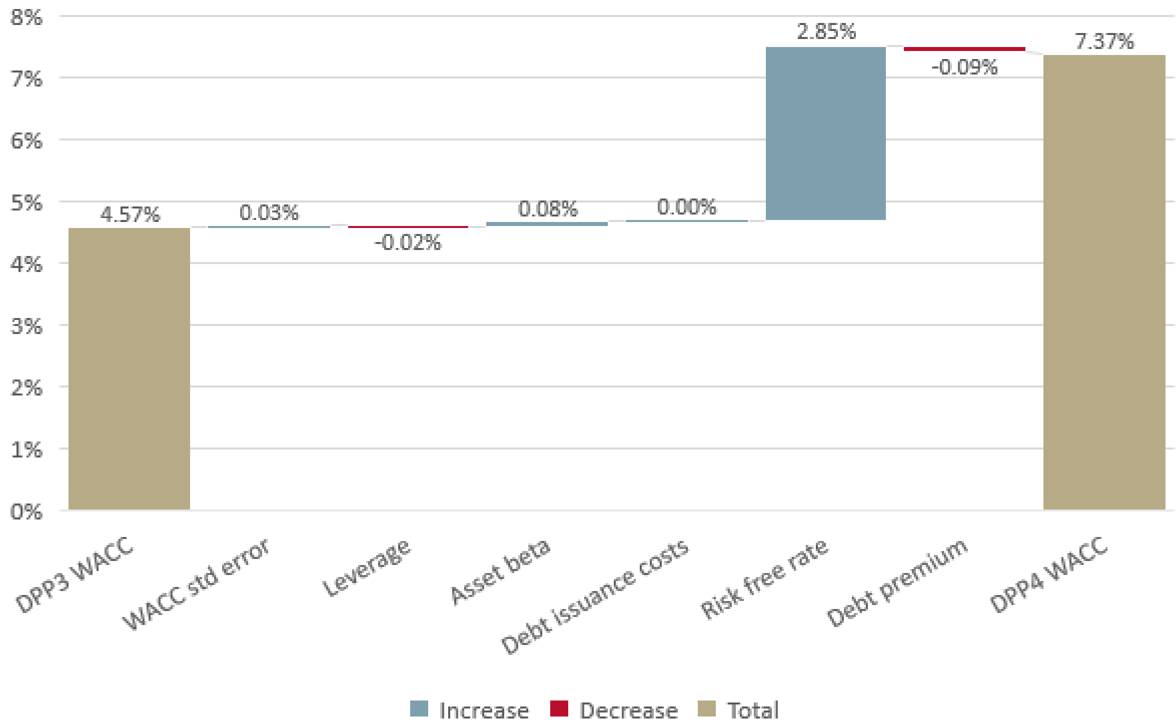
### Changes in the cost of capital

F24 Changes in the estimated WACC we use to calculate the return on capital EDBs can earn are the most material driver of changes in net allowable revenue. As shown below in Figure F5, this change has been driven primarily by increases in the risk-free rate. Given we determine a nominal WACC, the higher risk-free rate is also affected by higher (implicit) forward inflation assumptions.

F25 Changes to other parameters (that were reviewed and amended as part of our 2023 IM Review) have had a less material effect.[574]

[574] Commerce Commission "Input methodologies review 2023 - Final decision - Cost of capital topic paper" (13 December 2023)

**Figure F5 Drivers of the change in WACC**




*Impact of wash-up drawdown and IRIS incentive amounts*

F26 While what we determine when setting a DPP is the forecast net allowable revenue each EDB can recover, recoverable costs – predominantly IRIS incentive amounts and wash-up drawdown amounts – can have a material impact on the revenues EDBs can earn and in turn on the distribution prices consumers face.

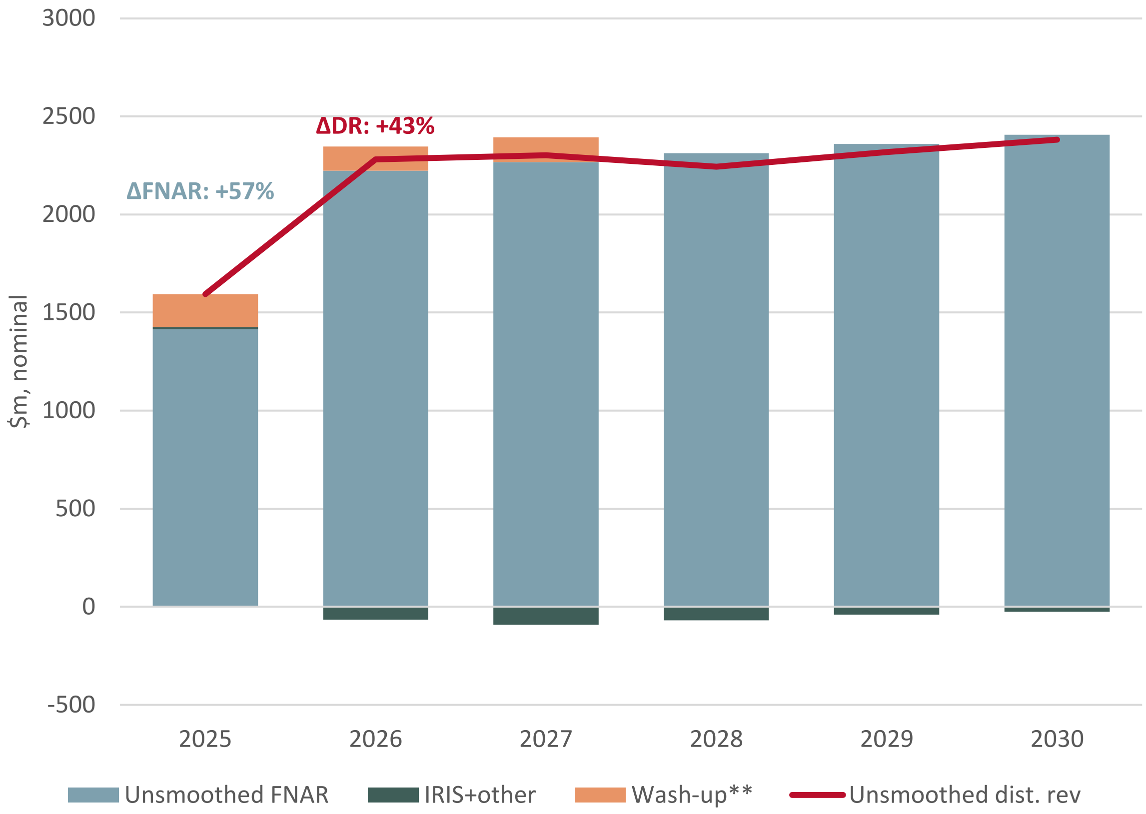
F27 We use the term "distribution revenue" for this combined total. This is because the main component of revenue it excludes from total forecast allowable revenue is the revenue needed to cover the transmission charges paid to Transpower and other pass-through costs.

F28 This section explains the effect this has on EDB revenues and the change in those revenues between the end of DPP3 and the beginning of DPP4.

**Changes in distribution revenue**

F29 The impact that wash-ups and IRIS will have on changes in distribution revenue are illustrated at an industry-wide level in Figure F6 below.

**Figure F6 Draft unsmoothed distribution revenue – all DPP EDBs (excludes Aurora)**




* Forecast net allowable revenue as presented here is based on current forecasts of inflation, and without any smoothing. As discussed further below, we have proposed smoothing FNAR via alternative X-factors to mitigate price-shocks. Over the regulatory period, it will increase in line with annual updates of inflation.

** In 2025 this is the "opening wash-up account balance", for 2026 and 2027 it is the "wash-up drawdown amount" assuming EDBs recover the full amount of outstanding balances that year. EDBs may choose to recover less than the full amount.

F30 Looked at in isolation, the change in unsmoothed forecast net allowable revenue would amount to a 57% nominal increase at a sector-wide level. However, once the net effect of estimated wash-ups, IRIS, and other recoverable costs are accounted for this change is only a nominal 43% increase.

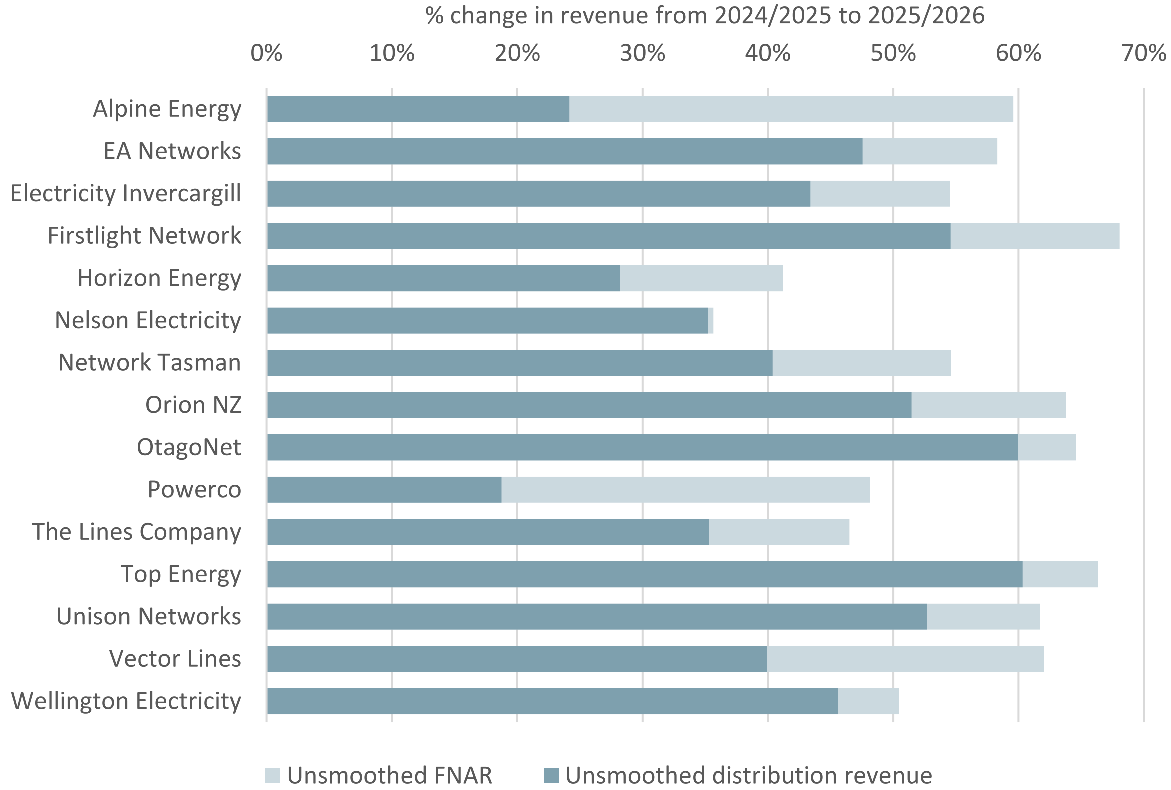
F31 These effects vary significantly on an EDB-by-EDB basis. The estimates we have used for each parameter are set out in Table F3 below. The overall impact that accounting for distribution revenue has on the change in revenue between 2025 and 2026 is shown in Figure F7.

**Table F3 Estimated components of distribution revenue (nominal $m, unsmoothed)**

| Regulatory Year | 2025 | | | | 2026 | | | |
|---|---|---|---|---|---|---|---|---|
| **EDB** | *FNAR* | *Wash-ups* | *IRIS and other* | ***Dist. revenue*** | *FNAR* | *Wash-ups* | *IRIS and other* | ***Dist. revenue*** |
| **Alpine Energy** | 46.2 | 13.0[575] | 3.3 | **62.4** | 73.7 | 13.9 | -7.9 | **79.7** |
| **EA Networks** | 36.0 | 3.0 | 0.3 | **39.3** | 57.0 | 7.0 | -3.9 | **60.1** |
| **Electricity Invercargill** | 13.3 | 1.6 | -0.1 | **14.8** | 20.5 | 1.8 | -0.6 | **21.7** |
| **Firstlight Network** | 26.0 | 2.3 | -0.6 | **27.7** | 43.7 | 3.5 | -3.3 | **43.9** |
| **Horizon Energy** | 25.9 | 3.1 | 0.7 | **29.7** | 36.5 | 3.8 | -1.4 | **39.0** |
| **Nelson Electricity** | 6.0 | 0.7 | 0.0 | **6.6** | 8.1 | 0.8 | 0.2 | **9.1** |
| **Network Tasman** | 28.6 | 6.5 | -0.4 | **34.7** | 44.3 | 8.9 | -2.6 | **50.5** |
| **Orion NZ** | 171.5 | 14.5 | 1.6 | **187.6** | 280.9 | 21.8 | -6.9 | **295.8** |
| **OtagoNet** | 27.9 | 2.3 | -0.7 | **29.5** | 45.9 | 3.6 | 0.2 | **49.7** |
| **Powerco** | 328.1 | 36.7 | -2.9 | **361.9** | 486.1 | -40.6 | -1.4 | **444.1** |
| **The Lines Company** | 37.6 | 4.7 | 0.1 | **42.4** | 55.0 | 5.1 | -1.3 | **58.9** |
| **Top Energy** | 41.1 | 3.8 | -0.6 | **44.3** | 68.4 | 10.8 | -5.8 | **73.5** |
| **Unison Networks** | 108.5 | 4.0 | 4.5 | **117.0** | 175.5 | 14.4 | -5.4 | **184.5** |
| **Vector Lines** | 420.6 | 68.3 | 4.5 | **493.4** | 681.6 | 59.4 | -24.0 | **717.0** |
| **Wellington Electricity** | 96.7 | 2.3 | 2.7 | **101.7** | 145.5 | 8.6 | -1.5 | **152.6** |

[575] This figure is based on Alpine Energy's reported 'opening wash-up account balance' per their 2025 price-setting compliance statement. As discussed in Attachment I, Alpine has disclosed that they were non-compliant with the revenue path over DPP3. While the reported value may be non-compliant, it accurately reflects the basis on which Alpine set its prices for 2025.

**Figure F7 Impact of IRIS and wash-ups on 2025 to 2026 change in distribution revenue**




### Changes in wash-up drawdown amounts

F32 Wash-up amounts are a regulatory mechanism to make EDBs or consumers whole for past under- or over-recovery of revenue caused by defined factors (such as forecasts of demand or inflation differing from actuals).

F33 The "opening wash-up account balance" (the DPP3 equivalent of a wash-up drawdown amount) for 2025 has been taken from EDBs' 2025 price-setting compliance statements.

F34 To estimate the wash-up drawdown amounts for 2026 and 2027 we have:

F34.1 estimated wash-up accruals for 2024 and 2025, based on:

F34.1.1 "forecast revenue from prices" as disclosed in price-setting compliance statements as a proxy for "actual revenue from prices"; and

F34.1.2 estimates of "actual allowable revenue" starting with "actual allowable revenue for 2023 then applying the latest available CPI inflation information to estimate the 2024 and 2025 values, and assuming actual pass-through and recoverable cost are equal to forecast pass-through and recoverable costs; and

F34.2 applied a time-value of money adjustment to each accrual to carry it forward to the year it is available to be drawn down.

F35 This approach does not account for any wash-up balance accrued due to differences between forecast and actual quantities, so will not be a complete reflection of the wash-up accruals EDBs. Despite this assumption, as the CPI component of the wash-up accrual is the most significant element (and its value is reasonably certain), we consider this is a reasonable reflection of balances EDBs will have accrued.

F36 For accruals in 2024, we will update this analysis in our final decision to include annual compliance statement information when it is available.

**Changes in IRIS incentive amounts and other recoverable costs**

F37 IRIS incentive amounts and other recoverable costs for 2025 are based on values disclosed in 2025 price-setting compliance statements.

F38 For values over DPP4, IRIS estimates are based on actual expenditure data from ID up to 2023, and AMP forecasts for 2024 and 2025. Other recoverable costs are assumed to be zero as they are either not able to be forecast with any accuracy (quality incentives) or are not significant enough to materially affect the results.

F39 We have excluded transmission changes from both 2025 and values over DPP4, as from following the 2023 IM review these will be pass-through costs, and not subject to smoothing decisions.

F40 As with our estimate of wash-up balances, we will update these estimates once actual ID data for 2024 is available.

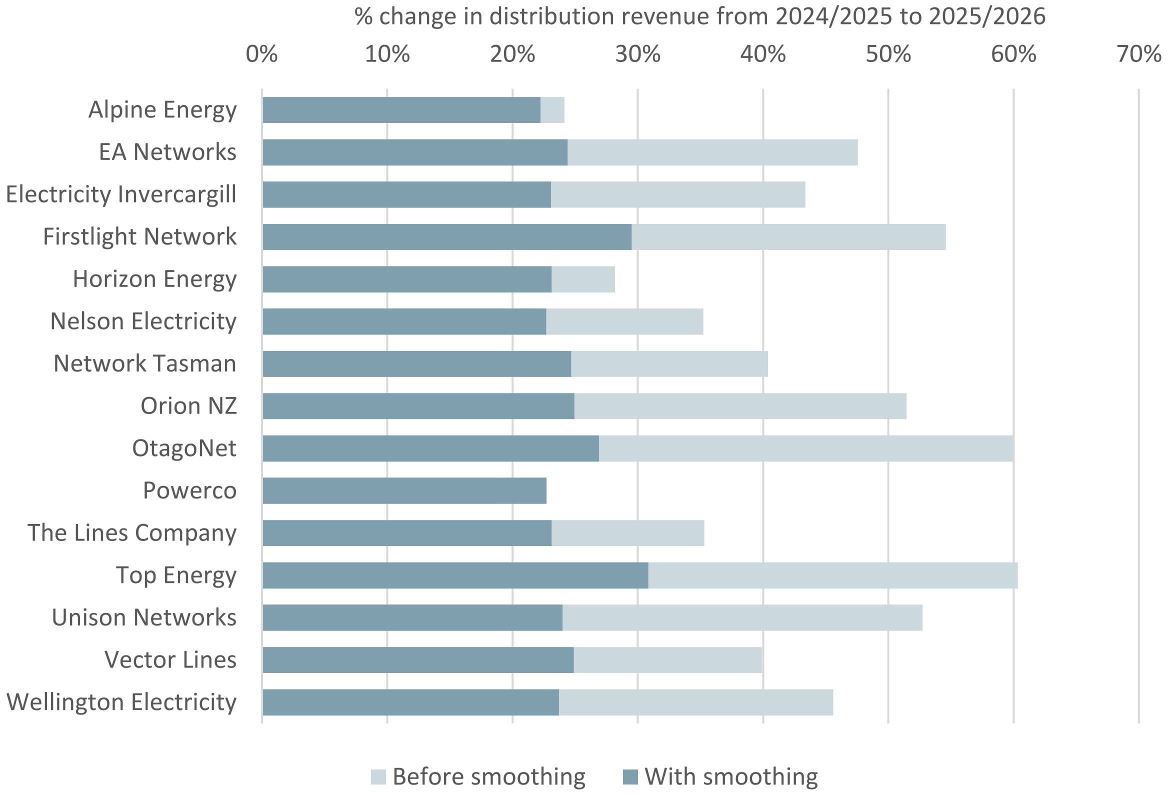
Effect of revenue smoothing decisions

F41 As discussed below in relation to decisions P3-P5, we have proposed smoothing revenue over the DPP4 period to mitigate price shocks for consumers. We do this via the use of “alternate X-factors”. These allow forecast net allowable revenue to increase year-on-year at a rate greater than CPI over the regulatory period, trading off initial price shocks for on-going increases later in the period and deferring revenue recovery.

F42 The effect of these smoothing decisions on the change in total distribution revenue from 2025 to 2026 is shown in Figure F8.

F43 This figure best represents the overall change in EDB revenues that would result from our draft decision and is used as the basis for our analysis of consumer bill impacts.

**Figure F8 Nominal change in smoothed distribution revenue from 2025 to 2026**




F44 As Figure F8 shows, these figures average around 24% in nominal terms. This is consistent with our decision to:

F44.1 cap real per-ICP increases at 20% in most cases;

F44.2 forecast CPI of 2.1%; and

F44.3 weighted-average ICP growth of 1.4%.

F45 Variations between EDBs are explained by:

F45.1 variations in forecast ICP growth (between 0.2% to 3.2%); and

F45.2 for Firstlight and Top Energy, our draft decision to allow higher than 20% real per-ICP increases to avoid on-going price shocks over the regulatory period.

F46 In Powerco's case, there is no difference between the unsmoothed and smoothed change. This is because its initial real per-ICP increase was already below 20%.

**Draft decisions on net allowable revenue**

F47 Section 53P(1) of the Act requires us to specify the revenue path by:

F47.1 specifying a 'starting price'[576] for the first year of the regulatory period;

F47.2 determining a 'rate of change' over the course of the regulatory period.

F48 The Act requires the Commission to set one rate of change for electricity distribution services for the regulatory period.[577] This 'default' rate of change (or default 'X-factor') is expressed relative to CPI, in the form 'CPI-X', and is used to determine revenue for each subsequent year of the regulatory period.

F49 As we noted above, we may also set 'alternative rates of change' for a particular supplier(s) if we consider this is necessary or desirable to minimise any undue financial hardship to the supplier or to minimise price shock to consumers.[578]

*Draft decision P1: Set starting prices based on the current and projected profitability of each supplier using a BBAR model*

**Nature of the decision**

F50 As we noted above, a key component of the revenue path is the "starting price" for the first year of the regulatory period.

F51 In our DPP4 Issues Paper,[579] we proposed determining revenue in the first year of the DPP4 period based on the "current and projected profitability" of each distributor using a building blocks model – in other words based on forecast costs.[580] This is the same approach taken at past DPP resets.

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[576] As noted above at paragraph F5, the term used in the Act is "starting prices" but given we apply a revenue cap to EDBs, this is in effect a starting revenue.

[577] Section 53P(5) of the Act.

[578] Section 53P(8)(a) of the Act.

[579] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), paragraph 5.22

[580] See s 53P(3)(b) of the Act.

F52 As an alternative, the Act allows revenue to be set by "rolling over" the revenues which apply at the end of the preceding regulatory period.[581]

**Draft decision**

F53 Our draft decision is to determine the starting price for each non-exempt EDB using a building blocks model, with no deferral into DPP5 of building blocks allowable revenue (BBAR).

F54 Combined with our draft decisions on the "revenue smoothing limit" (see paragraphs F119 to F168 below), this provides EDBs a reasonable expectation that they will be able to recover both their underlying "building blocks" revenue and any wash-up amounts accrued during DPP3.[582]

**What we heard from stakeholders**

F55 Multiple submitters noted the substantial increase in EDBs' costs since the last reset, and the challenges this presents. The ENA submitted that it was likely that both a starting price adjustment and "inter-period smoothing" would be required to manage price shocks to consumers.[583]

F56 While sympathetic to the need to smooth revenue to mitigate the price shock, multiple submitters reiterated that full recovery of allowed revenue within the regulatory period should be the goal.[584]

F57 Submitters also identified the impact that medium-term (longer than a DPP regulatory period) revenue deferrals could have on the ability of EDBs to attract capital on reasonable terms to finance their investments (or the "financeability" of EDB's revenue paths).[585] We consider financeability in **Attachment G**.

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[581] See s 53P(3)(a) of the Act.

[582] Given wash-ups accrued over the DPP4 period cannot be forecast with any certainty, and drawdowns necessarily operate on at least a two-year lag, there may still be some deferral of DPP4 revenue into DPP5. Additionally, within the undercharging limit discussed below at para F185 to F194, EDBs may choose to defer recovery of some revenue.

[583] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 63.

[584] Alpine Energy "DPP4 Issues paper submission" (19 December 2023), p. 12; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 3.

[585] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 7.

## Analysis

F58 Were current net allowable revenues rolled over, EDBs' revenues for the DPP4 period would not reflect their costs. As set out in Figure F2 above, EDBs' costs have grown over the DPP3 period, primarily due to high inflation but also reflecting growth in the size of their networks and customer bases. Rolling over current prices would fail to account for this, and would not reflect changes in the cost of capital since the last reset (as reflected in the WACC). This would hinder EDBs' ability and incentives to invest in their networks, and their ability to provide services at a quality which reflects consumer demand (contrary to s 52A(1)(a) and (b) of the Act). At the same time, allowing an increase in revenue would not represent excess profitability, so is consistent with (s 52A(1)(d)).

F59 Between our draft decisions on starting revenues and our decisions on revenue smoothing during the regulatory period (discussed below), we intend for EDBs to have a reasonable prospect of recovering their entire building-blocks revenue over the DPP4 period.

F60 Extended and significant revenue deferral could lead to financeability constraints on EDBs, reducing incentives to invest, which would be inconsistent with s 52A(1)(a) of the Act.

F61 While deferral of revenue would reduce price shocks for current consumers, it would create the potential for compounding price-shocks leading into DPP5, disadvantaging future consumers. Even though such a deferral would be present-value neutral and consistent with the FCM principle (because under the wash-up mechanism EDBs accrue a time-value of money adjustment) [586], consumers would pay more overall in nominal terms.

## Conclusions

F62 On balance, we consider allowing EDBs to fully recover BBAR and any accrued wash-up amounts within the DPP4 regulatory period, with no deferral into DPP5, better promotes the purpose of Part 4 than the alternatives.

[586] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.4(1)(b).

F63 Deferral of revenue increases over the short term (within a regulatory period) has less of an effect on the outcomes in the Part 4 purpose described above and are discussed below in relation to alternative rates of change.

*Draft decision P2: Set the default 'X' factor at 0%*

**Nature of the decision**

F64 Section 53P(1) of the Act requires us to determine a "rate of change", which is used to determine net revenue for each year after year 1 of the regulatory period. The rate of change comprises:

F64.1 the rate of increase in forecast CPI, the treatment of which is determined in the specification of price IMs;[587] and

F64.2 a default rate of change relative to forecast CPI – the default X-factor) [588].

**Draft decision**

F65 Our draft decision is to determine a default X-factor of 0% (before considering the desirability of alternative rates of change for particular suppliers, which we discuss in the following section).

**What we heard from stakeholders**

F66 In the DPP4 Issues paper, we proposed retaining our approach under DPP3 of setting a default X-factor of 0%. Submissions on the issues paper supported this approach.[589]

F67 Horizon, while supporting a default X-factor of 0%, acknowledged that the scale of forecast investment would likely mean that EDBs would require alternative rates of change. It submitted:[590]

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[587] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(5)(b).

[588] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(5)(c).

[589] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 30; Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 24; Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 72

[590] Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 21

> Horizon Networks supports retaining a default X-factor of 0%. However, we also recognise that the investment requirements of EDBs will likely require a variation on X to be applied during the regulatory period in order to achieve the permitted maximum allowable revenue while avoiding price shocks at the beginning of the regulatory period.

**Analysis**

F68 Because our draft decision is to set starting prices using a building blocks model, the starting price already incorporates forecast changes in productivity, so the rate of change in productivity in the EDB sector relative to the economy as a whole will be 0%.[591] Our draft decision is therefore to set a default X-factor of 0%. This view was supported by submissions on the DPP4 Issues paper.[592]

F69 Together with our draft decision P1 to set starting prices based on the current and projected profitability of each supplier using a BBAR model, and before considering the desirability of alternative rates of change for particular suppliers, a default X-factor of 0% promotes incentives for EDBs to innovate and invest, while limiting their ability to extract excessive profits (consistent with s 52A(1)(a) and (d)). Retaining a default X-factor of 0% is also consistent with our framework intention of retaining approaches from DPP3 where they remain fit for purpose.

F70 We have the discretion under s 53P(8) of the Act to set alternative rates for change for a particular supplier, or suppliers, where we consider this is necessary or desirable to minimise undue financial hardship to suppliers or to minimise price shock to consumers. We discuss our draft decisions on alternative rates of change below.

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591 For more detail, see Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), p. 55 and Attachment H.

592 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 17; Horizon Networks "DPP4 Issues paper submission" (19 December 2023) p. 21; Orion "DPP4 Issues paper submission" (19 December 2023), p. 24; Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 24, Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 74.

*Draft decisions P3, P4, and P5: Approach to determining alternative rates of change*

**Nature of the decisions**

F71 As we discussed in **Chapter 2** of this paper, due to a combination of factors EDBs' costs have increased substantially since the last DPP reset. At the same time, there is broad consensus that EDBs will need to make significant new investments, as well as make better use of existing assets, to meet the challenges related to the energy transition.

F72 Submitters have identified the inherent tension between mitigating price shocks to consumers and avoiding undue financial hardship for suppliers; some EDBs have told us that they may face financeability challenges over the next regulatory period.[593]

F73 In addition, based on the most recently available information in EDB compliance statements, most EDBs will have substantial accrued wash-up amounts leading into DPP4. Our draft financial modelling shows that only one non-exempt EDB (Powerco) will have a negative wash-up amount leading into DPP4. While these balances are necessary to preserve ex ante FCM and help to mitigate financeability concerns raised by EDBs, they exacerbate the potential price-shock consumers face.

F74 Section 53P(8) of the Act gives us a discretion when resetting a DPP for a particular regulatory period to set "alternative rates of change" for a particular supplier(s). This is a tool that can be used to manage the challenge of minimising price shocks to consumers, and the ability for EDBs to finance investments where there is undue financial hardship.

**Draft decision**

F75 Our approach on smoothing via alternative rates of change is made up of three interlocking draft decisions:

F75.1 **decision P4:** to consider consumer price shocks:

F75.1.1 on a distribution revenue basis – that is including forecast net allowable revenues and major recoverable costs;

F75.1.2 in real terms (net of forecast CPI); and

[593] Financeability refers to the ability of firms to raise and repay debt and raise equity in financial markets readily and on reasonable terms.

F75.1.3 on a per-ICP basis, as a proxy for end consumer price impact.

F75.2 **decision P3:** where possible to limit price shocks to:

F75.2.1 20% (or approximately 6% on a retail bill) between regulatory periods; and

F75.2.2 10% (or approximately 3% on a retail bill) per year on average across the remaining years of the regulatory period.

F75.3 **decision P5:** to apply a financeability 'sense check' to assess notional financeability drawing on metrics form the Standard & Poor's (S&P) methodology. We focus on the core S&P ratios FFO/Debt and Debt/EBITDA with reference levels consistent with a BBB+ credit rating, and also consider leverage and FFO interest cover ratio. We have considered allowing a greater initial level of revenue uplift where we were satisfied that doing so would better promote the Part 4 purpose.

F76 Where limiting the initial and on-going price shocks to the levels described in F73.2 would result in deferral of building blocks allowable revenue into DPP5, our draft decision is to allow an initial increase in estimated prices greater than 20%.

F77 This applies to two EDBs:

F77.1 Firstlight; and

F77.2 Top Energy.

F78 For both EDBs, the initial change in real distribution revenue per ICP we have allowed is 27%, the amount necessary to limit on-going increases to 10% without deferral into DPP5.

F79 This approach is consistent with our **draft decision P1** to determine the starting price for each non-exempt EDB using a building blocks model, with no deferral into DPP5 of building blocks allowable revenue (BBAR) (see above).[594]

F80 Beyond the price shock limits and alternate X-factors set as above, we have not additionally adjusted any alternative rates of change due to financeability considerations. We discuss our approach to financeability further below (from paragraph F98), and in **Attachment G**.

[594] For our reasons for draft decision P1, see from paragraph F50 above.

**What we heard from stakeholders**

F81 Submissions on the DPP4 Issues paper recognised that this DPP reset will have a substantial impact on consumers' electricity bills.

F82 Stakeholders highlighted:

F82.1 the need to make significant investments during the DPP4 regulatory period, including to support electrification; and

F82.2 the challenge of balancing consumer price shocks against financeability considerations and EDBs' ability to invest in their networks.

F83 The ENA proposed smoothing within the DDP4 period be applied, to mitigate the upfront impact on consumer bill increases from the jump in allowable revenues between DPP3 and DPP4.[595]

F84 Several stakeholders noted that any assessment of consumer price shock should take account of changes in quantities, for example:[596]

> Quantity increases are not a price shock. … When a customer increases the quantity of service they purchase, they will not view the higher charge as a price shock. … Another contribution to higher quantities is new customers, and while the addition of new customers contributes to a revenue increase, existing customers will not view this as a price shock regardless of the magnitude of the increase caused by new customers.

**Analysis conducted**

F85 In arriving at our draft decision on alternative rates of change, we have considered:

F85.1 how to assess consumer price shocks within the relatively low cost DPP framework, taking into account the impact of changes in quantities; inflation; and regulatory factors that contribute to revenue volatility – in particular IRIS amounts and wash-up drawdowns;

F85.2 the need to mitigate any increase in estimated initial prices versus the potential for large year-on-year increases over the period; and

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[595] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 3

[596] EA Networks "DPP4 Issues paper submission" (19 December 2023), p. 1

F85.3 financeability, to the extent this is consistent with the overall Part 4 purpose.[597]

**Approach to assessing consumer price shocks**

F86 While the Act allows us to consider price shocks for consumers when considering alternative rates of change, it does not require any specific assessment or threshold. The discretion under s 53P(8)(a) is framed broadly, in terms of whether "in the Commission's opinion, [an alternative rate of change] is necessary or desirable to minimise any undue financial hardship to the supplier or to minimise price shock to consumers".[598]

F87 Our draft decision is to assess price shocks for consumers using the real change in distribution revenue both at the start of the regulatory period (between DPP3 and DPP4) and over the course of the DPP4 period, measured on a 'per ICP' basis.

F88 We have decided to assess potential price shocks based on distribution revenue, that is the sum of:[599]

F88.1 forecast net allowable revenue;

F88.2 IRIS incentive amounts; and

F88.3 forecast wash-up drawdowns.

F89 IRIS amounts and wash-up drawdowns can have a substantial impact on distribution revenues in any given year, and so contribute to the potential for consumer price shocks. Our estimates indicate most EDBs have substantial accumulated wash-up amounts over the course of DPP3 that will be available to draw down in DPP4. Conversely, most EDBs will see negative IRIS incentive amounts over DPP4. The combined impact of these is shown in Figure F9 below.[600]

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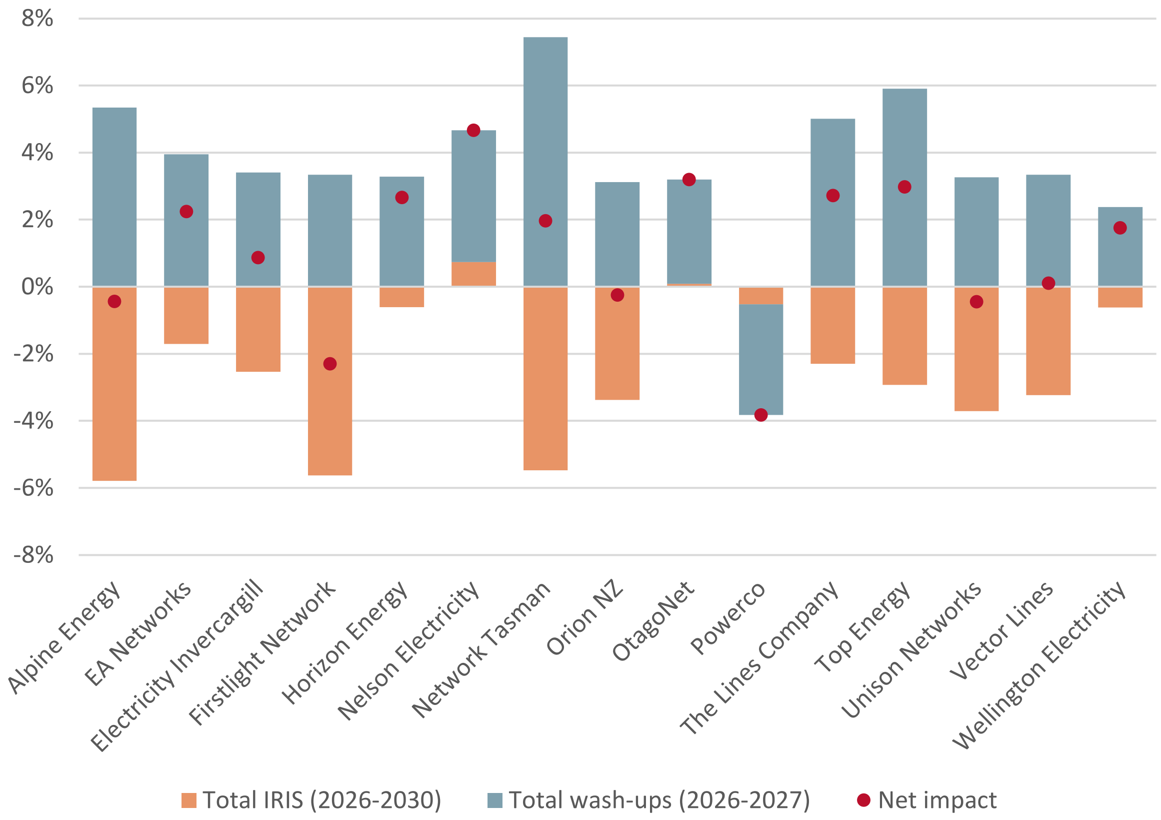
[597] **Attachment G** discusses our approach to considering financeability at this reset and provides details on the financeability sense check we have completed.

[598] Commerce Act 1986, section 53P(8)(a).

[599] Our approach to estimating wash-up drawdown amounts and IRIS incentive amounts is described above at F26 to F40.

[600] Our draft decision on the "revenue smoothing limit" (discussed below) will help to reduce significant swings in incentive payments and wash-up amounts. However, this does not apply in the first year of the regulatory period.

**Figure F9 Estimated impact of wash-ups and IRIS on distribution revenue over DPP4**[601]




F90 Our draft decision is to assess consumer price shock in real terms (net of forecast CPI). Assessing price shock in nominal terms risks suppressing EDBs' real revenues which could lead to substantial future wash-up balances (as has been the case over DPP3), resulting in price shocks in the future. While this would be present-value neutral to EDBs consistent with the FCM principle,[602] substantially deferring the timing of cashflows in this way may cause financeability concerns in the future.

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[601] IRIS amounts are estimated based on actual expenditure data where available (2021-2023), and on EDB AMP forecasts for the remainder of the period (2024 and 2025). Wash-up amounts only account for the difference between forecast net allowable revenue and actual net allowable revenue (the inflation-driven aspects of the DPP3 revenue wash-up) for accruals in 2024 and 2025.

[602] As we have noted elsewhere because the wash-up mechanism for EDBs includes a time-value of money adjustment (Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.4(1)(b)).

F91 Our risk allocation principle was also relevant to our draft decision. Under that principle, we ideally allocate risks to suppliers or consumers depending on who is best placed to manage them.[603] Inflation is outside the control of EDBs, and it is not clear that they are better placed to manage inflation risk than consumers of electricity distribution services.

F92 Stakeholders proposed several options for assessing consumer price shocks:

F92.1 adjusting for changes in energy volumes (kWh), using either forecast or historic data;[604]

F92.2 adjusting for network growth, i.e. the number of connections (ICPs);[605] or

F92.3 analysing retail customer-switching behaviour.[606]

F93 Retail customer-switching behaviour is driven by a number of other factors, such as electricity retailers' pricing and marketing decisions. Further, this is not a practical option within the DPP framework, as reliable annual data for each EDB is not readily available.

F94 Historical data on energy volumes and the number of connections are both available from annual information disclosures.[607] Of the two, our preference is to use growth in connections as a proxy for consumer demand, as this will allow for a smoother and more predictable revenue path. Energy volumes tend be more volatile year-on-year due to exogenous factors (for example due to weather patterns). Using growth in connections also reflects that EDBs' costs tend to be relatively weighted to fixed costs over the short term.[608]

603 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), paragraph A21.2.

604 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 6

605 Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), pp. 72-73

606 Contact Energy "DPP4 Issues paper submission" (15 December 2023), p. 2. Contact Energy cited research on New Zealand residential bill-payers from 2019, suggesting that 40% of customers would switch energy retailers if they could save 6% (or more) of their total customer bill.

607 Our decision-making framework for DPP4 provides that, where possible, we will use existing information disclosed under ID regulation in this reset see Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), para A13

608 Compare for example our analysis of scale drivers in EDB opex discussed in **Attachment C**.

F95 For these reasons, our draft decision is to consider price shocks on a "per ICP" basis. We consider this approach better reflects the intent of s 53P(8) of the Act, while maintaining a relatively low-cost regulatory regime, compared to the alternatives.[609]

F96 We note that where there is an increase in per-consumer energy volumes – as may be the case where we see increased electrification – and EDBs price in per-unit terms, this may see prices rise more slowly on a per-unit basis than is implied by our analysis.

**Balancing estimated initial price increases versus year-on-year increases:**

F97 Our draft decision for our approach to setting alternative rates of change (**draft decision P4**) is to:

F97.1 attempt to limit revenue changes between regulatory periods to 20% (roughly 6% on a retail bill).

F97.2 attempt to limit revenue changes between years within the regulatory period to 10% (roughly 3% on a retail bill).

F98 We considered three options for minimising price shocks to consumers in the transition from DPP3 to DPP4. These profiles are based on estimated changes in consumer distribution prices, calculated on a real revenue per ICP basis, in accordance with our approach to assessing price shock (above):

F98.1 **No smoothing:** Allow the full price shock between periods, then growth at CPI (illustrated by the red line in Figure F10);

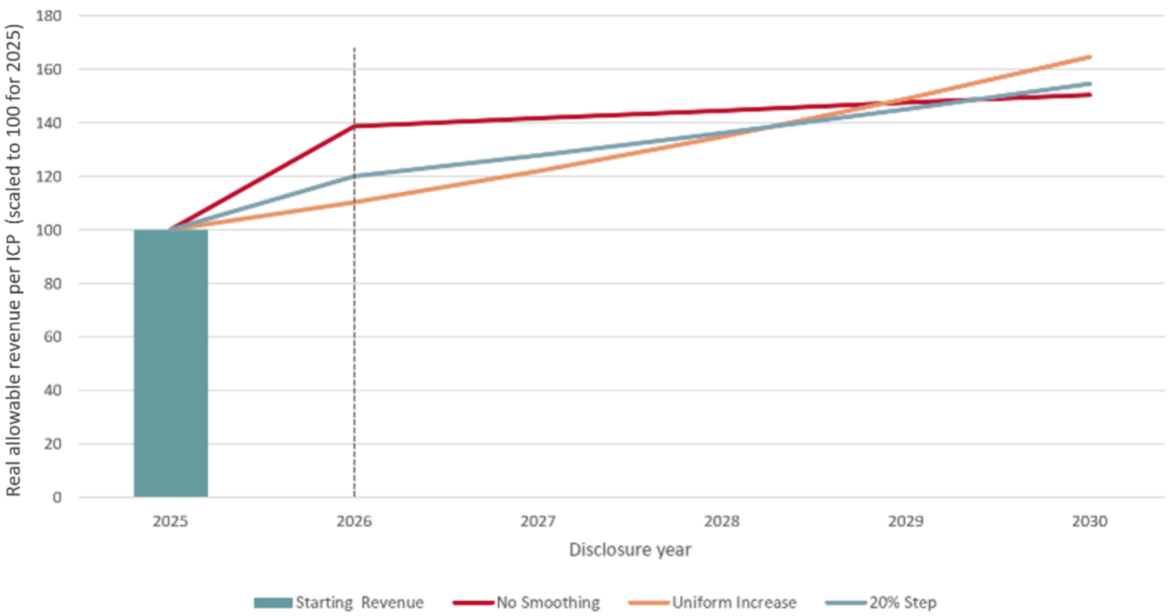
F98.2 **Uniform smoothing:** Entirely smooth the revenue path so that the initial price shock matches the average year-on-year growth rate (illustrated by the orange line in Figure F10);

F98.3 **Medium smoothing:** A combination of an initial step followed by smaller year-on-year growth (illustrated by the blue-grey line in Figure F10).

F99 Figure F10, below, provides an illustrative comparison of the impact of these three options on EDBs' revenue profiles.

[609] As noted elsewhere, eg, paragraph F90 above, our decisions on consumer price shock and alternative rates of change are net present-value neutral to EDBs, and consistent with the FCM principle.

**Figure F10 Illustration of options considered for alternative rates of change**




Illustrative comparison of the options we considered for minimising price shocks to consumers from DPP3 year 5 (2025) to DPP4 year 1 (2026). Values are revenue per ICP, scaled to 100 for 2025. All scenarios are equal in present-value terms; the difference is in the timing of the revenue profile.

F100 Of these available options, we consider the "medium smoothing" option best gives effect to section 53M(8) while still promoting the over purpose of Part 4, because:

F100.1 best balances the need to mitigate the initial price shocks in the transition from year 5 of DPP3 to year 1 of DPP4, and the potential for large year-on-year growth rates.

F100.2 is likely to mitigate the size of the inter-period step into DPP5 compared to the uniform smoothing option.

F100.3 provides some room for growth in year-on-year revenue in the out years should reopeners be allowed.

F100.4 provides room for EDBs to do their own discretionary smoothing should they wish to (subject to the revenue smoothing limit and undercharging limit, which we discuss below).

F101 The "no smoothing" option would lead to an estimated initial price shock in year 1 of DPP4 ranging between 19% and 60% for each EDB, with a weighted average of 38% across EDBs.

F102 The "uniform smoothing" option would lead to a lower initial price shock, but would give rise to annual increases in estimated prices of over 10% on average, and as high as 15% some EDBs. As well as deferring EDBs' revenue recovery and potentially detrimentally affecting financeability, the uniform smoothing option provides less room to adjust in the out-years should revenue grow from reopeners.

**Financeability considerations**

F103 We have completed a financeability sense check, as detailed in **Attachment G - Financeability**. Informed by submissions on the IM review and DPP4 financeability issues paper, and approaches in other jurisdictions, we have evaluated various Standard & Poor's (S&P) ratios. The two core S&P metrics we considered are:

F103.1 funds from operations as a percentage of notional debt; and

F103.2 notional debt to EBITDA.[610]

F104 We also evaluated:

F104.1 FFO interest cover ratio, and

F104.2 notional leverage based on forecast free cashflows.

F105 We have assessed notional financeability using the core S&P ratios FFO/Debt and Debt/EBITDA and the supplementary ratio FFO ICR, against levels consistent with a BBB+ credit rating. We have considered allowing a greater initial level of revenue uplift where we are satisfied that doing so would better promote the Part 4 purpose.

F106 We took the results into account in our draft decisions on alternative rates of change, set out in the section *'Balancing estimated initial price increases versus year-on-year increases'*. We considered but have not adjusted any alternative rates of change due to financeability considerations.

F107 The results of our notional financeability sense check results are presented in **Attachment G**, Table G3. These results apply to revenues after price shock limits and alternate X-factors have been applied.

[610] Earnings Before Interest Tax Depreciation and Amortisation, calculated as revenue less opex.

F108 Financeability metrics improve over the DPP4 period. After the adverse impact from the price shock caps in year 1, they improve in subsequent years on the compounding effects on revenue of alternate X factors. Given the tilted nature of the revenue path – to mitigate price shocks while allowing full in-period revenue – a full-period view of financeability is appropriate.

F109 At this aggregate level, the only breach of the indicative BBB+ reference levels is the Debt / EBITDA ratio for Powerco which is 4.15 compared to a reference level of 4.0. While this could suggest a concern, this result is due to a negative wash-up balance and repayments owed to consumers arising from over-recovery of revenue in previous years.[611]

F110 The other results of our notional financeability sense check, over the whole DPP4 period, for Powerco show:

F110.1 the primary financeability metric, FFO / debt = 16%, exceeding the BBB+ reference level of 13%,

F110.2 the FFO interest cover ratio is 3.6, exceeding the BBB+ reference level of 3.0, and

F110.3 their notional leverage rises by a maximum of 0.3% to 41.3% with one year of negative cashflow on the back of their negative wash-up balance.

F111 Keeping these factors in mind for our decision, our draft decision is that the Part 4 purpose would be better promoted by no additional changes to the revenue path settings for Powerco.

F112 Draft starting prices and draft alternate X-factors for each EDB, incorporating our approach to alternative rates of change, are set out in Table F1 above.

**Rate of change in CPI**

F113 **Draft decision R1.2** is to forecast CPI based on the four-quarter average change in CPI between the first year of the regulatory period and the current year. This is an implementation decision that gives effect to the IMs.

[611] See **Attachment G** for further detail on our use of a financeability 'sense check', in the context of the Part 4 regime.

F114 This is the approach we have used in the past, and in DPP3. We consider this method for calculating forecast CPI remains appropriate for modelling current and projected profitability for each supplier using the “building blocks” approach.

F115 Our draft decision is therefore to confirm this approach for DPP4, consistent with the intent in our decision-making framework to retain approaches from DPP3 where they remain fit for purpose.[612]

**Revenue path over the regulatory period**

F116 Some aspects of how the revenue path will operate are provided for by the specification of price IMs but leave certain matters to be determined by the Commission in a DPP (or CPP) determination. These include:

F116.1 the revenue smoothing limit;

F116.2 implementation of the wash-up mechanism, including the undercharging limit; and

F116.3 implementation of our decision, as part of the IM Review, to apply IRIS in real (CPI-adjusted) terms.

*Draft decision R1.1: Apply a revenue cap with washup as the form of control*

F117 As a result of the IM Review in 2016, we changed the form of control for distributors from a weighted average price cap to a revenue cap, including a wash-up for over and under-recovery of revenue. This form of control was implemented for the DPP3 regulatory period, and was retained in the 2023 IM Review.[613]

F118 As provided for in the IMs, we are applying a revenue cap with washup as the form of control for DPP4. This is consistent with the form of control currently applying to EDBs under DPP3.

*Draft decisions R2.1 and R2.2: Form and size of the “Revenue Smoothing Limit”*

F119 Our draft decision is to set a revenue smoothing limit (RSL) for DPP4 for the purpose of smoothing volatility in recoverable costs over the regulatory period.

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[612] Commerce Commission, “Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper”, (2 November 2023), Attachment A, paragraph A17.

[613] Commerce Commission “Input methodologies review decisions: Report on the IM review” (20 December 2016), p. 78; Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2020” (27 November 2019), p. 91.

**Nature of these decisions**

F120 The annual 'forecast revenue from prices' an EDB is allowed to earn comprises forecast net allowable revenue plus forecast recoverable costs, forecast pass-through costs, and revenue forecast to be received under large connection contracts.[614] The IMs provide that the Commission may specify a RSL in a DPP or CPP determination,[615] to smooth year-on-year fluctuations in these annual revenues.

F121 Under DPP3 this smoothing is implemented through a nominal limit of 10% on annual increases in forecast revenue from prices. That is, under DPP3 revenue smoothing applies to all forecast revenues – forecast net allowable revenue, forecast recoverable costs, and forecast pass-through costs.

F122 Our final decisions on the 2023 IM Review included changes to this smoothing mechanism, to exclude pass-through costs (including transmission charges), and to provide more flexibility in how the RSL is specified.

F123 The original intent of the RSL was to manage volatility in (total) allowable revenue and to protect customers from price-shocks during a regulatory period. As a result of the Commission's decisions in the 2023 IM Review, the RSL smooths the sum of forecast net allowable revenue and forecast recoverable costs.[616] As forecast net allowable revenue is already smoothed through the revenue path mechanism, in effect the RSL only smooths fluctuations in recoverable costs.

F124 There is no explicit statutory requirement to consider price volatility outside the s 53P(8) discretion to determine alternative rates of change when resetting prices. However, price stability and predictability is generally valued by consumers. To the extent that we can achieve the Part 4 Purpose without creating volatility, we consider it worthwhile to do so.

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[614] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(3).

[615] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 1.1.4(2) & 3.1.1(1)(b). The 'revenue smoothing limit' is defined as: "a maximum limit on revenue (excluding recovery of pass-through costs) specified by the Commission in a DPP determination or CPP determination".

[616] This is because pass-through costs, including transmission charges, and revenue received under large connection contracts are now excluded from the revenue smoothing limit for EDBs. Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(1)(b)

F125 Recoverable costs include IRIS amounts, quality incentive adjustments, and wash-up drawdown amounts.[617] These amounts have a substantial impact on revenue volatility during a regulatory period. In our final decisions on the 2023 IM Review, the Commission decided to address the cashflow impact of IRIS and quality incentives as part of the RSL.[618]

F126 Our draft decisions on alternative rates of change (discussed above) take account of estimates for IRIS amounts and accrued wash-up amounts up to the beginning of DPP4. Our draft decisions on the RSL relate to smoothing the impact of IRIS amounts, quality incentives, and wash-up drawdown amounts that occur during the DPP4 regulatory period.

F127 Our draft decisions on the RSL address two questions, which we discuss below:

F127.1 The most appropriate form of any RSL; and

F127.2 The level of the RSL. We have subsumed consideration of whether to set a RSL for DPP4 within this question.

**Draft decisions**

F128 Our draft decision on the form of the RSL (**draft decision R2.1**) is:

F128.1 to specify the RSL with reference to the sum of forecast net allowable revenue and forecast recoverable costs for the previous year ($FNAR_t$ and $FRC_{t-1}$), with adjustments to preserve the revenue path for forecast net allowable revenue and for CPI.

F128.2 In formulaic terms, this means that:

$$FRP_t - FPTC_t - FRLCC_t \leq (FNAR_t + FRC_{t-1} \times (1+\Delta SFCPI)) \text{ x } (1 + \text{Y}\%)$$

Where–
FRP means forecast revenue from prices
FPTC means forecast pass-through costs
FRLCC means revenue forecast to be received under "large connection contracts"

[617] See Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.3.

[618] Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper - Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), Chapter 3 (topic 3b), and Attachment D.

| | |
|---|---|
| FNAR | means forecast net allowable revenue |
| FRC | means forecast recoverable costs |
| ΔSFCPI | is forecast CPI for revenue smoothing |
| Y% | is the size of the RSL. |

F129 Our draft decision on the size of the revenue smoothing limit (**decision R2.2**) is to set the RSL at the level of 10%.

F130 That is, in the formula above, Y = 10%, such that: net allowable revenue for the current year *plus* real (CPI adjusted) forecast recoverable costs for the previous year may not increase by more than 10% each year.

**What we heard from stakeholders**

F131 There is a recognition, particularly from the ENA, that some form of smoothing will be appropriate in DPP4.[619] However, EDBs have expressed the firm view that the mechanism in DPP3 – which limited annual increases in forecast revenue from prices to 10%, without adjusting for CPI (see paragraph F121 above) - is untenable.[620]

F132 Submissions on the DPP4 issues paper emphasised that any decisions on revenue smoothing and rates of change should:

F132.1 take account of financeability;[621] and

F132.2 enable revenue recovery to be "largely completed during the regulatory period (DPP4) with minimal carryover to the following regulatory period"[622] – at a minimum allowing full recovery of building blocks allowable

[619] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 3; Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 8, p. 71; Major Electricity Users' Group "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 6.

[620] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 6; The Lines Company "DPP4 Issues paper submission" (19 December 2023), p. 16; Unison "DPP4 Issues paper submission" (19 December 2023) p. 6; Orion "Cross-Submission on DPP4 Issues Paper" (26 January 2024), p. 4-5.

[621] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 74; Alpine Energy "DPP4 Issues paper submission" (19 December 2023), p. 12; Orion "DPP4 Issues paper submission" (19 December 2023), p. 24-25; Unison "Cross-submission on the DPP4 Issues paper" (26 January 2024), p. 3; EA Networks "DPP4 Issues paper submission" (19 December 2023), p. 2; Vector "DPP4 Issues paper submission" (19 December 2023), p. 12-13, p. 17, p. 18.

[622] Alpine Energy "DPP4 Issues paper submission" (19 December 2023), p. 12.

revenue,[623] preferably all revenue including wash-ups and wash-up balances accumulated during DPP3.[624]

**Views on the form of the RSL**

F133 In arriving at our draft decision on the form of the RSL, we have considered submissions received during consultations on DPP4, as well as during the 2023 IM Review, including on:

F133.1 whether the RSL should be expressed in real or nominal terms;

F133.2 what reference to use in specifying the limit; and

F133.3 whether to include an adjustment for growth in demand.

F134 Submitters strongly supported specifying any RSL in real terms.[625]

F135 EA Networks stated that any RSL should not be set relative to total revenue, as this does not account for the impact of increases in quantities.[626]

F136 Similarly, Network Tasman recommended the Commission "consider whether there are more appropriate, targeted and proportionate tools" to mitigate the risks it is seeking to address through the RSL. As an example, they suggested only applying the limit to smooth for high wash-up account balances (e.g. where the wash-up balance exceeds a set percentage of revenue).[627] This is conceptually similar to our draft decision, which smooths the net impact of wash-ups, IRIS, and other financial incentives.

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623 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 3, p. 5-7.

624 Orion "DPP4 Issues paper submission" (19 December 2023), p. 26; Powerco "DPP4 Issues paper submission" (19 December 2023), p. 31; Vector "DPP4 Issues paper submission" (19 December 2023), p. 12; Vector "Cross-submission on DPP4 Issues paper" (26 January 2024) p. 2, p. 9-10; Unison "Cross-submission on the DPP4 Issues paper"{ (26 January 2024), p. 3 and p. 5.

625 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 4; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 6; The Lines Company "DPP4 Issues paper submission" (19 December 2023), p. 16; Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 22; Powerco "DPP4 Issues paper submission" (19 December 2023), p. 30; Wellington Electricity, "DPP4 Issues paper submission" (19 December 2023), p. 73; Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 290-294.

626 EA Networks "DPP4 Issues paper submission" (19 December 2023), p. 1.

627 Network Tasman "DPP4 Issues paper submission" (19 December 2023), p. 2-3.

F137 The ENA, along with four of the non-exempt EDBs, called for any limit to include an adjustment for volumes, ie, growth in units of electricity delivered[628] and/or in the number of connections,[629] on the basis that a volume-based adjustment will:

F137.1 ensure that EDBs with higher network growth are not disadvantaged;[630]

F137.2 account for the impacts of the substitution of electricity for fossil fuels;[631] and

F137.3 ensure any limit on revenue increases is truly a measure of consumer price impact.[632]

F138 Two submitters raised concerns relating to this approach:

F138.1 Contact Energy suggested that adjusting any smoothing limit for growth in demand risks placing a greater burden on consumers due to potential forecasting error.[633] This concern could be avoided by using historical data rather than forecasts.[634]

F138.2 Powerco commented, in relation to price shocks that "assessing price changes at a price category level for all non-exempt EDBs may be too complex for a DPP".[635]

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628 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 4 & p. 18-19; Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 6; The Lines Company "DPP4 Issues paper submission" (19 December 2023), p. 16; Unison "DPP4 Issues paper submission" (19 December 2023), p. 25, Unison "Cross-submission on the DPP4 Issues paper" (26 January 2024), p. 4; Wellington Electricity, "DPP4 Issues paper submission" (19 December 2023), p. 73.

629 The Lines Company "DPP4 Issues paper submission" (19 December 2023), p. 16; Unison "DPP4 Issues paper submission" (19 December 2023), p. 25.

630 For example, Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 6.

631 For example, Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 6.

632 For example, Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 4-5.

633 Contact Energy "DPP4 Issues paper submission" (15 December 2023), p. 2.

634 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), paragraph 74.

635 Powerco "DPP4 Issues paper submission" (19 December 2023), p. 30.

F139 During the 2023 IM Review, Frontier Economics on behalf of the 'Big Six' EDBs also suggested that the limit could be restricted to a shorter, defined period of time (e.g., one or two years), or include a sliding scale such that it becomes progressively 'looser' over the regulatory period, to reduce the period over which cost recovery is deferred.[636]

**Views on the size of the RSL**

F140 During the IM Review and in submissions on the DPP4 Issues paper, EDBs proposed that any RSL be set at a level – a "high bar" – such that it will bind infrequently.[637] For example, the ENA submitted that capping revenue increases at 10% per annum is not viable, or appropriate for DPP4."[638] Contact Energy stated it supports a 10%+CPI limit on total revenue as a "lenient estimate" of a price shock.[639]

F141 EA Networks pointed out that:[640]

> "the decision to carve out transmission charges from the price cap will actually likely result in a more restrictive cap in years where transmission charges are not increasing. A 10% cap on total revenue movement is much greater than a 10% cap on net distribution revenue. In light of the above, we submit that the price cap itself be set to a significantly higher level."

**Analysis conducted**

F142 Below, we set out our analysis on the form and size of the RSL.

F143 Decisions on the form of the RSL include:

F143.1 Whether to specify the limit in real or nominal terms;

F143.2 What reference to use in specifying the limit;

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636 Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), paragraph 26(a) & (c) and paragraph 315(a) & (c).

637 Vector "DPP4 Issues paper submission" (19 December 2023), p. 12; Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 73; Frontier Economics "A review of the limit on EDB price increases" (report prepared for 'Big 6' EDBs', 19 July 2023), para 26(b) and para 315(b); Powerco "Cross-submission on IM Review 2023 Draft Decisions" (9 August 2023), p. 2.

638 Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission", (19 December 2023), p. 6.

639 Contact "DPP4 Issues paper submission" (19 December 2023), p. 2. Contact's view was disputed in cross-submissions by the ENA, Aurora & Vector (Electricity Networks Aotearoa (ENA) "Cross-submission on the DPP4 Issues Paper" (26 January 2024), p. 1-2; Aurora Energy "Cross-submission on the DPP4 Issues Paper" (25 January 2024), p. 2; Vector "Cross-submission on DPP4 Issues Paper" (26 January 2024), p. 5.

640 EA Networks "DPP4 Issues paper submission" (19 December 2023), p. 2.

F143.3 Whether to include an adjustment for growth in demand substantially greater than forecast.

**Whether to specify the limit in real or nominal terms**

F144 The IMs provide that the most up-to-date CPI inflation data is used when determining forecast net allowable revenue at the start of each regulatory year.[641] This reduces the delay for the wash-up for CPI to take effect, and mitigates the risk of overpayment by consumers or financial pressure for suppliers[642].

F145 Setting a nominal RSL would undermine the intent of that amendment. Accordingly, we consider any RSL should be specified in real terms, using the same up-to-date CPI data used in calculating FNAR.[643]

**What reference to use in specifying the limit**

F146 We have considered the merits of specifying the limit by reference to:

F146.1 the previous year's forecast revenue from prices;

F146.2 the current year's allowable revenue;

F146.3 the sum of the previous year's forecast net allowable revenue and forecast recoverable costs, with adjustments to preserve the revenue path.

F147 The third option – specifying the limit with reference to the sum of the previous year's forecast net allowable revenue and forecast recoverable costs – most closely targets the purpose of the RSL and so is our preferred option.

[641] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(6).

[642] Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper - Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), paragraph 4.181.

[643] This approach was supported by the ENA, Powerco, and Vector in recent submissions on the Financeability Issues Paper. For a full discussion of our reasons for using the most up-to-date CPI inflation data when determining forecast net allowable revenue at the start of each regulatory year, see Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper - Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), p. 224 and p. 371-375.

F148 In implementing this option, we have specified the RSL with reference to forecast net allowable revenue for the current year, plus real (CPI adjusted) forecast recoverable costs for the previous year. This is to preserve the rate of change applied to forecast net allowable revenue in each year of the regulatory period, for each EDB.

F149 Any revenue deferral arising from the revenue smoothing limit would be present-value neutral to EDBs and consistent with the FCM principle.[644] However, as we have noted elsewhere, extended and significant revenue deferral could lead to financeability constraints on EDBs, reducing incentives to invest (inconsistent with s 52A(1)(a) of the Act).

F150 Our preferred option avoids this outcome; using forecast net allowable revenue for the current year, plus real (CPI adjusted) forecast recoverable costs for the previous year, as the reference for the RSL will smooth volatility in recoverable costs, without deferring recovery of forecast net allowable revenue.

F151 Powerco suggested a similar approach in its submission on the Financeability Issues Paper, proposing that the reference should be the previous year's forecast allowable revenue, and stating:

> "This will eliminate the concern of undercharging leading to a lower revenue limit in the future. This is consistent with having a limit that is less likely to bind in most cases and doesn't lead to excessive value in the wash-up account."[645]

F152 Vector proposed an alternative methodology in its submission on the Financeability Issues Paper, based on "determining all revenue accruals from DPP3 and DPP4 that are due to be drawn down within DPP4 in the absence of revenue capping or smoothing" and setting the revenue cap and RSL to allow these accruals to be recovered withing the DPP4 regulatory period.[646]

F153 Our view is that Vector's proposal is not practical, as the necessary data (for example wash-up balance for the 2025 regulatory year) will not be available until after the revenue path is set.

[644] This is because under the wash-up mechanism EDBs accrue a time-value of money adjustment, see Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.4(1)(b).

[645] Powerco "Submission on Financeability issues paper" (15 March 2024), p. 3.

[646] Vector "Submission on Financeability issues paper" (15 March 2024),.p. 14.

F154 Conceptually, our draft decision is similar to what Powerco recommends, but adjusted to remove pass through costs, consistent with the IMs.[647]

F155 With respect to the other options above:

F155.1 Specifying the limit with reference to the previous year's forecast revenue from prices would potentially create a "ratchet effect" – should an EDB set forecast revenue from prices below forecast allowable revenue in any given year, this would reduce the level of the RSL in future years. This has a compounding effect and could lead to substantial build-up of unrecovered revenue.[648]

F155.2 Specifying the limit with reference to the current year's allowable revenue does not provide for year-on-year smoothing, and so would not accomplish the purpose of the limit.

**Whether to include an adjustment for growth in demand**

F156 In submissions on the IM Review and on the DPP4 issues paper, submitters proposed the idea of including a 'quantity' adjustment to the smoothing limit,[649] citing the principle that prices are a function of revenue and demand, so any assessment of price shocks must account for changes in demand.

F157 As we have discussed above,[650] we have accounted for changes in quantities in our approach to assessing price shock and specifying alternative rates of change. We do not consider it appropriate to also include a quantity adjustment in specifying the RSL, as:

F157.1 Under the IMs, the focus of the RSL is limited to the impact of regulatory mechanisms that are not directly correlated with changes in demand (IRIS, quality incentives, and recovery of wash-ups);

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647 Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.1(b).

648 While our preferred option could create a similar "ratchet effect", the potential impact is smaller as the option effectively only smooths the recoverable cost component of the revenue path.

649 For example, Aurora Energy "Submission on Commerce Commission Part 4 Input Methodologies Review 2023 - Draft Decision" (19 July 2023), Section 4.3, and Aurora Energy "DPP4 Issues paper submission" (19 December 2023), paragraph 72.

650 See paragraph F94.

F157.2 The form of control applying to EDBs is a revenue cap. Within that context it is appropriate to smooth for year-on-year fluctuations in revenue; including a demand adjustment as part of the RSL mechanism would increase complexity.

**Other options considered for the form of the RSL**

F158 We have considered the other options proposed by Frontier Economics during the 2023 IM Review. Frontier's suggestion of limiting the RSL to shorter, defined period of time (e.g., one or two years) would not accomplish the objective of smoothing for year-on-year fluctuations in recoverable costs such as IRIS, quality incentives, and wash-up. This approach, and the suggested sliding scale, would add considerable additional complexity in implementation of, and compliance with, the limit. For these reasons we have not adopted these options.

**Size of the RSL**

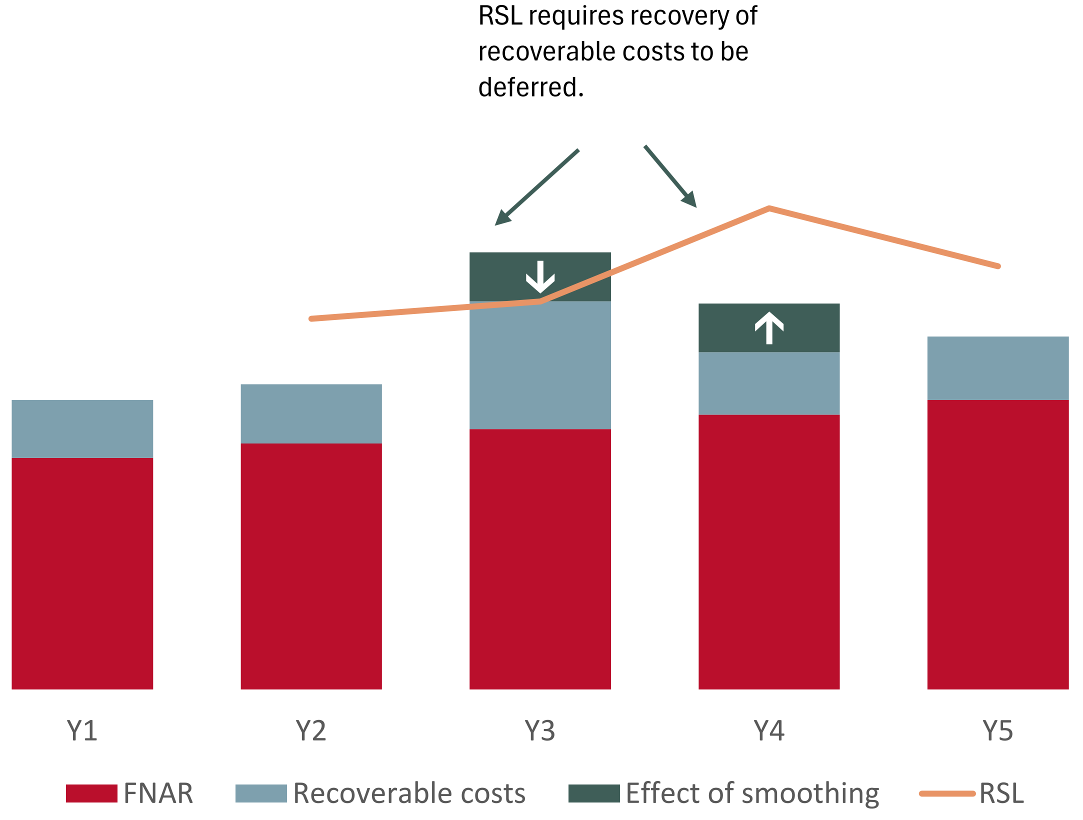
F159 To arrive at draft decisions on the level of the RSL, we reviewed information disclosure data for the past 5 available disclosure years (2019 to 2023),[651] to estimate the variation in net allowable revenue plus recoverable costs (NAR + RC), in real terms.

F160 The data shows substantial real year-on-year swings in NAR + RC, ranging between - 27% and + 25%. This variability arises primarily from the impact of IRIS amounts.

F161 The RSL acts to smooth for "outlier" spikes due to volatility in recoverable costs (primarily IRIS and wash-up amounts). Where the RSL binds in one year, the deferred revenue helps mitigate downswings in distribution revenues in future years. The hypothetical illustration in the figure below shows how a spike in revenues in a particular year – for example arising from higher than usual wash-up accruals - is smoothed. The portion of revenue above the RSL in one year (the green shaded portion in Year 3 in the illustration) is deferred for recovery in the following year (the green shaded portion shown in Year 4). The net present value of total revenue over the regulatory period remains the same.

[651] We have selected 5 years, as historic data prior to 2019 is less directly comparable due to changes in the composition of recoverable costs.

**Figure F11 Illustration of the 'spike' recoverable cost scenario**




F162 In arriving at our draft decision on the size of the RSL, we have weighed this intent alongside the impact on revenue paths, and prices to consumers, of the RSL combined with above CPI year-on-year revenue increases (see decisions P4 and P5 above, on alternative rates of change).

F163 Based on our analysis of historical data, a RSL of 10% equates to the 60$^{th}$ percentile of annual real changes in net allowable revenue plus recoverable costs, across non-exempt EDBs over the period. That is, over time a 10% limit could be expected to bind in 4 out of 10 years.

F164 We also considered the option of using the 90$^{th}$ percentile of annual real changes in net allowable revenue plus recoverable costs (The 90$^{th}$ percentile is consistent with the event occurring once in every 10 years for an EDB, and so smooths for large, infrequent spikes in recoverable costs).

F165 The 90$^{th}$ percentile, based on our analysis of historic data, is 21%. Were we to set the RSL at this level the compounded impact on revenues over the regulatory period - when combined with higher than CPI rates of change – could result in significant year-on-year increases.

F166 As we've already noted,[652] any revenue deferral arising from the RSL would be present-value neutral to EDBs and consistent with the FCM principle. Further, our draft decision on the form of the RSL means that, even though a 10% limit will bind more frequently, EDBs can expect to recover their full BBAR over the DPP4 regulatory period.[653] Should the RSL bind for an EDB, in any given year, the effect will be limited to deferring a portion of the EDB's recoverable costs, to be recovered in the future (including a time value of money adjustment) through the wash-up mechanism.

**Conclusions**

F167 Our draft decisions on the RSL reduce the potential for significant swings in the size of recoverable costs to cause year-on-year volatility in EDB revenues and prices to consumers, while balancing financeability concerns with the compound effect of real increases in consumer prices.

F168 In particular, our draft decisions preserve:

F168.1 the underlying building blocks allowable revenue, and

F168.2 the intent of the recent change in the IMs, to ensure the most up-to-date CPI inflation is used when determining NAR at the start of each regulatory year.

**Implementation of amendments to the wash-up from the IM Review**

**Nature of the decisions**

F169 As part of the 2023 IM Review, the Commission decided on a package of changes to the wash-up mechanism for EDBs. These decisions are reflected in clause 3.1.4 of the EDB IMs Amendment Determination 2023, which specifies:

F169.1 the formula for calculating the 'wash-up account balance' for each disclosure year;

[652] See paragraph F149 above.

[653] Should the RSL bind in the final year of DPP4, some or all of the EDB's recoverable costs would be deferred to DPP5. Our draft decision on the form of the RSL preserves EDBs' ability to recover their forecast net allowable revenue within DPP4.

F169.2 specific adjustments required for the calculation of 'actual allowable revenue', to be accomplished by re-running the relevant components of the DPP financial model; and

F169.3 transitional provisions for all non-exempt EDBs.

F170 Schedules 1.6 and 1.7 of the DPP4 Draft determination implement the wash-up provisions in the IMs (**draft decision R3.1**). We intend to release a demonstration wash-up model to assist understanding and compliance with the revised wash-up mechanism during DPP4.

F171 The wash-up provisions in the IMs provide for the following specific matters to be determined in DPP determinations:[654]

F171.1 Calculation of the CPI adjustment for year 1 of DPP4, for the purpose of the new wash-up for inflation in the first year of a regulatory period;

F171.2 Whether to set a "base wash-up drawdown" for EDBs, for the purpose of returning wash-up account balances to zero over time;

F171.3 The level of the undercharging limit for the DPP regulatory period

F171.4 The time value of money adjustment for the opening wash-up balance; and

F171.5 An adjustment for allowable revenue from large connection contracts.

*Draft Decision R3.2: Calculation of the Y1 inflation wash-up based on the four-quarter average change in inflation between Y0 and Y1.*

**Nature of the decision**

F172 As part of the 2023 IM Review, the Commission decided to amend the EDB IMs to wash-up allowable revenue for the first year of a regulatory period, to account for any variation between predicted and outturn inflation for the first year of a regulatory period.[655]

[654] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.4.

[655] Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper - Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), Topic 4b paragraphs 4.79.2 and 4.111-4.116.

F173 The IMs specify the calculation of the new wash-up for inflation for the first year of the regulatory period at clause 3.1.4(4)(c), as:[656]

> (4) For the purposes of subclause (3), and subject to subclause (10), ‘actual allowable revenue’ for a **disclosure year** means an amount calculated on the same basis as the **forecast allowable revenue** for the **disclosure year**, adjusted (as specified by the Commission in a **DPP determination** or **CPP determination**) by substituting:
>
> ...
>
> (c) in respect of the first **disclosure year** of the **regulatory period**:
>
> (i) the amount determined in accordance with the formula–
> **forecast net allowable revenue** for the disclosure year /
> (1 + **forecast CPI** *change*) x (1 + *actual* **CPI** *change*)
> Where–
> ‘**forecast CPI** change’ means the derived change in the **forecast CPI** for the **disclosure year**, calculated in accordance with a **DPP determination** or **CPP determination**; and
> ‘actual **CPI** change’ means the derived change in the **CPI** for the **disclosure year**, calculated in accordance with a **DPP determination** or **CPP determination**; for
>
> (ii) **forecast net allowable revenue** for the **disclosure year**;

F174 This formula has the effect of “backing out” the forecast CPI change used by the Commission in setting forecast net allowable revenue (‘FNAR’) for the first year of the regulatory period, and instead applying the actual change in CPI for that year. This allows the impact on allowable revenue of any variation between predicted and outturn inflation, to be reflected in the wash-up accrual amount for year 1.

F175 To implement this IM provision, the DPP4 determination must specify the ‘forecast CPI change’ and ‘actual CPI change’.

### Draft decision

F176 Our **draft decision 3.2** is that, for the purpose of calculating the wash-up for inflation for the first year of the regulatory period under clause 3.1.4(4)(c) of the EDB IMs:

F176.1 ‘forecast CPI change’ is 2.12%. This is the value for “forecast changes in the CPI element of the price path” for regulatory year 2026, used in the DPP4 financial model; and

[656] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35” (13 December 2023), clause. 3.1.4(4)(c).

F176.2 'actual CPI change' is specified in accordance with the formula:

$$\Delta CPI = \frac{CPI_{Jun,t-1} + CPI_{Sep,t-1} + CPI_{Dec,t-1} + CPI_{Mar,t}}{CPI_{Jun,t-2} + CPI_{Sep,t-2} + CPI_{Dec,t-2} + CPI_{Mar,t-1}} - 1$$

Where: $CPI_{q,t-n}$ is the CPI for the quarter year ending ***q*** in the 12-month period ***n*** years prior to the year ***t***; and ***t*** is the year 2026.

**Analysis**

F177 *'Forecast CPI change':* The Commission's financial model for DPP4 includes an input term "Forecast changes in the CPI element of the price path", which is used in calculating forecast net allowable revenue for each year of the regulatory period. The value for this term, for regulatory year 2026, is the 'forecast CPI change' for the purpose of the inflation wash-up for year 1 of the regulatory period. For the purpose of our draft decisions, this value is 2.12%.

F178 *'Actual CPI change':* The formula for calculating 'actual CPI change' for the purpose of wash-ups was specified in Schedule 1.6 of the DPP3 determination as:

$$\Delta CPI = \frac{CPI_{Jun,t-1} + CPI_{Sep,t-1} + CPI_{Dec,t-1} + CPI_{Mar,t}}{CPI_{Jun,t-2} + CPI_{Sep,t-2} + CPI_{Dec,t-2} + CPI_{Mar,t-1}} - 1$$

Where: $CPI_{q,t-n}$ is the CPI for the quarter year ending **q** in the 12-month period **n** years prior to the year **t**; and **t** is the year in which the assessment period ends.

F179 We have retained this formula in the draft DPP4 determination, as it remains fit for purpose.

F180 The same calculation applies when calculating the actual CPI change from the last year of DPP3 to the first year of DPP4. Accordingly, our draft decision is to use the above formula for *ΔCPI* for the calculation of "actual CPI change", in washing up for inflation in year 1 of DPP4, where the year *t* is 2026 (the first year of the DPP4 regulatory period).

*Draft Decision R3.3: Base wash-up drawdown*

**Nature of the decision**

F181 The IMs provide a discretion for the Commission to specify for each year of the regulatory period:

"an amount to be drawn down by the **EDB** in the **disclosure year**, as determined by the **Commission** for the purpose of returning the **wash-**

**up account balance** towards zero over time and specified in a **DPP determination** or **CPP determination**"[657]

### Draft decision

F182 Our **draft decision R3.3** is ***not*** to specify a base wash-up drawdown amount for non-exempt EDBs, in DPP4.

### Analysis

F183 Our draft decisions on assessing price shock and specifying alternative rates of change already account for estimated accrued wash-up amounts up to the beginning of DPP4.[658]

F184 Accordingly, there is no reason to set a base wash-up drawdown for DPP4.

*Draft Decision R1.3: Level of the undercharging limit for DPP4*

### Nature of the decision

F185 The IMs provide for an 'undercharging limit', as part of the wash-up mechanism. In setting the DPP4 determination, the Commission is required to specify the level of that undercharging limit.

### Draft decision

F186 Our draft decision is to set the undercharging limit for DPP4 as 90% of a non-exempt EDB's forecast allowable revenue for a year (subject to the application of the revenue smoothing limit).

### What we heard from stakeholders

F187 We received one substantial submission on this topic, from Network Tasman, who proposed the Commission remove the undercharging limit as there is:[659]

> "no basis for the Commission to cap the value of an EDB's wash-up balance because the risk of an EDB accruing a large wash-up balance and then subsequently creating a price shock for consumers is either non-existent or immaterial."

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[657] Commerce Commission "Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), cl. 3.1.4(5)(b)(i).

[658] See paragraph F73, above.

[659] Network Tasman "DPP4 issues paper submission" (19 December 2023), p. 1-2.

F188 Network Tasman also noted that, to their knowledge, “the only EDBs that have materially priced below their revenue allowance over the past two regulatory periods (DPP2 and DPP3) are those that are consumer owned”.

**Analysis**

F189 The purpose of the ‘undercharging limit’ is to set a floor for the amount by which EDBs can voluntarily accrue under-recovered revenue to the wash-up balance in a given year. This limits the potential for an EDB to accrue a large wash-up balance by substantially under-recovering allowed revenue in one year, with the revenue being recovered, on a NPV neutral basis, through the wash-up mechanism in future years.

F190 Should an EDB voluntarily charge below this floor, the difference between the undercharging limit and its forecast revenue from prices is not accrued to the wash-up account, and is therefore foregone.

F191 The DPP3 determination set this limit at 90% of forecast allowable revenue, subject to the 10% limit on annual increases in forecast revenue from prices for DPP3. The 90% limit for DPP3 was chosen to allow EDBs some flexibility to smooth their revenue recovery, while at the same time minimising the risk of future price shocks.[660]

F192 While we note the points made by Network Tasman, the requirement to set an undercharging limit is set out in the EDB IMs, which we reviewed in 2023. The question for the DPP Determination is what the level of the limit should be.

F193 There is no evidence that the 90% undercharging limit under DPP3 is currently causing any detriment to suppliers or consumers; accordingly we have decided to retain it under DPP4. This is consistent with our decision to retain approaches from the DPP3 where they remain fit for purpose.[661]

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[660] Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper” (27 November 2019) (27 November 2019), paragraph 6.34

[661] Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper” (2 November 2023), paragraph A17

F194 Forecast allowable revenues (and therefore prices) will increase substantially under DPP4. Our draft decisions on alternative rates of change mitigate the impact of these increases, taking account of the Part 4 purpose. As a package, our draft decisions give EDBs a degree of flexibility to adjust revenues – and consumer price impacts – during the regulatory period, without foregoing revenue in the long run.[662]

**Other technical matters for the calculation of the washup**

**Nature of the decision**

F195 The revised EDB IMs provide that the DPP determination specify:

F195.1 The time value of money adjustment for the opening wash-up balance; and

F195.2 An adjustment for allowable revenue from large connection contracts.

**Draft decisions**

F196 Our draft decisions on these matters are:

F196.1 **Draft decision R3.4** to calculate the time-value of money of the opening wash-up balance using one year of the DPP3 WACC and one year of a blended DPP3/DPP4 WACC (for a value of 5.25%)

The final cost of capital determination for DPP4 will be made before 30 September 2024, incorporating data up to 1 September 2024. We will apply an updated the time-value of money for the opening wash-up balance in our final DPP4 decision;

F196.2 **Draft decision R1.4** (forecast large connection contract compliance) is to include a large connection contract wash-up term in the wash-up.

**Stakeholder views**

F197 During consultation on the 2023 IM Review, the ENA providing a technical submission, raising number of "practicality issues". As part of that submission, the ENA stated:[663]

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662 As noted above an EDB may voluntarily charge below the undercharging limit. The difference between the undercharging limit and its forecast revenue from prices is not accrued to the wash-up account, and is therefore foregone

663 ENA "Appendix D – IM Practicality Issues Log" (19 July 2023), "Cost of Capital".

> It is unclear what time value of money value to apply when lagging across DPP/CPP periods. For example, for a revenue wash-up where the wash-up amount is from one regulatory period but it affects forecast allowable revenue in the next regulatory period, it is unclear which WACC value (ie from which regulatory period) should be used.

**Analysis**

F198 In response to the ENA's submission, the EDB IMs provide that we specify, in the relevant price-quality determination, the time-value of money adjustment to be used for the wash-up calculation when lagging across regulatory periods (ie, in calculating the opening 'wash-up account balance').[664]

F199 As the amounts to be accrued into the opening wash-up account balance for DPP4 fall across two regulatory periods, the appropriate approach is to incorporate a 'blended' WACC reflecting the extent to which the wash-up amounts will fall between DPP3 and DPP4.

F200 Accordingly, the draft value for the time-value of money to be used in calculating the 'wash-up account balance' for the first year of DPP4 uses one year of the DPP3 WACC and one year of a blended DPP3/DPP4 WACC, giving a draft value of 5.25%.[665] We will apply an updated value in our final DPP4 decision, using the final cost of capital determination for DPP4.

F201 The 2023 IM Review also introduced an optional mechanism for large new customer-initiated and funded connections that meet certain criteria (large connection contracts, or 'LCCs').[666] **Attachment B** of this paper discusses the implementation of this mechanism in DPP4.

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[664] Commerce Commission "Input methodologies review 2023 - [Final] Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 3.1.4(2).

[665] See Schedule 1.7 of the DPP4 Draft determination.

[666] Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments topic paper" (13 December 2023), Chapter 8.

F202 Revenues received under large connection contracts are incorporated in the revised wash-up mechanism. Clause 3.1.4(11) of the IMs requires us to specify in the DPP determination the calculation of allowable revenue in respect of a LCC, for the purpose of the wash-up. This avoids recovery of LCC revenue from other customers through the operation of the wash-up. Accordingly, we have included an adjustment in the wash-up accrual formula in the DPP4 Draft determination.[667]

**Other matters affecting the revenue path (draft decision R1.5)**

F203 **Draft decision R1.5** is to allow distributors to agree a reasonable reallocation of revenue following an asset transfer.

F204 This decision is unchanged from DPP3. We have not identified any problems with the transaction provisions in the DPP3 Determination and have retained them in the DPP4 Draft determination, in accordance with our decision-making framework.[668]

Draft Decision I2: Implementation of amendments to the IMs to determine IRIS opex and capex forecasts in real (CPI-adjusted) terms

**Nature of the decisions**

F205 As part of our final decisions on the 2023 IM Review, we amended the IMs to set inflation-adjusted IRIS allowances (based on actual CPI) for the purposes of calculating opex and capex incentive amounts.

F206 Schedule 2.2 of the DPP4 Draft determination implements this change to the IMs.

**Draft decision**

F207 Our draft decision is to implement ‘real’ IRIS by:

F207.1 Specifying in paragraph (1) and (2) of schedule 2.2 an adjustment for the difference between forecast CPI and actual CPI

F207.2 Specifying in paragraph (3) of schedule 2.2 a definition for $\Delta CPI_{Yt}$ in accordance with the following formula

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[667] See Schedule 1.7, clause (9) of the DPP4 Draft determination.

[668] Our decision-making framework for DPP4 is to retain approaches from DPP3 where they remain fit for purpose, see Commerce Commission “Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper” (2 November 2023), Attachment A, paragraph A17.

$$\Delta CPI_{Yt} = \frac{CPI_{Jun,Yt} + CPI_{Sep,Yt} + CPI_{Dec,Yt} + CPI_{Mar,Yt}}{CPI_{Jun,2024} + CPI_{Sep,2024} + CPI_{Dec,2024} + CPI_{Mar,2024}}$$

Where: $\boldsymbol{CPI_{q,y}}$ is the CPI for the quarter year ending $\boldsymbol{q}$ in the relevant year, $Yt$ is the assessment period and 2024 is the disclosure year ending 31 March 2024

**What we heard from stakeholders**

F208 Stakeholders engaged extensively on this topic in relation to the 2023 IM review,[669] where they considered that inflation adjusted IRIS allowances would protect consumers and suppliers from windfall gains and losses due to differences between forecast and actual inflation.

F209 We did not receive any submissions on this topic in response to the DPP4 Issues paper.

**Analysis**

F210 Our draft decision implements inflation adjusted IRIS allowances by providing an adjustment term to the IRIS allowances set in the determination. This term adjusts each year's allowances by the difference between forecast CPI and actual CPI with respect to the base year. As discussed in the IM Review final reasons paper,[670] we consider that CPI best represents uncontrollable economy wide inflation.

F211 We consider that specifying CPI changes compared to the base year better promotes s 52A (1)(b) of the Act by ensuring that the IRIS incentives account for all differences between forecast and actual CPI following the determination are captured, rather than just those that arise within the period.

[669] See Commerce Commission "Financing and incentivising efficient expenditure during the energy transition topic paper - Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023), topic 5c

[670] Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper" (13 December 2023), p. 267

# Attachment G Financeability

### Purpose of the attachment

G1 This attachment explains the rationale for decisions related to financeability. It also provides background analysis to those decisions and responds to stakeholder submissions on this topic area.

G2 This attachment focuses on our use of a financeability 'sense check' including details of our methodology. We refer to this as a sense check or assessment. It is a decision support tool, not a financeability test as applied in some other jurisdictions with prescribed responses in the event of 'failing' the test.

G3 The results of this sense check have informed decisions related to revenue-setting discussed in **Attachment F – Revenue Path**.

### Financeability at the DPP4 reset

G4 Our proposed approach to considering financeability at the DPP4 reset was presented in the DPP4 Financeability Issues paper, published 23 February 2024.[671] That paper was published after the overall DPP4 Issues paper[672] so that it could incorporate aspects of the final decisions from the 2023 IM Review published December 2024.[673,674]

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671 Commerce Commission "DPP4 reset – Financeability of electricity distribution services in the default price-quality path – Issues paper" (22 February 2024).

672 Commerce Commission "Default price-quality path for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023).

673 Commerce Commission "Report on the IM Review 2023: Part 4 Input Methodologies Review 2023 – Final decision" (13 December 2023).

674 Relevant IM decisions included not to adopt a financeability test in the IMs. They also included changes to revenue setting likely beneficial to EDBs, including treatment of CPI in the revenue path, minimising delays in cashflow through was-ups where inflation is higher than forecast; increasing EDB's flexibility to make early drawdowns of any accrued wash-up balances; reclassifying transmission-related charges to pass-through costs, so their recovery is not deferred for revenue smoothing purposes; and greater flexibility in how the 'revenue smoothing limit' within a DPP is specified. See our DPP4 Financeability issues paper (reference 1 in this Attachment) above for discussion.

G5 Unlike some other jurisdictions, New Zealand's Part 4 regime does not set any express statutory duty or direction requiring the Commission to consider financeability in our decision making. We may take financeability into account where relevant to our decisions, but only to the extent doing so would assist in promoting the Part 4 purpose.

G6 In the DPP4 Financeability Issues paper we acknowledged the financeability context for DPP4, and that we are alive to financeability issues associated with the regulated profile of cashflows in the DPP4 reset. Equally, we were clear that financing significant new capacity and new investment is the responsibility of regulated businesses through normal, efficient capital raising and management.

G7 Our decisions under Part 4 are intended to provide the expectation of a normal return for investors, and it is primarily the responsibility of the supplier to manage timing differences between revenues and costs and to finance new investment. Within this approach there are certain conditions where the timing of cash flows, and the impact of that on financeability, may be relevant to the promotion of the Part 4 purpose.

G8 We have applied notional financeability sense checks, the results of which have informed our choices about what best promotes the Part 4 purpose when making revenue path decisions related to cash flow timing (**Attachment F – Revenue Path**).

**Submissions have informed our approach**

G9 Financeability is a very high-interest topic for some stakeholders. We received 12 submissions on the DPP4 Financeability Issues paper from a range of stakeholders including a report from Oxera[675] prepared for the 'Big Six' EDBs. We received cross submissions from four parties.

G10 At a high level, submissions focussed on three themes:

G10.1 Support for a notional financeability sense check, with calls for more details to increase certainty on how financeability would be assessed for DPP4;

[675] Oxera "Response to the New Zealand Commerce Commission consultation on the financeability of electricity distribution services in the fourth default price-quality path (DPP4)" report prepared for the 'Big Six' EDBs (15 March 2024).

G10.2 Concerns that smoothing DPP4 revenue paths would result in revenue deferrals of significant amounts with strong, adverse short-term impact on cashflows;

G10.3 Longer term concerns about financeability and investability with respect to high investment needs (through and after DPP4) to support an electrification transition.

G11 The development of our approach to financeability for the DPP4 reset has been informed by these submissions and cross submissions. We refer to them below where relevant to our draft decisions.

G12 Our approach has also been informed by reports previously submitted in the IM Review process in 2023. In particular the report by NERA Economic Consulting for ENA[676] has been valuable in informing the details of our financeability sense check.

G13 In keeping with the low-cost nature of the DPP regime, we have sought to appropriately size our approach to financeability assessments to the likely size and prevalence of financeability issues for DPP4.

**Financeability outlook and DPP4 draft decisions**

G14 The results of our financeability sense check, on the post-smoothing DPP4 draft revenue path, do not support the view of a widespread financeability problem for DPP4.

G15 The overall financeability outlook for DPP4 has been improved by several aspects of our regulatory regime and the consequence of changes in economic conditions under it:

G15.1 the increase in WACC;

G15.2 the impact of inflation:

G15.2.1 inflation wash-ups on the RAB and the price paths feeding through to allowed revenues, making EDBs whole for past inflation; and

G15.2.2 decrease in forecast inflation, which means forecast RAB revaluations, when treated as income, should not have an otherwise potentially material impact on allowed revenues.

[676] NERA "Financeability considerations under the DPP: Appendix D -Submission on IM Review CEPA report on cost of capital " report prepared for Electricity Networks Association (16 January 2023).

G15.3 IM changes to revenue settings, including flexibility in the way revenue smoothing limits are applied, transmission costs deemed pass-through costs and therefore not subject to such smoothing, and changes to enable faster recovery of wash-up balances.

G16 Notional financeability assessments have informed our draft decisions on capping initial 'price shocks' and setting alternative X-factors for each EDB. (See **Attachment F – Revenue Path** for more details).

**Financeability sense check**

**Nature of the decision**

G17 The key new proposal in our DPP4 Financeability Issues paper was to apply a financeability 'sense check' to assist us in understanding the extent to which financeability issues may be relevant to this reset, and to inform how we might take financeability into account in our DPP4 decision making.

G18 Under this proposal, this would be the first time we published a financeability assessment of this nature, considering all non-exempt EDBs, at a DPP reset.

G19 Submissions supported a financeability sense check and called for more details to improve certainty.

*P5: Assess notional financeability drawing on metrics from the S&P methodology*

G20 **Draft decision P5** is to apply a financeability sense check to assess notional financeability drawing on metrics form the Standard & Poor's (S&P) methodology. We focus on the core S&P ratios FFO/Debt and Debt/EBITDA[677] with reference levels consistent with a BBB+ credit rating, and also consider leverage and FFO interest cover ratio. We considered allowing a greater initial level of revenue uplift where we were satisfied that doing so would better promote the Part 4 purpose.[678]

G21 We outline below various details of this sense check. We have published the results of this sense check with our financial modelling suite for the DPP4 draft decision[679].

[677] FFO is funds from operations, and EBITDA is Earnings Before Interest Tax Depreciation and Amortisation. See the *'Financeability Metrics'* section for details on how these ratios are calculated in our case.

[678] As discussed in Attachment F in regard to alternative rates of change and revenue smoothing, we have not in practice made any adjustments for financeability reasons, as we did not consider them necessary.

[679] Commerce Commission "Financeability model – EDB DPP4 draft determination" (29 May 2024)

G22 Our financeability sense check is a support tool for decision making. This assessment is not a ‘financeability test’ in the sense used in some jurisdictions where there may be prescribed responses or outcomes to address the test result(s) of a supplier not meeting defined thresholds.

G23 How we considered the results of our financeability sense check in making decisions on the revenue path is discussed in **Attachment F – Revenue Path**.

**Details of our financeability sense check**

G24 We have further developed our financeability sense check methodology from the approach we proposed in the DPP4 Financeability Issues paper[680]. We have considered various approaches to financeability assessments and tests in other jurisdictions, including in Australia (IPART (NSW),[681] ESC (Victoria),[682] AEMC/AER for approved transmission network projects [683,684]) and the UK (Ofgem[685] and Ofwat[686]).

G25 Useful summaries and comparisons of financeability assessments across jurisdictions can be found in the IPART final report on its financeability test[687] and the NERA submission on the recent IM Review.[688]

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680 Commerce Commission “DPP4 reset – Financeability of electricity distribution services in the default price-quality path – Issues paper” (22 February 2024)

681 IPART (Independent Pricing and Regulatory Tribunal, NSW) “Review of our financeability test” (November 2018)

682 Essential Services Commission, Victoria (ESC) “Assessing the Financial Viability of Victorian Water Businesses – Summary of Views and proposed new indicators” (June 2014)

683 AEMC (Australian Energy Markets Commission) “National Electricity Amendment (Accommodating financeability in the regulatory framework) Rule 2024” (March 2024)

684 Under the AEMC Rule change above, AER (Australian Energy Regulator) must develop Financeability Guidelines specifying its financeability test, but this has not been published to date.

685 Ofgem (Office of Gas and Electricity Markets, UK) ”Financeability Assessment for RIIO-2” (26 March 2019)

686 Ofwat (Office of Water, UK) “ PR19 final determination, Aligning risk and return technical appendix“ (December 2019, updated 30 April 2020)

687 IPART (Independent Pricing and Regulatory Tribunal, NSW) “Review of our financeability test” (November 2018)

688 NERA “Financeability considerations under the DPP: Appendix D -Submission on IM Review CEPA report on cost of capital ” (report prepared for Electricity Networks Association 16 January 2023).

G26 Our approach is based on the S&P Methodology[689] considered in relation to regulated electric and gas networks by NERA[690] and overviewed by IPART[691]. The use of an S&P framework, rather than one based on other ratings agencies, is supported by S&P being the rating agency most relevant to the NZ distribution businesses.

G27 Within this approach we have calculated core S&P financeability metrics and compared them against reference levels derived below from that methodology. We consider these to be 'reference levels' rather than thresholds, to again emphasize that we are applying a sense check, not a test with prescriptive responses.

G28 The key features of our draft decision approach, expanded on below, are:

G28.1 A notional assessment, using notional cost of debt;

G28.2 Leverage is initially the notional level and allowed to vary dynamically;

G28.3 The only actual inputs are IRIS and wash-up amounts from DPP3, recovered in regulatory years 2026 and 2027;

G28.4 We do not specify an allowed dividend level;

G28.5 We have assessed several S&P metrics, primarily the core ratios FFO/Debt, and Debt / EBITDA, and others including FFO interest cover ratio; and

G28.6 We compare results for these metrics with reference levels indicative of a 'strong' business maintaining a bbb+ anchor credit rating, which is in turn consistent with an overall BBB+ issuer credit rating.

## Notional analysis

G29 In our financeability Issues paper we proposed for DPP4 an approach where would start with a notional analysis, and if a financeability issue arose under the notional analysis, we would then assess if there was in fact likely to be a financeability issue for the particular supplier.

G30 Out notional analysis is described below. We have not found it necessary to assess the actual circumstances of any suppliers in this sense for DPP4 draft decisions.

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689 S&P Global "General: Corporate Methodology" (19 November 2013, updated 2019)

690 NERA "Financeability considerations under the DPP: Appendix D -Submission on IM Review CEPA report on cost of capital " (report prepared for Electricity Networks Association, 16 January 2023).

691 IPART (Independent Pricing and Regulatory Tribunal, NSW) "Review of our financeability test" (November 2018)

G31 The notional cost of debt for DPP4 draft prices is 6.12%.

G32 Leverage is initially the notional leverage 41% and allowed to vary dynamically under our notional analysis as follows. These are intended as reasonable modelling assumptions, required to model leverage dynamically, not expectations for how EDBs would actually manage such circumstances.

G33 We start with a notional leverage of 41%;

G33.1 We calculate cashflow available to equity by including the additional borrowing capacity from increased RAB at a level to maintain the notional leverage;

G33.2 In years where this results in a negative cashflow available to equity, we assume additional borrowing at the level to provide zero cashflow available to equity, ie increasing leverage above 41%; and

G33.3 In years where, as a result of the above additional borrowing, leverage is above 41% and there is a positive cashflow available to equity, then repayments are made to reduce leverage. The repayment amount is the lesser of cashflow available to equity and the amount required to restore leverage to 41%.

G34 Our one use of actual amounts is to account for revenue balances from DPP3 through IRIS payments and wash-ups. We have applied these in regulatory years 2026 and 2027.

## No specified dividend levels

G35 Our notional assessments do not include a specified dividend yield. We do calculate cash available to equity as an output.

## Financeability metrics

G36 Informed by submissions on the IM review and DPP4 Financeability Issues paper, and approaches in other jurisdictions, we have evaluated various S&P ratios. The two core S&P metrics we have considered are:

G36.1 funds from operations (FFO) as a percentage of notional debt, and

G36.2 notional debt to EBITDA.[692]

[692] Earnings Before Interest Tax Depreciation and Amortisation, calculated as revenue less opex.

G37 We have also evaluated:

G37.1 FFO interest cover ratio, and

G37.2 notional leverage, based on forecast free cashflows.

G38 FFO / debt is the primary measure for S&P credit ratings, and the most common (or in some cases only) metric mentioned in ratings reports. As such, we place most weight on it.

G39 These metrics have been calculated as below, where notional Interest is notional cost of debt x notional debt, and notional debt is notional leverage x RAB: [693]

G39.1 FFO / Debt = (revenue - opex - tax - notional interest) / (notional debt)

G39.2 Debt / EBITDA = notional debt / (revenue - opex)

G39.3 FFO interest cover ratio (ICR) = (revenue - opex - tax) / (notional interest)

## Reference Levels

G40 We have used reference levels for these ratios at the S&P anchor rating of bbb+ which are generally consistent with an issuer credit rating of BBB+.

G40.1 FFO / Debt > 13%

G40.2 Debt/EBITDA < 4

G40.3 FFO ICR > 3

G41 We show below how these are derived from the S&P Methodology.

G42 In the S&P methodology, the ratios above are used to determine an 'anchor rating' expressed in lower case, eg, bbb+. The S&P 'issuer credit rating' (eg, BBB+) is derived from the anchor rating by considering modifiers such as diversification, capital structure, financial policy, liquidity, management / governance, and comparable ratings analysis. Evaluating these considerations for all EDBs is beyond the scope of a DPP reset. We have made the simplifying assumption to equate financial metrics supporting a bbb+ anchor rating with an issuer credit rating of BBB+.

[693] S&P refer to FFO ICR as 'FFO plus interest to interest' to emphasize the numerator is not the same as in the FFO / debt ratio (otherwise these metrics would be directly proportional in a notional assessment).

G43 The S&P methodology to link the values of these ratios with anchor ratings depends on some other factors: industry and country risk volatility, business risk profile, and financial risk profile.

G44 In 2018 S&P revised upwards the regulatory framework score for New Zealand regulated utilities to 'strong', noting:[694]

> Due to recent regulatory decisions and a consistent track record of regulatory resets, the New Zealand regulatory landscape for the country's electricity and gas networks is now more mature, predictable, and strong, as well as being stable and transparent.
>
> As a result, we are now assigning a higher regulatory advantage score of strong for New Zealand regulated utilities from strong/adequate, the most important factor in assessing a utility's competitive advantage.
>
> With this improved regulatory score, entities can operate with a somewhat lower threshold of financial metrics for a given rating, all else being equal.
>
> We are affirming the ratings on three New Zealand regulated utilities: Transpower New Zealand, Powerco, and Vector Ltd. The rating outlooks remain stable.

G45 Based on this and the IM Review submission on this topic from NERA,[695] who applied a 'low' volatility, we have used 'low' volatility rating and 'strong' business risk profile.

G46 As in the table below, for a business with a 'strong' business risk profile to achieve a bbb+ anchor rating its financial risk profile should lie above the boundary between 3(Intermediate) and 4(Significant):

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694 Regulatory framework score for New Zealand regulated utilities revised to strong (22 April 2018), https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/2481871 (accessed online May 2024).

695 NERA "Financeability considerations under the DPP: Appendix D -Submission on IM Review CEPA report on cost of capital" (report prepared for Electricity Networks Association, 16 January 2023).

**Table G1 S&P Methodology anchor table: combining the business and financial risk profiles to determine the anchor**[696]

| | --Financial risk profile-- | | | | | |
|---|---|---|---|---|---|---|
| **Business risk profile** | **1 (minimal)** | **2 (modest)** | **3 (intermediate)** | **4 (significant)** | **5 (aggressive)** | **6 (highly leveraged)** |
| 1 (excellent) | aaa/aa+ | aa | a+/a | a- | bbb | bbb-/bb+ |
| 2 (strong) | aa/aa- | a+/a | a-/bbb+ | bbb | bb+ | bb |
| 3 (satisfactory) | a/a- | bbb+ | bbb/bbb- | bbb-/bb+ | bb | b+ |
| 4 (fair) | bbb/bbb- | bbb- | bb+ | bb | bb- | b |
| 5 (weak) | bb+ | bb+ | bb | bb- | b+ | b/b- |
| 6 (vulnerable) | bb- | bb- | bb-/b+ | b+ | b | b- |

G47 The table below gives the values for this boundary between 'Intermediate' and 'Significant' financial risk profile for 'low' volatility. From this we find reference levels for our financeability sense check notes above: FFO / Debt > 13%; Debt / EBITDA < 4 and FFO ICR > 3.

**Table G2 S&P Methodology metric value table: cash flow/ leverage analysis ratios – low volatility**[697]

| | --Core ratios-- | | --Supplementary coverage ratios-- | | --Supplementary payback ratios-- | | |
|---|---|---|---|---|---|---|---|
| | **FFO/debt (%)** | **Debt/EBITDA (x)** | **FFO/cash interest (x)** | **EBITDA/interest (x)** | **CFO/debt (%)** | **FOCF/debt (%)** | **DCF/debt (%)** |
| Minimal | 35+ | Less than 2 | More than 8 | More than 13 | More than 30 | 20+ | 11+ |
| Modest | 23-35 | 2-3 | 5-8 | 7-13 | 20-30 | 10-20 | 7-11 |
| Intermediate | 13-23 | 3-4 | 3-5 | 4-7 | 12-20 | 4-10 | 3-7 |
| Significant | 9-13 | 4-5 | 2-3 | 2.5-4 | 8-12 | 0-4 | 0-3 |
| Aggressive | 6-9 | 5-6 | 1.5-2 | 1.5-2.5 | 5-8 | (10)-0 | (20)-0 |
| Highly leveraged | Less than 6 | Greater than 6 | Less than 1.5 | Less than 1.5 | Less than 5 | Less than (10) | Less than (20) |

[696] S&P Global "General: Corporate Methodology" (19 November 2013, updated 2019), p. 6.

[697] *Ibid*, p. 34.

## Results of our notional sense check

G48 The inputs, calculations, and results of our notional financeability assessment are included in our published draft DPP4 financial model suite.[698] Shown below are financeability sense check results for draft DPP4 draft decisions. These are post-smoothing, based on revenue allowances after 'price shock' caps, alternate X-factors and revenue smoothing have been applied.

G49 Our draft decision approach to smoothing, in terms of 'price shock' limits and alternate X-factors and secondary smoothing is discussed in **Attachment F – Revenue Path**. This included consideration of our notional financeability sense check results before and after any smoothing.

G50 On the whole, all EDBs will be able to fully recover their draft DPP4 allowed revenue plus outstanding DPP3 balances within the DPP4 regulatory period. This reflects revenue path **draft decision P1** which includes no deferral of building blocks allowable revenue into DPP5. Given that we have capped 'price shocks' from the last year of DPP3 to year-one of DPP4 at 20% (with a few exceptions) this has led to us setting alternate X-factors at levels to enable full in-period recovery on a PV-neutral basis.[699]

G51 Table G3 shows results of our financeability sense checks, after those year-one 'price shock' limits and alternate X-factors have been applied. We have not additionally adjusted any alternate X-factors for financeability reasons.

G52 On the whole, financeability metrics improve over the DPP4 period. After the adverse impact from 'price shock' limits at (in all but two cases) 20% applied in year one, they improve in subsequent years on the compounding effects on revenue of alternate X-factors. Given the tilted nature of the revenue path – to mitigate price shocks while allowing full in-period revenue – a full-period view of financeability is appropriate.

G53 At this aggregate level, the only breach of the indicative BBB+ reference levels is the Debt / EBITDA ratio for Powerco which is 4.15 compared to a reference level of 4.0.

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698 Commerce Commission "Financeability model – EDB DPP4 draft determination" (29 May 2024)

699 For more information, see **Attachment F – Revenue Path**: Given wash-ups accrued over the DPP4 period cannot be forecast with any certainty, and drawdowns necessarily operate on at least a two-year lag, there may still be some deferral of DPP4 revenue into DPP5. Additionally, within the undercharging limit, EDBs may choose to defer recovery of some revenue.

Table G3 **Financeability test results from applying our financeability sense check to post-smoothing prices over DPP4 as a whole**[700]

| EDB<br>Reference level | FF0/debt<br>>13% | Debt/EBITDA<br><4.0 | FFO ICR<br>>3.0 | Maximum Leverage<br>41% |
|---|---|---|---|---|
| **Alpine Energy** | 17% | 3.8 | 3.8 | 41% |
| **EA Networks** | 18% | 3.6 | 3.9 | 41% |
| **Electricity Invercargill** | 18% | 3.6 | 4.0 | 41% |
| **Firstlight** | 18% | 3.9 | 3.9 | 42% |
| **Horizon Energy** | 21% | 3.2 | 4.5 | 41% |
| **Nelson Electricity** | 18% | 3.7 | 3.9 | 41% |
| **Network Tasman** | 18% | 3.7 | 3.9 | 41% |
| **Orion NZ** | 17% | 3.8 | 3.8 | 41% |
| **OtagoNet** | 20% | 3.6 | 4.3 | 41% |
| **Powerco** | 16% | 4.2 | 3.6 | 41% |
| **The Lines Company** | 19% | 3.5 | 4.1 | 41% |
| **Top Energy** | 18% | 3.7 | 4.0 | 41% |
| **Unison Networks** | 20% | 3.4 | 4.2 | 41% |
| **Vector Lines** | 18% | 3.8 | 3.9 | 41% |
| **Wellington Electricity** | 18% | 3.7 | 3.9 | 41% |

### What we heard from stakeholders

### Overall support for financeability sense checks and a call for more details

G54 Submissions on our financeability issues paper from a range of parties overall supported our proposal to include a financeability sense check, with calls for more details on our methodology to improve certainty.[701]

[700] These results, and their inputs and calculation can be found in the financeability workbook of our draft DPP4 financial models published with this paper. Commerce Commission "Financeability model – EDB DPP4 draft determination" (29 May 2024)

[701] For example, Electricity Networks Aotearoa (ENA) "Submission to the Commerce Commission on Financeability issues paper" (15 March 2024); Consumer Advocacy Council "Submission to the Commerce Commission on Financeability issues paper " (15 March 2024); Powerco, "Submission to the Commerce Commission on Financeability issues paper " (15 March 2024).

G55 The approach detailed above for DPP4 draft decisions, and its application in **Attachment F – Revenue Path**, provides detail and direction setting on how we intend to assess and consider financeability assessments at the DPP4 final decisions.

### Thresholds

G56 Several submissions including ENA[702] , Powerco[703], Vector[704] and Oxera for the 'Big Six' EDBs[705] specifically called for thresholds to be set for financeability ratios at a level corresponding to the BBB+ rating used in setting the WACC.

G57 Whilst not using 'thresholds' with prescriptive responses should they not be met we have set reference levels for the financial ratios we have considered at the S&P bbb+ anchor rating level. As discussed above, this is generally in line with a BBB+ issuer credit rating.

### Dividends

G58 Some submissions (notably Oxera for the 'Big Six' EDBs[706] and in Vector's cross submission) emphasized the importance of stable dividends to infrastructure equity investors. Vector asserted that: [707]

> ..financeability testing should include the ability to pay dividends as well as pay interest (i.e., both funders not just one).

G59 The cross submission from Vector included a report from Oxera[708] on this topic, with detailed analysis of the dividend expectations of infrastructure investors.

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702 Electricity Networks Aotearoa (ENA) "Submission to the Commerce Commission on Financeability issues paper" (15 March 2024), p. 3.

703 Powerco "Submission on Financeability issues paper" (15 March 2024), p. 3.

704 Vector "Submission on Financeability in EDB DPP4 reset" (15 March 2024), p. 2.

705 Oxera "Response to the New Zealand Commerce Commission consultation on the financeability of electricity distribution services in the fourth default price-quality path (DPP4)" report prepared for the 'Big Six' EDBs (15 March 2024), p. 41.

706 *Ibid*, p. 31.

707 Vector "Cross submission on Financeability in EDB DPP4 reset " (28 March 2024), p. 11-12.

708 Oxera "DPP4 financeability consultation cross- submission—dividend yields" report prepared for Vector (28 March 2024).

G60 We accept the general position of the importance of dividends to equity investors. We have considered this and, in reaching our draft decision, maintain our position from the 2023 IM Review that it is not efficient for suppliers to pay dividends and then incur costs from raising new equity.[709] We have avoided making strong assumptions about investor behaviour (ie, additional borrowing or dividends) beyond matching to the 41% leverage assumption where possible.

G61 We also note that infrastructure investors in New Zealand have been prepared to forego dividends at times when significant investment has been required, for example Transpower and Chorus.[710] This is consistent with what we observe in workably competitive markets. Ultimately, we consider that, as long as investment continues to occur, maintaining our approach better promotes the Part 4 purpose, rather than frontloading cashflows in order to allow suppliers to pay dividends, at the same time as they state a need to raise new equity to finance investment. We remain open to reconsidering this position, including if we were presented with credible evidence that equity investors are less willing to invest in infrastructure regulated under Part 4 (eg, evidence of suppliers actually trying and failing to raise equity readily and on reasonable terms).

G62 We have not included in DPP4 draft decisions any move to indicate support for any specific level of dividend yield for equity holders of EDBs. We have not included a specific dividend level in our financeability sense check.

G63 This approach is in line with the decision of IPART (Independent Pricing and Regulatory Tribunal, NSW Australia) to not include dividends in its financeability test:[711]

> The objective of the financeability test is to assess whether there are sufficient cash flows for the regulated business to remain financially sustainable. Whether the regulated business then decides to use the cash flows generated by our pricing decisions to fund dividend payments, pay down debt or build capital reserves, is outside the scope of the financeability test. Furthermore, because most of these ratios are not included by credit ratings agencies in their methodologies, it would be more difficult to establish a target ratio that a BBB rated business would need to meet.

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709 Commerce Commission "Input methodologies review 2023 - Final decision - Cost of capital topic paper" (13 December 2023), p. 193.

710 Commerce Commission "Input methodologies review 2023 - Final decision - Financing and incentivising efficient expenditure during the energy transition topic paper " (13 December 2023) paragraph 3.145 ".. in times in the past where Transpower has faced significant increases in investment, as is likely to be the case again for RCP4 and RCP5, it has suspended dividend payments. Similarly, investors in Chorus in the early years of the fibre rollout forewent some dividends in favour of growth of Chorus's equity value."

711 IPART "Review of our financeability test" (November 2018)

G64 We note that the cashflow available to equity over RAB for our notional analysis of post-smoothing DPP4 draft prices averages 2.5% pa over the DPP4 period, and 4.6% in the last year of the period.

**Notional assessment**

G65 In our DPP4 Financeability Issues paper we proposed an approach including a notional analysis, and that if a financeability issue arose under the notional analysis, we would then assess whether there was in fact likely to be a financeability issue for the particular supplier.

G66 The intention of this approach was to inform our assessment of whether there was likely an actual risk that financeability concerns may disincentivise or otherwise impact investment in a way that would risk actual harm to the long-term benefit of consumers.

G67 All submissions with a view on this topic supported notional assessments, and some argued against actual assessments.

G68 One concern raised was to avoid the outcome of a notional financeability issue being addressed if a real issue also existed, but not if an EDB had arranged its affairs so that no actual issue existed. Oxera for the 'Big Six' EDBs noted:[712]

> ..while we agree that testing financeability of the actual company is important, we do not find it appropriate to not remedy notional financeability issues.

G69 For the DPP4 draft decisions, we have conducted only notional assessments. Given then results of this notional analysis (where the only issue identified is adequately explained by wash-up accruals) it has not been necessary to engage in any actual financeability assessments or to seek additional information.

**Consideration of financeability when setting the revenue path**

G70 The revenue path related decisions in DPP4 where we noted in our financeability issues paper that financeability may be relevant are:

G70.1 determining an alternate X-factor to change the profile of cash flows during the regulatory period; and

[712] Oxera "Response to the New Zealand Commerce Commission consultation on the financeability of electricity distribution services in the fourth default price-quality path (DPP4)" report prepared for the 'Big Six' EDBs (15 March 2024), p. 44.

G70.2 how we determine the revenue smoothing limit.

G71 As noted above, one theme of submissions was a concern about the cashflow and financeability impacts of decisions on starting price adjustments and alternate X-factors, and the potential for revenue smoothing limits to result in revenue recovery deferred beyond the DPP4 regulatory period.

G72 ENA expressed this as:[713]

> Cashflows are at the heart of financeability and its assessment. The Commission's decision on revenue smoothing within the regulatory period will be a key determinant of the outcome of all financeability assessments. Therefore, any financeability assessment must be conducted using post-smoothing revenues.

G73 Powerco said:[714]

> The Commission should set revenue smoothing limits, and X-factors in a way that ensures the notional supplier that does not have periods of sustained negative cashflows, to ensure the financeability of the supplier. This will protect the long-term interest of consumers and preserve EDBs incentives to invest. Any Financeability test should be performed post application of X-factors or revenue smoothing.

G74 Following **draft decision P5** above we have conducted financeability sense checks through the draft DPP4 revenue setting process. An overall consideration of financeability has informed our revenue path decisions related to limiting 'price shocks' in starting price adjustments, and alternate X-factors. (**See Attachment F – Revenue Path.**) Our financeability results shown above are post application revenue smoothing via alternative rates of change.

### Other matters in the financeability issues paper

G75 Beyond the financeability sense check, we here discuss other financeability matters raised in submissions which are relevant to DPP4 draft decisions.

[713] Electricity Networks Aotearoa (ENA) "Submission to the Commerce Commission on Financeability issues paper" (15 March 2024), p. 5.

[714] Powerco "Submission on Financeability issues paper", (15 March 2024), p. 3.

### Equity issuance costs

G76 In the financeability issues paper we noted that currently no equity issuance costs are provided in the cost of capital IMs. We added that where notional modelling and evidence from an EDB demonstrates that they need to issue new equity to finance investment, and that they are willing and able to do so, there's an argument that providing this allowance better supports ex ante FCM.

G77 Several submissions on this topic supported adoption of the Australian Energy Regulators (AER) approach. Powerco said:[715]

> We support the inclusion of additional allowances for equity issuance costs, equity raising, if required, is not a costless exercise and support the Commission adopting an approach like the AER in the financial model as part of the return on capital BBAR component.

G78 ENA also supported the AER approach:[716]

> ENA in its IM submission, proposed that an equity raising allowance be incorporated into the WACC IM and that the AER approach to the calculation of this equity raising allowance be adopted in the Commissions' financial model. ENA's view remains that the equity allowance is best incorporated within the return on capital component of the DPP determination .. rather than an opex allowance as the inclusion of an opex allowance would give rise to IRIS implications and unnecessary complexity.

G79 Vector in its cross submission generally supported views on this topic expressed by Oxera for the 'Big Six' EDBs[717] , including on the direct and indirect costs of equity issuance. Vector noted it was:[718]

> ..open to considering different approaches but highlighted that both the direct and indirect costs of obtaining new equity injections must be considered in any proposed approach.

G80 After considering submissions, and the results of our financeability sense check, our draft decision is that we see no demonstrated need for providing equity issuance costs in DPP4:

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[715] *Ibid*, p. 3.

[716] Electricity Networks Aotearoa (ENA), "Submission to the Commerce Commission on Financeability issues paper ", (15 March 2024), p. 5.

[717] Oxera "Response to the New Zealand Commerce Commission consultation on the financeability of electricity distribution services in the fourth default price-quality path (DPP4)" report prepared for the 'Big Six' EDBs (15 March 2024), p. 47.

[718] Vector "Cross submission on Financeability in EDB DPP4 reset " (28 March 2024), p. 9.

G80.1 our notional financeability sense check indicates variations from notional leverage of at most 2% (from 41% to 43% leverage) so accordingly we do not see a need for equity raising in DPP4. (Noting that submissions strongly supported a notional view on financeability.)

G80.2 We received no evidence or indication that any EDB was actually considering issuing new equity in the DPP4 regulatory period.

G80.3 Based on information available to us, equity issuance in the New Zealand EDB sector is relatively uncommon in practise.

G81 We have not provided equity issuance costs for DPP4 in our draft decision.

G82 If an EDB sees a genuine need to raise equity associated with expenditure beyond what it accommodated under the default price path, a CPP could include an allowance for the cost of equity issuance.

**Capital contributions**

G83 Some submissions referred to the potential interaction of financeability and any changes to capital contributions (ie, connection pricing) stemming from the Electricity Authority's work in progress on distribution pricing. In particular, Vector said:[719]

> With the Electricity Authority due to release its emerging views on distribution pricing due in April 2024, we would like assurances from the Commission that they have taken account of the possible outcomes from the Authority's work in their assessment of EDB financeability.

G84 Capital contributions were identified by the Electricity Authority as an area of interest in an Issues paper on distribution pricing.[720] In a recent paper, the Authority has said it will "work with industry on a draft Code amendment to regulate connection pricing" via consultation later in 2024.[721] Final decisions will be released during the DPP4 regulatory period.

G85 Section 54V(5) of the Act enables us to accommodate changes from that review if asked by the EA, in certain circumstances, such as Code changes that affect distribution pricing methodologies.

**Discretionary adjustment of asset lives**

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[719] Vector "Submission on Financeability in EDB DPP4 reset" (15 March 2024)

[720] Electricity Authority "Targeted Reform of Distribution Pricing – Issues Paper" (5 July 2023)

[721] Electricity Authority "Distribution Pricing Reform: Next steps" (7 May 2024), p. 2.

G86 In our Financeability Issues paper we noted that "the IMs provide for a discretionary shortening of asset lives for existing assets triggered by application from an EDB and the Commission considering that doing so would better promote the Part 4 purpose."[722]

G87 We did not receive any applications by the 29 February 2024 deadline.

G88 Oxera for the 'Big Six' EDBs disagree with our suggestion that while this adjustment was introduced in the context of mitigating potential economic stranding risk for existing assets, broader application may be an option to consider in the future: [723]

> .. asset life shortening may not be the most appropriate financeability remedy when it introduces a disconnect between the technical and regulatory asset lives. Over time, this may lead to a situation in which the RAB is not reflective of the revenue generating assets owned and operated by the business. The EDBs do not foresee a major risk of asset stranding, and instead, expect the network to expand, requiring cash flows in the future. Therefore, the NZCC should be mindful of the long-term implications of any potential measures in relation to the shortening of the asset lives.

G89 We have not further considered discretionary shortening of asset lives for DPP4.

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[722] Commerce Commission "Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023 [2023] NZCC 35" (13 December 2023), clause 4.2.2(5).

[723] Oxera "Response to the New Zealand Commerce Commission consultation on the financeability of electricity distribution services in the fourth default price-quality path (DPP4)" report prepared for the 'Big Six' EDBs (15 March 2024), p. 49.

# Attachment H Other matters

**Purpose of the attachment**

H1 This attachment explains the rationale for draft decisions related to other policy matters relevant to the DPP4 reset. It provides background analysis to those decisions and responds to stakeholder submissions on each topic area.

H2 It covers:

H2.1 regulatory period length

H2.2 Aurora Energy's CPP/DPP transition, and

H2.3 CPP application deadlines.

**Draft decision**

*X1 Retain the current five-year regulatory period length*

**Nature of the decision**

H3 Section 53M(4) of the Commerce Act (the Act) specifies a five-year duration for a DPP as a default. However, Section 53M(5) grants us the authority to establish a regulatory period ranging from four to five years if it aligns better with the purpose of Part 4.

H4 Recognising the forecasting challenges in the DPP due to heightened uncertainty, along with potential heightened requirements for decarbonisation investment, we have considered whether the long-term benefit of consumers would be improved by having a four-year regulatory period.

**Draft decision**

*Our draft decision is to retain a five-year regulatory period.*

**What we heard from stakeholders**

H5 Most stakeholders who responded to the Proposed process paper were in favour of retaining the five-year period because they considered that reducing the period length was unwarranted and would add further cost and complications to the regime to reduce the regulatory period.[724,725]

H6 In response to the Issues paper, stakeholders shared that altering the duration of the regulatory period would: [726]

H6.1 significantly heighten uncertainty in the regulatory framework, potentially disrupting capacity to effectively manage and execute projects in a cost-efficient manner

H6.2 shorten the available 'in period' information to as little as two years, complicating the us ability to draw conclusions about the effectiveness of its actions in the current DPP, hindering the ability to inform future DPPs, and

H6.3 reduce stability, indicating that a minimum of three years of DPP experience is required to inform any potential changes to the DPP.

H7 PowerNet submitted in favour of the reduced regulatory period and suggested aligning the input methodology review period and price-quality reset to provide a more current regime to deal with sector changes.[727] They submitted that the five-year period is problematic because it doesn't adequately deal with increasing uncertainty, step changes, and the recognised rate of change.

H8 They also saw that reducing the regulatory period to four years would provide benefits such as:

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[724] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025: Proposed process" (25 May 2023).

[725] *Submissions by Alpine, Horizon, Aurora, ENA, MEUG, Orion, The Lines Company, Unison and Wellington Electricity on the Commerce Commission "DPP4 Issues paper" (19 December 2023).*

[726] *Submissions by Alpine, Horizon, Aurora, ENA, MEUG, Orion, The Lines Company, Unison and Wellington Electricity on the Commerce Commission "DPP4 Issues paper" (19 December 2023).*

[727] PowerNet Limited "DPP4 Issues paper submission" (19 December 2023).

H8.1 Enhancing the DPP's adaptability to handle volatility and offer more timely information, with the possibility of addressing this through adjustments in the approach to WACC and other typically fixed settings.

H8.2 Aids in addressing challenges arising from forecasting uncertainty and policy changes, allowing for a more agile response from both regulators and EDBs.

**Analysis**

H9 We have sought to determine whether there might be value in reducing the regulatory period to better address significant contextual uncertainty affecting all EDBs during the regulatory timeframe.

H10 Given the evolving context for DPP4 and the challenges of scrutinising forecast capex within this context in a relatively low-cost way, it is our view that there may be some merit in shortening the regulatory period. The shorter regulatory period would allow us to consider and reflect relevant market changes sooner, it would also provide greater ability for EDBs to evidence the accuracy of forecasting practices in a changing environment.

H11 On the other hand, we consider the following factors support retaining a five-year regulatory period.

H11.1 Altering the regulatory period heightens the interest rate hedging risk, a primary concern for EDBs.[728] Opting for a lengthier reset period offers distributors greater certainty in managing this risk, as it remains locked in for an extended duration. Securing capital for long-term capex projects would become challenging for distributors, as creditors would face increased uncertainty regarding the settings four, eight, or nine years into the future.

H11.2 We have increased the availability of reopeners as part of the recent IM review, which may be a more appropriate tool to address increased uncertainty for individual EDBs

H11.3 More frequent DPP resets would increase compliance costs. Further, as noted in submission, the shorter regulatory cycle would reduce the time available to make any changes to our performance monitoring regime under ID, build up a timeseries of information, and to make changes to DPP settings as a result.

[728] Commerce Commission "Notes on EDB DPP3 Workshop on innovation and dealing with uncertainty" (8 March 2019), p. 3.

H12 We note, a shorter regulatory period works to reduce the strength of efficiency incentives under the IRIS mechanism, with EDBs retaining any gains for a shorter period before they are passed on to consumers.

**Conclusion**

H13 We have proposed to retain the five-year regulatory period as we consider on balance it better promotes the overarching objectives in s52A of the Act and aligns with the relatively low-cost way of setting price-quality paths set out in s 53K of the Act.

H14 However, we are interested in stakeholder views, particularly given the complexity identified in earlier sections regarding scrutinising forecast capex.

**Decision for Aurora Energy's CPP/DPP transition**

*X2 Include Aurora in the DPP4 expenditure and revenue setting process*

**Nature of the decision**

H15 With Aurora's CPP ending on 31 March 2026, we need to determine prices for its CPP to DPP transition and need to consider whether we should include Aurora in the DPP determination.

**Draft decision**

H16 Include Aurora in the DPP4 expenditure and revenue setting process.

H17 This involves setting indicative opex, capex, and revenue forecasts as part of this DPP4 reset process, then finalising Aurora's revenue path in 2025 prior to the transition, taking account of the most recent information available at the time.

**How the decision is aligned to the decision-making framework for the DPP**

H18 Section 53X (2) of the Act gives us two options for determining prices for the CPP-DPP transition:

H18.1 rolling over the starting prices which applied at the end of the CPP period or

H18.2 determining different starting prices that will apply after giving the supplier four months' notice.

**What we heard from stakeholders**

H19 All the submissions we received on this issue were in support of the proposed approach.

H20 Aurora submitted on the Issues paper:[729]

H20.1 supporting our stance to include Aurora in the DPP4 reset. They emphasize that this inclusion will offer them greater certainty for robust financial planning. This, in turn, enables strategic preparations, including reopener applications for projects where regulatory allowances might pose uncertainties.

H20.2 seeking clarification on whether the finalisation process solely entails updating financial model inputs for Aurora's last CPP year or if the Commission is considering other modelling adjustments. Additionally, they are interested in understanding if the Commission plans to utilise Aurora Energy's 2025 AMP to enhance expenditure assumptions for future growth projects that might be uncertain during the preparation of the 2024 AMP and

H20.3 invited the Commission to engage with them directly regarding setting allowances to clarify how the process works so that they have more certainty.

H21 Unison proposed that the Commission enhance clarity during the transition from CPP to DPP by issuing a framework.[730] This framework should cover alignment with standard DPP processes, timing, approach, EDB-specific considerations, and criteria for assessing expenditure allowances, incentives, and quality standards. They also stated that greater clarity is needed on the processes for CPPs ending early or later in a DPP period.

**Analysis conducted**

H22 Similar to Wellington Electricity in DPP3, Aurora's CPP only coincides with the DPP4 for a single year. This implies that assessing its revenue requirements for the DPP4 period presents only minor additional challenges compared to other EDBs on the DPP. With Wellington Electricity, we did not set starting prices for when it transitioned in 2020, but provided guidance on how we would set the starting price in 2020 and we set indicative opex and capex allowances.[731,732]

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729 Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 5.

730 Unison "DPP4 Issues paper submission"(19 December 2023), p. 20.

731 Commerce Commission "Wellington Electricity Lines Limited's transition to the 2020-2025 default price-quality path Reasons paper" (26 November 2020).

732 The price path for DPP4 will apply to distributors as a 'revenue cap'. A revenue cap limits the maximum revenues a distributor can earn, rather than the maximum prices that it can charge. For this reason, while

H23 With Powerco's CPP to DPP transition in 2023 we decided to set starting prices closer to the time it would transition because the DPP3 reset was taking place too far in advance of Powerco's transition.[733] We did not give indicative prices as we could not reliably forecast what its starting prices should be in the year starting 1 April 2023. Closer to the reset in 2022 we used a BBAR approach to establish initial prices, taking into consideration both current and projected profitability. This method closely mirrored the approach used for other EDBs under DPP3, but it incorporated information from Powerco's latest disclosures for a more comprehensive assessment.

H24 Much like the CPPs of Powerco and Orion, Aurora's CPP experienced a notable increase in opex and capex levels. When determining opex and capex allowances, it is crucial to determine whether these increases are a temporary consequence of the CPP or indicate a permanent rise in baseline expenditure. We expect to engage closely with Aurora in advance of deciding how we will set its prices, when finalising Aurora's revenue path in 2025 prior to the transition taking place 1 April 2026.

H25 As we approach the transition, we intend to work closely with Aurora, providing them with clearer guidance on the finalisation process for financial models. We also plan to clarify how transition process works, to provide them with greater certainty.

H26 In response to Aurora's query on how we plan to use its 2025 AMP, our emerging view is that we would use it as a starting point for our assessment of forecast capex. In previous transitions we have used a recent AMP and this approach worked well, so we consider this would be the most practical and consistent approach. We also note recent AMP disclosures have exhibited significant changes from the prior year, so using the most up to date information is appropriate.

H27 We do not consider that the process will necessarily just be updating financial model inputs. We consider some adjustment of the expenditure assessment framework particularly for capex may be required, dependent on the extent of change forecasted in Aurora's 2025 AMP.

the terminology in the Act refers to a 'price path' and to 'starting prices', in this paper we have generally referred to 'allowable revenues' a distributor can earn. For consistency with the decision framing in DPP3 and our statutory requirements we have referred to "starting prices" here.

[733] Commerce Commission "Powerco Limited's transition to the 2020-2025 default price-quality path Reasons paper" (18 August 2022).

**Alternative considered**

H28 While we see merit in creating a framework and understand it could improve certainty, we do not see the need to implement one yet. In our experience with Powerco and in previous transitions the approach we used worked well and was flexible enough to cater to the EDB's circumstances. The goal is to transition seamlessly from the CPP without compromising the implementation of network improvements or future growth initiatives. We consider our approach has been demonstrated to work well.

**Conclusions**

H29 In making our draft decision, we will be exercising discretion granted by s 53X when Aurora transitions, and we are guided by the principles outlined in s 52A and s 53K. By upholding Aurora's incentives for innovation and investment, we aim to limit the potential for excessive profit extraction. This approach underscores our commitment to a transition strategy that is both effective and cost-conscious and promotes the long-term benefit of consumers.

**Decision for CPP application windows**

*X3 Retain the CPP application timings set for DPP3*

**Nature of the decision**

H30 Setting the date each year for when EDBs must submit CPP applications is one of the statutory requirements for the DPP determination.[734]

**Draft decision**

H31 We propose to keep the final application date for CPPs as 190 working days before the commencement of the upcoming pricing year for the first four years of DPP4. In the final year of the DPP period, we have set a final application date of 29 March, as there is a statutory prohibition on CPP applications in the final year of the DPP period.[735] The dates are set out in the table H1 below:

[734] s 53O(e) of the Commerce Act 1986

[735] Commerce Act 1986, s 53Q(3)

**Table H1 Proposed CPP application deadlines**

| CPP beginning | Final date for application |
|---|---|
| **1 April 2026** | 11 June 2025 |
| **1 April 2027** | 9 June 2026 |
| **1 April 2028** | 15 June 2027 |
| **1 April 2029** | 12 June 2028 |
| **1 April 2030** | 29 Mar 2029 |

H32 If a distributor wants to be informed of its final CPP starting prices in time to notify retailers of price adjustments, the CPP application would need to be submitted earlier than the final date mentioned above. Based on a 190 working day timeline, our estimation for the deadline by which a distributor would need to apply for a CPP with a four-month notice period are outlined in Table H2 below.

**Table H2 CPP application with four-month notice period[736]**

| CPP beginning | CPP final decision date | Approximate application date |
|---|---|---|
| **1 April 2026** | 28 November 2025 | 27 February 2025 |
| **1 April 2027** | 30 November 2026 | 27 February 2026 |
| **1 April 2028** | 30 November 2027 | 1 March 2027 |
| **1 April 2029** | 30 November 2028 | 1 March 2028 |
| **1 April 2030** | 30 November 2029 | 1 March 2029 |

### What we heard from stakeholders

H33 Submissions received expressed agreement with the current approach to adopt a similar timeframe for CPP application windows as utilised in DPP3. Submitters saw no compelling reasons to modify the application windows.

[736] These dates assume a 190 working-day consideration period, and are for guidance only, and are not part of the DPP determination.

**Analysis conducted**

H34 Consistent with Section 53T of the Commerce Act, we have established a final application date 190 working days before the commencement of the upcoming pricing year for the initial four years of the DPP period in DPP3.

H35 The 190-working day lead time was based on the CPP assessment timeframes set out in the Act:

H35.1 the Commission has 150-working days to assess a CPP and determine starting prices and quality standard.[737]

H35.2 and by agreement with the distributor, may apply a 30-working day extension[738]

H35.3 process of preliminary assessment of a CPP proposal, as contemplated by s 53S of the Act. Which allows the Commission 40 working days to assess whether a CPP proposal complies with the relevant IMs.

H36 If an EDB wants to know its final CPP starting prices early enough to give notice of price changes to retailers, it needs to submit its CPP application earlier than the current 190 working day timeline.

H37 During the DPP3 regulatory period, we only received one CPP application from Aurora Energy on June 12, 2020, which was the last day for applications for a price path starting from April 1, 2021. Notably, Aurora's price-quality path was finalised on March 31, 2021, resulting in the first year of pricing being based on the draft decision, with wash-ups applying for differences in value.

[737] Commerce Act 1986, s 53T(2)

[738] Commerce Act 1986, s 53U. This option to extend remains available; however, may result in a final decision date after 1 April the following year.

# Attachment I Other inputs to the financial model

### Purpose of this attachment

I1 This attachment explains the other inputs to the financial model we must include in addition to the forecasts of capex and opex discussed in earlier attachments. It discusses:

I1.1 the estimate of the weighted-average cost of capital (WACC) we have used

I1.2 forecasts of asset disposals

I1.3 forecasts of depreciation on existing assets

I1.4 base year financial information, and

I1.5 forecasts of CPI as the revaluation rate and for indexing the forecast revenue path.

### High level approach

I2 The inputs discussed in this attachment (except for forecasts of asset disposals) are determined in accordance with the EDB Input Methodologies (IMs) (specifically the cost of capital and asset valuation IMs). As such, our high-level approach to these issues is largely to apply the relevant IMs, including amendments made as part of the 2023 IM review.

I3 This attachment comments on the results of applying the IMs, and in some instances on the source data and any adjustments necessary to apply them.

### Cost of capital

I4 **Draft decision M1:** For the draft decision, we have used a WACC estimate of 7.37%.

I5 This figure was determined:

I5.1 as at 1 April 2024

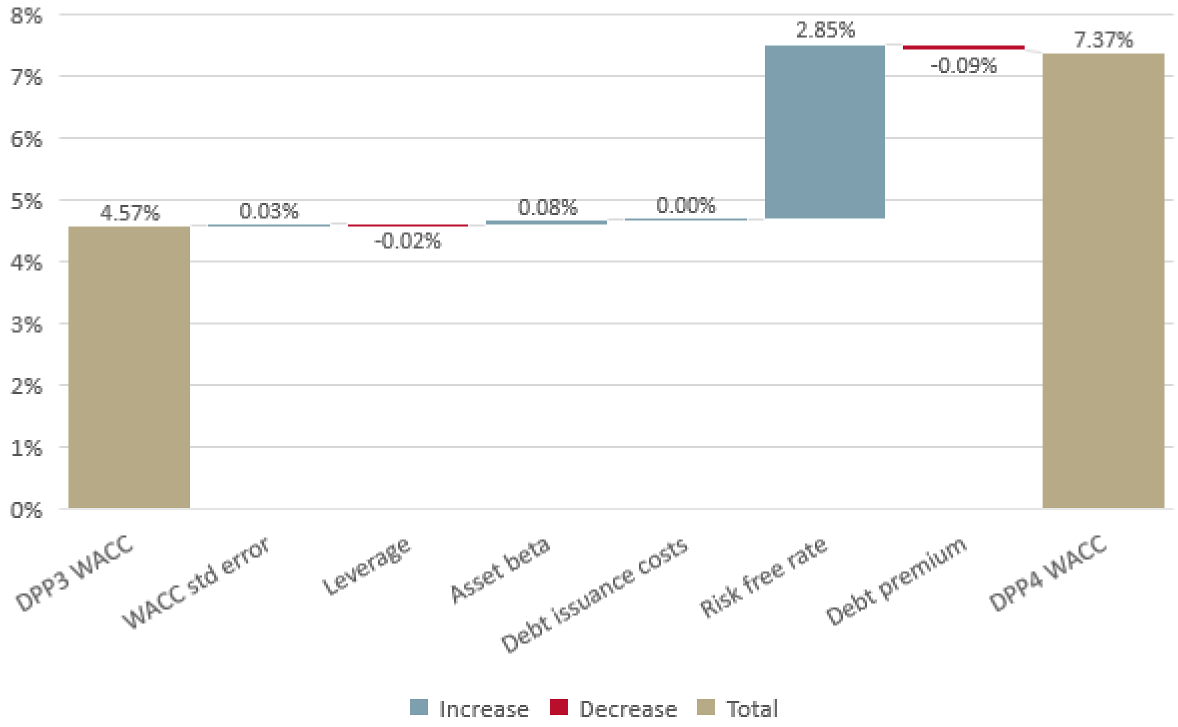
I5.2 using the same input data as our WACC for information disclosure,[739] and

[739] Commerce Commission Cost of capital determination for disclosure year 2025 for information disclosure regulation – For electricity distribution businesses and Wellington International Airport [2024] NZCC 37 (1 May 2024).

I5.3 applying the recently-amended EDB IMs, including using the 65th percentile in place of the previous 67th percentile.[740]

I6 The final cost of capital determination for DPP4 will be made before 30 September 2024, incorporating data up to 31 August 2024. The DPP4 final decision will apply this updated WACC.

**Figure I1 Cumulative effect of changes in WACC since DPP3**




**Forecast of asset disposals**

I7 **Draft decision M2:** We have forecast asset disposals by extrapolating historical asset disposals. This approach is unchanged from our DPP3 decision.

I8 A disposed asset is an asset that is sold or transferred, or irrecoverably removed from a distributor's possession (but is not a lost asset). We are required to forecast disposed assets because disposed assets are removed from the RAB when rolling forward the RAB value.

[740] Commerce Commission "Input methodologies review 2023 - Final decision - Cost of capital topic paper" (13 December 2023), Chapter 6

I9 For our draft decision, the forecast value of disposed assets in each year of the regulatory period has been forecast in real terms as equal to the historical average real value of disposals. The real forecast time series has then been converted to a nominal time series by adjusting for forecast CPI changes. These results are set out in Table I1 below.

I10 We have made one exclusion to the historic data series for Vector Lines to remove the impact of a one-off extraordinary disposal in 2020.[741]

**Table I1 Forecasts of disposed assets ($m)**

| EDB | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 |
|---|---|---|---|---|---|---|
| **Alpine Energy** | 0.02 | 0.02 | 0.02 | 0.02 | 0.03 | 0.02 |
| **EA Networks** | 0.75 | 0.77 | 0.78 | 0.80 | 0.81 | 0.75 |
| **Electricity Invercargill** | 0.09 | 0.09 | 0.10 | 0.10 | 0.10 | 0.09 |
| **Firstlight Network** | 0.04 | 0.04 | 0.04 | 0.04 | 0.05 | 0.04 |
| **Horizon Energy** | 0.29 | 0.29 | 0.30 | 0.30 | 0.31 | 0.29 |
| **Nelson Electricity** | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Network Tasman** | 1.14 | 1.16 | 1.19 | 1.21 | 1.24 | 1.14 |
| **Orion NZ** | 0.97 | 0.99 | 1.01 | 1.03 | 1.05 | 0.97 |
| **OtagoNet** | 0.11 | 0.11 | 0.12 | 0.12 | 0.12 | 0.11 |
| **Powerco** | 22.12 | 22.56 | 23.01 | 23.47 | 23.94 | 22.12 |
| **The Lines Company** | 0.15 | 0.15 | 0.16 | 0.16 | 0.16 | 0.15 |
| **Top Energy** | 0.16 | 0.16 | 0.16 | 0.17 | 0.17 | 0.16 |
| **Unison Networks** | 1.51 | 1.54 | 1.57 | 1.61 | 1.64 | 1.51 |
| **Vector Lines** | 16.58 | 16.92 | 17.25 | 17.60 | 17.95 | 16.58 |
| **Wellington Electricity** | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

[741] The value of disposals in 2020 was $289 million, compared to an average historical figure of $17 million.

**Forecasts of depreciation for existing assets**

I11 As part of the 2023 IM review, we amended the asset valuation IMs to change the way forecast depreciation on existing assets is calculated.[742] This change was to ensure depreciation attributable to fully depreciated assets was not incorrectly included in depreciation forecasts.

I12 To obtain these forecasts, on 20 March 2024 we issued an information gathering request to EDBs for forecasts of depreciation applying the IMs.[743]

I13 In most cases, we have included the EDBs forecasts as they were provided. However, in two cases (Electricity Invercargill and OtagoNet) we have had to apply the DPP3 forecasting method as a proxy, given the data they provided implied no change in weighted-average remaining asset lives over the period (an impossible outcome). The forecasts we have used are shown in Table I2 below.

I14 The information provided in response to the s 53ZD Notic was not subject to audit and will be updated for the final decision based on 2024 assets data. We intend to engage with EDBs to ensure the IMs are applied correctly in calculating these forecasts and they are free of errors.

I15 We are also aware of inconsistencies between the forecasts of disposed assets above in Table I1 and the disposed asset forecasts EDBs used in preparing these. We intend to resolve this as part of the process for finalising the final 53ZD request.

[742] Commerce Commission "Input methodologies review 2023 - Final decision - Report on the Input methodologies review 2023 paper" (13 December 2023)

[743] Commerce Commission "EDB DPP4 – s53ZD Notice for non-exempt EDBs" (20 March 2024)

**Table I2 Forecasts of depreciation on existing assets ($m)**

| EDB | 2024/25 | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 |
|---|---|---|---|---|---|---|
| **Alpine Energy** | 13.48 | 13.46 | 13.36 | 13.43 | 13.21 | 13.48 |
| **EA Networks** | 13.30 | 13.53 | 13.59 | 13.70 | 13.81 | 13.30 |
| **Electricity Invercargill** | 4.34 | 4.45 | 4.55 | 4.64 | 4.74 | 4.34 |
| **Firstlight Network** | 8.96 | 9.20 | 9.39 | 9.59 | 9.79 | 8.96 |
| **Horizon Energy** | 7.86 | 7.78 | 7.63 | 7.50 | 7.28 | 7.86 |
| **Nelson Electricity** | 1.77 | 1.76 | 1.69 | 1.66 | 1.66 | 1.77 |
| **Network Tasman** | 8.37 | 7.95 | 7.10 | 6.98 | 6.98 | 8.37 |
| **Orion NZ** | 58.32 | 58.91 | 57.74 | 57.21 | 56.61 | 58.32 |
| **OtagoNet** | 11.71 | 12.03 | 12.28 | 12.54 | 12.80 | 11.71 |
| **Powerco** | 113.24 | 106.06 | 102.00 | 98.18 | 95.81 | 113.24 |
| **The Lines Company** | 11.16 | 11.45 | 11.68 | 11.92 | 12.15 | 11.16 |
| **Top Energy** | 13.27 | 13.34 | 13.08 | 13.06 | 13.19 | 13.27 |
| **Unison Networks** | 40.62 | 41.73 | 42.61 | 43.51 | 44.43 | 40.62 |
| **Vector Lines** | 162.46 | 158.10 | 153.47 | 152.03 | 151.95 | 162.46 |
| Wellington Electricity | 33.13 | 33.28 | 31.43 | 31.14 | 31.01 | 33.13 |

### Base year financial information

I16 To calculate necessary values such as the roll-forward of the RAB and tax building block, the DPP financial model requires "initial conditions" data from a base year. For the draft decision, we have used base year data from 2023 information disclosures (ID), rolled forward an additional year to cover the "gap" year in 2024.

I17 For the final decision, we intend to use actual ID data from 2024.

### Treatment of Alpine Energy's base year data

I18 On 6 October 2023, Alpine Energy redisclosed its ID data for the years between 2013 and 2023 to correct for an error in the calculation of depreciation. Our draft decision is based on this redisclosed data.

I19 The DPP does not include any adjustments to account for any historic over-recovery of allowable revenue due to these errors. The matter is subject to an ongoing investigation by the Commission.

**Forecasts of CPI**

I20 The revenue path is determined on a nominal basis (consistent with the CPI-X DPP/CPP regime outlined in Subpart 6 of the Act). When using a BBAR/MAR model to determine starting prices, we require a forecast of CPI to project annual revenues for each year of the DPP3 period. Because the asset valuation IMs requires the RAB to be revalued at the rate change of CPI, we also require a forecast of CPI to determine BBAR.

I21 For both the rate of change of forecast CPI for RAB revaluations and the rate of change for the price path calculation, the forecasts are based on the Reserve Bank of New Zealand's (RBNZ) forecasts of inflation issued as part of the Monetary Policy Statement immediately prior to the determination of the WACC for the DPP.[744] The results of this approach are set out in Table I3 below.

**Table I3 Forecasts of CPI**

| Pricing year ending in calendar year | CPI used for revaluations | CPI element of the price path |
|---|---:|---:|
| **2024/25** | 2.60% | n/a |
| **2025/26** | 2.00% | 2.12% |
| **2026/27** | 2.00% | 2.00% |
| **2027/28** | 2.00% | 2.00% |
| **2028/29** | 2.00% | 2.00% |
| **2029/30** | 2.00% | 2.00% |

744 Reserve Bank of New Zealand "Monetary Policy Statement February 2024" (28 February 2024).

# Attachment J Glossary of terms

**Purpose of attachment**

J1 This attachment provides a short explanation of how we have used figures in the document, and a list of acronyms and their corresponding full term.

**References to years are to regulatory years**

J2 All references to years in this paper (unless otherwise stated) are to regulatory years ending 31 March. For example, '2026' is a reference to the year commencing 1 April 2025 and ending on 31 March 2026.

**How we have used numbers in this document**

J3 The revenue path and expenditure allowances we determine are required to be specified in nominal terms. Consumers also face costs in nominal dollars. In this document we provide allowances for the DPP4 period and compare our allowances to EDB AMP forecasts for DPP4 in nominal terms.

J4 When explaining trends in revenue over time we do this in constant 2025 dollars – the terms that will apply at the start of DPP4 on 1 April 2025. We deflate revenue to 2025 price terms using the consumer price index as a measure of economy-wide inflation.

J5 When explaining how we have built up our expenditure allowances we do this in 2024 constant dollar terms. This enables like-for-like comparisons between expenditures over time, and comparisons between regulatory period allowances. We translate expenditure to 2024 price terms using the same approaches used to set DPP4 allowances for increases in input costs (ie, cost escalation indices relevant to opex and capex with adjustments for input cost growth beyond these indices). For purposes of comparison, DPP3 allowances are escalated using the consumer price index as a measure of economy-wide inflation. In all cases, we clarify the terms being used.

## Glossary of terms

| Acronyms and abbreviations | Full term |
|---|---|
| **ACOD** | Avoided Cost of Distribution |
| **AIC** | Akaike Information Criteria |
| **ADR** | Annual Delivery Report |
| **AER** | Australian Energy Regulator |

| Acronyms and abbreviations | Full term |
|---|---|
| **AMP** | Asset Management Plans |
| **ARR** | Asset Replacement and Renewals |
| **BBAR** | Building Blocks Allowable Revenue |
| **BIC** | Bayesian Information Criteria |
| **CAIDI** | Customer Average Interruption Duration Index |
| **Capex** | Capital expenditure |
| **CEPA** | Cambridge Economic Policy Associates |
| **CGPI** | Capital Goods Price Index |
| **CPI** | Consumer Price Index |
| **CPP** | Customised Price-quality Path |
| **Debt/EBITDA** | Debt over Earnings Before Interest, Tax, Depreciation and Amortisation |
| **DER** | Distributed Energy Resources |
| **DFFITS** | Difference in Fit(s) |
| **DMIS** | Demand Management Incentive Scheme |
| **DOE** | Dynamic Operating Envelope |
| **DPP** | Default price-quality path |
| **DPP2** | DPP that applied from 1 April 2015 to 31 March 2020 |
| **DPP3** | DPP that applies from 1 April 2020 to 31 March 2025 |
| **DPP4** | DPP that will apply for the next four to five years from 1 April 2025 |
| **DPMC** | Department of the Prime Minister and Cabinet |
| **DSO** | Distribution System Operations |
| **EA** | Electricity Authority |
| **EBITDA** | Earnings Before Interest, Tax, Depreciation and Amortisation |
| **EDB** | Electricity Distribution Business |
| **EECA** | Energy Efficiency and Conservation Authority |
| **EIPC** | Electricity Industry Participation Code |
| **ENA** | Energy Networks Aotearoa |
| **EV** | Electric Vehicle |
| **IPP** | Individual Price-quality Path |
| **FCM** | Financial capital maintenance |
| **FFO/Debt** | Funds From Operations over Debt |
| **FNAR** | Forecast Net Allowable Revenue |

| Acronyms and abbreviations | Full term |
|---|---|
| **GSL** | Guaranteed Service Level |
| **HHG** | Statistics NZ Household Growth |
| **HILP** | High Impact Low Probability |
| **IAEngg** | Innovative Assets Engineering |
| **ICP** | Installation Control Points |
| **ID** | Information Disclosure |
| **IEEE** | Institute of Electrical and Electronics Engineers |
| **IEGA** | Independent Electricity Generators Association |
| **IM** | Input Methodologies |
| **INTSA** | Innovation and non-traditional solutions allowance |
| **IPA** | Innovation Project Allowance |
| **IPAG** | Innovation and Participation Advisory Group |
| **IPART** | Independent Pricing and Regulatory Tribunal (NSW, Australia) |
| **IRIS** | Incremental Rolling Incentive Scheme |
| **LCC** | Large Connection Contract |
| **LCI** | Labour Cost Index |
| **LV** | Low Voltage |
| **MAE** | Mean Absolute Error |
| **MAR** | Maximum Allowable Revenue |
| **MBIE** | Ministry of Business, Innovation and Employment |
| **MED** | Major Event Day |
| **MEPS** | Minimum Efficiency Performance Standards |
| **MEUG** | Major Electricity Users Group |
| **MSE** | Mean Square Error |
| **MW** | Megawatt |
| **NAR** | Net Allowable Revenue |
| **NPV** | Net Present Value |
| **NTS** | Non-traditional solutions |
| **NZIER** | New Zealand Institute of Economic Research |
| **OECD** | Organisation for Economic Co-operation and Development |
| **OLS** | Ordinary Least Squares |
| **Ofgem** | Office of Gas and Electricity Markets (United Kingdom) |

| Acronyms and abbreviations | Full term |
|---|---|
| **Opex** | Operational expenditure |
| **Part 4** | Part 4 of the Commerce Act 1986 |
| **PFP** | Partial Factor Productivity (the phenomenon) |
| **PPI** | Producers Price Index |
| **PPF** | Partial Productivity Factor (parameter in models) |
| **PQ** | Price-quality |
| **PV** | Present Value |
| **QIS** | Quality Incentive Scheme |
| **RAB** | Regulatory Asset Base |
| **RBNZ** | Reserve Bank of New Zealand |
| **RC** | Recoverable Costs |
| **RMSE** | Root Mean Squared Error |
| **RPE** | Real Price Effects |
| **RSL** | Revenue smoothing limit |
| **RS&E** | Reliability, Safety and Environment |
| **Solar PV** | Solar Photovoltaics |
| **S&P** | Standard & Poor's |
| **SAIDI** | System Average Interruption Duration Index |
| **SAIFI** | System Average Interruption Frequency Index |
| **TAMRP** | Tax Adjusted Market Risk Premium |
| **The Act** | Commerce Act 1986 |
| **TIDR** | Targeted Information Disclosure Review |
| **VoLL** | Value of Lost Load |
| **WACC** | Weighted Average Cost of Capital |