Attachment C Operational expenditure

Purpose of the attachment

C1 This attachment outlines and explains the rationale for our final decisions on forecasting operational expenditure (opex) allowances for the DPP4 period and responds to stakeholder submissions on these issues.

C2 This attachment covers decisions for:

C2.1 the use of the base, step, and trend (BST) approach to set opex allowances;

C2.2 the opex 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 opex scale growth (opex elasticities and growth trends);

C2.6 cost escalators for forecasting input cost increases; and

C2.7 the application of an opex partial productivity factor.

Decisions on our high-level approach to operating expenditure

O1.1. Apply a base, step, and trend approach to forecast opex.

Final decision

C3 Our final decision is to retain the base, step, and trend approach to set opex allowances for DPP4. This is the same as our draft decision.

C4 The general approach is shown below where opex(t) is the opex allowance for year t:

$$
\begin{aligned}
\text{opex}(t) = \; & \text{opex}(t-1) \times \\
& (1+ \Delta \text{ due to scale growth}) \times \\
& (1+ \Delta \text{ due to cost escalation}) \times \\
& (1- \Delta \text{ partial productivity for opex}) \pm \\
& \text{step changes}
\end{aligned}
$$

C5 Year one of the regulatory period (2026) is a special case where the reference year is the base year. As in DPP3, the DPP4 base year is year-four of the previous regulatory period (ie, 2024) and the 'deltas' above applied for year one account for this interval being two years not one.

Analysis

C6 As noted in the DPP4 Issues paper[1] and as stakeholders reinforced in their issues paper submissions, we are setting DPP4 opex allowances for a changing and uncertain environment.

C7 The base, step, and trend approach is based on identifying an EDB's current level of operating expenditure, then making reasonable adjustments to represent what a prudent and efficient EDB would be expected to spend over the regulatory period.

C8 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 final decision includes changes to ensure it remains fit for purpose in a faster-changing context.

C9 Alongside the changes in approach to forecasting opex, as part of the 2023 review of input methodologies, we expanded and updated the range of DPP reopeners that apply. These reopeners allow for specific circumstances over the regulatory period to be taken into account.

C10 The DPP4 forecasts that result from our final decisions are presented in Table C1 and Figure C1.

Alternatives considered

C11 Below we consider key points raised in submissions on the base, step, and trend approach. These include calls for greater reliance on forecast opex from EDB AMPs, perceived limitations and caveats with applying the base, step, and trend approach through a period of change, and the importance of scrutiny.

[1] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), pp. 17-23.

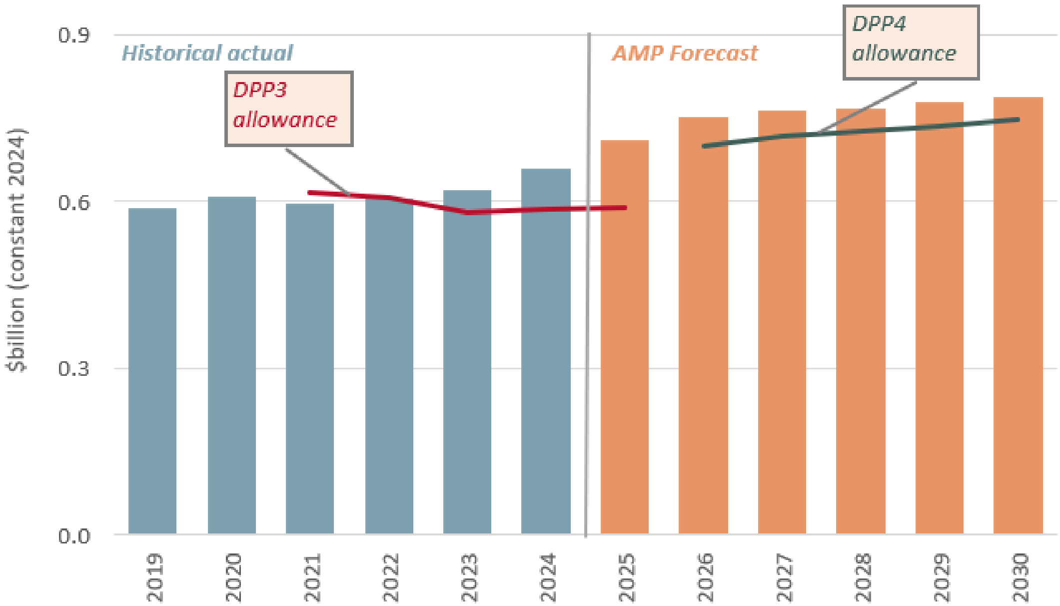
C12 Overall, our view remains that the base, step, and trend approach better promotes the Part 4 purpose in a low-cost way than other alternatives. And we consider that our changes to the components of this approach, including providing for step changes and a cost escalation uplift, can appropriately account for future uncertainties.

Table C1 DPP4 opex allowances by year (nominal, $ million)

EDB	2026	2027	2028	2029	2030	DPP4 total
Alpine Energy	35.2	36.4	37.8	39.2	40.6	189.2
Aurora Energy [2]	47.6	55.1	56.9	58.9	60.9	279.4
EA Networks	17.3	17.7	18.0	18.4	18.8	90.2
Electricity Invercargill	6.8	7.1	7.3	7.6	7.8	36.6
Firstlight Network	17.2	17.7	18.2	18.8	19.4	91.3
Horizon Energy	14.5	15.7	14.8	15.1	15.6	75.7
Nelson Electricity	2.7	2.8	2.9	3.0	3.1	14.6
Network Tasman	17.1	17.7	18.3	19.0	19.7	91.8
Orion NZ	94.6	98.6	102.9	108.3	112.8	517.2
OtagoNet	11.8	12.3	12.8	13.3	13.9	64.2
Powerco	137.7	143.8	151.2	157.4	164.3	754.4
The Lines Company	20.3	21.2	21.9	22.6	23.3	109.2
Top Energy	26.3	27.1	27.8	28.7	29.5	139.4
Unison Networks	58.1	61.5	62.9	65.9	69.1	317.5
Vector Lines	194.8	202.8	211.3	220.4	229.9	1,059.3
Wellington Electricity	45.2	46.8	48.4	50.2	52.0	242.7
Total	**747.4**	**784.3**	**813.5**	**846.6**	**880.9**	**4,072.7**

[2] The figures for Aurora Energy are indicative only, with the 2026 value from its CPP. They will be finalised when Aurora Energy transitions from their CPP to the DPP, noting its CPP ends 31 March 2026.

Figure C1 Opex profile over DPP3 and DPP4 (constant 2024$)



C13 Table C2 shows final opex allowances by EDB, compared to draft opex allowances. Key opex changes from draft to final include: updating the base year opex for 2024 from AMP forecasts to 2024 actuals reported in ID data; changes to step changes including the exclusion of specified amounts from the aggregate 5% cap; and updated forecasts for cost escalators used to cast constant dollar amounts into nominal amounts. We discuss these more below.

Table C2 DPP4 opex allowances, change from draft to final (nominal, $ million)

EDB	Opex allowance ($m)	Draft Opex allowance ($m)	Change ($m)	Change (%)
Alpine Energy	189.2	177.1	12.0	6.8%
Aurora Energy	279.4	282.3	-3.0	-1.1%
EA Networks	90.2	96.2	-6.0	-6.2%
Electricity Invercargill	36.6	37.2	-0.6	-1.7%
Firstlight Network	91.3	88.2	3.1	3.5%
Horizon Energy	75.7	72.8	2.9	4.0%
Nelson Electricity	14.6	13.1	1.5	11.1%
Network Tasman	91.8	89.6	2.3	2.5%
Orion NZ	517.2	486.8	30.4	6.2%
OtagoNet	64.2	60.6	3.6	5.9%
Powerco	754.4	726.0	28.4	3.9%
The Lines Company	109.2	99.5	9.7	9.8%
Top Energy	139.4	137.3	2.1	1.6%
Unison Networks	317.5	310.9	6.6	2.1%
Vector Lines	1,059.3	1,017.5	41.8	4.1%
Wellington Electricity	242.7	233.5	9.2	3.9%
Total	**4,072.7**	**3,928.6**	**144.1**	**3.7%**

What we heard from stakeholders

C14 Submissions on the DPP4 Draft decision expressed a range of views on the base, step, and trend approach.

C15 Many of these superseded prior submissions on the DPP4 Issues paper, especially in relation to our draft decisions to approve five non-network opex step changes which alleviated some concerns around applying the BST method through a period of anticipated change.

C16 ENA supported our retention of the base, step, and trend approach as appropriate for the relatively low-cost approach to DPP resets:[3]

[3] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 10.

> 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. ENA's members (excluding Top Energy) view is that the Commission has provided this due consideration in the draft decision, and therefore ENA supports the continued use of the base-step trend approach for DPP4.

C17 The main alternative to base, step, and trend put forward in submissions on both the DPP4 Issues paper and the DPP4 draft decision, was to make increased use of AMP forecasts.

C18 Vector submitted that "As a matter of principle, we consider there is scope to make better use of AMP forecasts for opex forecasting." [4]

C19 Top Energy were dissatisfied with the level of their draft opex allowance relative to their AMP.[5] We agree with them that this reflects in part a different view of underlying price pressure/ future cost escalation.

C20 The base, step, and trend approach links revealed costs with future expenditure allowances, which broadly results in cost reflectivity and sharing of efficiency gains with consumers, in line with s 52A(1)(c) of the Act. A reliance on AMPs when setting opex allowances would on the face of it create a moral hazard for EDBs through the incentive to inflate, or at least not restrain, cost forecasts. This would in turn undermine incentives to improve efficiency and share efficiency gains with consumers under s 52A(1)(b) and (c), and mean EDBs are less limited in their ability to extract excessive profits, contrary to s 52A(1)(d).

C21 Wellington Electricity "disagreed with the BST approach without the addition of other flexibility mechanisms as it will not capture all new costs or steps in existing costs." [6]

[4] Vector "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 39.

[5] Top Energy "Submission on EDB DPP4 draft decisions" (11 July 2024), p. 2-3.

[6] Wellington Electricity "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 21.

C22 On the consumer side, Fonterra supported the use of the base, step, and trend approach.[7] As did MEUG, noting this "… ensures consistency between regulatory periods, and is an approach that is well understood by EDBs and interested stakeholders such as MEUG."[8] MEUG also noted concerns that BST relies on the assumption that historical expenditure is efficient and prudent.

C23 Powerco raised perceived limitations with the BST approach and overall considered that the BST approach is not appropriate for the current context without wide approval of step changes: [9]

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

C24 Given the uncertainties around the rate of change in electrification and timing of other context changes, we consider that the step changes approved in our final decision strike an appropriate balance between recognising new costs and incentivising efficient EDB expenditure.

C25 In its submission on the DPP4 Issues paper, the Consumer Advocacy Council accepted that while there may be reasons for overall cost increases, this highlighted the need for scrutiny:[10]

> 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.

C26 We agree with the importance of scrutiny, to see that both consumers and other stakeholders have confidence, and that EDBs' forecasts are prudent and efficient. The importance of this scrutiny is behind our decision to retain our use of the base, step, and trend approach, and our decision to place a cap on the level for which step changes are provided. Beyond this, a higher level of cost increase would justify the more detailed engagement, verification, and scrutiny in a CPP, in line with the purpose of DPP/ CPP regulation under s 53K.

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[7] Fonterra "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 2.

[8] Major Electricity Users Group (MEUG) "Submission on EDB DPP4 draft decisions" (12 July 2024), p 5.

[9] Powerco "Submission on EDB DPP4 draft decisions" (12 July 2024), p 11.

[10] Consumer Advocacy Council (CAC) "DPP4 Issues paper submission" (19 December 2023), p. 3.

What we heard from stakeholders on the DPP4 Issues paper

C27 A theme in EDB submissions on the DPP4 Issues paper was a call to either revise or replace the base, step, and trend approach to deal with a faster-changing and more uncertain environment for consumers and distribution networks over DPP4.

C28 Aurora noted the scale of change, but reinforced the uncertainties involved:[11]

> 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.

C29 Opex allowances of themselves cannot manage uncertainty. However, the uncertainty Aurora highlights has informed our 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 decision of a 0% productivity factor.

C30 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).

C31 In its submission, Horizon expressed scepticism about the use of reopeners to manage uncertainties:[12]

> 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.

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

[12] Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 13.

C32 While we accept that over-reliance on reopeners may drive an increase in regulatory costs, we consider our decision (where more certain changes have been dealt with via opex allowances, some costs may be met with reopeners in specific circumstances and larger and more systemic changes with CPPs) strikes a balance between regulatory burden, cost impact on consumers, and the benefits of regulatory flexibility. Opex reopeners are discussed below in relation to the opex step change framework (**decision O1.2)**.

C33 Alpine Energy supported retention of the base, step, and trend approach in general, but called for adaptations: [13]

> 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.

C34 Alpine highlighted the difficulties of forecasting non-network opex using historical data, given changes in customer behaviours and expectations.[14] We agree that, overall, the dynamics affecting non-network opex are more complex, as reflected in our final decisions to change non-network scale drivers and allow step changes all relating to non-network opex.

C35 Similarly, ENA submitted that were we to retain the base, step, and trend approach, changes to the step and trend elements would be necessary:[15]

> 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.

C36 Powerco identified four potential issues with the base, step, and trend methodology were we to retain it unaltered:[16]

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[13] Alpine Energy "DPP4 Issues paper submission" (19 December 2023), p. 7.

[14] Alpine Energy "DPP4 Issues paper submission" (19 December 2023), p. 7; Vector "DPP4 Issues paper submission" (19 December 2023), pp. 2 and 9.

[15] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 11.

[16] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 17.

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.

C37 We address these challenges in the sections below on the elements of the methodology.

C38 SolarZero fundamentally questioned the relevance of a historically based approach to opex:[17]

> 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.

C39 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.

C40 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** may be available.

[17] Solar Zero "DPP4 Issues paper submission" (15 December 2023), p. 7.

Decisions for opex base year

Decision O1.2: For opex base year data in final decision financial models, use 2024 opex numbers reported in information disclosure.

Nature of the decision

C41 As part of the base, step, and trend approach we must specify the 'base year' for opex data. This sets the level from which opex steps and trends are then applied.

Final decision

C42 To set DPP4 final opex, our decision is to retain the approach in DPP3 to use reported actuals from year four of the prior regulatory period, meaning base year opex data is that reported in 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.

C43 This decision was signalled at the draft, where we used 2024 AMP forecasts ahead of 2024 ID data becoming available.

Analysis

C44 In the DPP4 draft decision, we used 2024 opex forecasts from EDBs' 2024 AMPs for base year opex figures. This was a change in approach from the DPP3 draft decision, where we used the latest available actual opex data, the DPP4 equivalent of which would have been 2023 actuals reported in ID data.

C45 The aim of this approach in the draft decision was to reduce the changes from draft to final opex allowances. This approach has been supported by opex values from 2024 ID data turning out to be much closer to 2024 AMP forecasts than 2023 ID values (in constant 2024 prices).

C46 Table C3 shows this comparison by EDB and overall. Total opex, across all non-exempt EDBs, in 2024 ID data was $659.3m compared to $655.1m in 2024 AMP forecasts. It was much lower at $615.4m from 2023 ID data (in constant 2024 prices). Mean and mean absolute variances by EDB was also smaller when compared with 2024 AMP forecasts than with 2023 ID data.

Table C3 Change in base year opex from Draft (2024 AMPs) to Final (2024 ID data) in constant 2024 prices.

EDB	Base year Opex Draft (2024$ million)	Base year Opex Final (2024$ million)	Change (2024$ million)	Change %
Alpine Energy	29.1	30.4	1.3	4.5%
Aurora Energy	52.5	48.0	-4.5	-8.6%
EA Networks	17.0	15.5	-1.5	-8.9%
Electricity Invercargill	6.2	5.9	-0.3	-4.5%
Firstlight Network	14.8	14.9	0.1	1.0%
Horizon Energy	12.2	12.2	0.1	0.4%
Nelson Electricity	2.2	2.5	0.2	10%
Network Tasman	14.9	15.1	0.3	1.8%
Orion NZ	78.2	81.6	3.4	4.4%
OtagoNet	9.8	10.1	0.3	3.4%
Powerco	121.0	123.0	2.0	1.7%
The Lines Company	17.4	17.9	0.5	2.7%
Top Energy	23.4	23.5	0.1	0.5%
Unison Networks	51.1	50.9	-0.2	-0.5%
Vector Lines	167.0	169.2	2.2	1.3%
Wellington Electricity	38.4	38.6	0.2	0.4%
Total	**655.1**	**659.3**	**4.2**	**0.6%**

Decisions for opex step change decision-making framework

C47 This section discusses our final decisions on changes to the decision-making framework for assessing opex step changes.

C48 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:

C48.1 be significant;

C48.2 be robustly verifiable;

C48.3 not be captured in the other components of the DPP allowance;

C48.4 be largely outside the control of the EDB; and

C48.5 in principle, be applicable to most, if not all, EDBs.

C49 For DPP4, we reassessed the above decision-making framework. Our final decisions are informed by 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.

C50 Our final decisions here are the same as our draft decisions, which as discussed below were widely supported in submissions on the DPP4 Draft decision.

O2.1: Consider potential step changes against a defined set of factors, applying judgement

Problem definition

C51 A strict application of the decision-making framework previously used for opex step changes would lead to a step change 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.

C52 Alternatively, a framework that is relaxed too far and does not apply criteria with enough checks increases the risk of allowances 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.

Final decision

C53 Our final decision is to change the opex step change decision-making framework to one that uses factors that inform judgement, rather than criteria that all must be met. This is the same as our draft decision.

C54 The factors used to assess step changes, and to discuss them in more detail below, are whether the step change is:

C54.1 significant (**decision O2.2**);

C54.2 adequately justified with reasonable evidence in the circumstances (**decision O2.3**);

C54.3 not be captured in the other components of the DPP allowance (**decision O2.4**);

C54.4 have a driver outside the control of a prudent and efficient supplier (**decision O2.5**); and

C54.5 be widely applicable (**decision O2.6**).

How the decision is aligned to the decision-making framework for the DPP

C55 This decision aligns with the decision-making framework for the DPP, specifically to better promote the purpose of Part 4.[18] This is because 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, consistent with s 52A(1)(a) of the Act.

What we heard from stakeholders

Submissions on Issues paper

C56 A number of submissions on the DPP4 Issues paper stated that they felt the opex step change criteria were too stringent in DPP3.[19] They stated that step changes were denied that eventuated to opex costs over the DPP3 period, resulting in IRIS penalties for the EDBs.

C57 Aurora Energy in their submission stated: [20]

> 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.

[18] Commerce Act 1986, section 52A.

[19] Submissions by Aurora Energy, Horizon Networks, Powerco, Network Tasman, Unison, Vector, Wellington Electricity and FlexForum on the Commerce Commission "DPP4 Issues paper submission" (19 December 2023).

[20] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 4.

C58 Horizon Networks stated they were: [21]

> .. concerned that the criteria are too rigid and incentivise EDBs to avoid additional OPEX, even if there are long-term consumer benefits.

C59 Unison noted that: [22]

> ..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.

Submissions on draft decision

C60 In response to our draft decision, most submitters supported the changes made to the decision-making factors (**decisions O2.1 - O2.6**). Most supported the increased flexibility and discretion in the new decision-making framework and said that it would recognise the practicalities and costs facing EDBs over the next DPP.

C61 For example, Orion NZ stated that:[23]

> The proposed changes to the criteria better enable the intent of the mechanism to be met, while recognising the practicalities facing EDBs. As the Commission noted in the draft reasons paper, the existing criteria were too rigid to provide the incentive that the Commission was looking for. We agree that the proposed changes to the criteria better capture the intent of the mechanism, while better reflecting the realities facing EDBs.

C62 Similarly, TLC in their submission said they agree that:[24]

> …amending the criteria 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. This is a good thing to allow greater discretion and flexibility.

C63 Aurora in their submission qualified their support by suggesting there should be allowance for opex reopeners, for opex costs that appear mid-DPP:[25]

> We support the Commission's approach to assessing step-changes in DPP4. However, this approach only captures step changes that can be adequately justified at the time of the DPP4 reset. The DPP regime should also include a mechanism to reopen opex allowances when new step changes emerge during a

[21] Horizon Networks "DPP4 Issues paper submission" (19 December 2023), p. 13.

[22] Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 18.

[23] Orion "Submission on EDB DPP4 draft decisions" (11 July 2024), p. 8.

[24] The Lines Company (TLC) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 2.

[25] Aurora Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 10.

DPP period. For example, the draft Electricity (Hazards from Trees) Amendment Regulations 2024 will result in increased costs for the industry if they are implemented as proposed.

Analysis

C64 For this decision, we considered two options:

C64.1 Option 1: Keep the decision-making framework as criteria, all of which a potential step change must meet to be approved (same as DPP3).

C64.2 Option 2: Instead of criteria, the test will require consideration of five factors, which will be applied using judgement (same as draft decision).

C64.2.1 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.

C64.2.2 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.

C65 We consider that the key advantages/benefits of Option 1 are:

C65.1 Consistency between reset periods – maintaining the status quo from DPP3 will ensure consistency for EDBs when providing information for step changes to be assessed.

C65.2 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.

C65.3 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.

C66 We consider the key disadvantages/risks with Option 1 are:

C66.1 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.

C66.2 Risks not giving effect to s 52A(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.

C66.3 May incentivise high numbers of reopeners or CPPs – creating higher costs for EDBs, which would not be in the long-term interests of consumers.

C67 We consider the key advantages/benefits to Option 2 are:

C67.1 Increased flexibility to account for different contexts between DPP3 and DPP4.

C67.2 Ability to approve a step change that might have previously been declined for minor reasons, following the application of strict criteria.

C67.3 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.

C68 We consider the key disadvantages/risks to Option 2 are:

C68.1 Less certainty for EDBs and consumers – 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.

C68.2 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 s 52A(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.

Opex reopeners

C69 We have not considered further expanding the existing scope for opex reopeners as a mechanism for adding additional flexibility into the opex step changes regime. The current suite of reopeners allows for opex solutions and the scope was considered during the 2023 IM Review. We consider the current IMs cover the appropriate range of uncertainties for opex.[26]

[26] Commerce Commission "Input methodologies review 2023 - Final decision - CPPs and in-period adjustments finance topic paper" (13 December 2023), chapter 6, pp. 91 - 98.

C70 The example given by Aurora above,[27] for an opex reopener if the Electricity (Hazards from Trees) Regulations are amended, is already provided for in the current IMs. Under clause 4.5.5,[28] an amendment to the tree regulations could be a 'change event' provided other criteria are met, and therefore opex cost increases arising from the new regulations could be considered through the existing reopener provisions.

Conclusions

C71 In considering and balancing the benefits and risks for either option, we consider that Option 2 will best give effect to s 52A. It is also consistent with s 53K of the Act, and will most appropriately address the context within which DPP4 is being set.

C72 This is because amending the criteria to factors means that there is more flexibility in the opex allowance determination process to ensure that EDBs can make opex spending decisions that promote the long-term benefit of consumers. The flexibility provided also enables step changes to be considered in a relatively low-cost way through applying proportionate scrutiny relative to the size of the step.

C73 To mitigate the risk of opex costs being provided for that do not eventuate, we have applied 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.

[27] Aurora Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 10.

[28] 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 4.5.5(2), p. 142.

Table C4 Comparison of DPP3 and DPP4 approach to assessing opex step changes

DPP3 'Criteria'	DPP4 'Factors'
Significant	Significant (**decision O2.2**)
Robustly verifiable	Adequately justified with reasonable evidence in the circumstances (**decision O2.3**)
Not be captured in the other components of the DPP allowance	Not be captured in the other components of the DPP allowance (**decision O2.4**)
Be largely outside the control of the EDB	Have a driver outside the control of a prudent and efficient supplier (**decision O2.5**)
Be applicable to most, if not all, EDBs	Be widely applicable (**decision O2.6**)

O2.2: Step changes should be significant

Nature of the decision

C74 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.

Final decision

C75 In DPP4, we are proposing to retain the 'significance' factor. This is the same as the draft decision.

What we heard from stakeholders

C76 Only two submissions on the DPP4 Issues paper 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".[29] Wellington Electricity 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.[30]

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[29] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 19.

[30] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 35.

C77 Draft **decision O2.2** received full support in submissions on our DPP4 draft reasons paper.[31, 32] There were no specific comments about the significance factor, besides general support for the decision-making framework.

Analysis

C78 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.

C79 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 opex costs elsewhere.

C80 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.

C81 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 decision (**decision O3.6**, discussed further below) to cap the total level of step changes relative to overall opex.

Conclusions

C82 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.

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[31] Powerco "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 27.

[32] Unison Networks "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 10.

C83 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.

C84 In addition, we clarify that the impact on consumers is already inherent in the decision-making process. This is because applying the decision-making framework is how we ensure that decisions on opex step changes give effect to the purpose outlined in s 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

C85 In DPP3, the second criteria applied was whether the step change was 'robustly verifiable'. For a potential 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.

C86 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.

Final decision

C87 Our final decision is that the second factor is amended to be that a step change should be adequately justified with reasonable evidence in the circumstances. This is the same as the draft decision.

C88 This is intended to be less stringent than 'robustly verifiable' (the DPP3 criteria), 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

C89 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.

C90 Aurora stated: [33]

> 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.

C91 PowerCo advocated for: [34]

> …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."

C92 This change to the second decision-making factor from DPP3 received strong support in submissions on the DPP4 Draft decision reasons paper.

C93 Aurora stated that:[35]

> On balance, the Commission's approach to assessing the reasonableness of step changes in DPP4 is appropriate. We note that, by definition, step changes are expenses that have no historical precedent, so the Commission will need to apply some discretion in determining the quantum of step changes required.

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[33] Aurora Energy "DPP4 Issues paper submission" (19 December 2023), p. 11.

[34] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 19.

[35] Aurora Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 10.

C94 Vector also submitted in support of this decision:[36]

> We believe this change makes sense in a low-cost regulatory framework such as the DPP, providing more flexibility for step changes that are either less significant, or sufficiently satisfied through the remaining factors.

C95 Wellington Electricity also showed strong support for our draft decision, noting:[37]

> This is an important change. As highlighted in the narrative, evidence is often not available to verify a new cost. It is important to allow some discretion for cost increases that can only be estimated.

Analysis

C96 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.

C97 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.

C98 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.

C99 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 the time of the reset.

C100 For the reasons outlined above and taking account of strong support in submissions on our draft decision, our final decision is the same as our draft decision.

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[36] Vector "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 18.

[37] Wellington Electricity "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 27.

O2:4: Step changes must not be included elsewhere in the expenditure allowance

Nature of the decision

C101 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.

Final decision

C102 Our final decision is to keep this factor unchanged, requiring that a step change must not be included elsewhere in the expenditure allowances. This is the same as our draft decision.

What we heard from stakeholders

C103 No submissions critiqued this factor as applied in DPP3. In their submission on the DPP4 Issues paper, 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."[38]

C104 Similarly, we received full support for this decision-making factor in response to the DPP4 Draft decision reasons paper. The only submitter that specifically mentioned this decision was Aurora, who noted they agreed step changes must not be included elsewhere in the expenditure allowances.[39]

Analysis

C105 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

C106 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.

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[38] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 36.

[39] Aurora Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 10.

Final decision

C107 Our final 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. This is the same as our draft decision.

What we heard from stakeholders

C108 A small number of submissions on the DPP4 Issues paper 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.

C109 Wellington Electricity also noted that: [40]

> 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'.

C110 In response to our draft decision, all submissions except one who mentioned this decision were in support. The exception was Aurora, who stated:[41]

> We would like to see this requirement replaced with a requirement that step changes should be in the long-term interests of consumers.

Analysis

C111 As discussed in the DPP4 Issues paper and draft decision reasons 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 would undertake the activity that gives rise to the cost.

C112 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 s 52A(1)(b) and (c).

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[40] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 36.

[41] Aurora Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 10.

C113 For clarity, there may be situations where a step change is appropriate where the cost is the choice 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.

C114 We do not consider it necessary to amend the factor to require that step changes should be in the long-term interests of consumers. The Part 4 purpose is to 'promote the long-term benefit of consumers'. This is the overriding statutory driver of all of our decision making, and our decision-making framework criteria are consistent with it.

O2:6: Step changes should be widely applicable

Nature of the decision

C115 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 with the relatively low-cost purpose of DPP regulation under s 53K of the Act.

C116 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.

Final decision

C117 Our final decision is that this factor is amended to assess whether a step change is widely applicable. This is the same as our draft decision.

What we heard from stakeholders

C118 A few submissions on the DPP4 Issues paper submitted 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.

C119 Wellington Electricity stated:[42]

> 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.

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[42] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 37.

C120 Vector noted in their submission on the DPP4 Issues paper that some EDBs may be more advanced in certain areas than others, and a strict application of this factor would have the effect of "hold[ing] those EDBs back".[43]

C121 In their submission on the DPP4 Issues paper, PowerCo expressed support for a relaxation of this criteria to be allow for a step change that applies to a 'group' of EDBs:[44]

> 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.

C122 In submissions on the DPP4 Draft decision reasons paper, we received strong support to the draft decision to relax this decision-making factor. For example, PowerCo stated:[45]

> We support the use of this decision-making factor. However, the absence of similar step change applications from other EDBs, and the possibility that an EDB is at the forefront of an initiative, does not undermine its necessity or validity for DPP4. As noted in paragraph C120 of the Reasons paper, a step change should be permissible if it has the potential to be generally applicable across all EDBs, even if it currently applies to only a few.

C123 Similarly, Vector submitted:[46]

> This change is welcomed because there may be circumstances where:
>
> A step change that clearly satisfies the other factors but only applies to a group of EDBs could efficiently be assessed; and
>
> 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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[43] Vector "DPP4 Issues paper submission" (19 December 2023), p. 32-33.

[44] Powerco "DPP4 Issues paper submission" (19 December 2023), p. 19.

[45] Powerco "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 27.

[46] Vector "Cross-submission on EDB DPP4 draft decisions" (2 August 2024), p. 19.

Analysis

C124 We agree with the views expressed in the submissions on the DPP4 Issues paper, and the supportive submissions on the DPP4 Draft decision reasons 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.

C125 For example, a group of suppliers may be ready to transition away from traditional capex systems and replace them with opex software solutions (ie, Software-as-a-Service). In this scenario, if not all EDBs were ready or would require that step change during the regulatory period, it may be still efficient for us to assess the step change application for only the affected group of EDBs.

C126 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.

C127 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.

C128 Allowing for step changes across a group of EDBs who share some common factor may also help avoid a high number of CPPs or reopeners, thereby avoiding an increase in the regulatory cost of the regime overall.

Decisions for opex step changes

C129 The below section outlines the final decisions on individual step changes that were suggested through submissions on the DPP4 Issues paper, directly from EDBs following an informal information gathering process, or through submissions on the DPP4 Draft decision reasons paper.

C130 The first half of this section discusses the step changes we have approved for DPP4. The second half discusses the step changes we have declined.

C131 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.

C132 All step changes have been assessed using the final decisions on the decision-making process outlined above, meaning that each step change was considered against the following five factors, applying judgement. The step change should be:

C132.1 Significant (**decision O2.2**)

C132.2 Adequately justified with reasonable evidence in the circumstances (**decision O2.3**)

C132.3 Not included elsewhere in the expenditure allowance (**decision O2.4**)

C132.4 Have a driver outside the control of a prudent and efficient supplier (**decision O2.5**)

C132.5 Be widely applicable (**decision O2.6**).

C133 All step change decisions have all been assessed in constant 2024 prices.

O3.1: Include a step change to reflect increasing insurance costs

C134 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.

Final decision

C135 Our final decision is to approve a step change to reflect increasing insurance costs for all EDBs. Where EDBs have submitted the amount and timing of insurance cost increases, we have applied those. As part of this step change, for the years where EDBs have not provided us with specific amounts, we have allowed insurance costs to increase faster than inflation by applying an insurance-specific 'real price effect' forecast from Principal Economics (PEL).[47]

C136 In our draft decision, we applied the PEL real price effect only to the EDBs who did not provide us with specific insurance forecasts. Our change to apply this more broadly was prompted by submissions on the DPP4 Draft decision. It is also to recognise that figures provided by EDBs were likely limited to the years their insurance brokers were able to provide quotes for, as opposed to the EDB assuming their insurance premiums would stabilise.

[47] Principal Economics Limited forecast insurance costs to rise by 28% between 2024 - 2030, with a real price effect of 13% above their inflation forecast. We have applied this real price effect to allow insurance step change amounts to increase in constant 2024-dollar terms. These amounts are later expressed in nominal terms using the opex cost escalators in **decision O4.2**, after aggregation with other opex components.

What we heard from stakeholders

C137 We received submissions on O3.1 insurance as a step change from Alpine Energy, Aurora, ENA, Orion, PowerCo, PowerNet, Top Energy, The Lines Company, Unison, Vector, Wellington Electricity, and MEUG.

C138 The majority of the submissions were supportive of our draft decision to recognise the increases in insurance for EDBs. Some submissions however qualified their support with a preference for the increases to be accounted for either as a pass-through cost or a step change and insurance specific cost escalation.

C139 For example, Orion submitted:[48]

> While Orion welcomes the proposed step change for insurance, we submit that the Commission should consider an alternative mechanism for the on-going treatment of insurance costs as they are likely to continue to increase at a rate that far exceeds the opex inflation rate, such as making it a pass-through cost.

C140 The ENA submitted that while their preference is for insurance to be a pass-through cost, the Commission could also consider a specialised cost escalator for insurance costs.[49]

> [The Commission should] adopt an individual, specialised cost escalator for insurance costs. This escalator could be based on either the insurance components of Stats NZ price indexes (CPI, PPI) or an expert report like the Principal Economics forecasts procured for the draft DPP decision.

Analysis

Alternative considered - Use of an insurance-specific cost escalator only

C141 Compared to applying a separate insurance cost escalator (ie, to base-year insurance costs), our final decision is that a step change can more easily and more accurately capture recent and near- future insurance cost increases driven by extreme weather events. Accounting for the increases in insurance through a step change, and an insurance-specific real price effect, will better capture the quotes given to EDBs by their insurers for the forecast increase in premiums for the next financial year (typically the insurance brokers only provide an estimate for one year).[50]

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[48] Orion "Submission on EDB DPP4 draft decisions" (11 July 2024), p. 9.

[49] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 11.

[50] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 10.

Alternative considered - Insurance as a pass-through cost

C142 The IMs allow us to specify additional pass-through costs in addition to those already listed in the IMs at a DPP reset.[51] The criteria for inclusion are:[52]

> (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.

C143 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.

C144 Outside these criteria, an IM amendment would be required to give effect to this option.

C145 The Commission considered whether insurance should be treated as a pass-through cost during the 2023 IM Review.[53] In retaining the status quo of insurance being treated as ordinary opex we noted:

C145.1 the importance of retaining incentives for suppliers to manage their risks efficiently – including through the types of insurance they hold;[54] and

[51] 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.

[52] 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.

[53] 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.

[54] Commerce Commission "Input methodologies review 2023 - Final decision - Report on the Input methodologies review 2023 paper" (13 December 2023), paragraph 17.18.

C145.2 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.

C146 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.

C147 We also consider there are other decisions within the control of the EDB that could help to manage insurance costs. For example, investment into the reinforcement and resilience of an asset could lower insurance costs and might be a more efficient solution overall. Or alternatively, paying insurance costs might be more efficient than resilience investments. We want the regime to incentivise this type of decision-making behaviour.

Consideration of the step change against the decision-making factors

C148 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. [55, 56]

C149 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 Principal Economics.

C150 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.

C151 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 sufficiently insured, at a level that is appropriate for consumers to pay.

[55] Electricity Networks Aotearoa (ENA) "DPP4 Issues paper submission" (19 December 2023), p. 12.

[56] 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.

C152 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

C153 Our final decision is to apply a step change for insurance costs to all EDBs. We consider it satisfies all of the above factors, and maintaining a prudent level of insurance cover is in the long-term interests of consumers. An adequate level of insurance should protect consumers from unexpected or higher costs in response to certain events. Where EDBs have submitted the amount and timing of insurance cost increases, we have applied those. For the years where EDBs have not provided us with specific amounts, we have allowed insurance costs to increase faster than inflation by applying an insurance-specific real price effect forecast from Principal Economics (PEL). Where EDBs have not provided us with insurance forecasts, we have applied an increase based on their information disclosures and the PEL forecast real price effect.

O3.2: Include a step change for greater consumer engagement

C154 Some EDBs have indicated that they are looking to increase their spend on consumer engagement due to their increase in capex.

Final decision

C155 Our final decision is to approve a consumer engagement step change for the EDBs who applied for it and provided sufficient information. This is EA Networks, Orion, Powerco, Vector, Wellington Electricity, and Unison Networks.

C156 This is the same as our draft decision, but with the approved step change also applied to Unison.

What we heard from stakeholders

C157 In response to the DPP4 Draft decision reasons paper, we received strong support for the approved step changes. A few submissions noted the importance of providing for consumer engagement. For example, Alpine Energy stated in their cross submission:[57]

> We support submissions made by the Consumer Advocacy Council and others that a customer focus must be integrated into distribution and transmission planning.

[57] Alpine Energy "Cross-submission on EDB DPP4 draft decisions" (2 August 2024), p. 8.

> We support the DPP4 draft decision including (for the first time) an opex step change to recognise the costs associated with customer engagement.
>
> Alpine is committed to increasing engagement across all customer groups and stakeholders so our planning and service delivery can best reflect their electricity needs and quality expectations. Effective engagement is a resource-hungry and time-consuming activity. To deliver on the valuable recommendations of the Consumer Advocacy Council, EDBs need to be able to recover reasonable costs through our prices.

C158 SolarZero also submitted in support of this step change and suggested that EDBs should use part of the funding to support consumer engagement in non-network solutions, flex and efficiency.[58]

C159 Unison Networks submitted for this step change to also apply to them for DPP4 and provided us with supporting material to satisfy the decision-making factors.

Analysis

Consideration of the step change against the decision-making factors

C160 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.

C161 Adequately justified with reasonable evidence in the circumstances: Numbers provided were signalled to be from market research on salaries.

C162 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.

C163 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.

C164 Be widely applicable: This step change could be generally applicable across all EDBs, however currently only applies to a few.

[58] SolarZero "Submission on EDB DPP4 draft decisions" (12 July 2024), p 12.

Conclusion

C165 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. This is because greater consumer engagement should better enable EDBs to provide services at a quality that reflects consumer demands, in line with s 52A(1)(b). 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

C166 This step change has three components – the cost for the access of 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.

Final decision

C167 Our final decision is to approve the step change for low voltage (LV) monitoring and smart meter data. Our final decision is to approve the costs for access to LV network data for all EDBs, and to approve the additional costs (associated with additional staff, analysis or software) only for those EDBs who submitted for it. This is the same as our draft decision.

What we heard from stakeholders

C168 A number of submissions on the DPP4 Draft decision reasons paper noted strong support for the approval of this step change. In addition to EDBs, SolarZero and FlexForum also submitted in support of this approved step change.[59, 60]

C169 PowerCo submitted in support but qualified their support with an application for the additional costs to analyse the data collected.

[59] SolarZero "Submission on EDB DPP4 draft decisions" (12 July 2024), p 12.

[60] FlexForum "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 4.

Analysis

Consideration of the step change against the decision-making factors

C170 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. We also consider that providing an opex step change to purchase the LV data is more cost efficient, than EDBs having to purchase and install the metering technology themselves as a capex solution.

C171 Adequately justified with reasonable evidence in the circumstances: Where available, EDBs have provided quotes or current prices from potential smart meter data vendors. Software costs are said to be based off licence fees (where applicable), and salary figures are stated to be from market research.

C172 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.

C173 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.

C174 Be widely applicable: This step change is generally applicable to all EDBs.

Conclusion

C175 Our final 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.

C176 We understand there is a possibility of work being completed by the EA that would make access to LV data more readily accessible.[61] We will stay connected with the EA on the progress of this work. If the EA amended the Code during the DPP4 regulatory period to provide for this, there may be scope for a change event reopener if the IM criteria are met, or the EA could request we reconsider the DPP under s 54V(5) of the Act.

O3.4: Include a step change for increasing cyber-security costs

C177 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.

Final decision

C178 Our final is decision is to approve a step change in cyber-security costs for those EDBs who submitted for it and provided sufficient information. This is Alpine Energy, EA Networks, Electricity Invercargill, Network Tasman, Orion NZ, OtagoNet, Unison, Vector, Wellington Electricity, and Firstlight.

C179 This is the same as the draft decision, with the step also being applied to Firstlight following their submission on the DPP4 Draft decision.

What we heard from stakeholders

C180 This decision received strong support in submissions on the DPP4 Draft decision reasons paper.

Analysis

Consideration of the step change against the decision-making factors

C181 Significant: EDBs have provided evidence to support a significant increase in cyber-security costs in recent years.

[61] Electricity Authority "Delivering key distribution sector reform: Work programme" (16 October 2023), pp. 13-14. Accessed at https://www.ea.govt.nz/projects/all/network-connections/

C182 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.

C183 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.

C184 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.

C185 Be widely applicable: This step change is widely applicable to most EDBs for this reset.

Conclusion

C186 We consider that this step change clearly satisfies all five factors, and it is beneficial for EDBs to ensure they have sufficient security systems to protect consumers data and their business information.

O3.5: Include a step change for the costs of software-as-a-service (SaaS)

C187 EDBs have indicated that they are looking to transition their current IT systems (accounted for as capex) to cloud-based 'Software as a Service' (SaaS) systems. 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.

Final decision

C188 Our final decision is to approve this step change for all EDBs who applied for it and supplied sufficient information. This is Alpine Energy, EA Networks, Electricity Invercargill, Firstlight, Horizon Energy, Network Tasman, Orion NZ, OtagoNet, The Lines Company, Top Energy, Unison, Wellington Electricity, and Vector.

C189 This is the same as our draft decision, with the step change also being applied to The Lines Company and Vector following their submissions on our draft decision.

What we heard from stakeholders

C190 This decision received strong support in submissions on the DPP4 Draft decision. In addition to support received from EDBs, FlexForum submitted in support of this step change.[62]

C191 Vector qualified their support with a request for the step change to also apply to them for their new SaaS costs between DPP3 and DPP4.[63] The Lines Company also submitted in support and provided information to be given the step change in their opex allowance. Vector similarly provided further information to the Commission to receive a step change for their increase in SaaS costs from 2024 to 2025.[64]

Analysis

Consideration of the step change against the decision-making factors

C192 Significant: Shifting systems towards cloud-based solutions is coming at a significant opex cost for EDBs – both initial installation costs and then ongoing subscriptions.

C193 Adequately justified with reasonable evidence in the circumstances: The relevant EDBs have provided quotes and estimates to support their submitted expenditure.

C194 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, this will be reflected in the RAB to ensure there is no double-counting.

C195 Have a driver outside the control of a prudent and efficient supplier: We expect a prudent and efficient EDB to upgrade systems over time to find efficiencies in operation.

C196 Be widely applicable: A large number of EDBs submitted they were seeking to move to SaaS solutions during DPP4.

Conclusion

C197 We consider this step change category satisfies all five decision-making factors. Where more efficient opex solutions are available, we would expect a prudent and efficient EDB to transition their systems across.

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[62] FlexForum “Submission on EDB DPP4 draft decisions” (12 July 2024) , p. 4.

[63] Vector “Submission on EDB DPP4 draft decisions” (12 July 2024), p. 3.

[64] Vector “Submission on EDB DPP4 draft decisions” (12 July 2024), p. 24.

O3.14: Include a step change for a graduate programme

C198 To service customer needs, new technology and to address resourcing capability constraints, Powerco resubmitted for a step change in opex to expand their graduate programme.

Final decision

C199 Our final decision is to approve a graduate programme step change for Powerco. Our draft decision was to decline this step change, due to the amount sought for this step.

What we heard from stakeholders

C200 In response to the DPP4 Draft decision reasons paper, only Powerco resubmitted for a step change relating to increasing their resourcing. They did so across three areas, one of which is their graduate programme.[65]

> In addition, we appreciate the opportunity to provide further evidence for step changes and we have submitted a separate document setting out our application for step changes assessed against the Commissions draft decision-making framework. The step changes we are submitting / resubmitting are:
>
> Additional resource for LV monitoring
>
> Graduate programme
>
> Additional resource to address a future focused network

Analysis

Consideration of the step change against the decision-making factors

C201 Significant: The step change is for $5.6m (constant 2024 prices) total over DPP4, covering 17 additional FTE. We consider this is a significant enough increase to be considered as a step change.

[65] Powerco "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 14.

C202 Adequately justified with reasonable evidence in the circumstances: Powerco submitted that they have a need to grow their graduate programme to support the growth of the industry and their own programme of work. We consider this is justified, given resourcing concerns across the sector for predicted network growth. Powerco also provided information to support the salaries for the graduates, based on industry practice and comparisons with similar organisations (eg, Transpower).[66]

C203 Not included elsewhere in the expenditure allowance: This step change is for new graduates. The amount requested is not inclusive of current FTEs.

C204 Have a driver outside the control of a prudent and efficient supplier: While resourcing decisions can be within the control of an EDB, there are outside drivers impacting the level of investment required by EDBs (such as decarbonisation, increasing requirement for demand-side flexibility). The coincidence of increases in spending by EDBs means increases in industry training is desirable. This is not within the control of a single EDB. We would also expect a prudent and efficient EDB to increase resourcing to keep pace with external change and to take active steps to mitigate deliverability risks.

C205 Be widely applicable: Only Powerco submitted for a graduate programme.

Conclusion

C206 While this step change is only applicable to Powerco for DPP4, we consider that expanding a graduate programme to address deliverability and capability risks within the organisation and sector is in the long-term benefit of consumers. It will help to address workforce capability and capacity issues, ensuring the EDB can deliver the required projects/upgrades to meet consumers demands, in line with the s 52A(1)(b) limb of the Part 4 purpose. We were also satisfied with the information provided against the other four decision-making factors.

[66] Powerco "Revised opex step-change request for 3 steps not approved in the DPP4 Draft decision" (12 July 2024), pp. 11-12.

Step changes that we have declined in the final decisions

C207 This section discusses step changes we have declined in final decisions. We first discuss a change from the draft decision, where our final decision is to not apply a step change to account for the end of Aurora's CPP investment programme in the opex allowance we set for indicative purposes (if Aurora transitions back to the DPP). We then summarise potential step changes that we declined in the draft decisions and remain declined in our final decisions.

Not include a step change to account for the end of Aurora's CPP investment programme

Final decision

C208 Our final decision is to not apply an opex base-year reduction, which we had applied in draft **decision O3.6**.

What we heard from stakeholders

C209 In their submission on the draft decision, Aurora said they "do not agree with the rationale for applying a negative step-change for the end of Aurora Energy's CPP period." [67]

Analysis

C210 Aurora is currently subject to a CPP that will end on 31 March 2026. 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.

C211 Aurora's current CPP included a significant uplift in opex to enable delivery of Aurora's investment programme. With the CPP coming to an end, the risk is that elevated opex to meet one-off CPP costs are locked in for future periods.

C212 In the draft decision, we applied a $3.5m reduction to Aurora's base year opex, deducted from their 2024 AMP opex forecast. This was included in the draft to signal a possible transitional arrangement from their CPP to the DPP, and was assessed outside the above decision-making framework applied to step changes put forward by stakeholders.

[67] Aurora Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p 10.

C213 Since the draft decision, we have received Aurora's 2024 actual opex costs through information disclosure. Aurora's actual 2024 opex of $48.0m was $4.5m (about 9%) below their 2024 AMP forecast of $52.5m. For our present indicative purposes, we are satisfied the 2024 ID data provides an appropriate opex base level.

C214 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 from its CPP.

C215 For an explanation of how we have treated Aurora in the DPP4 process generally, see **Attachment H**.

Final decisions to decline other potential step changes

C216 Our final decision is to decline the list of step changes discussed below. A description of the requested step change and the reasons to decline them are set out in Table C5 below.

C217 There is one change from our draft decision, which is to approve the step change for Powerco's graduate programme. This was declined in the DPP4 Draft decisions.

What we heard from stakeholders

C218 Below are step changes declined in the DPP4 draft decisions, which remain declined following submissions on them from Firstlight, Vector, Wellington Electricity and Powerco.

C219 Firstlight resubmitted for a routine and corrective maintenance step, as well as a resilience/storm response step.[68]

C220 Vector resubmitted for a resilience/storm response step.[69]

C221 Powerco and Wellington Electricity submitted against our draft decision to decline a step change for their Field Service Agreement renewals. They submitted that the costs associated with their Field Service Agreements should be accounted for through a reopener following their tender process.

[68] Firstlight Network "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 6.

[69] Vector "Submission on EDB DPP4 draft decisions" (12 July 2024), pp. 20-24.

C222 Powerco stated:[70]

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

C223 Wellington Electricity submitted: [71]

> The draft decision was to not award a step change for retendered field service agreements. The step change was declined because there is a 'strong argument' that the increase should be captured through the application of the 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'.
>
> We think that an opex reopener would provide a better tool for assessing changes in the costs of field services. An EDB could make a reopener application once they receive vendors' prices for the market tender. See section 7.1.1.1 of this response for a detailed explanation.
>
> If an opex reopener isn't available, then an opex step change is the next best mechanism. An EDB can only meet its regulatory quality targets if it can fund the maintenance and emergency outage response functions needed to maintain service quality.

C224 Powerco also submitted for an additional resourcing step for 'customer expectations and technology', which is separate to the approved graduate programme step change.[72]

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[70] Powerco "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 14.

[71] Wellington Electricity "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 28.

[72] Powerco "Revised opex step-change request for 3 steps not approved in the DPP4 Draft decision" (12 July 2024), p. 14.

Table C5 Analysis of step changes that we have declined for the final decision

Description of potential 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 included a capex driver in the trend factors for setting the opex allowance, which should cover this increase. This is the same as the draft decision.
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. This is the same as the draft decision.
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. This is the same as the draft decision.
Operating costs relating to **routine and corrective maintenance and inspection**, requested by Firstlight.	Firstlight provided more information in response to the draft decision to decline this step change. However, this step was for a significant amount (relative to the size of the EDB) which we consider would be more suited to a CPP and we consider it was not due to a driver outside the control of the EDB. This is the same as the draft decision.
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 C336 for a more detailed discussion on the decision to include a capex 'driver' in our non-network opex trending. This is the same as the draft decision.
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. In response to the draft decision, the EDBs also suggested an opex reopener would be a better process for these costs.	There is insufficient evidence at present to justify increases beyond what is already captured through the application of trend factors and input cost escalators. Extending the scope of the reopeners to account for any cost increases after the tender process would undermine a fundamental part of this being ex-ante regulation and diminish incentives on EDBs to manage costs. This is the same as the draft decision.

Description of potential step change	Analysis and reason for declining
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. Current amendments to the Electricity (Hazards from Trees) Regulations 2003 have not materially impacted EDBs' opex spend. Further amendments, if significant enough, could be considered via an opex reopener if made within the DPP4 period. Through submissions on the DPP4 Draft Decision, this was re-submitted for as a resilience/storm response step. The EDBs provided evidence of likely increase in storm events, and expected spend to respond to those events.	From the requests in the Issues paper, 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. The remaining two EDBs requested allowance for a larger programme to better identify and target areas of high risk. The size of the step change requested suggests it may be better accounted for through a CPP. From the resubmissions for this step in response to the DPP4 Draft decision, we retain our decision to decline this as a step change. For events that do not meet the criteria, current spend in DPP3 will be captured in the base spend and will be increased with the trend factors applied in the base, step, and trend approach. It is difficult to be sufficiently certain on the extent or impact of extreme weather events that will occur in the next five years. For this reason, we consider this spend is better accounted for as a catastrophic event reopener if the extreme weather event meets the reopener criteria. This is the same as the draft decision.
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. Powerco resubmitted for an increase in resources across three categories. Two of those have been approved (discussed above), for resourcing for a graduate programme and LV monitoring. We have declined their request for increase resource for 'customer expectations and technology'.	Increases in workforce related to system growth (capex) are captured in the capex driver in the trend factors. For Powerco, we consider that the types of roles described under 'customer expectations and technology' could be fulfilled within their existing allowance including the increased FTE approved under the LV monitoring step and graduate programme.
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. This is the same as the draft decision.

C225 Table C6 below shows which EDBs the approved step changes apply to.

Table C6 Summary of approved step changes by EDB

Step	Alpine Energy	Aurora Energy	EA Networks	Electricity Invercargill	Firstlight	Horizon Energy	Nelson	Network Tasman	Orion NZ	OtagoNet	Powerco	The Lines Company	Top Energy	Unison	Vector	Wellington Electricity
Insurance	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Consumer Engagement			✓						✓		✓			✓	✓	✓
LV Monitoring	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Cybersecurity	✓		✓	✓	✓			✓	✓	✓				✓	✓	✓
SaaS	✓		✓	✓	✓	✓		✓	✓	✓		✓	✓	✓	✓	✓
Graduate programme											✓					

O3.7: Apply an aggregate cap to total step changes, equal to 5% of opex excluding step changes, with exclusions

Problem Definition

C226 Undertaking a detailed assessment of all potential step change costs submitted under a DPP process would not be consistent with the relatively low-cost purpose of DPP regulation under s 53K of the Act.

C227 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 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 CPP, in line with s 53K.

Final decision

C228 Our final decision is to apply a 5% cap to the level of increase from approved opex step changes in DPP4, excluding a specified amount for insurance and LV monitoring step changes.

C229 The 5% cap and step change amounts are calculated in constant 2024 prices. Our modelling combines these with base and trend components to calculate total opex profiles in constant 2024 prices. Finally, these are expressed in nominal terms using the cost escalators in **decision O4.2**.

C230 Separately to the 5% cap we have allowed step changes for insurance and LV monitoring costs for all EDBs. We have calculated the amount for these step changes using the same approach for all EDBs. Where an EDB did not apply, this is the total amount we have allowed them for these step changes. For EDBs that did apply for these step changes, any additional amounts applied for above this value have been included in their opex step changes that are subject to the 5% cap.

C231 For insurance, the specified amount is the uplift using an insurance-specific real price effect from Principal Economics (PEL). For LV monitoring the specified amount is the cost per ICP for access to the LV network data using an estimate submitted by the ENA.

C232 This is a change from our draft decision, which was to apply a 5% cap to the level of increase from approved opex step changes in DPP4 (ie, without any exclusions).

What we heard from stakeholders

C233 We received 14 submissions on O3.7 the 5% aggregate cap, from Alpine Energy, Aurora, EA Networks, ENA, Horizon, Orion, Powerco, PowerNet, Top Energy, Unison, Wellington Electricity, ETNZ, FlexForum, and MEUG.

C234 There was strong opposition to this decision in submissions from some EDBs, in particular from those whose step changes were limited in the draft by a 5% cap. While MEUG supported the use and level of a 5% cap, the majority of submitters were opposed to the application of an aggregate cap on opex step changes at all. They submitted that it did not make sense for the Commission to approve a step change by being satisfied it met enough of the decision-making factors, only to then limit the approved amount of the step change.

C235 For example, Orion submitted that:[73]

> Given that the step changes are, by definition, able to be justified, are significant and outside the control of the EDB, such a cap seems to be counter to the intent of this mechanism.

[73] Orion "Submission on EDB DPP4 draft decisions" (11 July 2024), p. 9.

C236 Powerco similarly submitted:[74]

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

C237 A number of submissions therefore asked for the cap to be removed completely. If the cap was not removed completely, many submitters also offered alternative options to the blanket 5% aggregate cap across all EDBs.

C238 Orion NZ submitted that if the cap were to remain, it should be increased to 10%:[75]

> If the Commission does consider that an aggregate cap is necessary, we would encourage the Commission to increase it to 10% which remains within what the Commission has considered to be a price shock historically, rather than the 5% that is currently proposed.

C239 The ENA submitted that the 5% cap should be applied to each individual step change, instead of being applied in aggregate.[76] EA Networks also noted that a 5% limit in aggregate unfairly impacts those EDBs applying for multiple step changes, compared to those applying only for one or two.[77]

C240 Wellington Electricity submitted that the 5% cap is appropriate if there is an opex reopener available for critical expenditure and if there is a sliding scale which signals at which point an EDB is better off applying for a CPP.[78]

> We support the approach of applying a cap if:
>
> An opex reopener is available for critical expenditure needed to maintain a network's quality standards. Applying an arbitrary cap to critical delivery functions could inadvertently impede an EDB's ability to meet its quality expectations. We think a cap makes sense for the reason provided in the Draft Decision if critical expenditure could be excluded for a more detailed scrutiny.
>
> Add a minimum total cap before the 5% of total opex sliding scale applies to better reflect the point at which all networks would consider a CPP. The minimum total cap reflects the point up to which a customer would be better off applying the

[74] Powerco "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 6.

[75] Orion "Submission on EDB DPP4 draft decisions" (11 July 2024), p. 9.

[76] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024) , pp. 3-4.

[77] EA Networks "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 3.

[78] Wellington Electricity "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 29.

proposed low-cost step change acceptable criteria. Above this point, a customer would be better off paying for a share of a CPP application to apply a higher level of scrutiny.

C241 Alpine Energy submitted a list of alternative options, that step-changes are approved in full where increased expenditure forecasts are supported with documentation, reporting is required for each cost category to help inform the approach in DPP5, or to apply the cap to a subset of non-critical costs only.[79]

C242 Firstlight Network in their cross-submission agreed with statements made by Horizon and Wellington Electricity and submitted that a 5% cap unfairly impacts smaller EDBs looking to undertake opex costs that do not scale to EDB size.[80] The submitted the following alternative options:[81]

> "We ask the Commission to reconsider the application of the Opex step change cap for smaller EDBs. Potential solutions could include:
>
> Deeming steps changes that are largely independent of EDB scale (e.g. cybersecurity) exempt from the cap.
>
> Specifying a dollar value cap to apply before the use of a percentage cap, with the cap set at the greater amount. We believe this is consistent with the suggestion made by Wellington Electricity (WE) in its submission."

C243 In contrast to the above submissions, MEUG submitted in support of the 5% cap:[82]

> We support the use of the 5% cap to the level of approved OPEX step changes in DPP4. This recognises the rising costs facing EDBs going forward, while still keeping pressure on efficient costs and ensuring the EDBs have clear rationale for any step changes.

[79] Alpine Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 7.

[80] FirstLight Networks "Cross-submission on EDB DPP4 draft decisions" (2 August 2024), p. 1.

[81] FirstLight Networks "Cross-submission on EDB DPP4 draft decisions" (2 August 2024), p. 1.

[82] Major Electricity Users Group (MEUG) "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 5.

Analysis

C244 We acknowledge the arguments made by Orion and other submitters that the step changes have been assessed and deemed to sufficiently meet the decision-making factors. However, we disagree with the position that applying a cap then contradicts that decision-making process. While we might accept the category or driver of the step change, or agree that it is significant enough to be considered as a step change, the limits of information considered in this DPP reset and the level of scrutiny we can provide does not mean we can always be confident that any specific amounts are prudent and efficient. Moreover, as noted above, the step change decision-making factors are considerations to guide our judgement, not determinative.

C245 The application of the cap also does not necessarily mean that the EDB will be unable to undertake most of, or meet the full cost for, their intended step changes. Since a DPP sets a general opex allowance, the EDB will be able to reprioritise within that allowance to accommodate spend they consider best delivers on outcomes for consumers (or to find efficiencies while delivering the same outcomes). Under the relatively low-cost approach to setting DPPs, we do not have information on the full extent to which an EDB would be able to reprioritise.

C246 The application of a cap therefore ensures that an EDB has incentives to operate efficiently for the long-term benefit of their consumers. There are other tools available in the Part 4 regulatory regime, such as reopeners for specific circumstances and CPPs for larger and more systemic changes.

C247 It should also be noted that the scale trends applied for the opex allowances could also account for some of the costs not fully accounted for through the step change process through increases to the base level opex, for businesses who will have the 5% cap applied.

C248 It is appropriate to remove the insurance and LV monitoring steps from the 5% cap as we have separate evidence to justify/verify a reasonable amount for those costs. For insurance costs, we have independent advice provided to us by Principal Economics, which forecasts insurance costs over the DPP4 period. For LV monitoring, we have information on cost per ICP of accessing the LV data.

C249 This option best achieves the policy intent of this decision, to apply a limit on costs where we do not have the ability or information to properly assess whether they are set at a prudent and efficient level.

C250 We also consider the 5% threshold is sufficient due to the underlying predictability of opex, and the growth to opex allowances already applied through trend factors.

C251 Table C7 below shows the total step change amounts allocated by EDB, and whether the aggregate 5% cap with exclusions has bound.

Table C7 Total step changes allocated by EDB, noting if aggregate cap (5% with exclusions) has bound

EDB	Aggregate Step Changes allocated (constant 2024$)	Did aggregate 5%* cap bind?
Alpine Energy	8,713	Yes
Aurora Energy	5,105	No
EA Networks	4,563	Yes
Electricity Invercargill	1,903	Yes
Firstlight	4,417	Yes
Horizon Energy	3,716	Yes
Nelson Electricity	235	No
Network Tasman	2,035	No
Orion NZ	23,080	Yes
OtagoNet	3,145	Yes
Powerco	22,899	No
The Lines Company	5,203	Yes
Top Energy	5,372	No
Unison Networks	16,108	Yes
Vector Lines	47,100	Yes
Wellington Electricity	13,981	Yes

Alternative options considered

C252 We have assessed the alternative options and their key advantages and disadvantages in Table C8 below.

Table C8 Consideration of alternative options for the application of an aggregate cap on opex step changes

Alternative option	Key advantages	Key disadvantages
Retain 5% cap (same as draft decision)	• Maintains an incentive to find efficiencies. • Treats all EDBs the same, regardless of size. • Maintains a low regulatory burden on EDBs.	• Could restrict expenditure that is necessary and in consumers long term best interest, or cause undesirable trade-offs to have to be made by the EDB.
Increase the cap (eg, 7%, 10%)	• Will allow for greater investment by EDBs, where they signalled it is required. • Could allow for increases in forecasted costs due to inflation.	• Increases the possibility of providing for opex costs that do not eventuate, leading to excessive profits for EDBs. • Could lead to increases in opex that are not prudent, efficient and in the long-term best interests of consumers.
Apply the 5% cap and an alternative $ amount	• Recognises that not all opex costs scale with EDB size (e.g. SaaS). This may benefit smaller EDBs.	• Difficult to determine the appropriate $ amount alternative to apply, to achieve the desired policy outcomes.
Remove the cap	• Ensures all indicated costs are recoverable. • Low effort for the Commission and EDBs.	• Increases the possibility of providing for opex costs that do not eventuate, leading to an increase in profits for the EDB. • Could lead to increases in opex that are not prudent, efficient and in the long-term best interests of consumers. • Reduces incentive for EDBs to find efficiencies.
Implement a sliding scale (suggested by Wellington Electricity)	• Likely the most effective at signalling the threshold for which an EDB would be better off applying for a CPP.	• Most complex to implement.
Accept steps that are supported by sufficient documentation (suggested by Alpine) - note we have assumed this option has a higher level of scrutiny that the option above to 'remove the cap'	• Ensure a high level of certainty for the long-term benefit of consumers. • Decreases the chance of providing for costs that might not eventuate.	• Time intensive solution and would require further information requests from EDBs. • Likely above the level of scrutiny expected in a DPP.

Decision making for opex trends

C253 The following sections set out our decisions on opex scale growth, cost escalation and opex partial factor productivity. Across these decisions, we have sought forecasts that we generally consider are the most statistically robust and reliable predictions of the drivers of EDB opex. Many of the decisions are technical in nature and are made in pursuit of this goal of accurate forecasting. This in turn results in opex allowances that balance incentives to find efficiencies under s 52A(1)(a), the sharing of those efficiencies with consumers under s 52A(1)(c), and limits on excessive profits under s 52A(1)(d).

Decisions for opex scale growth

Overview of approach to opex scale growth

C254 This section discusses decisions related to the first of our three trend factors: changes in opex with scale growth. Our final decisions are to retain our econometric modelling approach to scale trends from DPP3, with updates and refinements.

C255 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.[83]

C256 Our approach to calculating opex scale growth trends involves multiplying together then summing:

C256.1 elasticities from our econometric modelling to select which factors we use to model opex scale growth; and

C256.2 forecast growth rates for these factors over the DPP4 period.

C257 The results of applying the approach detailed in the rest of this section is that for DPP4 final decisions we have calculated opex scale trends as below, with elasticities summarised in Table C9:

[83] The use of log-transformed variables means that the model coefficients are elasticities.

C257.1 Network opex (NO) growth:

$$\Delta\%(NO) = 0.44\ D\ \%\ (ICP) + 0.53\ \Delta\ \%\ (lines)$$

C257.2 Non-network opex (NNO) growth:

$$\Delta\ (NNO) = 0.20\ D\ \%\ (ICP) + 0.35\ D\ \%\ (lines) + 0.31\ D\ \%(capex)$$

C257.3 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 C9 DPP4 final elasticities for opex scale growth

Opex category	Elasticity to ICP growth	Elasticity to lines length growth	Elasticity to capex
Network opex (decision O5.3)	0.44	0.53	-
Non-network opex (decision O5.4)	0.20	0.35	0.31

Data preparation

C258 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.

C259 Prior to fitting econometric models, we have de-trended data for inflation effects, to cast nominal ID costs in constant 2024 prices. In line with **decisions C3, C6 and O4.2** we have done this using the opex and capex cost escalators with additional adjustments +0.3% per annum for opex and +0.8% per annum for capex.

C260 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.[84]

Analysis methods

C261 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.

[84] Information disclosure data is available at our Information disclosed by electricity distributors webpage.

C262 The approach in our draft decisions was informed by a review by Cambridge Economic Policy Associates (CEPA) conducted ahead of our DPP4 Issues paper[85] and by the Frontier Economics report provided by ENA.[86] We acknowledge the usefulness of this review and report, and in the sharing of model fitting analysis (R code) between parties.

C263 Submissions on our draft decision included suggestions to reconsider aspects of our econometric modelling, including different predictor variables and our model structure.[87, 88, 89] Following analysis, we have retained the overall modelling approach and variables for our draft decision. From draft to final we have included 2024 ID data (which became available between draft and final decisions), removed the filtering of irregular input data applied at the draft, and updated the cost escalators to include the additional adjustments included elsewhere. This has resulted in minor changes to elasticity values.

C264 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. The opex scale growth elasticities are the coefficients of the scale variables in our final model fits.

C265 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.

C266 Our general process was as follows:

C266.1 choose the reference period / input data date range. Initially based on expected models and reassessed after final model selection based on reference period chosen;

C266.2 decide level of opex aggregation. Uncontroversial, and not sensitive to data quality and reference period, with no iteration required;

C266.3 choose and apply input data filtering approach;

[85] Commerce Commission “Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper” (2 November 2023), Attachment D.

[86] Frontier “Opex econometric modelling” (report prepared for Electricity Networks Aotearoa, 9 January 2024)

[87] Firstlight Network “Submission on EDB DPP4 draft decisions” (12 July 2024), p. 11.

[88] Alpine Energy “Submission on EDB DPP4 draft decisions” (12 July 2024), p. 9.

[89] Unison Networks "Cross-submission on EDB DPP4 draft decisions" (2 August 2024), p. 2.

C266.4 choose preferred model selections for base variables;

C266.5 choose preferred models including possible additional variables (capex, time);

C266.6 choose whether to apply iterative model outlier exclusion based on preferred model specifications; and

C266.7 generate final elasticities for preferred models with outlier exclusions and cluster robust standard errors.

C267 The order above is reflected in the sections below, noting that this means **decision O5.2** on reference period is presented ahead of modelling methods and **decision O5.1** on level of aggregation.

C268 Our approach and conclusions are generally consistent with those from the CEPA and Frontier analysis. Key differences are:

C268.1 Our choice of a reduced reference period in order to better predict future trends (2018-2023 at the draft and 2018-2024 at the final, 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.

C268.2 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 2018-2024

Problem definition

C269 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.

Final decision

C270 For our DPP4 final decisions, we have used a reference period 2018 – 2024. This includes 2024 ID data, which became available after the time of preparing the draft. This is in line with our draft decision to use 2018-2023 for the draft and to extend this to 2018-2024 as 2024 ID data become available.

Alternatives considered

C271 At the draft 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

C272 There is a trade-off here between recency and model quality.

C272.1 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.[90]

C272.2 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.

C273 Our choice of 2018-2024 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:

C273.1 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. This change is statistically significant, albeit small in magnitude. No clear evidence for a break was observed in network opex elasticities.

C273.2 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.

C273.3 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

[90] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 29.

network opex elasticities, but improving model fit quality as earlier years with noisier data are omitted.

C274 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.

C275 These observations all point to overall smooth changes rather than clear breaks in data quality or modelled elasticities. While they do not 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.

C276 Our final 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.

What we heard from stakeholders

C277 There were no submissions on the DPP4 Issues paper 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.[91]

C278 Our final decision on the reference period was strongly informed by the view that - within our overall 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.

C279 In their submission on the DPP4 draft decision, Firstlight suggested we consider the full period and apply a hold-out approach to split data into one subset for training or fitting the models, and a separate subset to test model performance.[92]

[91] Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 29

[92] Firstlight Network "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 11.

C280 This approach is commonly used to guard against model 'over fitting' especially when opaque or 'black box' machine learning methods with many degrees of freedom are trained and then used to predict or forecast beyond available data. Our econometric models are simple, transparent and interpretable, where we fit past costs with defined relationships to expected drivers. Our case is different to using predictive machine learning models with complex methodologies, for which predictive accuracy is more important than interpretability, and for which hold-out testing is commonly applied. Through model selection, we are satisfied that we have sense-checked the reasonableness of our models via the elasticity values size and sign.

Approach to data quality and model fitting

Problem definition

C281 Within our overall modelling approach, choices are required on how to consider data quality and model fitting.

Final decision

C282 We have addressed data quality in the same way as in DPP3, by applying an iterative process to remove outliers from our model fits.

C283 This involves fitting an initial model, applying four outlier tests to all data points, removing all data points failing three 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.

C284 The effect of this step is discussed with model fitting results below. We have applied our iterative model outlier exclusion process for network opex and non-network opex models.

Change from our draft decision

C285 Our final decision involves removing an additional data quality step which had been included in our draft analysis, namely the exclusion from modelling of irregular ICP and lines data. This involved inspection of ICP and lines data over time for each EDB to identify irregular or anomalous ICP and lines length values (ie, those which clearly departed from the prevailing trends for an EDB).

C286 At the draft this resulted in the manual identification and exclusion of 25 data tuples (ie, "rows of data") from 17 EDBs out of 174 data points. In the end this had no impact on our selection of model variables and only small changes in the calculated elasticities (changes in the order of +/- 0.01). At the draft we applied this step as appropriate in-principle.

C287 Revisiting this choice and recognising that this step would have needed to be repeated and has minimal impact on final elasticity values, we have simplified our analysis by removing this step because the additional complexity brought no clear benefit.

What we heard from stakeholders

C288 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.[93]

C289 In their submission on the draft DPP4 decision, ENA "encourage[d] the Commission to resolve any issues with historical information disclosure (ID) data by ... engaging with EDBs to correct ... or replacing outliers with interpolated estimates… ".[94]

C290 As outlined above, we have taken account of these submissions and decided to remove the draft step of identifying and excluding irregular data points. Relatedly, we have also made some changes to how we forecast trend growth, see section on **decisions O5.5, O5.6 and O5.7** below.

O5.1: Scale growth forecast separately for network and non-network opex

Problem definition

C291 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.

Decision

C292 Our final decision is to retain the split for opex into network opex and non-network opex and model their scale trends separately.

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[93] 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).

[94] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024) , p. 11.

Alternatives Considered

C293 In terms of aggregation, we have considered:

C293.1 using total opex; and

C293.2 breaking network and non-network expenditure into one or more subcategories.

Analysis

C294 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 in response to the DPP4 issues paper or our draft decision.

C295 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.

C296 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 DPP3 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

C297 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.

C298 We present these final decisions side by side, as the process and considerations were the same.

Final decisions

C299 Our final **decision O5.3** is to forecast network opex scale growth with ICP count (elasticity 0.44) and line length (elasticity 0.53).

C300 Our final **decision O5.4** is to forecast non-network opex scale growth with ICP count (elasticity 0.20), line length (elasticity 0.35) and capex (elasticity 0.31).

Changes from draft to final

C301 We have retained our pooled ordinary least squares modelling approach, and as supported by updated modelling results below, we have retained the same model variables (ie, "cost drivers") for both network- and non-network opex as in the draft.

C302 Our final elasticities follow from updating our econometric modelling in the following ways:

C302.1 the reference period of ID data was extended to 2018-2024 (from 2018-2023 in the draft);

C302.2 the DPP3 approach to data quality was retained;[95] and

C302.3 the cost escalators used in our data preparation include the additional adjustments +0.3% each year for opex and +0.8% annually for capex, in line with their use elsewhere in our final decisions.

C303 Individual elasticity values have changed by at most 0.02 from the draft.

What we heard from stakeholders

C304 Our approach to opex scale trends in the draft DPP4 decision was broadly supported, with some calls to consider specific aspects.

C305 ENA provided high level support to our approach, noting "The use of econometric models to forecast the impact of network growth on opex is an appropriate, if highly technical, approach."[96]

C306 Wellington Electricity supported our "refinements to the model which includes a focus on more recent data as this may better reflect future changes in costs".[97]

[95] As discussed below, as in DPP3, we have applied an iterative model outlier exclusion process when fitting the econometric models used to calculate elasticity values. We have not applied an additional step, introduced in our draft decision, to filter out irregular input data.

[96] Electricity Networks Aotearoa (ENA) "Submission on EDB DPP4 draft decisions" (12 July 2024) , p. 11.

[97] Wellington Electricity "Submission on EDB DPP4 draft decisions" (12 July 2024) , p. 31.

C307 Wellington Electricity also repeated a concern with this approach raised in their DPP4 Issues paper submission that "... if a trend in expenditure is new then it will still not be captured".[98] We accept this as a general feature of this type of modelling, and that within the base, step, and trend approach, particular examples of new expenditure can be addressed via step changes.

C308 Powerco generally agreed and supported our approach and refinements, particularly the inclusion of a capex term for non-network opex.[99]

C309 Alpine Energy repeated their Issues paper submission call for a 'demand' variable. "We recommend the Commission include the increase in network demand as an additional cost driver for network opex."[100] Unison supported this in cross submissions.[101] Below, as in the draft, we have assessed ratcheted peak demand as a potential model variable and ruled it out.

C310 Firstlight made observations on technical aspects of our econometric modelling approach.[102] These included: the high correlations between variables and suggestion of RAB as a model variable, and the observation that the data is hierarchical.

C311 As discussed further below, we have investigated in detail the points raised by Firstlight, and do not find evidence to support a change from our approach or model variables used in the draft. In summary, we find:

C311.1 as noted in the draft, and common in econometric analysis, multicollinearity is present in our data, but we do not find it has introduced problems in our selection of scale trend variables or calculation of their elasticity values;

C311.2 from model selection analysis, RAB is not supported as either an alternative or additional variable; and

C311.3 as a possible variation on our pooled OLS approach, we have assessed fixed effect models, but they are unable to resolve reasonable elasticity values. We have retained pooled OLS and the use of clustered robust

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[98] Wellington Electricity "Submission on EDB DPP4 draft decisions" (12 July 2024) , p. 31.

[99] Powerco "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 13.

[100] Alpine Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 8.

[101] Unison Networks "Cross-submission on EDB DPP4 draft decisions" (2 August 2024), p. 2.

[102] Firstlight Network "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 11.

standard errors (CRSE) to avoid underestimating model standard errors due to our data being clustered by EDB.

Alternatives considered - model selection and methodology

C312 In terms of scale factor drivers, we considered different combinations of the following variables, from ID data:

C312.1 total circuit length (km);

C312.2 ICP count (average number of total ICPs in the reporting year);

C312.3 annual energy delivered (MWh);

C312.4 maximum coincident peak demand (MW); and

C312.5 capex (Expenditure on Assets) ($000).

C313 As a result of feedback in submissions on the DPP4 Issues paper we have also considered:

C313.1 ratcheted (ie, cumulative annual maximum) coincident peak demand (MW) and energy delivered (MWh); and

C313.2 a ‘time’ variable (year).

C314 In response to Firstlight's submission on the DPP4 Draft decision, we have also considered:

C314.1 use of regulatory asset base (RAB) ($000) as an explanatory variable; and

C314.2 a variation to our model structure from pooled ordinary least squares to include a 'fixed effect' by EDB to reflect the grouped nature of the data.

C315 Our 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.[103]

C316 We first considered base model variables, then RAB, capex and time, and then applied iterative model outlier exclusion to our preferred models.

[103] Frontier “Opex econometric modelling” (report prepared for Electricity Networks Aotearoa, 9 January 2024)

C317 This approach allows us to consider AIC (Akaike information model fit criterion) and BIC (Bayesian information criterion) model fit metrics in our model selection, in addition to adjusted R squared and RMSE (root mean squared error). The values of AIC and BIC are not comparable for models fit to a different number of data points, which occurs after our outlier exclusion process.

C318 In our model selection, we considered a range of factors when comparing the results of our econometric analysis, including:

C318.1 explanatory power of the model primarily using the adjusted R squared metric, also root mean squared error (RMSE), and (where models have the same number of data points) AIC and BIC;

C318.2 statistical significance of coefficients for model variables (p-values based on value estimates and standard errors); and

C318.3 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).

C319 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 - model selection

C320 Our start point from DPP3 was to use ICP and lines as explanatory variables for both network and non-network opex. These are the most fundamental measures of network size. We then considered model variations by substituting or adding other variables.

C321 The performance of our DPP3 forecasts using models with ICP and lines was reviewed by CEPA and included in our DPP4 Issues paper.[104] 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 and new costs not captured in the absence of step changes.

[104] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), Attachment D, p. 92-96.

C322 Nevertheless, the results below (updated with 2024 data) from our model selection comparison confirm that ICP and lines provide the best 2-variable model fits for both network and non-network opex.

C323 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.[105]

C324 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.[106]

C325 Tables C10 and C11 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), ratcheted delivery (GWh) and RAB. 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.

C326 Neither network or non-network models are improved by adding or substituting either ratcheted peak or ratcheted delivery.

C327 Results for models (8) and (9) in Tables C10 and C11 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.

C328 Results for models (2)-(7) show that substituting lines or ICP any of these variables leads to worse fit metrics than the model using lines + ICP in all cases.

[105] For example, Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 29-31.

[106] Frontier "Opex econometric modelling", prepared for Electricity Networks Aotearoa (9 January 2024), p. 19.

C329 In response to Firstlight's submission, we investigated using RAB as a possible model variable, using the average of opening and closing RAB reported in ID data. Modelling results did not support the addition or substitution of RAB as a variable for either network opex (Table C10) or non-network opex (Tables C11 and C13). This appears in part to be because RAB is very highly correlated with ICP count,[107] leading to model fitting issues which are not present in our preferred models.

C330 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.

C331 However, to Firstlight's submission, the presence of correlated variables when fitting regression models is a common consideration, and not necessarily an issue. For example, as noted in Applied Statistical Linear Modelling:[108]

> ".. the fact that some or all predictor variables are correlated among themselves does not, in general, inhibit the ability to obtain a good fit nor does it tend to affect inferences about mean responses or predictions of new observations, provided these inferences are made within the region of observations. "

C332 After considering factors including the correlation coefficients between variables, variance inflation factors (VIFs) of fitted models, and the overall reasonableness and acceptance of the elasticity values, we do not find that multicollinearity has introduced problems in our selection of scale trend variables or their elasticity values.

C333 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 do not.

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[107] Of all the variables we considered, RAB and ICP count are the most correlated pair.

[108] Kutner et al. Applied Linear Statistical Models, p283-284, 5th Edition.

C334 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.[109] We have confirmed this result.

C335 We conclude that ICP and lines are the best 'base models' for both network and non-network opex models. Beyond this choice, we 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.

[109] Frontier "Opex econometric modelling" prepared for Electricity Networks Aotearoa (9 January 2024), p. 19.

Table C10 Comparison of network opex base models[110]

	(1) lines+icp	(2) lines+peakR	(3) lines+delR	(4) lines+rab	(5) icp+peakR	(6) icp+delR	(7) icp+rab	(8) +peakR	(9) +deliveryR	(10) +rab
Opex category	network	network	network	network	network	network	network	network	network	network
(Intercept)	-0.188	1.978***	1.591***	-1.399***	0.489	1.533***	-1.943***	-0.313	-0.154	-0.239
	(0.159)	(0.188)	(0.172)	(0.249)	(0.583)	(0.436)	(0.306)	(0.376)	(0.308)	(0.275)
lines	0.563***	0.630***	0.576***	0.450***				0.564***	0.561***	0.555***
	(0.033)	(0.035)	(0.039)	(0.050)				(0.033)	(0.035)	(0.047)
icp	0.421***				0.766***	0.478***	0.198**	0.442***	0.414***	0.410***
	(0.028)				(0.097)	(0.095)	(0.070)	(0.065)	(0.063)	(0.057)
peak_rat		0.356***			0.061			-0.023		
		(0.030)			(0.096)			(0.062)		
delivery_rat			0.399***			0.358***			0.009	
			(0.033)			(0.094)			(0.066)	
rab				0.520***			0.690***			0.018
				(0.045)			(0.074)			(0.080)
Num.Obs.	203	203	203	203	203	203	203	203	203	203
R2	0.944	0.930	0.931	0.929	0.862	0.871	0.903	0.944	0.944	0.944
R2 Adj.	0.943	0.930	0.931	0.928	0.861	0.870	0.903	0.943	0.943	0.943
AIC	0.9	43.3	40.8	47.9	182.3	168.7	109.9	2.7	2.8	2.8
BIC	14.1	56.5	54.1	61.2	195.6	181.9	123.1	19.3	19.4	19.4
RMSE	0.24	0.26	0.26	0.27	0.37	0.36	0.31	0.24	0.24	0.24
p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001										

[110] 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 peak, delivery or rab variables. Here peak_rat refers to ratcheted peak demand (MW) and delivery_rat refers to ratcheted delivery (total energy delivered, MWh). All models fit to the same data, ie prior to model outlier exclusion procedure.

Table C11 Comparison of non-network models[111]

	(1) lines+icp	(2) lines+peakR	(3) lines+delR	(4) lines+rab	(5) icp+peakR	(6) icp+delR	(7) icp rab	(8) +peakR	(9) +deliveryR	(10) +rab
Opex category	nonnetwork	nonnetwork	nonnetwork	nonnetwork	nonnetwork	nonnetwork	nonnetwork	nonnetwork	nonnetwork	nonnetwork
(Intercept)	0.644**	3.693***	3.099***	-1.251***	1.465**	1.615***	-0.657*	1.036*	0.709+	-0.025
	(0.215)	(0.246)	(0.232)	(0.319)	(0.556)	(0.427)	(0.320)	(0.507)	(0.415)	(0.366)
lines	0.304***	0.379***	0.322***	0.095				0.301***	0.302***	0.206**
	(0.045)	(0.046)	(0.052)	(0.064)				(0.045)	(0.047)	(0.062)
icp	0.580***				0.686***	0.601***	0.354***	0.513***	0.567***	0.433***
	(0.038)				(0.092)	(0.093)	(0.074)	(0.087)	(0.085)	(0.076)
peak_rat		0.510***			0.116			0.071		
		(0.039)			(0.091)			(0.083)		
delivery_rat			0.551***			0.204*			0.016	
			(0.044)			(0.092)			(0.089)	
rab				0.770***			0.489***			0.240*
				(0.057)			(0.078)			(0.107)
Num.Obs.	203	203	203	203	203	203	203	203	203	203
R2	0.890	0.872	0.866	0.875	0.866	0.868	0.887	0.891	0.890	0.893
R2 Adj.	0.889	0.870	0.864	0.874	0.864	0.866	0.886	0.889	0.889	0.891
AIC	122.1	153.8	163.2	147.9	163.1	159.8	127.9	123.4	124.1	119.0
BIC	135.4	167.0	176.5	161.2	176.3	173.1	141.2	139.9	140.6	135.6
RMSE	0.32	0.35	0.35	0.34	0.35	0.35	0.33	0.32	0.32	0.32
p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001										

[111] 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 peak, delivery or rab variables. Here peak_rat refers to ratcheted peak demand (MW) and delivery_rat refers to ratcheted delivery (total energy delivered, MWh). All models fit to the same data, prior to model outlier exclusion process.

Capex variable

C336 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 models with a statistically significant elasticity. For network opex, the effect was too small to resolve with statistical significance.

C337 Here 'capex' refers to Expenditure on Assets, the quantity reported in ID data.

C338 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 – for example, Orion who noted:[112]

> 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.

C339 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.[113]

C340 Tables C12 and C13 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 2018-2024.

C341 The model metrics in Table C12 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 a larger value is better) and it increases the AIC and BIC (for which smaller is better).

C342 Model (2) here has a small negative coefficient for capex (-0.063) but this is similar magnitude as its standard error (0.040). In other words, any capex-effect is too small to reliably resolve.

[112] Orion "DPP4 Issues paper submission" (19 December 2023), p. 11.

[113] Frontier "Opex econometric modelling" (report prepared for Electricity Networks Aotearoa, 9 January 2024), p. 9.

Table C12 Comparison of network models adding capex and time variables [114]

	(1) lines+ICP	(2) +capex	(3) +time	(4) +capex+time
Opex category	network	network	network	network
(Intercept)	-0.188	-0.272	-36.254*	-38.317*
	(0.159)	(0.167)	(16.842)	(16.800)
lines	0.563***	0.599***	0.564***	0.603***
	(0.033)	(0.040)	(0.033)	(0.040)
icp	0.421***	0.461***	0.419***	0.464***
	(0.028)	(0.038)	(0.028)	(0.038)
capex		-0.063		-0.069+
		(0.040)		(0.040)
year			0.018*	0.019*
			(0.008)	(0.008)
Num.Obs.	203	203	203	203
R2	0.944	0.944	0.945	0.946
R2 Adj.	0.943	0.943	0.944	0.945
AIC	0.9	0.4	-1.8	-2.8
BIC	14.1	16.9	14.8	17.1
RMSE	0.24	0.24	0.24	0.23
p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001				

C343 Table C13 compares non-network opex models, adding capex, RAB and time variables to our preferred base model. It shows that adding a capex term in model (2) is supported. Adding capex improves the fit metrics: adjusted R squared increases, and AIC and BIC decrease. The capex coefficient is also statistically significant. In extension to our draft analysis, we note that adding RAB also improves these metrics, but adding capex does better by all metrics.

[114] 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 C13 Comparison of non-network models adding capex and time [115]

	(1) lines+ICP	(2) +capex	(3) + rab	(4) +time	(5) +capex+time
Opex category	nonnetwork	nonnetwork	nonnetwork	nonnetwork	nonnetwork
(Intercept)	0.644**	0.962***	-0.025	-59.678**	-52.768*
	(0.215)	(0.216)	(0.366)	(22.562)	(21.591)
lines	0.304***	0.169**	0.206**	0.306***	0.175***
	(0.045)	(0.052)	(0.062)	(0.044)	(0.051)
icp	0.580***	0.426***	0.433***	0.578***	0.429***
	(0.038)	(0.049)	(0.076)	(0.037)	(0.048)
capex		0.241***			0.232***
		(0.052)			(0.051)
rab			0.240*		
			(0.107)		
year				0.030**	0.027*
				(0.011)	(0.011)
Num.Obs.	203	203	203	203	203
R2	0.890	0.901	0.893	0.894	0.904
R2 Adj.	0.889	0.899	0.891	0.892	0.902
AIC	122.1	103.3	119.0	116.9	99.0
BIC	135.4	119.9	135.6	133.5	118.9
RMSE	0.32	0.30	0.32	0.31	0.30
	p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001				

C344 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 **).

C345 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.

[115] 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.

C346 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.

C347 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 C12 and discussed above, any such effect in our data is too small to resolve.

C348 Our decisions on including a capex variable are therefore:

C348.1 for network opex, to not add a capex variable, as a statistically significant effect is not resolved, and model fits do not improve; and

C348.2 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

C349 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.[116]

C350 As shown in Tables C12 and C13 above, we confirm Frontier's results that network and non-network model fits are both improved by adding a time variable (year) with coefficients of 0.018 and 0.030. As we have not log-transformed the year variable, this can be interpreted as including in the models a roughly 2-3% per annum increase over time for network and non-network opex.

C351 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) and (4) in Tables C12 and C13. Unlike adding the capex term, adding a time term is explaining variance in the data which is not explained with the other model terms.

[116] Frontier "Opex econometric modelling" (prepared for Electricity Networks Aotearoa, 9 January 2024)

C352 This analysis and result are somewhat consistent with what is described as a productivity loss in the recent CEPA paper regarding the evolution of industry productivity.[117] CEPA's methodology and definition of costs differ slightly but not fundamentally, and the time effect differs by magnitude but not direction.

C353 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 may point to unmodelled costs.

C354 DPP4 opex allowances already capture actual incurred cost levels through ID-reported actual opex levels in the 2024 base year. 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 final decisions also include acceptance of multiple 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.

C355 Considering these factors, our final 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.

C356 However, this work has informed our final 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 **decision O4.2.** included an EDB-specific inflation differential in addition to forecasts of economy-wide labour and producer-price inflation.

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[117] CEPA "(FINAL) EDB Productivity Study" (report prepared for the Commerce Commission, 24 June 2024).

Model fits and elasticities after outlier exclusion

C357 Our final step to calculating elasticities is to fit models using our iterative model outlier exclusion method, the results of which are shown in Table C14. Applying the iterative model outlier exclusion 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 C14 Final econometric models and opex elasticities for DPP4

	Network	Non-network
Intercept)	-0.102	1.230***
	(0.292)	(0.354)
lines	0.532***	0.352***
	(0.045)	(0.073)
icp	0.437***	0.201**
	(0.049)	(0.074)
capex		0.307***
		(0.081)
Num.Obs.	200	188
R2	0.941	0.948
R2 Adj.	0.940	0.947
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 2018-2024.

C358 The effect of applying the iterative model outlier exclusion process on our preferred network model is to remove only three data points (ie, data for three EDB-year combinations), with changes to elasticities which are smaller than their standard errors.

C359 Applied to our preferred non-network model, the iterative model outlier process 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.

C360 Applying iterative model outlier exclusion removed 15 data points in our non-network model fit. All seven years of data were excluded for two EDBs and one year of data was excluded for one other EDB.

C361 Inspection of the excluded data 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.

C362 The standard errors in the model fits in Table C14 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).[118] The size of these standard errors indicates that an appropriate precision to specify these elasticities is two decimal places, as reflected in Table C9.

C363 Final DPP4 opex elasticities for network opex (ICP: 0.44 and lines: 0.53) are very similar to those used in DPP3 (ICP: 0.4514 and lines: 0.4727) with a relatively minor 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.

C364 Final DPP4 opex elasticities 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 outlying data points than in the DPP3 analysis.

Cost escalators for preparing ID data for elasticity modelling

C365 Prior to fitting econometric models, we need to de-trend data for inflation effects, and cast all nominal ID dollar amounts to a common basis (here, constant 2024 prices). In line with final **decisions C3, C6 and O4.2** we have done this using the opex and capex cost escalators used elsewhere in our final decisions: a 60/40 split of all industry LCI and PPI indices for opex data plus a 0.3% per annum adjustment, and All-Groups CGPI plus a 0.8% per annum additional adjustment for capex data.

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[118] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Issues paper" (2 November 2023), p. 101.

C366 This is a minor change from our approach at the draft, which did not include the additional adjustments in this data preparation step. We have made this change for consistency reasons and to better capture the expected cost inflation over the reference period. It has very minor impact on the resulting elasticities (either no change or a change of at most +/-0.01).

Considerations of including capex as a 'cost driver' of non-network opex

C367 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.

C368 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 practice. 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.

C369 In practice, 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% per annum. 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

C370 In response to DPP4 Issues paper 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 approach provides a more reliable forecast of opex scale growth trends.

C371 In response to Firstlight's submission on the draft decision, we also considered 'fixed effect' models but discounted them on performance grounds, with elasticities values unreasonably high and with large uncertainties.

C372 Firstlight's submission noted the hierarchal nature of the data used to model elasticities, suggesting we consider other modelling approaches to account for this:[119]

> Moreover, the data under consideration is hierarchical, in simple words the observations are not independent. This hierarchical structure leads to non-independent residuals, as confirmed by residual plots against fitted values showing clear clustering patterns. …
>
> Therefore, we encourage the Commission to explore other models, e.g., a Linear Mixed Model (LMM) to account for the clustering effects of the EDBs and to produce more accurate estimates.

C373 We agree with Firstlight on the general point that the data used to calculate elasticities from fitting econometric models is 'panel data' – ie, time series data 'clustered' (or grouped) by EDB. Data like this is not uncommon in econometric data analysis.

C374 Our approach called pooled ordinary least squares (OLS) fits all data together. It is a standard approach, similar to that used by AER in similar model fitting and was accepted without comment in the Frontier Economics report on our Issues paper.[120]

C375 We have revisited our modelling, to check two things here. First, that we are using the correct approach to test for the statistical significance of the elasticities. As noted in the DPP4 Issues paper, we do this using cluster robust standard errors (CRSE). We have double checked our model selection process using CRSE and our model selections for network and non-network opex stand.

C376 Secondly, we have considered alternatives to pooled OLS, recognising that data are clustered by EDB. Prior to the draft we considered and rejected a variation to pooled OLS called Fixed Effects (FE) models. Following Firstlight's submission, we revisited FE models, but the performance of this approach was very poor: elasticities values were unreasonably high with large uncertainties.

[119] Firstlight Network "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 11.

[120] Frontier "Opex econometric modelling" (report prepared for Electricity Networks Aotearoa, 9 January 2024)

C377 As such, we have retained the pooled OLS approach. We are satisfied that, within our base, step trend approach - which can also allow for step changes, cost escalation and productivity trends - the resulting scale trend variables and elasticities provide a reasonable, robust and supported basis to trend opex with forecast EDB scale growth. These decisions reflect our view noted above that the most statistically robust forecast promotes incentives to improve efficiency and or to invest.

O5.5, O5.6 and O5.7 decisions on forecasting scale growth factors

Problem definition

C378 The scale trend approach requires forecasts for the growth rates of the scale factors, namely: ICP count, total lines length and capex (Expenditure on Assets).

C378.1 We have reviewed our approach to ICP and lines forecasts; and

C378.2 Capex is a new scale variable, requiring a new method.

Final decisions

C379 **Decision O5.5**: Forecast lines length extrapolated using recent growth rate trend, and irregular data adjusted.

C380 **Decision O5.6**: Forecast ICP count extrapolated using recent growth rate trend, and irregular data adjusted.

C381 **Decision O5.7**: Forecast capex based on a constant growth rate.

C382 That is, for DPP4 final decisions we have forecast opex scale factor growth rates over the DPP4 period (% pa) as follows:

C382.1 ICP count and total lines length growth rates are forecast from recent trends in ID data subject to adjustments for data quality, and

C382.2 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 capex reference period and the middle year of the DPP4 regulatory period.

C383 For lines, this retains the approach used in DPP3. For ICP count, this is a change from our approach at DPP3 where we mapped Stats NZ forecasts of household growth to EDB regions. For capex this is a new method.

Change from the draft

C384 **Decisions O5.5, O5.6 and O5.7** are unchanged from the draft. The final scale growth trend values have been calculated from the trend between 2020-2024, rather than 2020-2023 at the draft. We have also revisited the adjustments to irregular data based on submissions and the updated data.

Alternatives Considered

C385 As alternatives, we have considered:

C385.1 No alternative for lines length;

C385.2 Household growth or EDB's own forecasts for ICP growth; and

C385.3 Average annual change rates implied by approved capex allowances.

Analysis

ICP and lines

C386 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.

C387 Our final decision is to retain this approach for DPP4, calculating the average rate of growth between 2020-2024. When fitting a small number of points (here five 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.

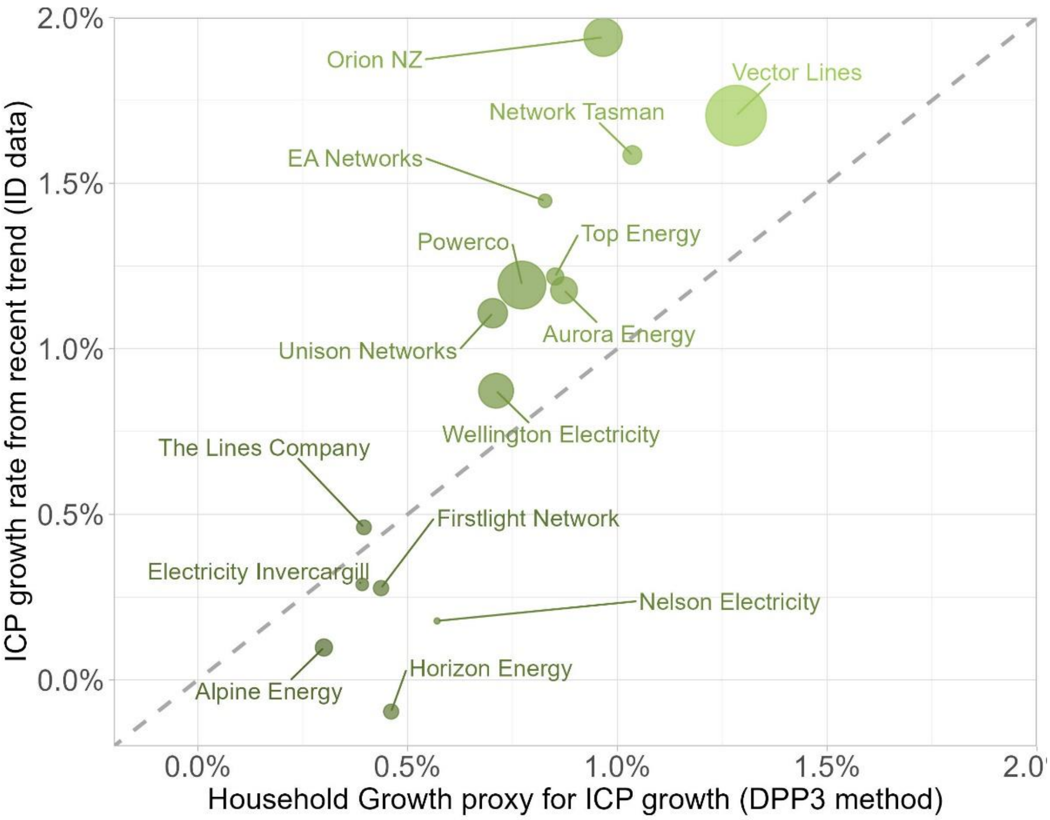
C388 We have made some adjustments to ID lines and ICP data solely for the purpose of this trend fitting. These adjustments are detailed in a DPP4 final decision modelling workbook.[121] Adjustments were made only in cases where not doing so would have resulted in forecasts clearly and significantly different from prevailing trends in the data, and as such would have been unreasonable predictors of future growth rates.

[121] Commerce Commission "Opex growth model-EDB DPP4 final determination" (20 November 2024).

C389 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.

C390 Figure C2 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.

Figure C2 Comparison of household growth and ICP growth [122]



C391 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.

[122] OtagoNet is not shown here. Its recent trend is an above-scale 4.0% per annum due to growth in its Lakeland Network, and its HHG-derived estimate is +0.5% per annum.

C392 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% per annum but the HHG model results in a 1.3% per annum increase. Conversely, the HHG model has over-estimated actual growth predominantly for smaller and lower-growth networks.

C393 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.

C394 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.

C395 As noted above, ENA's submission on the draft decisions "encourage[d] the Commission to resolve any issues with historical information disclosure (ID) data by […] engaging with EDBs to correct […] or replacing outliers with interpolated estimates […]".[123]

C396 Horizon also submitted with additional information to explain the step in the ICP counts in ID data as the result of a change in reporting convention. Since 2022 Horizon no longer report in ID data unbilled “inactive” ICPs.[124] Horizon also submitted an alternative estimate of their ICP growth rate using Electricity Registry data.

C397 As a result, we have used publicly available registry data accessed through the EA administered website to inform our adjustments to ICP counts in ID data prior to trend fitting. [125]

[123] Electricity Networks Aotearoa (ENA) “Submission on EDB DPP4 draft decisions” (12 July 2024) , p. 11.

[124] Horizon Networks “Submission on EDB DPP4 draft decisions” (11 July 2024) ,p. 4.

[125] Data accessed via https://www.emi.ea.govt.nz/

Capex

C398 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.

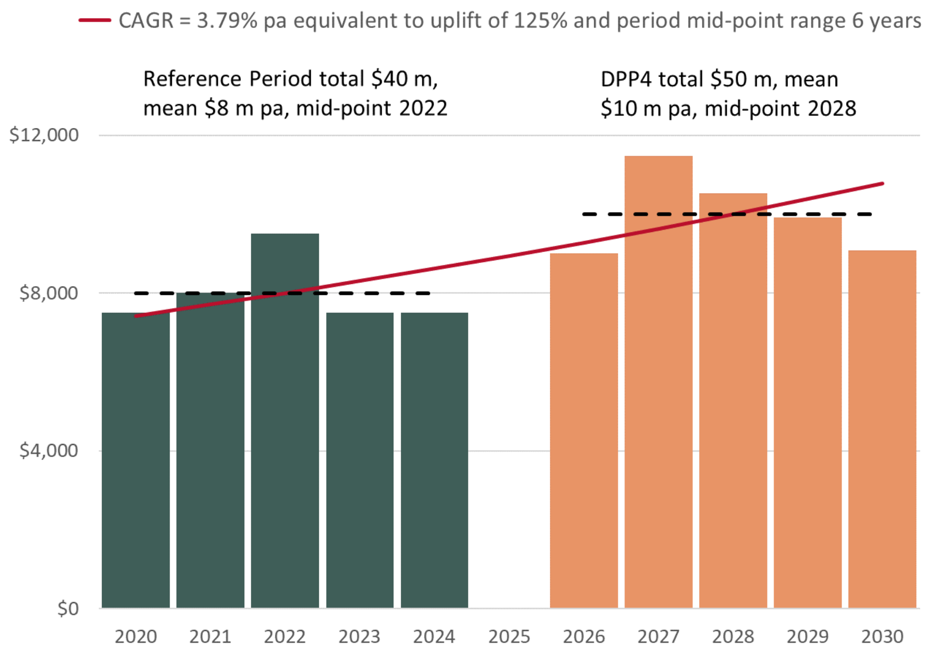
C399 We refer to the DPP4 capex allowance setting process, in which the total capex allowances have been set with consideration to the total capex in a reference period.[126] For DPP4 final decisions, the reference period for capex is the five years 2020-2024. For final DPP4 prices, we have set EDBs’ capex allowances (in constant 2024 prices) based on the lower of their total AMP forecast capex or 125% of their reference period capex while retaining the year-to-year shape from EDBs’ AMP forecasts.

C400 Following this, we have calculated a compounding average growth rate (CAGR) equivalent to this uplift. Figure C3 below illustrates this calculation, using illustrative numbers (in constant 2024 prices). 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 6-year period between mid-point of the reference period and mid-point of DPP4 is 3.79 % per annum.[127]

[126] **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.

[127] In this case, CAGR = (125%)^(1/(2028-2022)) -1 = 3.79%

Figure C3 Capex CAGR equivalent to allowed capex uplift, assessed in constant 2024 prices



C401 For the DPP4 final decision, we have applied this method per EDB, using reference period expenditure on assets reported in ID data, and allowed DPP4 expenditure on assets values (after the application of the 125% cap).

C402 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

C403 Wellington Electricity supported this approach, noting:[128]

> We agree with the Draft Decision to use forecast capex in a constant growth. We also agree with using the adjusted capex allowances to set prices.

[128] Wellington Electricity "Submission on EDB DPP4 draft decisions" (12 July 2024) ,p. 32.

C404 Wellington also submitted on the interaction between non-network opex and capex, noting "EDBs would not be able to avoid increases in non-network costs if the reopener capex is for essential works needed to maintain the quality standards".[129] They suggested that we "[a]djust the non-network growth capex calculation to include capex additions as part of the reopener process.

C405 We note that appropriate adjustments to opex can be considered as part of any reopener process.

Results

C406 The results of applying the methods above are shown in Table C15. 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.

[129] Wellington Electricity "Submission on EDB DPP4 draft decisions" (12 July 2024) ,p. 32.

Table C15 Scale factor growth and resulting opex scale cost growth (% pa)[130]

EDB	Circuit Length	ICP	Capex	Network Opex scale growth	Non-Network Opex scale growth
Alpine Energy	0.32%	0.82%	3.79%	0.53%	1.45%
Aurora Energy	0.84%	1.14%	1.17%	0.94%	0.88%
EA Networks	0.75%	1.69%	-5.51%	1.14%	-1.11%
Electricity Invercargill	0.19%	0.35%	3.79%	0.26%	1.31%
Firstlight Network	0.14%	0.25%	3.79%	0.18%	1.27%
Horizon Energy	0.30%	0.54%	3.79%	0.39%	1.39%
Nelson Electricity	0.15%	0.17%	3.79%	0.16%	1.26%
Network Tasman	0.63%	1.63%	3.52%	1.05%	1.64%
Orion NZ	1.01%	2.01%	3.79%	1.42%	1.93%
OtagoNet	0.30%	3.05%	3.79%	1.50%	1.89%
Powerco	0.73%	1.14%	3.79%	0.89%	1.66%
The Lines Company	0.34%	0.46%	2.56%	0.38%	1.00%
Top Energy	0.53%	1.20%	-1.19%	0.81%	0.06%
Unison Networks	0.18%	1.02%	3.79%	0.55%	1.44%
Vector Lines	0.84%	1.80%	2.93%	1.24%	1.56%
Wellington Electricity	0.53%	0.92%	3.79%	0.68%	1.54%

C407 In Table C15 the multiple EDBs with a capex growth rate of 3.79%, indicate EDBs whose capex allowances have been capped at a 125% of reference period capex (in constant 2024 prices).

C408 Table C15 also shows negative capex growth rates for EA Networks and Top Energy, reflecting DPP4 capex allowances lower in constant 2024$ terms than their reference period capex.

Decisions on cost escalation trends

C409 Within the base, step, and trend opex model, trend factors are intended to capture continuing and broadly predictable changes in forecasting EDB opex.

[130] 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 from Table C9.

C410 The purpose of cost escalators is to account for real input price increases beyond a prudent and efficient EDB's ability to avoid. [131] This is consistent with promoting s 52A, 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.

C411 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.

C412 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.

C413 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.

O4.1 Escalate all opex costs using the same cost escalator

Problem definition

C414 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.

Final decision

C415 Our final decision is to escalate all opex costs using the same cost escalator. This is the same as our draft decision.

Alternatives considered

C416 In addition to all opex, we have also considered:

C416.1 different escalation for non-network and network opex; and

C416.2 carving out subcategories (notably insurance) to be escalated separately.

[131] "Real price effects" refers to changes in input prices net of overall CPI inflation.

Analysis

C417 Using a different mix of indices for different categories of expenditure could be justified where we have evidence that both:

C417.1 the inputs required for different categories of expenditure differ significantly; and

C417.2 the relative proportions of those categories change materially over time or between suppliers.

C418 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.

C419 More importantly, the relative proportion of these categories has been reasonably static over time, with network opex amounting to between 38-41% of total opex each year since 2014, and non-network opex 59-62%. 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.

C420 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 the mix of input costs, we do not consider this approach appropriate.

C421 We note that separate to the overall escalation of opex costs to calculate nominal allowances, we have applied an insurance-specific real price effect in the calculation of insurance step changes (see **decision O3.1)**. This gives the forecast increase in insurance costs over and above the inflation specified by our opex cost escalators.

What we heard from stakeholders

C422 In its submissions on the DPP4 Issues paper, Horizon noted the different drivers of different opex elements:[132]

> …different OPEX elements will have different drivers. For example, cybersecurity and insurance costs have escalated out of line with other elements of OPEX. Any

[132] 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.

C423 Multiple submissions on the issues paper and draft decision supported a separate treatment for insurance costs, as either a pass-through cost or with its own cost escalator.[133] As discussed in more detail above regarding **decision O3.1** we have addressed increasing insurance costs as a step change.

C424 In response to the draft decision, Orion, Vector and Wellington Electricity submitted a jointly commissioned expert report from Oxford Economics Australia (OEA) on cost escalation.[134] This focussed on capex cost escalation (**draft decisions C3 and C6**). It supported the draft approach to non-network opex cost escalation but did "not support the use of this approach for network opex".

C425 We discuss our consideration of this submission below. Our final decision is the same as our draft decision, to apply the same cost escalation to all opex.

O4.2 Escalate opex using the all-industries labour cost (60% weighting) and a producers' price (40%) indices, plus a 0.3% adjustment to reflect EDB-specific inflation

Problem definition

C426 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).

C427 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 price effects can have a material impact on EDB profitability. Not reflecting these input price increases, would not be consistent with the financial capital maintenance (FCM) principle, and EDBs might not expect to earn an ex-ante normal return, in line with s 52A(1)(a) and (d).

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[133] For example submissions by Aurora, ENA, Horizon, Orion, Powerco, and Transpower on the Commerce Commission "DPP4 Issues paper submission" (19 December 2023); and submissions by Aurora, ENA and PowerNet on the Commerce Commission "EDB DPP4 draft decision" (12 July 2024).

[134] OEA "EDB Escalation Report" (prepared for Orion, Vector, Wellington Electricity - June 2024)

Final decision

C428 Our final decision is to escalate all opex costs using a 60/40 split of all industry LCI and PPI indices and apply a 0.3% per annum adjustment to reflect historical higher inflation in the electricity, gas, water, and waste sector that we consider is likely to persist in the medium-term. This is the same as our draft decision.

Alternatives considered

C429 As alternatives we have considered:

C429.1 retaining the use of the all-industries indices unadjusted; and

C429.2 applying an EDB-specific basket of cost escalators.

C430 In response to a submission on our draft decision from Orion, Vector and Wellington Electricity discussed below, we have also considered the suggestion to escalate network opex costs as 60% x (LCI+0.3%) + 40% x the capex escalator, with the capex escalator being the All-Groups CGPI+3.1%.

Analysis

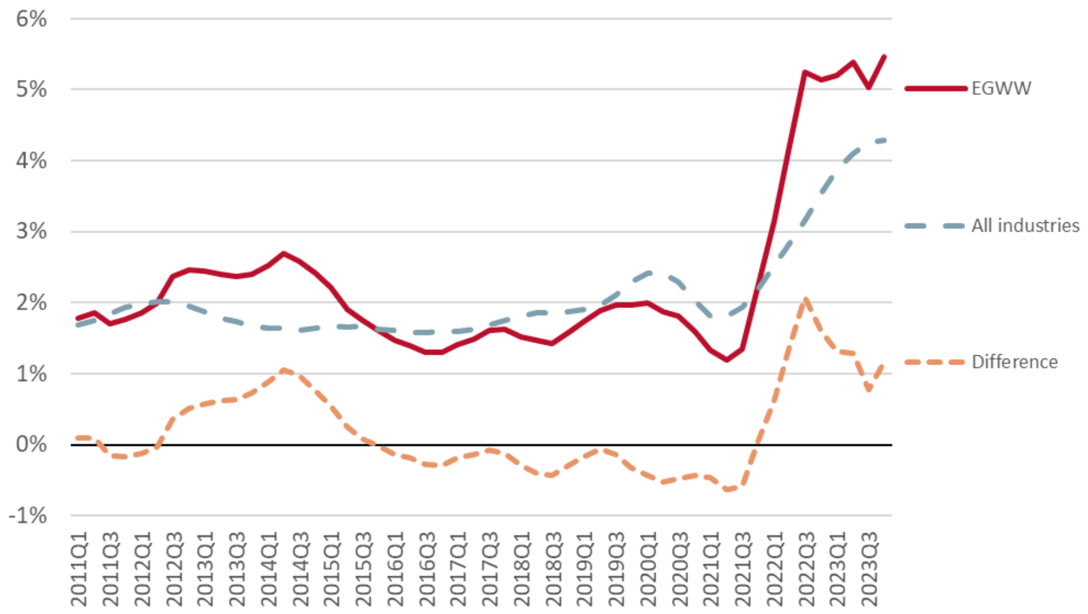
C431 The most material source of differences between forecast and actual cost escalation over the DPP3 period has been general inflation (represented by CPI). To insulate consumers and EDBs from CPI inflation risk, in the 2023 IM Review we introduced a “real IRIS”, where efficiency incentives are measured against expenditure adjusted for out-turn CPI.

C432 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.

C433 Historical evidence (see Figure C4 below) highlights the differences that can occur over the short to medium term between economy-wide and sectoral inflation. The +0.3% additional adjustment applied at the draft was based on the average difference between the Electricity, Gas, Water and Waste Services LCI ('EGWW', red line in Figure C4) and the all-industries LCI ('All industries', grey dotted line) over the period 2019-2023.

C434 Given the lack of information about breakdown of EDB-specific cost drivers (such as particular inputs like information technology or traffic management services, or particular categories of labour) we have not been able apply a more targeted approach.

Figure C4 Comparison of all-industries LCI and EGWW LCI change[135]



C435 Table C16 shows LCI and PPI forecasts, expressed as real price effects relative to CPI forecasts, and the opex cost escalator forecast after taking their 60/40 weighted average and including the 0.3% additional adjustment.

[135] Four-quarter average change, per StatsNZ.

Table C16 Opex cost escalator values and components [136]

Index	2025	2026	2027	2028	2029	2030
CPI	2.5%	2.3%	2.0%	2.0%	2.0%	2.0%
LCI RPE	1.1%	-0.3%	-0.3%	-0.1%	0.0%	0.1%
PPI RPE	1.4%	0.7%	0.7%	0.6%	0.5%	0.5%
EDB specific adj.	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Opex cost escalator	**4.0%**	**2.7%**	**2.4%**	**2.5%**	**2.5%**	**2.6%**

Consideration of OEA submission to change network opex cost escalation

C436 Orion, Vector and Wellington Electricity (OVW) jointly submitted on the topic of cost escalation[137] and commissioned an expert report by Oxford Economics Australia (OEA).[138] OVW submitted we replace the non-labour part of network opex with their suggested change to capex cost escalation, All-Groups CGPI + 3.1% per annum. We considered their suggestions sequentially.

C437 Our final capex **decisions C3 and C6** are to retain our draft approach to escalate capex as All-Groups CGPI + 0.8%.[139] Having made these decisions, we then considered and decided not to adopt the OEA approach to align the non-labour component of network opex cost escalation with capex cost escalation.

C438 In reaching this decision, we reviewed information disclosure (ID) data for insights on opex cost breakdowns and, in particular, what fraction of non-labour input costs for network opex relate to electrical materials costs and other in-field costs like plant and traffic management.

C439 The network opex categories in ID data are: (1) ARR, asset replacement and renewal; (2) VM, vegetation management (3) RCM, routine and corrective maintenance and inspection, and (4) SIE, service interruptions and emergencies.

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[136] RBNZ forecast CPI, August 2024 Monetary Policy Statement. NZIER forecast LCI and PPI, 5 September 2024. Real price effect RPE is index growth above general inflation (CPI). Opex cost escalator = 60% LCI + 40% PPI + 0.3% per annum is equivalent to CPI + 60% x (LCI RPE) + 40% x (PPI RPE) + 0.3% per annum.

[137] Orion, Vector, Wellington Electricity "Cost escalators - Submission on EDB DPP4 draft decisions" (8 July 2024)

[138] OEA "New Zealand Electricity Distribution Businesses Labour and Material Cost Escalation" (report prepared for Orion, Vector, Wellington Electricity, June 2024)

[139] See **Attachment B**, sections on **decisions C3 and C6** for discussion on these decisions.

C440 The category that most closely captures non-labour input costs is ARR, which constitutes about 7% of total network opex spend over the past five years. As such, the relative magnitude of 'asset replacement and renewal' is not a compelling factor in considering a change to the reference index as suggested by OEA.

C441 More generally, our approach to opex escalation is to assess an overall view of cost escalation rather than determining specific cost escalators for each EDB cost category. Such an approach would add complexity and risk overcompensating or undercompensating for inflation.

C442 We are satisfied our approach remains appropriate: to escalate both network and non-network opex with a 60/40 weighting of LCI and PPI indices (as at the DPP2 and DPP3 resets) plus an additional adjustment of 0.3% per annum. Submissions were also broadly supportive of this approach as well as the 0.3% per annum adjustment.

Stakeholder views on draft decision

C443 There was broad support of the draft decisions to escalate all opex costs (draft decision O4.1) with a 60/40 split of All-Industry Labour Cost Index (LCI) and Producers' Price Index (PPI) with a 0.3% per annum additional adjustment (draft decision O4.2).

C444 Powerco supported these draft decisions, including the 0.3% per annum adjustment:[140]

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

C445 Aurora and EA Networks supported the approach but considered the 0.3% per annum adjustment may not adequately compensate for future cost pressures.[141,142]

C446 In their combined submission, Orion, Vector and Wellington ("OVW") reiterated the views in the OEA report they jointly commissioned:[143]

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[140] Powerco "Submission on EDB DPP4 draft decisions" (12 July 2024), p 13.

[141] Aurora Energy "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 11.

[142] EA Networks "Submission on EDB DPP4 draft decisions" (12 July 2024), p. 3.

[143] Orion, Vector, Wellington Electricity "Cost escalators - Submission on EDB DPP4 draft decisions" (8 July 2024), p. 6.

C446.1 While the OEA report focused on the capex adjustment, they also argued for a change in network opex cost escalation.

C446.2 For non-network opex, they supported the draft approach as above, including the level of the 0.3% per annum adjustment.

C446.3 For network opex, they argued for a change in the non-labour component to be in line with their proposal for capex cost escalation:

Network Opex cost escalation = 60% x (LCI + 0.3%) + 40% x (All-Groups CGPI + 3.1%)

C447 OVW argued that non-labour inputs for network opex are either electrical materials costs or other in-field costs like plant and traffic management. They noted that this portion of network opex cost aligns better with non-labour inputs for capex. This is because non-labour inputs for non-network OPEX are items that are related to office-based activities, like IT, insurance, and the costs of operating a building.[144]

C448 The only relevant cross submissions were from Aurora and ENA. Aurora restated that their "… primary concern is that the proposed cost escalators will lead to opex allowances that are insufficient for EDBs to maintain safe and reliable operations without incurring IRIS penalties."[145] ENA cited the OEA report as evidence that the 0.3% per annum adjustment should at a minimum be maintained or increased.[146]

Stakeholder views on the DPP4 issues paper

C449 In its submission on the DPP4 Issues paper ENA expressed qualified support for retaining the all-industries approach:[147]

> [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
>
> […]

[144] Orion, Vector, Wellington Electricity "Cost escalators - Submission on EDB DPP4 draft decisions" (8 July 2024), p. 6-7.

[145] Aurora Energy "Cross-submission on EDB DPP4 draft decisions" (2 August 2024), p. 2.

[146] Electricity Networks Aotearoa (ENA) "Cross-submission on EDB DPP4 draft decisions" (2 August 2024) , p. 2.

[147] Electricity Networks Aotearoa (ENA) "Submission on DPP4 Issues paper" (19 December 2023), pp. 12, 15.

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.

C450 Similarly, Wellington Electricity submitted:[148]

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.

C451 Powerco and Unison supported using or exploring an EDB-specific escalation approach.[149] No submission put forward cost groupings that would better match EDB input costs.

Decisions on productivity

O6.1 Apply an opex partial productivity factor of 0%

Problem definition

C452 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 subset of inputs, in our case those captured by opex.

C453 The core of the base, step, and 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.

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[148] Wellington Electricity "Submission on DPP4 Issues paper" (19 December 2023), pp. 28, 31-32.

[149] Powerco "Submission on DPP4 Issues paper" (19 December 2023), p 15; Unison "Submission on DPP4 Issues paper" (19 December 2023), p. 15.

C454 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.

C455 The final decision on opex PFP will inform the 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.

C456 As indicated in the base, step, and trend overview above in paragraph C4, an opex PFP is applied as a factor of (1- opex PFP). A negative opex PFP is associated with a trend of lower productivity and gives rise to an increase in opex allowances. Conversely, a positive opex PFP is associated with increasing productivity (or a 'productivity target') and a decrease in opex allowances.

Final decision

C457 Our final decision is to apply an opex partial factor productivity of 0%. This is the same as our draft decision.

Alternatives considered

C458 In addition to an 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

C459 Within the base, step, and 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.

C460 Our forward view of productivity should reflect economy and sector-wide improvements, to ensure the base, step, and trend approach delivers an efficient baseline. The decision is ultimately an exercise in judgement, informed by context, historical evidence, and other decisions within the DPP.

C461 We have not sought to directly forecast productivity from analysis of EDBs historical outputs and costs. In part, this is because of the potential to create a perverse incentive because the productivity factor can create a circularity, where lower productivity leads to higher allowances, which feed through to future resets.

C462 In DPP3, we determined an opex productivity factor of 0%, based on historical trends in the electricity distribution sector (both domestically and in other jurisdictions) and in comparable sectors.[150] We did not undertake a full historical productivity study.

C463 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.[151]

C464 In our analysis to inform our final decision for DPP4, we have considered evidence from:

C464.1 the results from CEPA's study of historical productivity changes;

C464.2 comparisons to other similar sectors of the economy and the economy as a whole;

C464.3 recent studies in other jurisdictions; and

C464.4 the potential impact of other DPP4 decisions.

C465 We have also highlighted factors which, if weighted differently in exercising judgement, could support a higher or lower productivity factor.

C466 In this analysis, we have most heavily weighted:

C466.1 the trends in some comparable infrastructure sectors and overseas (and tentatively in the domestic EDB sector), supporting a positive productivity factor; and

C466.2 the future prospect of opex-capex substitution driving higher overall productivity but lower opex productivity, supporting a negative productivity factor.

C467 The overall findings from the evidence are summarised in Table C17 below.

C468 Overall, we consider these factors broadly balance out.

[150] 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.

[151] Economic Insights "Electricity Distribution Industry Productivity Analysis 1996-2013" (24 June 2014); CEPA "(FINAL) EDB Productivity report: A report prepared for the Commerce Commission" (24 June 2024)

Table C17 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

C469 Our primary source of evidence is the results from a historical productivity study undertaken by CEPA. Our draft decision referred to the draft report from CEPA.[152] Following consultation on this report, CEPA submitted a final report, the results of which we refer to below. In their final report CEPA note changes in response to stakeholder and Commission feedback, but also note that "none of which changes our overall findings".[153]

C470 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 reasonable to expect over the next five years.

[152] CEPA "(DRAFT) EDB Productivity Study" (report prepared for the Commerce Commission, 26 March 2024).

[153] CEPA "(FINAL) EDB Productivity Study" (report prepared for the Commerce Commission, 24 June 2024), p 10.

C471 Figure C5 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 scale factors for DPP4 network opex models. In terms of broad trends, model choice does not materially impact any conclusions, as they show a similar pattern. The average trends across all models except the outlying Model 5 (which includes reliability) are: [154]

C471.1 an overall decline (averaging -1.1% per year) since the start of the study period;

C471.2 a comparatively slower (-0.6%) decline over the DPP0 and DPP1 periods (2008-2015);

C471.3 a sharp decline (-2.2%) over DPP2 (2016-2020); and

C471.4 a flattening trend (+0.2%) over DPP3 (2021-2023).

[154] 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. Submissions on the draft CEPA report agreed that including reliability was problematic. See CEPA "(FINAL) EDB Productivity Study" (report prepared for the Commerce Commission, 24 June 2024), p. 8-9 and p. 34-36.

Figure C5 PQ-regulated EDB opex partial productivity - final CEPA study

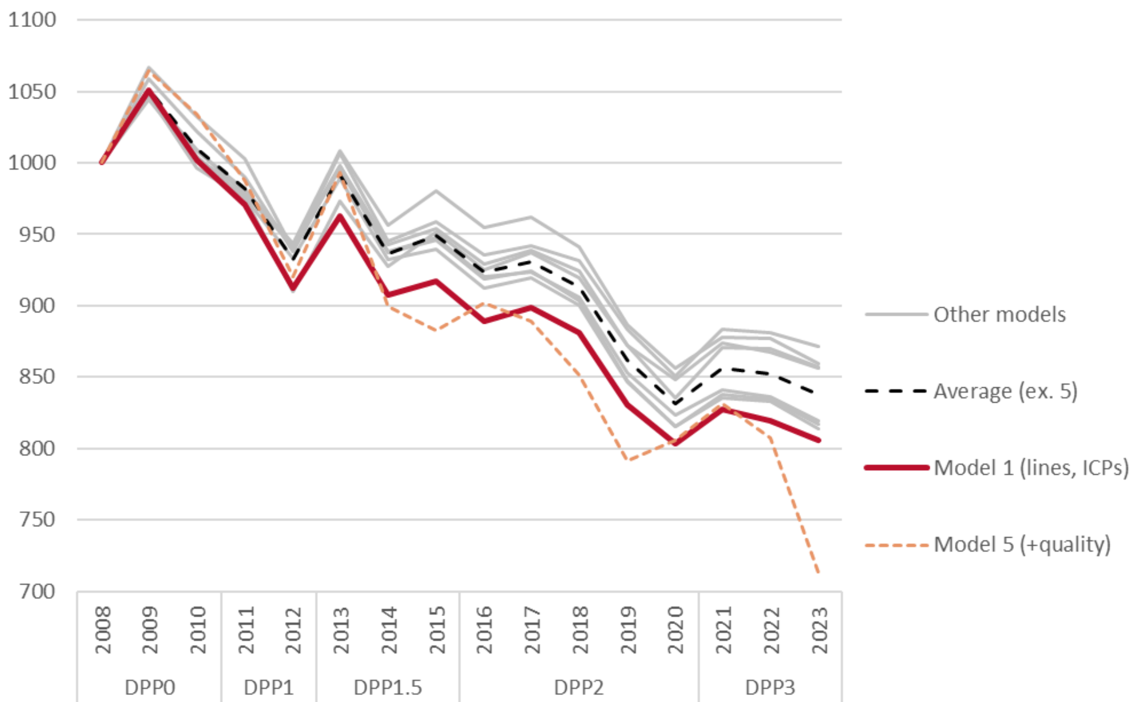
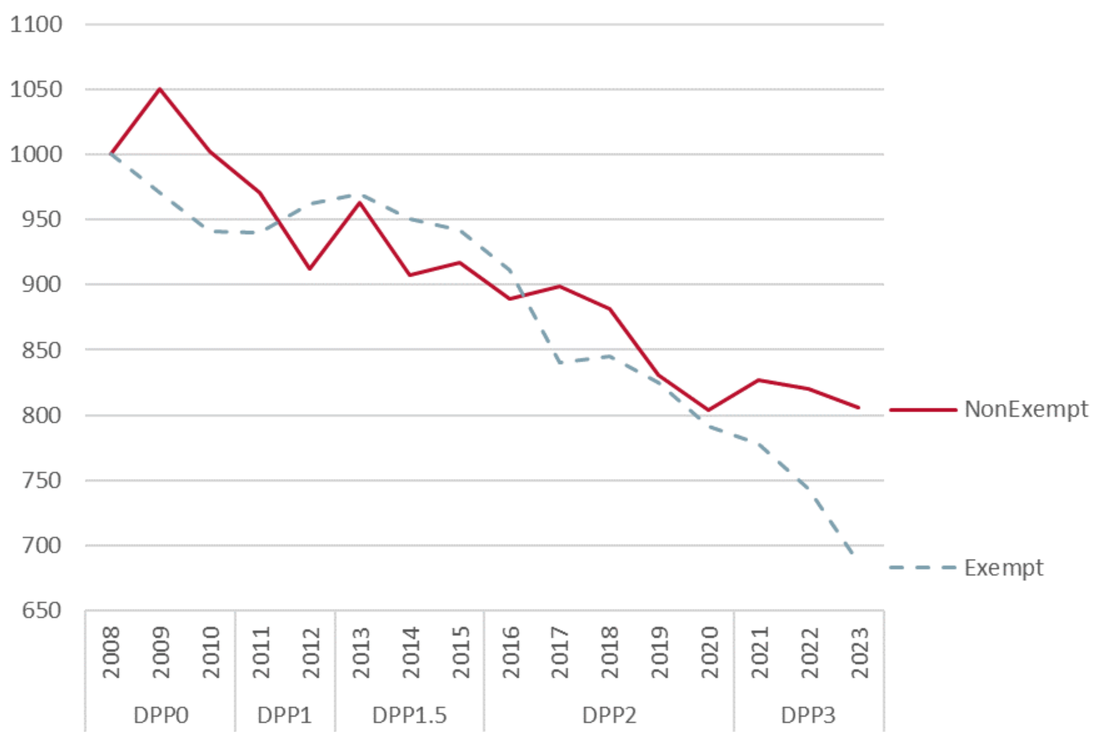
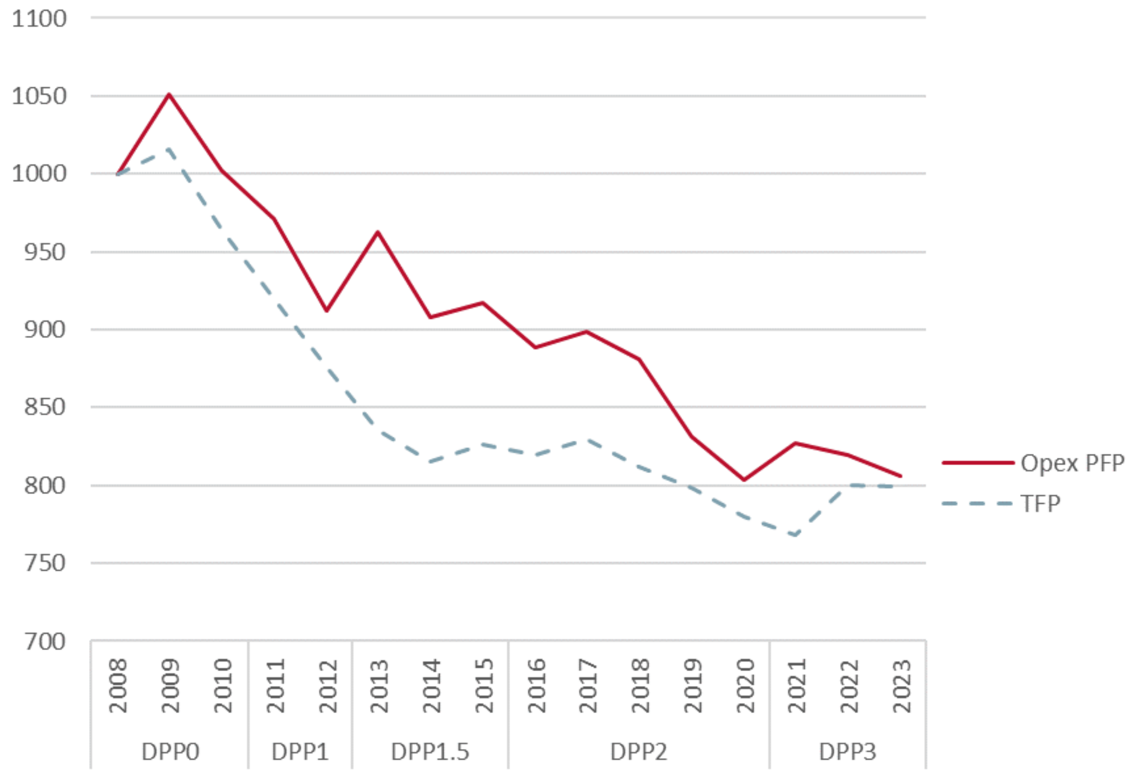


Figure C6 PQ-regulated EDB opex partial productivity - final CEPA study Model 1



C472 However, the more recent trend suggests these factors may be slowing. As Figure C6 shows, this is especially the case for non-exempt EDBs (ie, PQ-regulated EDBs who are subject to the cost-control incentives created by PQ-regulation) over DPP3 when a 0% PFP was applied.

Figure C7 PQ-regulated TFP vs opex PFP (Model 1) – CEPA study



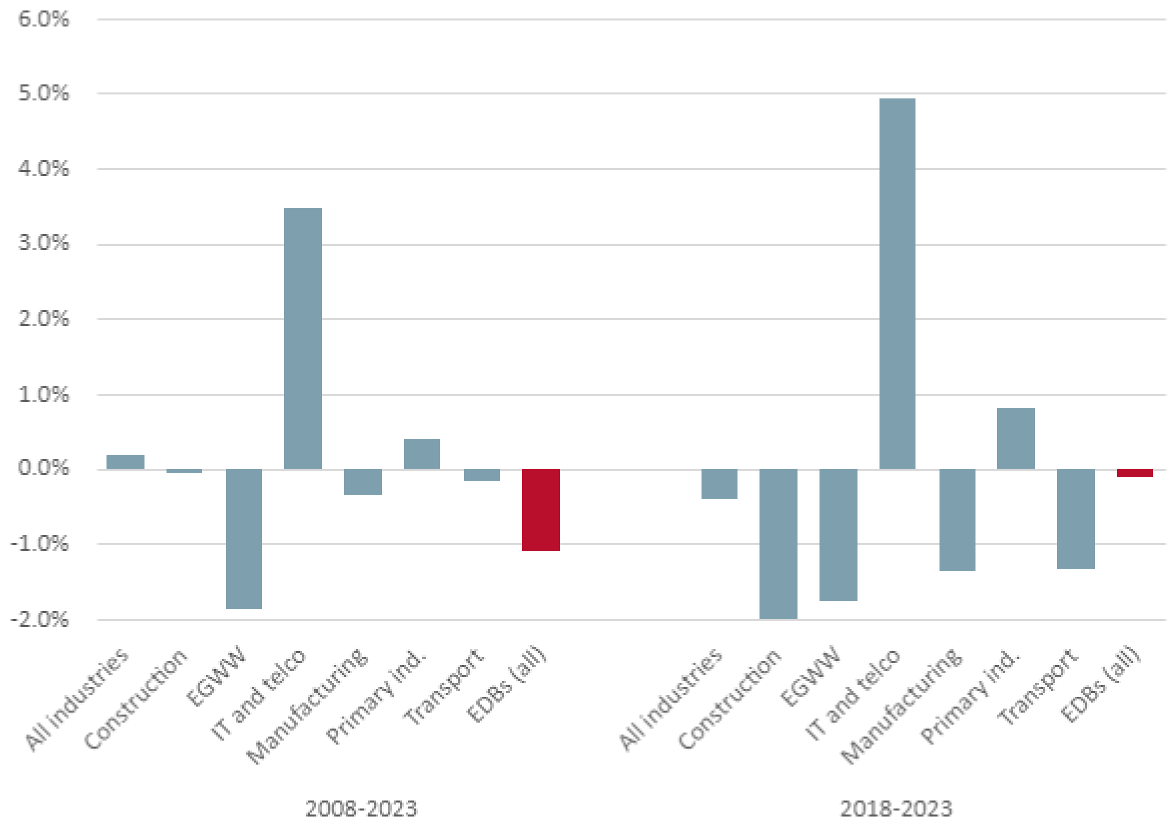
C473 We have also considered the relationship between opex PFP and TFP, because our goal is to promote improvements in overall efficiency. A focus on opex PFP exclusively (with a reducing opex allowance) risks creating or reinforcing a bias on EDBs' part towards capital investment.

C474 As shown in Figure C7, 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

C475 Figure C8 shows a comparison of total factor productivity (TFP) by sector in New Zealand, using data from the CEPA report and StatsNZ.

Figure C8 Average change in industry TFP 2008-2023 – StatsNZ[155]



C476 TFP for the EDB sector has declined while productivity in the overall economy (ie, All industries in Figure C8) has modestly increased over the medium term (CEPA's study period, 2008-2023, +0.2% for all industries 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% for all industries vs -0.1% for EDBs).

[155] EDB data sourced from CEPA 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.

C477 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 in the future.[156]

C478 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.

Comparisons with overseas jurisdictions

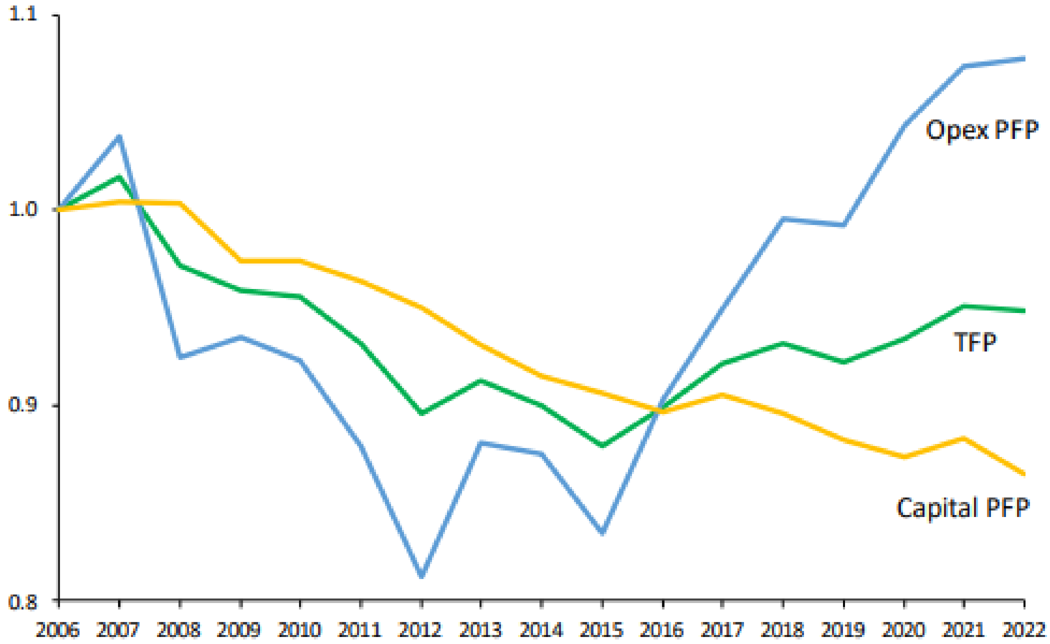
C479 The Australian Energy Regulator (AER) publishes annual benchmarking reports that include sector-wide productivity analysis. As shown in Figure C9, Australian EDBs experienced a similar decline in opex productivity up to 2015 but have seen a sharp improvement since then. Caution should be exercised 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.[157]

C480 While there are differences between the operating and regulatory environments in Aotearoa and Australia, the improving trend Australia has experienced suggests that declining productivity is not inherent to electricity distribution as a sector.

[156] For example, Counties Energy "DPP4 Issues paper submission" (19 December 2023), pp. 1-2; Drive Electric "DPP4 Issues paper submission" (19 December 2023), p. 8; FlexForum "DPP4 Issues paper submission" (19 December 2023), p. 3; and Rewiring Aotearoa "Cross-submission on DPP4 Issues paper" (26 January 2024), p. 4.

[157] See: AER "Annual Benchmarking Report Electricity distribution network service providers" (23 November 2023) , p. 24.

Figure C9 Australian electricity distribution productivity trends [158]



Potential impact of other DPP4 decisions

C481 The most directly relevant other final decisions are those related to opex forecasting. We have also considered decisions on capex and innovation allowances.

Step changes

C482 Our final decisions include approving 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.[159]

C483 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.

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[158] AER "Annual Benchmarking Report Electricity distribution network service providers" (23 November 2023), p. 25.

[159] Submissions from Aurora Energy "DPP4 Issues paper submission" (19 December 2023), pp. 17-18; Wellington Electricity "DPP4 Issues paper submission" (19 December 2023), p. 32; Unison Networks "DPP4 Issues paper submission" (19 December 2023), p. 8.

C484 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

C485 For opex scale growth trend modelling, out final 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. The decision to not to include a time variable in our forecasts means there is no assumption about productivity implicit in our opex scale trend growth. This allows an independent decision on future productivity.

C486 These factors would support a lower productivity factor.

Cost escalation

C487 We have considered an EDB-specific set of cost escalators for DPP4. 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)

C488 Our final decision to adopt a strengthened and broadened INTSA scheme (relative to the DPP3 innovation project allowance) may mean:

C488.1 additional spend on new activities that would otherwise appear as declining productivity in the short term will instead be funded via INTSA; and

C488.2 over the longer-term, the innovations this scheme supports may drive improvements in EDB productivity (including opex productivity).

C489 Again, both these factors would support a higher productivity factor. However, the impact from innovations may not fully 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.

Stakeholder views on the draft decision

C490 The draft decision of a 0% opex partial productivity factor was widely supported in submissions, especially from EDBs and ENA who said:[160]

> ENA strongly supports the retention of the 0% opex partial productivity factor. The CEPA report and submissions on that report by ENA and others demonstrate that there is no evidence to support the application of a partial productivity factor.

C491 Unison supported a 0% opex PPF but commented that there was effectively a productivity target through the overall level of opex funding and unmeasured outputs. [161] They quoted NERA's findings of the Big Six review of CEPA's draft Productivity Study that “Put another way, the presence of uncompensated outputs in the allowance-setting process is essentially a form of productivity target.”[162]

C492 Wellington Electricity went further, by not supporting a 0% PPF and proposing a negative PPF: [163] "Alternatively, we think a negative productivity factor should be applied to reflect that not all opex costs have been captured."

C493 We do not agree with the proposition that there are material general opex costs that have not been captured by one of the base, step, or trend components of our model. Those which have not been included - for example declined step-changes – are ones where we are unable to adequately verify within the context of a low-cost DPP, and that we are not convinced EDBs will in fact incur. A 0% PPF results in opex forecasts that - in combination with the IRIS incentive scheme - maintain an inventive to continue to act prudently and efficiently, and strikes an appropriate balance between incentives to invest and to improve efficiency.

C494 Conversely, FlexForum submitted there was not enough in the draft decision to promote productivity gains: [164]

> We think the lack of productivity improvement over the past decade indicates that more effort is required to ensure distributors are focused on delivering the most reliable and affordable outcomes possible for households, businesses and communities. The proposed DPP settings are broadly similar to those applied over the past 15 years where productivity has fallen on average by about 1.4% a year

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[160] Electricity Networks Aotearoa (ENA) “Submission on EDB DPP4 draft decisions” (12 July 2024), p. 4.

[161] Unison Networks “Submission on EDB DPP4 draft decisions” (12 July 2024), p. 13.

[162] NERA "Implications of CEPA’s draft findings for the NZCC’s decisions on opex productivity for DPP4", prepared for Big 6 EDBs (24 April 2024), p. 26.

[163] Wellington Electricity “Submission on DPP4 Issues Paper” (19 December 2023), p. 33.

[164] FlexForum “Submission on EDB DPP4 draft decisions” (12 July 2024), p. 2.

between 2008 and 2023. Though the decline in productivity has slowed between 2014 and 2023, it has still been declining.

C495 The purpose of the PPF is not to promote efficiency/productivity gains. The opex IRIS and the gains/losses EDBs face for any improvements or declines in efficiency - including productivity - are what create the incentive.

Stakeholder views on the draft CEPA report

C496 Stakeholder submissions on CEPA's draft report were considered by the Commissions and - together with the Commission's own response - taken into account in CEPA's final report.

C497 In summary, CEPA reported the following change, resulting in minor changes to numerical results and no change in overall findings:

C497.1 average percentage growth rates in productivity now use geometric- not arithmetic means;

C497.2 correction of an issue with Vector's assets in 2020;

C497.3 correction of an issue with the treatment of the de-merger of Vector and Wellington in 2009; and

C497.4 an update in assumed cost of capital from 6.05% to 5.6%.

C498 EDB submissions on CEPA's draft report generally shared a view that the modelling results of declining productivity could not be relied upon. And that there was no clear indication of how much of the apparent decline in productivity is due to unmeasured outputs (for example: consent and regulation compliance, traffic management, safety resource consents, environment, social and governance (ESG), stakeholder engagement).

C499 These submissions, along with the CEPA study, were taken into account in our final decision on the productivity factor.

Stakeholder views on the DPP4 issues paper

C500 In terms of model choice, Aurora noted in its submission that the choice of output measures in our productivity analysis may exclude relevant factors:[165]

[165] Aurora "Submission on DPP4 Issues Paper", p. 18; supported by Unison "Cross-submission on DPP4 Issues Paper", p. 8; Orion "Cross-submission on DPP4 Issues Paper", pp. 16-17.

> 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.

C501 Similarly, Wellington Electricity also note:[166]

> … 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.

C502 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.

C503 In terms of time period, the ENA cautions against overreliance on the most recent trends:[167]

> 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.

C504 In terms of opex PFP and TFP, Vector highlighted "…adopting dynamic efficiency rather than static efficiency as a means of reviewing suppliers' productivity performance."[168]

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[166] Wellington Electricity "Submission on DPP4 Issues Paper" (19 December 2023), p. 32.

[167] ENA "Submission on DPP4 Issues Paper" (19 December 2024), p. 14.

[168] Vector "Cross-submission on DPP4 Issues Paper" (26 January 2024), p. 13.

Conclusion

C505 Our final decision is to apply an opex PFP of 0%. This is based on the balance of evidence from factors supporting a higher PFP and a lower PFP, as well as our consideration of matters raised in submissions on the DPP4 Issues paper and DPP4 Draft decisions paper.