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Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision

Reasons paper

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Associated documents

Publication date	Reference	Title
31 January 2019	ISSN 1178-2560	Electricity Distribution Services Input Methodologies Determination 2012 – Consolidated as of 31 January 2019
28 November 2014	ISBN 978-1-869454-12-8	Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main Policy paper
28 November 2014	[2014] NZCC 33	Electricity Distribution Services Default Price-Quality Path Determination 2015
9 November 2017		Our priorities for the electricity distribution sector for 2017/18 and beyond
14 June 2018	ISBN 978-1-869456-42-9	Default price-quality paths for electricity distribution businesses from 1 April 2020 – Proposed Process
23 August 2018	ISBN 978-1-869456-53-5	Proposed amendments to Electricity Distribution Services Input Methodologies Determination in relation to accelerated depreciation – Draft reasons paper
6 September 2018		Default price-quality paths for electricity distribution businesses from 1 April 2020 – Process Update Paper
8 November 2018	[2018] NZCC 19	Amendment to Electricity Distribution Services Input Methodologies Determination in relation to accelerated depreciation
15 November 2018	ISBN 978-1-869456-70-2	Default price-quality paths for electricity distribution businesses from 1 April 2020 – Issues Paper
29 May 2019	ISBN 978-1-869457-00-6	[DRAFT] Electricity Distribution Services Default Price-Quality Path Determination 2020
29 May 2019	ISBN 978-1-869456-98-6	Proposed amendments to Input Methodologies for electricity distributors and Transpower New Zealand Limited: Reasons paper
29 May 2019	ISBN 978-1-869456-99-3	[DRAFT] Electricity Distribution Services Input Methodologies Amendments Determination 2019
25 September 2019	ISBN 978-1-869457-63-1	Default price-quality paths for electricity distribution businesses from 1 April 2020 – Updated draft models – Companion Paper
7 October 2019	ISBN 978-1-869457-66-2	EDB DPP3 – Recording of successive interruptions for SAIFI
26 November 2019	ISBN 978-1-869456-71-6	Amendments to electricity distribution services input methodologies determination – Reasons paper
26 November 2019	[2019] NZCC 20	Electricity Distribution Services Input Methodologies Amendments Determination (No. 2)
27 November 2019	[2019] NZCC 21	Electricity Distribution Services Default Price-Quality Path Determination 2020

Commerce Commission
Wellington, New Zealand

Foreword

Our focus during the EDB DPP3 reset has been on providing a stable regulatory platform that makes incremental improvements, drawing on what we have learned across the Part 4 portfolio and on the expertise of stakeholders. At the same time, we have aimed to provide sufficient flexibility to accommodate increasing uncertainty and change across the distribution sector.

As we said at the outset of this process, our view was that we were setting DPP3 within the context of a maturing regulatory regime.

The 2020 reset is the third time we have reset prices and quality standards for the distribution sector, and the eighth price-quality path reset overall. The 2016 and 2017 review of the Input Methodologies had given us the opportunity to reconsider whether the fundamentals of economic regulation for the distribution sector remained fit for purpose. This process served to promote greater certainty for distributors and customers over the medium and long term, albeit at the cost of some short-term flexibility.

Over the reset process, our engagement with stakeholders and other factors confirmed for us that we were also setting DPP3 within a context of change.

The Electricity Price Review process gave all sector participants an opportunity to reflect on the performance of the sector as a whole. From the findings of the Review, and from the DPP consultation process, we came to see that the DPP3 period will likely involve significant change and heightened uncertainty.

Changes in the way consumers and other industry participants make use of distribution networks, innovations in the way distributors deliver services, electrification driven by decarbonisation, and the risk of increasingly severe weather events all have the potential to reshape investment needs and quality expectations in unpredictable ways.

Part of our response to this has involved ensuring the DPP does not impose barriers to positive changes for consumers. Implementing a revenue cap (as opposed to the previous price cap) will give distributors the flexibility to price in ways that offer more choice to consumers and that enhance incentives for energy efficiency and demand-side management. At the same time, the revenue cap will give distributors greater certainty about revenue recovery.

Introducing reopeners for significant unforeseen or uncertain capital expenditure projects will allow distributors to undertake investments in response to changing conditions without risking capital under-recovery.

Ultimately, it is distributors who will have to respond to these changes while delivering outcomes for their consumers. Our role is to create incentives for them to do so in a way that promotes the long-term benefit of those consumers.

Equalising the retention factors for operating and capital expenditure – while seemingly a detailed technical change – gives distributors an better incentive to find the most efficient solution to meet their customers’ needs, regardless of the form it takes.

While the regime already provided incentives for innovations that improve the efficiency and the quality of distribution services, and distributors are already delivering a range of innovations, we have bolstered these incentives for DPP3. We anticipate that the innovation project allowance will encourage distributors to try new ways of doing business where they might not otherwise have done so.

Quality of service incentives have also been a major focus for us. Based on the evidence we have, we concluded that a 'no material deterioration' approach remained the right one. Aligning reliability incentives to the value consumers place on reliability frees distributors (within certain bounds) to target the level of reliability and of price that best meets the expectations of their consumers. Additionally, our new approach to normalisation is intended to prevent the effects of severe storms being mistaken for signs of deterioration.

The most obvious change for DPP3, the reduction in the weighted-average cost of capital, is not one that results from our DPP3 decisions, but instead reflects the current state of the broader economy. Record low global interest rates have led to lowered profitability expectations across many sectors. Given the purpose of our regime is to promote outcomes that are consistent with competitive markets, it is appropriate that distribution consumers market share in the benefits of a lower cost of capital through lower prices.

As we look forward, it is worth remembering that the DPP is only one of the tools we have to influence the performance of the distribution sector. At its core, the DPP provides a 'one-size-fits most' approach, based on historic levels of price and quality.

Where distributors either want to make substantial changes to the quality of the services they deliver (including the way they deliver them) or need to make substantial investments to maintain quality over and above 'business as usual', customised paths provide a key opportunity for individual distributors to have alternative price-quality paths that better meet their particular circumstances.

Finally, we would like to thank all stakeholders for the constructive ways they have engaged in the reset process. Through workshops, working groups, and targeted consultation processes, the decisions we present here are all the better for your involvement.

Kind regards

Sue Begg
Deputy Chair

John Crawford
Associate Commissioner

Stephen Gale
Commissioner

Elisabeth Welson
Commissioner

Contents

EDB DPP3 at a glance

Change relative to draft decision

Unchanged from draft	Update or change to input	Change of policy	New measure

#	Policy measure
Price path	
P1	Set starting prices based on the current and projected profitability of each supplier using a BBAR model.
P2	Set a default rate of change (X-factor) of CPI-0%.
P3	Do not set an alternate X-factor for Aurora Energy.
P4	Do not set starting prices for suppliers currently on CPPs (Powerco, Wellington Electricity).
P5	Set a single CPP application date in June of each year, except 2024 (29 March).
Operating expenditure	
O1	Retain the base, step, and trend approach to opex.
O2	Use actual opex from year 4 of the current DPP period (2019) as the base year.
O3	Treat Fire and Emergency New Zealand levies as a recoverable cost.
O4	Forecast scale growth for network opex using line length (with an elasticity of 0.4470) and ICP growth (0.4886).
O5	Forecast scale growth for non-network opex using line length growth (0.2185) and ICP growth (0.6525).
O6	Forecast line length growth using an extrapolation of historical growth.
O7	Forecast ICP growth using StatsNZ forecasts of household growth.
O8	Inflate opex using a weighted average of the all-industries LCI (60%) and PPI (40%).
O9	Apply an opex partial productivity factor of 0%.
O10	Apply a negative step changes to reflect IM decisions regarding pecuniary penalties and operating leases.
Capital expenditure	
C1	Forecast capex using distributor 2019 AMP forecasts.
C2	Forecast capex at a category level.
C3	Apply scrutiny checks to major categories of capex (consumer connection, system growth, asset renewal, RS&E).
C4	Cap non-network and asset relocations capex at the higher of a 120-200% 'sliding scale' cap and $1 million.
C5	Cap aggregate capex at 120% of historical level.
C6	Use 2013-2019 as the historical reference period for assessment.
C7	Do not apply a test of distributors' historical accuracy in forecasting expenditure on assets.
C8	Assess system growth capex in combination with consumer connection capex.
C9	Assess connection and growth capex against household growth and historical ICP growth.
C10	Assess per-ICP connection and growth capex against historical levels.
C11	Assess replacement and renewal capex against forecast depreciation.
C12	Inflate capex using the all-industries CGPI.
C13	Exclude forecast capital contributions from forecast capex.
C14	Include an allowance for cost of financing, scaled based on proportion of accepted capex.
C15	Include AMP forecasts of the value of vested assets.
C16	Exclude operating leases when scrutinising AMP forecasts, consistent with IM decisions

Change relative to draft decision

Unchanged from draft | Update or change to input | Change of policy | New measure

#	Policy measure
	Other inputs to the financial model
M1	Weighted average cost of capital (WACC) of 4.57%.
M2	Include an allowance for disposed assets, based on historical levels.
M3	Do not forecast constant-price revenue growth.
M4	Do not forecast other regulated income.
	Accelerated depreciation
A1	Assess distributor applications for accelerated depreciation against the IMs and Part 4 purpose.
A2	Decline Vector's application.
	Efficiency incentives
I1	Set the capex retention factor equal to the opex retention factor (~23.5%).
I2	Amend the opex IRIS IMs to correct for calculation errors.
I3	Do not amend DPP2 IRIS incentives to account for undercharging.
I4	Do not amend DPP2 IRIS opex incentives to account for spur asset expenditure.
I5	Do not amend DPP2 IRIS opex incentives to account for pecuniary penalties.
	Innovation and uncertainty
U1	Introduce major capex project reopeners for connections, asset relocations, and system growth.
U2	Introduce an innovation allowance recoverable cost, capped at the higher of 0.1% of revenue and $150,000.
U3	Remove the Energy Efficiency and Demand-side management incentive (D-Factor).
U4	Do not introduce a reduction of losses incentive.
	Revenue path
R1	Apply a revenue cap with wash-up as the form of control.
R2	Apply an NPV neutral 10% limit on the annual increase in forecast revenue from prices.
R3	Apply a 90% "voluntary undercharging" limit (or an alternative limit in some cases).
R4	Allow distributors to agree a reasonable reallocation of revenue following an asset transfer.
	Quality standards
QS1	Separate standards for planned and unplanned SAIDI and SAIFI.
QS2	Annual unplanned reliability standards for SAIDI and SAIFI.
QS3	Set unplanned reliability standard at 2.0 standard deviations higher than the historical average.
QS4	Remove the 2-out-of-3 rule for planned and unplanned standards.
QS5	Regulatory period length standard for planned SAIDI and SAIFI.
QS6	Planned outage standard at three times the historical average.
QS7	Introduce SAIDI extreme event standard set at 120 SAIDI minutes or 6,000,000 customer minutes where specified.
QS8	Introduce enhanced automatic reporting following a breach of a quality standard.
QS9	Add a new “notified planned interruption” with further de-weighting in the incentive scheme (revised criteria).
QS10	Set quality standards and incentives for distributors on CPPs (Powerco and Wellington Electricity).
QS11	Allow distributors to agree a reasonable reallocation of SAIDI and SAIFI parameters following an asset transfer.

Change relative to draft decision	Unchanged from draft	Update or change to input	Change of policy	New measure

#	Policy measure
Quality incentives	
QI1	Retain the revenue-linked quality incentive scheme for SAIDI.
QI2	Remove the revenue-linked quality incentive scheme for SAIFI.
QI3	Incentive rate based on VoLL ($25000/MWh), discounted for IRIS and effect of quality standards (to $5288/MWh).
QI4	Further discount the incentive rate for planned interruptions by 50% (to $2644/MWh).
QI5	Set the SAIDI target for the incentive scheme at the historical average.
QI6	Set the SAIDI cap for the incentive scheme at the compliance standard.
QI7	Set the SAIDI collar for the incentive scheme at zero.
QI8	Determine revenue at risk *endogenously*, but set a combined planned-unplanned cap of 2% of total revenue.
Reliability reference period	
RP1	For planned interruptions, use a 10-year reference period from 2009-2018.
RP2	For unplanned interruptions, use a 10-year reference period from 2009-2018.
RP3	Cap the inter-period movement in unplanned reliability targets and limits at ±5%.
RP4	Make no explicit step changes to reliability targets or incentives.
RP5	No disaggregation of reliability by region or customer type.
RP6	Defer any change to reliability information disclosures.
RP7	Require distributors to report SAIDI and SAIFI treating successive interruptions as they did for 2019 in the 53ZD
Reliability normalisation	
N1	Only normalise unplanned interruptions.
N2	Define a major event as 24-hour rolling periods (assessed in 30-minute blocks).
N3	Set the major event boundary as the 1104th highest 24-hour rolling period in the reference dataset.
N4	Replace the SAIDI/SAIFI value for half hours outside $1/48^{th}$ of the event boundary with the $1/48^{th}$ boundary value.
N5	SAIDI and SAIFI major events are triggered independently.
N6	Set a higher boundary for very small distributors.
N7	Introduce enhanced major event reporting requirements.
Other measures of quality of service	
OQ1	Do not introduce new compliance measures for quality of service.
OQ2	Do not introduce new revenue-linked incentives for quality of service.
OQ3	Explore options during DPP3 for introducing customer-facing measures in DPP4.
OQ4	Consider changes to Information Disclosure (separate workstream to the DPP).

Executive Summary

Purpose of this paper

X1 This paper sets out the default price-quality paths (DPP) for non-exempt electricity distribution businesses (distributors) from 1 April 2020 (DPP3). It also explains the changes we have made to these decisions since the draft in response to the submissions we have received throughout the consultation process.

X2 This summary sets out:

X2.1 the key decisions we have made on prices and on quality;

X2.2 the purpose and context that help explain these decisions; and

X2.3 our high-level approaches to the main components of the DPP:

X2.3.1 starting prices,[1] including forecasts of operating (opex) and capital expenditure (capex);

X2.3.2 the revenue path and incentives during the DPP3 period; and

X2.3.3 quality standards and incentives.

X3 In summarising these decisions, it also highlights areas of significant change relative to the draft decision.

Key decisions

X4 When setting a DPP, we must determine:

X4.1 the 'price path' (shown in Table X1) composed of:

X4.1.1 'starting prices' – the net allowable revenues each distributor can earn in the first year of the period; and

X4.1.2 the rate of change in revenues each distributor can charge over the DPP period; an

X4.2 the quality standards each distributor must meet (shown in Table X2).

[1] While the term used in section 53M of the Act is "prices", the Act defines 'prices' as including revenues, and allows us to set a revenue cap. In DPP3, distributors will be subject to a revenue cap, so we will generally refer to "revenues" in this document for the sake of clarity.

X5 We may also determine incentives for distributors to maintain or improve the quality of service they deliver, and the ways in which distributors must demonstrate compliance with the price-quality path.

X6 Across the 15 distributors currently subject to the DPP, we have set a net revenue allowance of $1.01 billion in the first year of the DPP3 period. This is an overall decrease of 6.7% relative to allowances in the final year of DPP2.

Table X1 Starting prices and rate of change for DPP3

Distributor	Allowable revenue in 2020/21 ($m)	Rate of change (relative to CPI)
Alpine Energy	42.65	0.00%
Aurora Energy	87.33	0.00%
Centralines	9.37	0.00%
EA Networks	33.26	0.00%
Eastland Network	24.03	0.00%
Electricity Invercargill	12.26	0.00%
Horizon Energy	23.91	0.00%
Nelson Electricity	5.50	0.00%
Network Tasman	26.45	0.00%
Orion NZ	158.50	0.00%
OtagoNet	25.78	0.00%
The Lines Company	34.71	0.00%
Top Energy	38.01	0.00%
Unison Networks	100.02	0.00%
Vector Lines	388.71	0.00%

X7 Over the DPP3 period, this equates to total revenue allowances of $5.2 billion in nominal terms. This is an increase in nominal terms of 2% above DPP2 revenue allowances. The allowance for DPP3 incorporates opex allowances of $2.1 billion over the period, and capex allowances of $2.5 billion.

Table X2 Quality standards for DPP3

Distributor	Unplanned SAIDI (1-year)	Unplanned SAIFI (1-year)	Planned SAIDI (5-year)	Planned SAIFI (5-year)	Extreme event[2] (per event)
Alpine Energy	124.71	1.1970	824.87	3.4930	120 SAIDI
Aurora Energy	81.89	1.4687	979.80	5.5385	6 mil CIM
Centralines	83.61	3.1616	1064.46	5.8573	120 SAIDI
EA Networks	91.98	1.2826	1376.08	4.8939	120 SAIDI
Eastland Network	219.46	3.1525	1290.68	7.4745	120 SAIDI
Electricity Invercargill	25.86	0.6956	114.49	0.5183	120 SAIDI
Horizon Energy	194.53	2.3904	858.63	5.4415	120 SAIDI
Nelson Electricity	19.60	0.4277	180.11	2.3663	120 SAIDI
Network Tasman	101.03	1.1956	1129.14	4.9021	120 SAIDI
Orion NZ	84.71	1.0336	198.40	0.7481	6 mil CIM
OtagoNet	160.35	2.4172	2114.43	9.6212	120 SAIDI
Powerco	180.25	2.2684	772.50	3.5113	6 mil CIM
The Lines Company	181.48	3.2715	1331.68	8.7527	120 SAIDI
Top Energy	380.24	5.0732	1905.36	7.7526	120 SAIDI
Unison Networks	82.34	1.8152	625.79	4.4649	6 mil CIM
Vector Lines	104.83	1.3366	585.38	2.8783	6 mil CIM
Wellington Electricity	39.81	0.6135	69.70	0.5536	6 mil CIM

How we regulate price and quality under Part 4

X8 We must reset the current DPP for distributors that are subject to price-quality regulation under Part 4 of the Commerce Act 1986 (the Act) four months before the end of the current DPP period. Part 4 provides for regulation in markets in which there is little or no competition, and little or no likelihood of a substantial increase in competition.

X9 We last reset the current EDB DPP in November 2014. The current DPP specifies the price path and quality standards that distributors must comply with during the regulatory period from 1 April 2015 to 31 March 2020 (DPP2).

X10 From 1 April 2020, distributors will be subject to new requirements set out in the DPP determination. The distributors we regulate using price-quality regulation, both DPPs and customised price-quality paths (CPPs), are set out in Table X3 below.

[2] These figures are indicative only. The extreme event standard is specified in either SAIDI minute and customer interruption minute (CIM) terms. Distributors for which the customer interruption minutes is applicable we have converted to a SAIDI equivalent. This is discussed in more detail in Attachment L.

Table X3 Distribution businesses subject to price-quality regulation

Distributors subject to the DPP			
Alpine Energy	Aurora Energy[3]	Centralines	Eastland Network
EA Networks	Electricity Invercargill	Horizon Energy	The Lines Company
Network Tasman	Nelson Electricity	Orion NZ	OtagoNet JV
Top Energy	Unison Networks	Vector Lines	
Distributors subject to a CPP			
Powerco (ends 2023)	Wellington Electricity (ends 2021)		

We must promote the purpose of Part 4 when regulating price and quality

X11 Through regulating price and quality, our purpose is to promote the long-term benefit of consumers of electricity distribution services. To do this, we focus on promoting outcomes that are consistent with outcomes produced in competitive markets, such that distributors have incentives to innovate, invest, improve efficiency, and to provide services at a quality that reflects consumer demands.[4]

X12 We also aim to ensure the benefits of efficiency gains are shared with consumers (including through lower prices) and to limit the ability of distributors to earn excessive profits.

X13 The statutory framework we must apply, and the other principles we use when setting a DPP are discussed in more detail in Chapter 3.

We are setting DPP3 in an evolving industry context

X14 A key goal of our DPP3 reset is to provide a stable regulatory platform within a changing industry context, while making incremental improvements to the way we regulate price and quality.

X15 On the one hand, to promote the stability of the Part 4 regime, we have generally retained approaches from DPP2 where they remain fit for purpose. This includes setting revenue allowances based on current and projected profitability and setting quality standards with reference to historical levels of performance.

X16 On the other hand, we recognise that substantial changes are occurring in the electricity sector. In part, this is driven by an increasing focus on decarbonisation and by the increasing affordability of technologies that provide both distributors and consumers with new opportunities. However, we recognise that there is uncertainty as to the extent, timing, and impact of these changes.

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3 Aurora Energy have indicated that it will apply for a CPP that is intended to begin 1 April 2021. Aurora will remain on the DPP until that point.

4 Commerce Act 1986, section 52A.

X17 As such, we have made changes to the DPP3 settings where we consider that change will better promote the long-term benefit of consumers, consistent with the purpose of Part 4.

X18 Examples of such changes include:

X18.1 allowing reopeners for some major capex projects (such as new sources of demand or generation, or relocation of distribution assets to respond to other infrastructure projects) as it will create better incentives for distributors to make these investments;

X18.2 equalising the incremental rolling incentive scheme (IRIS) incentive rates for opex and capex, to reduce or remove barriers to innovation;

X18.3 introducing a targeted innovation project allowance, to improve the incentives distributors have to innovate; and

X18.4 refining our approach to normalising major interruptions, to reduce the impact on reliability incentives due to the frequency of major events, and creating clearer incentives for distributors to manage the underlying quality they deliver.

X19 We discuss our view of changes in the electricity sector, and our responses to them, in Chapter 4.

Starting prices

X20 This section explains:

X20.1 our high-level approach to setting starting prices;

X20.2 the drivers of change in net allowable revenue, relative to net allowable revenue in DPP2; and

X20.3 the key decisions (on expenditure and accelerated depreciation) that inform them.

X21 It also sets out significant changes relative to our draft DPP3 decision, and the impacts these have on allowable revenue.

X22 Our approach to starting prices is discussed in more detail in Chapter 5.

How we approach setting starting prices

X23 'Starting prices' refer to the revenue distributors can earn in the first year of a regulatory period. The starting prices for each distributor are set out in Table X1 above.

X24 We have set allowable revenues based on the current and projected profitability of each distributor. To do this, we add together forecasts of each distributor's over the DPP3 period ('building blocks allowable revenue' or 'BBAR'). We then spread this revenue out over the period such that they increase at a consistent rate of forecast CPI-X, resulting in the 'maximum allowable revenue' (MAR).

X25 The maximum gross revenue each distributor can recover in each year is: MAR for each year, plus an allowance for any pass-through and recoverable costs. References in this decision paper to 'allowable revenues' and 'net allowable revenues' are to annual maximum revenues net of pass-through and recoverable costs. References to 'gross allowable revenues' include pass-through and recoverable costs.

X26 Setting revenue limits means that profitability depends on the extent to which distributors control costs. Actual costs may differ from allowances for a variety of reasons, but in any case, the incentive to increase profits creates an incentive for distributors to improve efficiency, consistent with section 52A(1)(b) of the Act.

The net allowable revenues for DPP3 are different from DPP2 allowable revenues

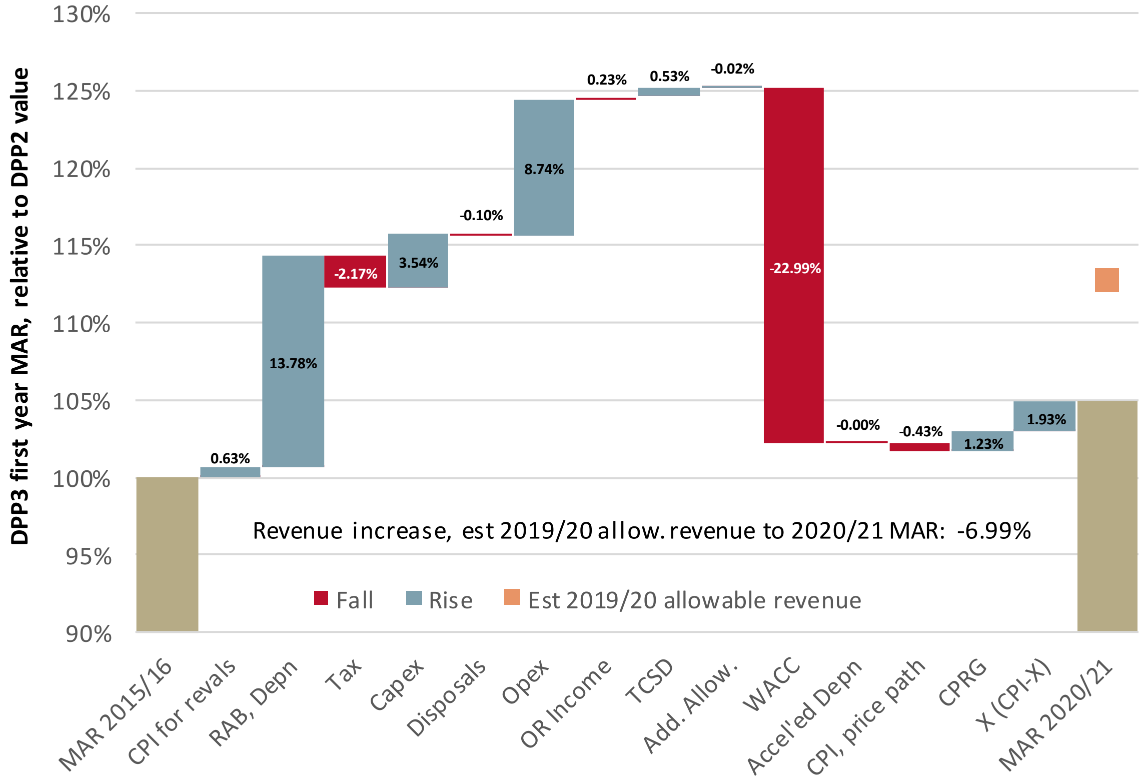
X27 Over time, the revenue allowance we set at the start of a regulatory period may cease to reflect a distributors' costs and the level of demand on its network.

X28 Were we to roll over current revenue allowances, distributors' revenues for the DPP3 period may not reflect their costs. In some cases, this would result in distributors earning excessive profits, contrary to section 52(A)(1)(d). In other cases, it may hinder their ability to invest in their networks to provide services at a level which reflects consumer demand, contrary to sections 52(A)(1)(a) and (b).

X29 Changes in the revenue allowances may have been caused by changes in a distributor's costs (including its cost of capital), or, under the price cap that applied during DPP2 changes in demand on the distributor's network.

X30 The influence of these factors at an industry-wide level is illustrated in Figure X1. This analysis is presented for each distributor on both DPP2 and DPP3 in Attachment O.

Figure X1 Drivers of change in net allowable revenue for DPP distributors[5]



X31 The figure reconciles in nominal terms allowable revenue in the first year of DPP2 (2015/2016) to allowable revenue in the first year of DPP3 (2020/2021), shown by the tan bars at either end.

X32 The impact of changes related to distributors' forecast costs relative to the start of DPP2 are illustrated in the waterfall bars in between.

X33 The changes caused by differences in net allowable revenue over the period (demand growth, Consumer Price Index (CPI), and X-factors) are illustrated by the orange marker at the right-hand end of the figure.

X34 The influence that our decisions on opex, capex, and accelerated depreciation have on starting prices are discussed in paragraphs X41 to X66 below. Significant changes due to other factors are discussed in paragraphs X35 to X40.

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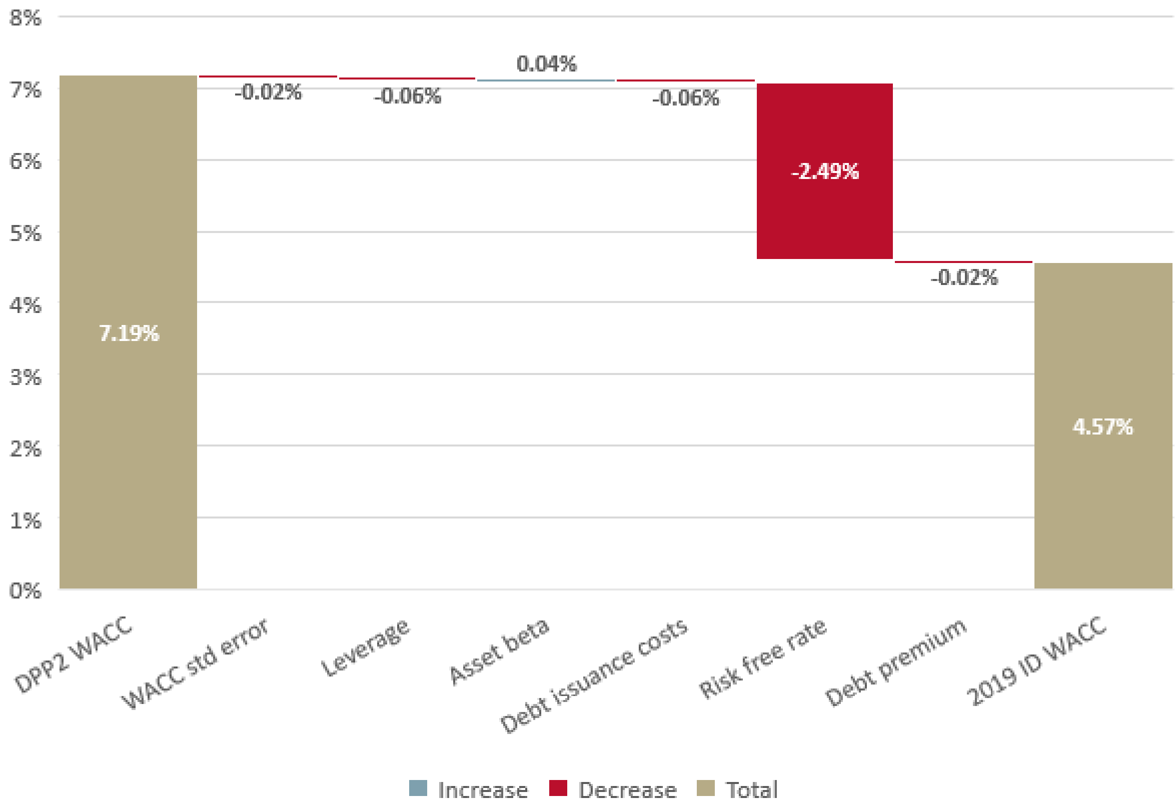
[5] Industry total excludes Orion, Powerco, and Wellington Electricity. The comparison is made between allowable revenue in the first year of each period (starting prices). Note the truncated Y-axis. Allowable revenue changes for individual distributors and the factors that explain them differ widely, and are set out in Attachment O.

The cost of capital estimate we use has changed since 2014

X35 The most significant driver of changing revenue allowances is the change in the weighted average cost of capital (WACC) between DPP2 and DPP3. This change has principally been driven by changes in the risk-free rate, as illustrated in Figure X2.

Figure X2 Changes in WACC since DPP2



X36 The WACC is determined by applying the method set out in the cost of capital IMs. While WACC has a material influence on our DPP3 decision, we have not made any changes to the underlying cost of capital IMs.[6]

Distributor asset bases have increased as they invest

X37 The second main factor driving changes in net allowable revenues is growing regulatory asset bases (RAB) over the DPP2 period. We use the closing RAB for each distributor from the penultimate year of the DPP2 period (2018/19) as one of the 'initial conditions' for 'rolling forward' the RABs over the DPP3 period.

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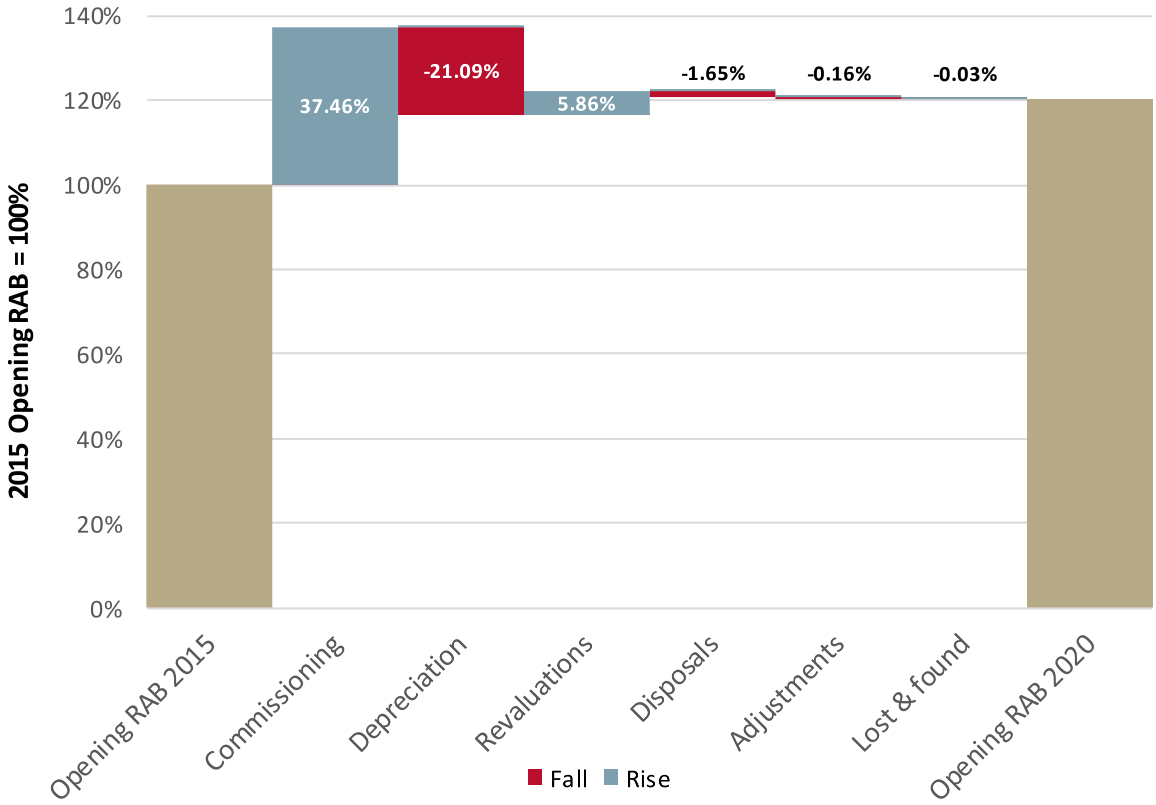
6 Our reasons for not making this change are discussed in Commerce Commission "Amendments to electricity distribution services input methodologies determination – Reasons paper" (26 November 2019), pp. 53-57.

X38 This RAB growth is primarily caused by distributors commissioning new assets, added together with revaluation of assets (at CPI), and partially offset by depreciation over the period. This cumulative change is shown in Figure X3.

Figure X3 DPP distributors roll-forward of RAB from 2014/15 to 2019/20 [7]



Quantity growth has influenced allowable revenue during DPP2

X39 Finally, there are factors that lead to allowable revenue in the final year of the DPP2 period being different from the allowable revenue we forecast at the start of the DPP2 period. These are:

X39.1 differences between forecast and actual CPI since 2015/2016;

X39.2 differences between the quantity growth we forecast at the start of DPP2 and actual quantity growth during DPP2; and

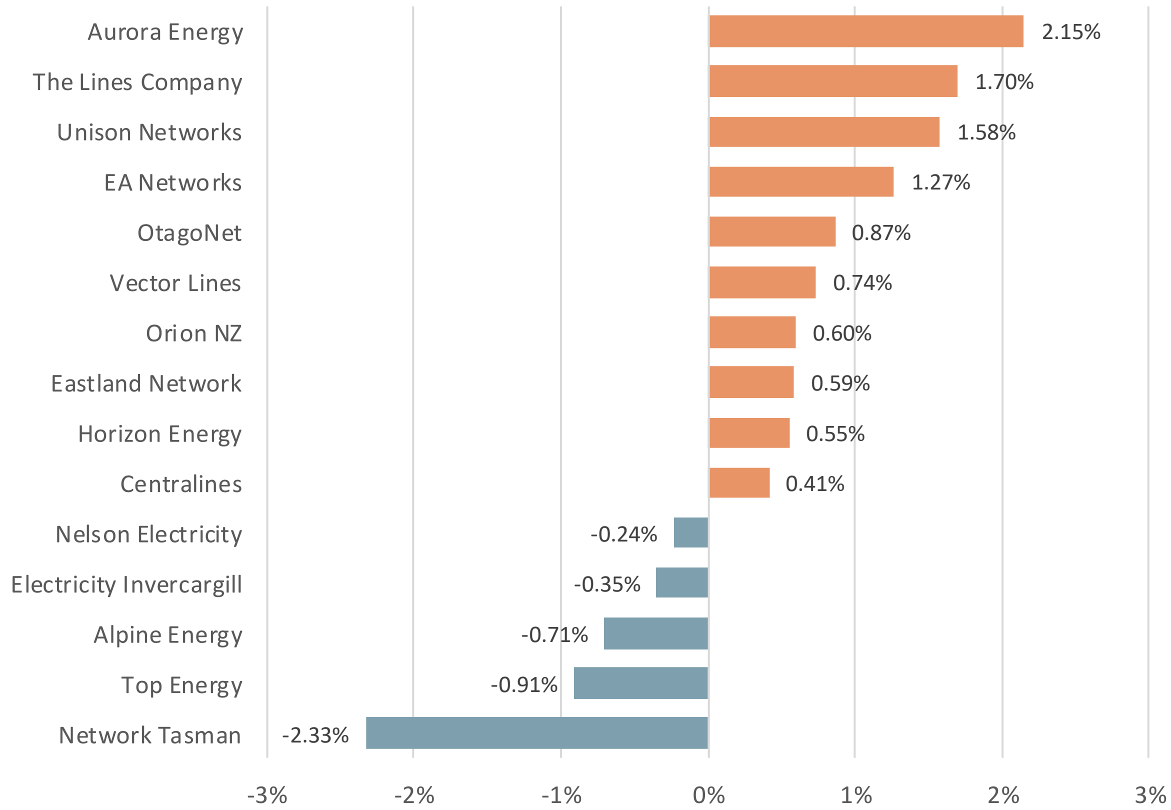
X39.3 for some businesses, the alternate X-factor we applied to smooth price increases over the DPP2 period.[8]

[7] Excludes Orion NZ , Powerco, and Wellington Electricity. Opening RAB 2014/15 to closing RAB 2018/19.

[8] Alpine Energy, Centralines, Eastland Network, and Top Energy.

X40 Of these, at an industry-wide level, the difference in quantity growth is the most significant. Under a price cap, distributors were exposed to quantity growth risk. Where demand growth was higher than forecast, allowable revenue was higher, and where demand growth was lower than forecast, allowable revenue was lower. Our estimate of these changes is set out in Figure X4.

Figure X4 Average annual constant-price revenue growth over the DPP2 period[9]



How we have approached forecasting opex

X41 To forecast opex for each distributor, we have retained at a high-level the base, step, and trend methodology from the DPP2 reset. The opex allowances that result from our decision are set out in Table X4 below. Changes in opex over time, at an industry-wide level, are illustrated in Table X5.

X42 Our decisions on opex are briefly summarised below, and are set out in detail in Attachment A.[10]

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9 Estimated annual constant-price revenue growth over the DPP2 period, based on DPP compliance statements.

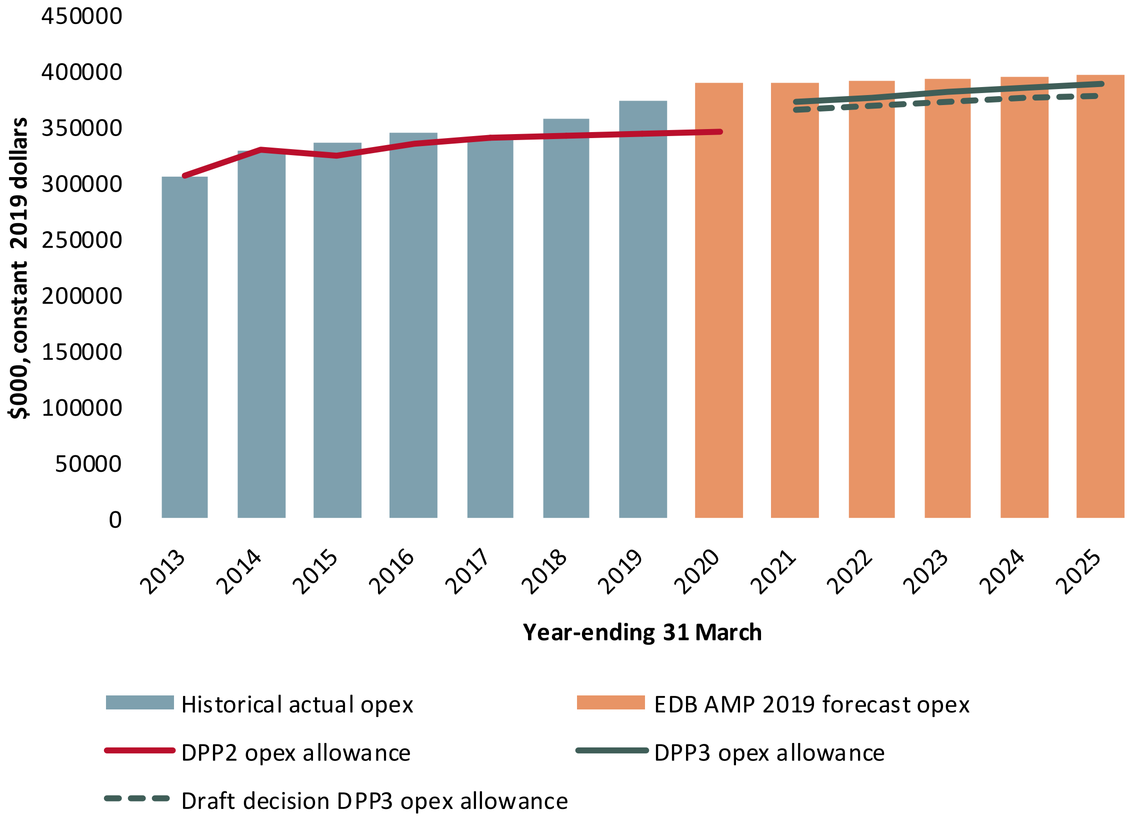
10 We have included indicative forecasts for Wellington Electricity for the four years it will be on the DPP, consistent with the approach discussed in Attachment I.

Table X4 Opex allowances for DPP3 ($m)

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25
Alpine Energy	19.42	20.01	20.63	21.24	21.82
Aurora Energy	44.72	46.25	48.13	50.19	51.96
Centralines	4.23	4.33	4.45	4.56	4.66
EA Networks	11.82	12.22	12.63	13.06	13.49
Eastland Network	10.62	10.90	11.19	11.50	11.78
Electricity Invercargill	5.18	5.31	5.45	5.59	5.72
Horizon Energy	9.89	10.17	10.49	10.83	11.11
Nelson Electricity	2.25	2.32	2.39	2.46	2.54
Network Tasman	11.16	11.51	11.88	12.25	12.61
Orion NZ	64.15	66.49	68.93	71.32	73.63
OtagoNet	9.16	9.43	9.70	9.96	10.20
The Lines Company	14.91	15.30	15.71	16.11	16.48
Top Energy	16.02	16.54	17.05	17.57	18.06
Unison Networks	41.58	42.90	44.33	45.72	47.03
Vector Lines	127.35	132.45	137.80	142.97	148.02
Wellington Electricity[11]	n/a	36.79	37.97	39.17	40.32

[11] The values included for Wellington Electricity are indicative only, and are subject to change as part of our decision on transitioning Wellington Electricity back to the DPP at the end of its CPP in 2021.

Figure X5 Opex time series (constant 2019 prices)



Key decisions for opex

X43 In applying the base, step, and trend methodology, we have:

X43.1 used 2018/2019 as the base year;[12]

X43.2 included step changes to remove:

X43.2.1 Fire and Emergency Management New Zealand (FENZ) levies (now a recoverable cost);

X43.2.2 pecuniary penalties (excluded from opex during DPP3); and

X43.2.3 costs related to operating leases (now treated as capex, consistent with IFRS 16);

X43.3 forecast growth due to changes in network scale using Statistics New Zealand household forecasts and projections of circuit length growth;

X43.4 inflated opex using a weighted average of the all-industries labour cost index (LCI) and producers price index (PPI); and

[12] As signalled in our draft decision, we have updated base-year now that it has been disclosed.

X43.5 applied a partial productivity factor of 0%.

X44 We have taken this approach because we consider that, when combined with the IRIS incentive scheme, it creates the right incentives for distributors to improve efficiency while at the same time providing an ex-ante expectation of a normal return.

X45 By linking future opex allowances to distributors' current revealed level of costs and predictable future changes, distributors should expect a normal return ex-ante, incentivising investment. By allowing distributors to keep a portion of any savings, they have an incentive to improve efficiency.

Changes to opex forecasts since our draft decision

X46 The majority of the changes to opex allowances since the draft decision relate to the updated input data we have used. Specifically, we have used updated data from 2019 Information Disclosure (ID) and updated forecasts of input price inflation.

X47 To forecast Installation Control Point (ICP) growth, we have used forecasts of household growth, rather than population growth. This is because our analysis suggests it is a better predictor of ICP growth, and because submissions resolved our concerns about data availability.

X48 We have not accepted any step changes proposed by stakeholders. In general, this is because we have not been able to verify the quantities involved, or because other DPP tools (such as reopeners or recoverable costs) are better at managing any potential increases or decreases in expenditure.

X49 We have retained a partial productivity factor of 0%. This is because on balance, between the evidence of historical productivity in the electricity sector in New Zealand, comparable overseas jurisdictions, and other industries in New Zealand, we consider a neutral setting is appropriate for DPP3. We remain unconvinced that declining productivity in the past is predictive of future declines.

X50 Combined, these changes have led to different opex allowances for each distributor compared to the draft decision. These changes are set out in Table X5.

Table X5 Changes in opex allowances relative to draft decision

Distributor	Opex allowance ($m)	Draft opex allowance ($m)	Change ($m)	Change (%)
Alpine Energy	103.11	100.51	2.61	2.60%
Aurora Energy	241.25	216.50	24.75	11.43%
Centralines	22.22	19.67	2.55	12.99%
EA Networks	63.21	72.29	-9.07	-12.55%
Eastland Network	55.99	57.14	-1.16	-2.03%
Electricity Invercargill	27.24	26.22	1.02	3.87%
Horizon Energy	52.49	59.44	-6.95	-11.70%
Nelson Electricity	11.96	11.27	0.68	6.05%
Network Tasman	59.41	64.16	-4.74	-7.39%
Orion NZ	344.53	327.43	17.10	5.22%
OtagoNet	48.45	42.19	6.26	14.83%
The Lines Company	78.52	70.37	8.15	11.57%
Top Energy	85.24	93.52	-8.27	-8.85%
Unison Networks	221.56	225.81	-4.25	-1.88%
Vector Lines	688.59	693.18	-4.59	-0.66%
Wellington Electricity	189.91	195.31	-5.39	-2.76%
Total	**2,293.68**	**2,275.01**	**18.67**	**0.82%**

How we have approached forecasting capex

X51 We have used distributors' 2019 asset management plans (AMPs) as the starting point for our capex allowances. However, we have made changes to the way we assess distributors' AMP capex for DPP3 compared to DPP2.

X52 Unlike DPP2, where we capped each distributors' AMP forecasts based on historical levels of expenditure, we have instead applied a series of tests of the reliability of AMP forecasts.

X53 We have made these changes because:

X53.1 we consider this kind of scrutiny of AMPs creates better incentives for distributors to invest, through allowing expenditure where it appears reasonable and deliverable, but not where it does not;

X53.2 it strikes the right balance between the low-cost scrutiny of a DPP, and the need to limit significant expenditure increase absent the proportionately higher scrutiny of a CPP; and

X53.3 the other changes we have made (the introduction of the capex reopener and the increase in the capex IRIS retention factor) mean distributors will still have incentives to invest efficiently.

X54 The resulting capex forecasts for each supplier are set out in Table X6. Our decisions on capex are discussed in detail in Attachment B.

Table X6 Capex allowances for each distributor

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25
Alpine Energy	16.66	16.98	15.38	14.67	14.15
Aurora Energy	50.95	50.75	48.25	38.77	43.21
Centralines	6.06	2.77	3.97	2.84	2.96
EA Networks	18.05	17.94	17.80	15.71	14.72
Eastland Network	9.68	10.14	8.98	9.38	10.05
Electricity Invercargill	4.66	5.05	5.57	5.58	5.13
Horizon Energy	8.32	6.72	8.08	8.52	8.57
Nelson Electricity	1.63	1.71	1.66	1.67	1.67
Network Tasman	10.29	12.26	9.04	10.07	8.47
Orion NZ	72.17	63.78	89.62	79.93	84.44
OtagoNet	13.99	13.50	18.00	23.07	13.93
The Lines Company	18.32	16.92	15.87	16.56	15.25
Top Energy	14.59	15.13	16.51	16.26	16.60
Unison Networks	46.75	52.52	50.53	46.85	48.04
Vector Lines	211.12	209.60	213.42	209.52	197.13
Wellington Electricity[13]	n/a	35.51	37.68	39.91	42.08

Key decisions for capex

X55 To forecast capex allowances for each distributor, we have used an amended version of the approach we took in DPP2 – using each distributor's 2019 AMP as the starting point for our forecasts, but applying a series of caps or tests to assess whether the forecast expenditure is likely to be required and deliverable.

X56 In particular, the approach seeks to determine whether the AMP forecasts:

X56.1 are internally consistent – for example, that a forecast increase in expenditure is supported by a corresponding increase in activity, and/or a realistic increase in costs; and

[13] The values included for Wellington Electricity are indicative only, and are subject to change as part of our decision on transitioning Wellington Electricity back to the DPP at the end of its CPP in 2021.

X56.2 identify large step changes in the planned level of investment, which may be more appropriate for us to consider under a CPP application.

X57 How we have done this is illustrated in Figure X6, and the tests we have applied are set out in Table X7. The results of this process (presented as our capex allowances as a percentage of AMP forecasts) are shown in Figure X7.

X58 Finally, the changes in capex over time, at an industry-wide level, are illustrated in Figure X8.

Figure X6 Capex assessment process

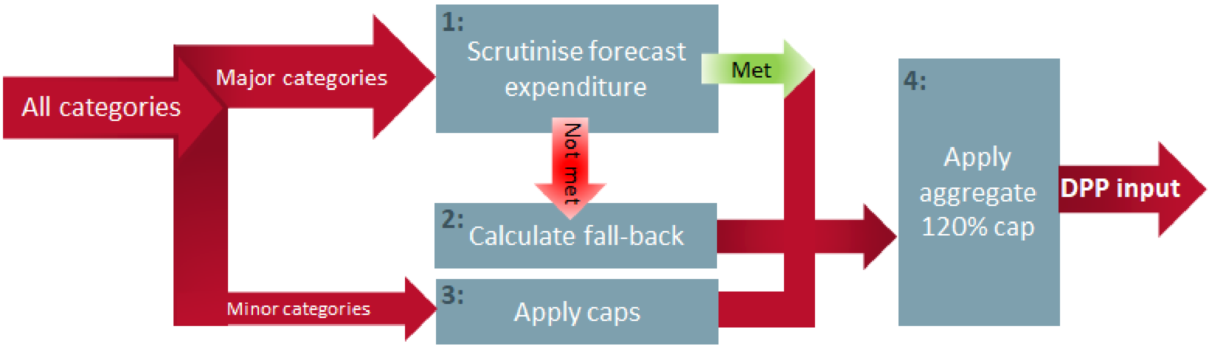
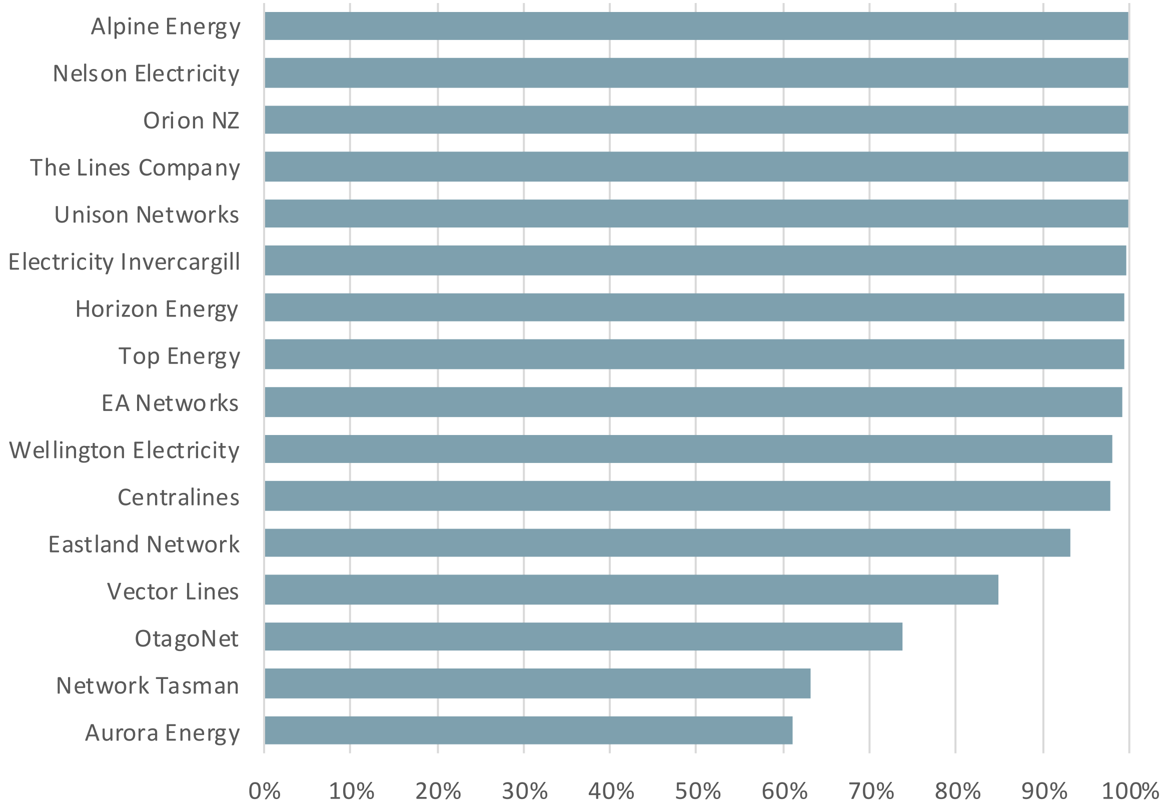


Table X7 Capex analysis tests

Test name	Category	Description
1: Residential connections	Consumer connection and system growth	Is the distributor forecasting growth in residential connections greater than both: 20% over their historical ICP growth, and forecasts of household growth for their area?
2: Per-connection expenditure	Consumer connection and system growth	Is the distributors' forecast per-connection spend increasing by more than 50%?
3: Renewal-depreciation	Asset replacement and renewal Reliability, safety, and environment	Is the distributor's combined ARR and RS&E expenditure more than 20% greater than their implied forecast depreciation?
4: Non-network cap	Expenditure on non-network assets	Is forecast expenditure on non-network assets greater than $1 million per year on average over the DPP3 period, or their historical expenditure, on a sliding scale from 120% to 200%, depending on historical proportions of expenditure on non-network assets?
5: Asset relocation cap	Asset relocation	Is forecast expenditure on asset relocations greater than $1 million per year on average over the DPP3 period, or their historical expenditure, on a sliding scale from 120% to 200%, depending on historical proportions of expenditure on asset relocations?

Figure X7 Capex forecast acceptance rates

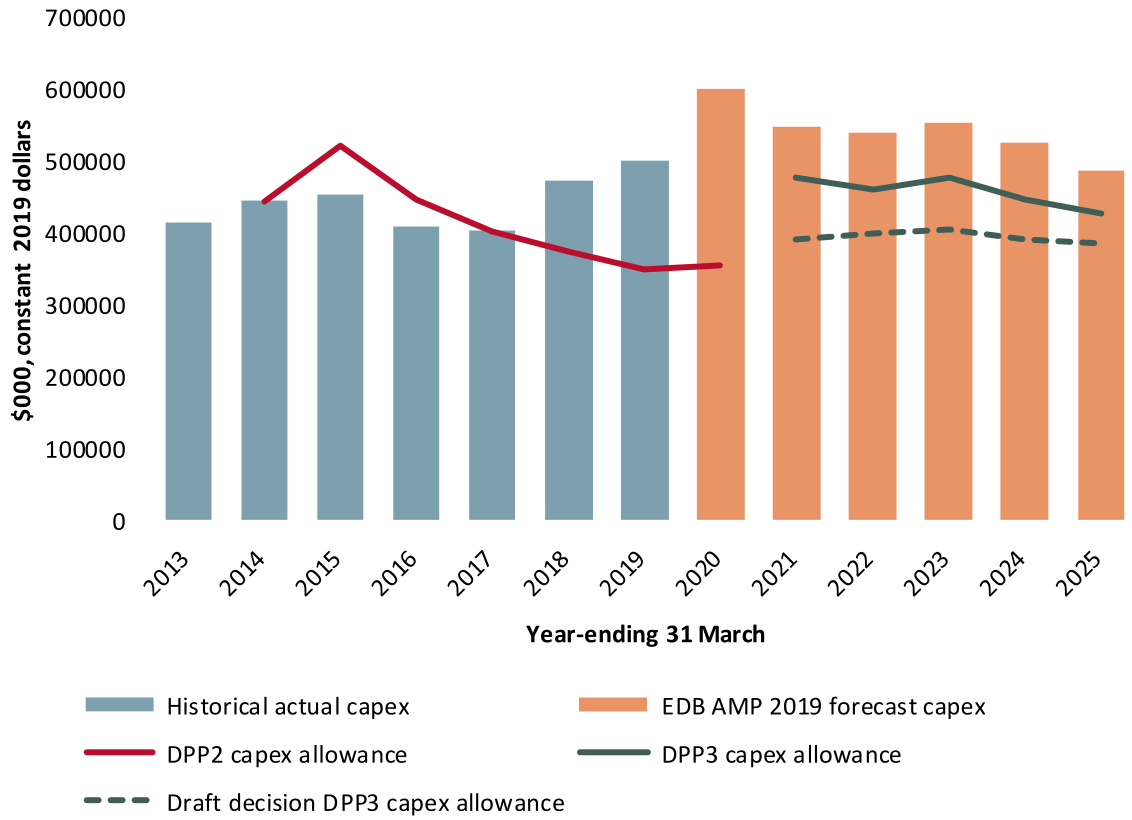


Some distributors have seen significant amounts of capex declined

X59 Aurora Energy, in response to the issues identified with its network following its quality standard contraventions, is forecasting a substantial increase in asset replacement and renewal expenditure, well in excess of the levels we could scrutinise under a DPP. We note that Aurora has signalled its intention to apply for a customised price-quality path (CPP) in 2020, that would apply from 1 April 2021.

X60 Network Tasman and OtagoNet are forecasting significant expenditure increases. However, these distributors are forecasting large growth projects or programmes that have uncertain timing, and as such, we consider that the new capex reopener is a better mechanism for dealing with these projects.

Figure X8 Capex time series (constant 2019 prices)



Changes to capex forecasts since our draft decision

X61 The most significant changes in capex forecasts since the draft decision are caused by our use of 2019 actual ID data and 2019 AMP forecasts, which showed increases in recent historical and forecast capex for almost all distributors. We consider it appropriate to use the most recent AMPs as the basis of our forecasts, as they represent distributors' most up-to-date view of the future needs of their networks.

X62 In terms of policy changes, in response to submissions we have:

X62.1 removed the assessment of historical forecast accuracy;

X62.2 changed our method for assessing system growth capex (as proposed in our updated draft decision);

X62.3 changed the 'fall-back' forecasts we use where a distributor's expenditure exceeds the limits we allow, from the historic average to the forecasts implied by our assessments of cost drivers; and

X62.4 introduced dollar-value caps to our tests for minor capex categories.

X63 Combined, these policy changes and the use of updated data have led to different capex allowances for each distributor compared to the draft decision. The changes in allowances are set out in Table X8.

X64 Some distributors have seen significant changes. Increases for three distributors contribute to most of the total change in forecasts, largely reflecting increases in their AMP forecast capex.[14]

Table X8 Changes in capex allowances

Distributor	Capex allowance ($m)	Draft capex allowance ($m)	Change ($m)	Change (%)
Alpine Energy	77.84	71.70	6.14	8.56%
Aurora Energy	231.93	147.99	83.93	56.71%
Centralines	18.61	14.76	3.84	26.02%
EA Networks	84.22	88.48	-4.26	-4.82%
Eastland Network	48.24	40.90	7.34	17.94%
Electricity Invercargill	25.98	20.80	5.18	24.88%
Horizon Energy	40.21	36.84	3.37	9.14%
Nelson Electricity	8.34	8.27	0.06	0.78%
Network Tasman	50.14	27.68	22.46	81.12%
Orion NZ	389.95	340.15	49.79	14.64%
OtagoNet	82.50	79.82	2.68	3.36%
The Lines Company	82.92	60.35	22.57	37.41%
Top Energy	79.10	90.26	-11.17	-12.37%
Unison Networks	244.69	232.94	11.75	5.04%
Vector Lines	1,040.79	953.59	87.21	9.15%
Wellington Electricity	192.92	181.52	11.40	6.28%
Total	**2,698.38**	**2,396.08**	**302.30**	**12.62%**

Accelerated depreciation

X65 As part of the Input Methodology (IM) review in 2016, we introduced the option for distributors to apply for accelerated depreciation of their existing assets where there is a plausible risk of network stranding due to emerging technologies.

X66 For this DPP reset, we received one application, from Vector. We have decided not to apply an adjustment factor in response to Vector's application, based on our assessment of Vector's application against the formal IM requirements, the risk of economic stranding, section 52A of the Act and our exercise of our overall discretion.

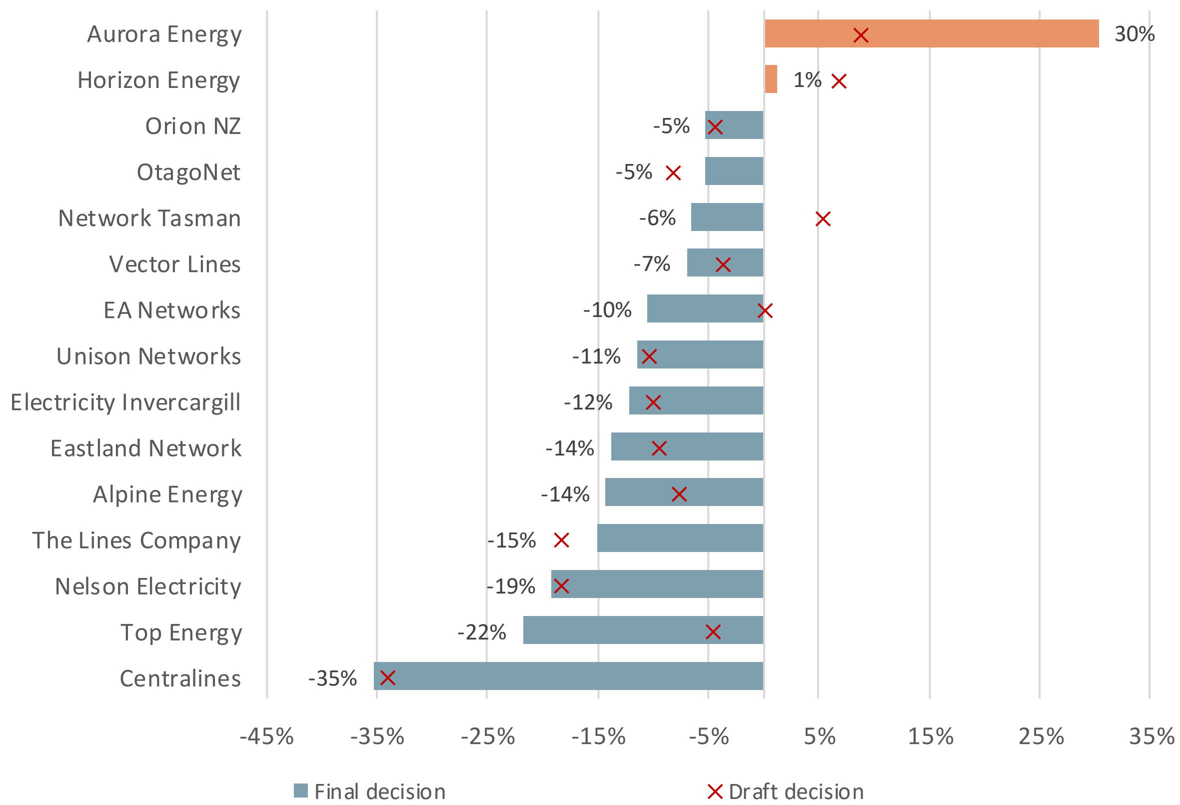
[14] Aurora Energy, Orion NZ, Vector Lines. Wellington Electricity have also seen a large dollar-value increase, but these forecasts are only indicative, due to Wellington's CPP transition.

Our decisions on the price path have different effects on different distributors

X67 The combined effect of the changes (relative to DPP2) and decisions above result in different changes in allowable revenue for different distributors. The change in allowable revenue for each distributor is shown in Figure X9 below.

X68 The general pattern of decline is caused by the reduction in the WACC discussed above. For some distributors, this is offset by either lower than forecast constant-price revenue growth (CPRG) during DPP2, or by growth in asset bases or opex. For others, this decline is compounded by higher than forecast CPRG or by very low levels of asset base and opex growth.

Figure X9 Changes in net allowable revenue from 2019/2020 to 2020/2021



X69 For distributors seeing large changes, we note:

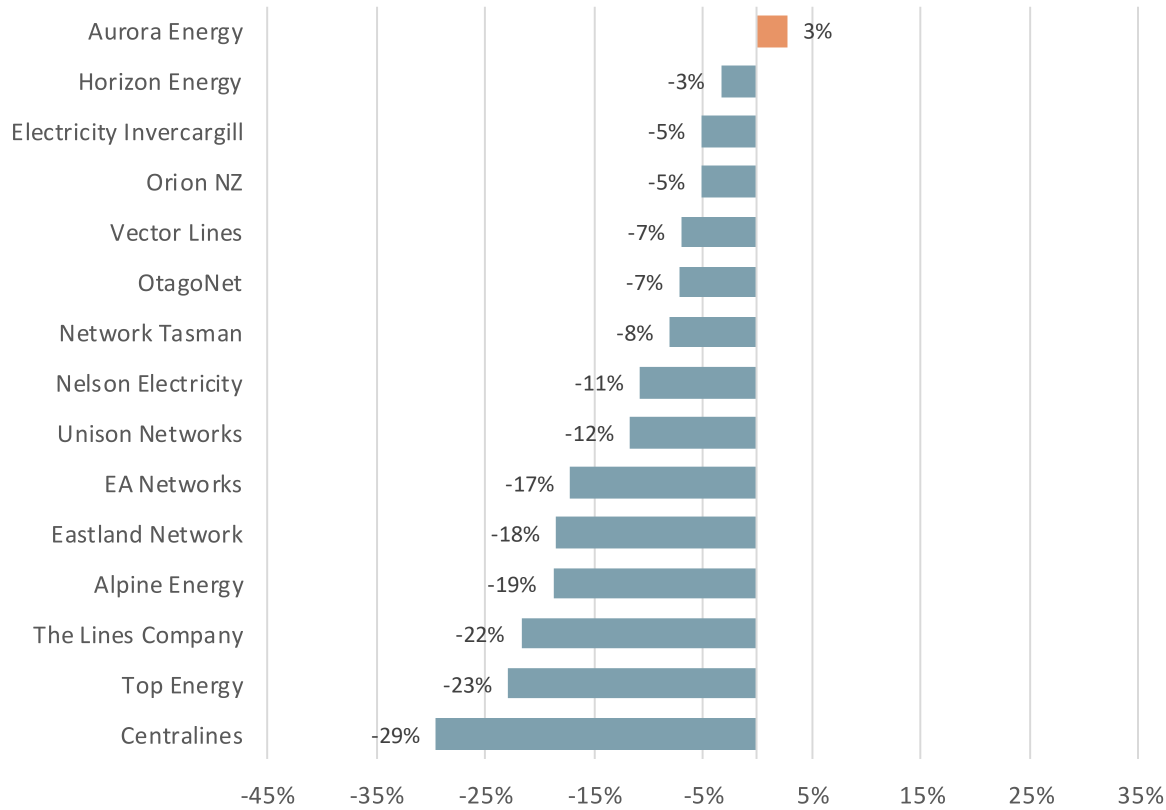
X69.1 Aurora Energy has seen a substantial increase in opex and substantial RAB growth during DPP2 as a result of its increased investment programme, note that this will be offset by an IRIS incentive cost reducing its *gross* revenue during DPP3 (see Figure X10 below);

X69.2 Centralines has underspent both its DPP2 opex and capex allowances, and as such its forecasts of opex and capex are lower, also note that Centralines has historically priced below its price cap, meaning the change in revenue (as opposed to revenue allowance) will likely be smaller; and

X69.3 Top Energy has been on a 'sloped' price path during DPP2 that deferred revenue recovery until later in the DPP2 period, increasing the step down at the end of DPP2, additionally, it has seen lower RAB growth than forecast, and only modest opex growth.

X70 We also note that distributors who have underspent on opex relative to our DPP2 forecasts will generally see gains in gross revenue during DPP3, as a result of IRIS efficiency incentives, as discussed in Attachment E. We have estimated the impact these IRIS incentive payments on the 2020 to 2021 change in allowable revenue. This is presented in Figure X10.

Figure X10 Change in allowable revenue accounting for IRIS incentives



X71 For most distributors, the impact of the IRIS is modest (with the difference between net of IRIS changes and gross of IRIS changes averaging around ±5%). However, it is significant for Aurora Energy (-28%), given a significant opex and capex overspend.

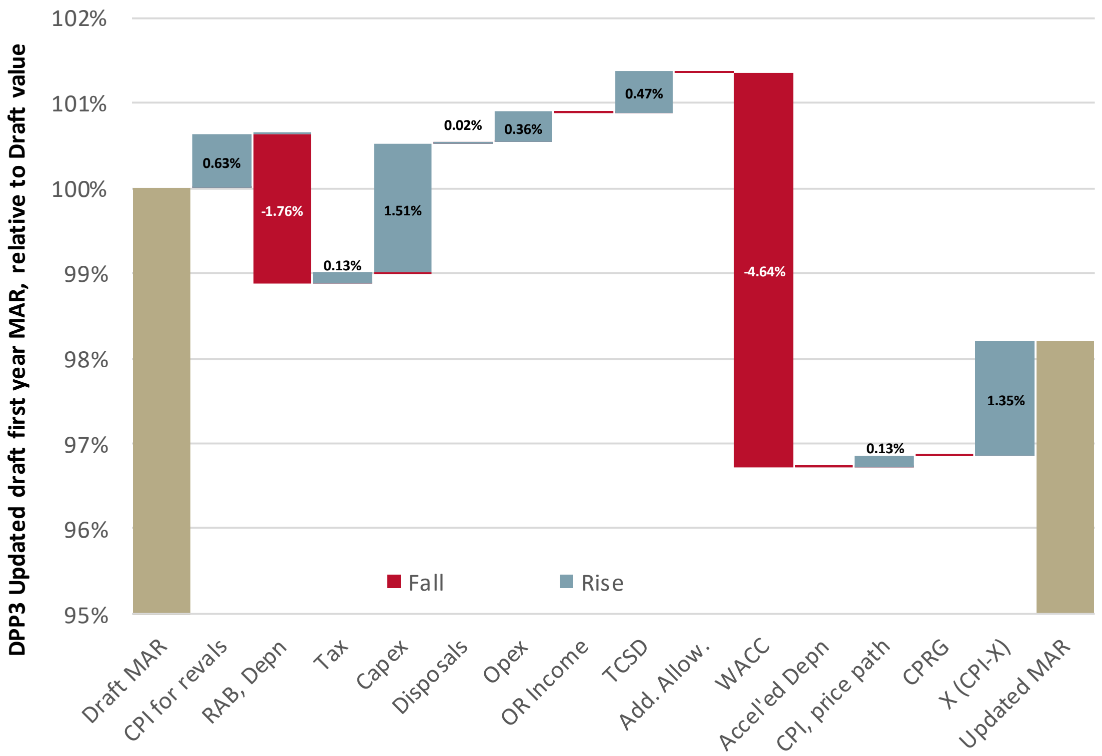
Changes in allowable revenue since the draft decision

X72 Changes in input data and in policy decisions since the draft decision have led to changes in revenue allowance for the final DPP3 decision. These changes are set out in Table X9 below. The factors driving this change (for distributors on the DPP as a whole) are shown in Figure X10.

Table X9 Allowable revenue in 2020/21 relative to DPP3 draft decision

Distributor	Allowable revenue in 2020/21 ($m)	Draft allowable revenue in 2020/21 ($m)	Change ($m)	Change (%)
Alpine Energy	42.65	45.36	-2.71	-5.97%
Aurora Energy	87.33	72.03	15.30	21.25%
Centralines	9.37	9.40	-0.03	-0.34%
EA Networks	33.26	37.70	-4.44	-11.77%
Eastland Network	24.03	25.06	-1.03	-4.10%
Electricity Invercargill	12.26	12.29	-0.03	-0.28%
Horizon Energy	23.91	25.01	-1.10	-4.38%
Nelson Electricity	5.50	5.59	-0.09	-1.55%
Network Tasman	26.45	28.78	-2.33	-8.09%
Orion NZ	158.50	161.17	-2.67	-1.66%
OtagoNet	25.78	25.08	0.69	2.77%
The Lines Company	34.71	33.94	0.76	2.25%
Top Energy	38.01	42.19	-4.17	-9.90%
Unison Networks	100.02	102.25	-2.23	-2.18%
Vector Lines	388.71	403.35	-14.64	-3.63%
Total	**1,010.49**	**1,029.20**	**-18.70**	**-1.82%**

Figure X11 Drivers of change between draft and final decisions



Revenue path

X73 In addition to allowable revenue in the first year of the period, we have also made decisions that affect how the revenue path will operate during the period. These decisions include:

X73.1 rates of change (relative to CPI);

X73.2 implementing the revenue cap with wash-up;

X73.3 incentives for improving efficiency and innovation;

X73.4 new recoverable costs; and

X73.5 circumstances in which the DPP can be reopened.

How allowable revenues will change over the period

X74 As shown in Table X1, we have implemented a default rate of change for all suppliers of CPI-0%. This is not a change from our draft decision for most suppliers, but is a change for Aurora Energy. We have moved to an X-factor of 0% for Aurora because, as Aurora identified in its submission, once IRIS incentive payments are accounted for, any price shock to consumers in 2021 is likely to be minimal.[15]

X75 We have not set any alternate X-factors. On the one hand, most distributors will see declines in allowable revenue, meaning there is limited risk of price shocks to consumers. On the other hand, revenue decreases notwithstanding, we have not identified any distributor who would face financial hardship as a result of our decision.

We will apply a revenue cap with wash-up in DPP3

X76 As part of the IM review in 2016, we changed the form of control for distributors from a weighted average price cap to a revenue cap, including a wash-up for over- and under-recovery of revenue.

X77 As part of implementing the revenue cap in the DPP3 determination, we have implemented:

X77.1 a 10% limit on the annual increase in each distributor's 'forecast revenue from prices'; and

X77.2 a limit on the accrual of wash-up balances from 'voluntary undercharging', which is the lesser of either:

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[15] Aurora have formally signalled their intention to apply for a CPP, with an intended commencement date of 1 April 2021. In this instance, the DPP would only apply to Aurora for a single year.

X77.2.1 90% of forecast allowable revenue for the year; or

X77.2.2 110% of the previous year's forecast revenue from prices.

X78 The voluntary undercharging limit does not prevent distributors from charging less than they are allowed to by the revenue cap; it merely prevents any undercharging beyond a certain point being accrued as a wash-up balance that is then used to increase allowable revenue in future years.

X79 None of these decisions have changed significantly from our draft decision. Our approach to the revenue cap, and our reasons for related policy decisions are discussed in more detail in Attachment H.

We have updated incentives for efficiency

X80 For the DPP3, we have made changes to the IRIS efficiency incentives. The most significant change is to the incentive rate for the capex IRIS. We have set a capex retention factor equal to the opex retention factor, or 23.5%.

X81 To ensure distributors have a consistent incentive to spend both opex and capex, and do not favour capital solutions over operating ones, we have equalised the capex retention factor with the opex one.

X82 We consider that this change will reduce or remove barriers to innovation. We do not want to disincentivise any potential emerging technologies from being used by distributors due to a lower capex incentive rate. Equalising rates will create a more level playing field to allow distributors to avoid spending capex through investing in innovative solutions that may include partnering with third parties to deliver services.

We have introduced new incentives for innovation

X83 In addition to equalising IRIS incentives, to further promote innovation, we have introduced a new targeted innovation recoverable cost.

X84 We have set the limit of the funding available for DPP3 at the greater of either 0.1% of our forecast of allowable revenue for the period or $150,000, and a requirement for half the funding to come from a distributor's regular opex or capex expenditure. In total, this would equate to $11 million of spending on innovation as part of this scheme.

X85 The introduction of the $150,000 limit, in addition to the 0.1% limit, is in response to submissions that a percentage-based limit alone would mean the incentive would be insufficient for smaller distributors to take advantage of it.

X86 We have set this conservatively, as there will be only limited scrutiny over how the allowance is spent. In response to submissions, we have made changes to the criteria that will apply, and the process for approving the relevant recoverable cost.

X87 Circumstances where a distributor wishes to undertake substantial changes to the way it manages its network are more appropriately considered as part of a CPP application. A CPP allows us the ability to apply greater scrutiny, and to vary the way the price-quality path functions to account for innovative approaches.

We have introduced new costs distributors can recover from their customers

X88 We have amended the IMs to introduce two new recoverable costs:

X88.1 one to implement the innovation project allowance described above; and

X88.2 one to allow for FENZ levies to be passed through to consumers.

X89 We have also made an amendment to clarify and extend the scope of the recoverable cost relating to charges payable by a distributor to Transpower in respect of a 'new investment contract' between those parties, or any equivalent contract with another transmission provider. The amendment will allow a distributor to use a third-party option to finance the new investment contract between the distributor and Transpower (or equivalent contract with another transmission provider). This amendment was proposed by Transpower in response to our draft DPP decision.[16]

X90 All of these changes required amendments to the IMs, which are described in the IM amendments reasons paper which was published on 26 November 2019.[17]

Circumstances in which the DPP can be reopened

X91 Given the increasing uncertainties in the industry (as discussed above at X18), we have reconsidered ways in which the price-quality path can be amended part way through the regulatory period. In general, we consider the existing reopeners (and in particular the change and catastrophic event reopeners) make adequate allowance for most unforeseeable events beyond the reasonable control of distributors.

X92 However, in addition to the existing reopeners, we have introduced new reopeners for some major capex projects and programmes.[18]

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[16] Transpower "Submission on IM amendments for DPP and IPP" (5 July 2019).

[17] Commerce Commission "Amendments to electricity distribution services input methodologies determination – Reasons paper" (26 November 2019).

[18] For the purposes of the reopeners "unforeseen" includes expenditure that was included in a suppliers AMP, but not included in DPP3 capex allowances, and projects that were foreseen but whose timing or scale has changed.

X93 There is potential for increases in process heat electrification, connection of new sources of distributed generation, or relocation of assets in response to other infrastructure investment activity. This could have a significant impact on distributors' investment needs. Given this, and the difficulties in predicting the timing of these developments, we consider reopeners are the best way to enable distributors to undertake any such investments.

X94 In response to submissions, since the draft decision, we have expanded the scope of these reopeners, so that now, in addition to major new connections and alterations to existing connections, it includes:

X94.1 major relocations of assets not able to be funded through capital contributions; and

X94.2 major system growth capex, such as network reconfiguration in response to new connections to Transpower's grid.

X95 We have also changed the thresholds that apply to the reopeners in response to submissions. In addition to the percentage threshold proposed in the draft decision, we have implemented a dollar-value threshold and a maximum value cap.

Quality standards and incentives

X96 As part of the Commission's 2018/19 priorities, we committed to focusing on quality standards and incentives as part of the DPP3 reset. Quality was also an area of intense interest in submissions. In particular, our decisions discussed below build on work undertaken by the Electricity Networks Association (ENA) Quality of Service Working Group, and on analysis undertaken by NZIER on behalf of the Major Electricity Users Group (MEUG).

X97 Given the statutory requirement to promote quality incentives and the areas for improvement in quality standards and incentives that we have identified through consultation so far, we consider that while the package of changes for DPP3 is substantial, it is proportionate to the importance of the issue, and the scale of change in the industry as a whole.

X98 We have made a number of changes to the quality standards and incentives scheme, relative to the draft decision. In part, this is in response to submissions on the draft and updated draft decisions. However, it is also in response to data quality issues identified through the section 53ZD information gathering process, specifically to do with the calculation of system average interruption frequency index (SAIFI) values.

High-level approach to quality of service

X99 Consistent with our overall low-cost DPP principles, our starting point for a DPP is that distributors should at least maintain the levels of quality that they have provided historically, all else being equal. We refer to this principle as 'no material deterioration'.

X100 The reliability standards and targets we have set are based on distributors historical performance, and are intended to give effect to this principle. Similarly, the absence of a historical data series for other measures of quality is part of the reason we are considering gathering more data on these measures through ID before setting any binding standards.

X101 While no material deterioration is a starting point for our approach to quality, we also acknowledge the need for distributors to make trade-offs about the level of quality they deliver, and the cost incurred in doing so. We also note that – as with revenue allowances – our quality standards only apply at an aggregate. We expect individual distributors to consider the needs and expectations of difference customers and customer groups when making trade-offs about quality on different parts of their networks. This consideration drives many of the changes to the quality incentive scheme.

X102 Even in a relatively stable industry environment, it would be important for distributors to consider price-quality trade-offs at the margins, and to have the ability to move towards a level of quality that better reflects:

X102.1 consumers' demands and willingness to pay; and

X102.2 the distributors cost to serve those consumer demands.

X103 Given the inconsistencies in the way distributors have calculated SAIFI values historically, we have changed the basis on which distributors report SAIDI and SAIFI for compliance purposes. These changes in effect mean that distributors will continue to report SAIDI and SAIFI in the way they did when calculating values in the section 53ZD response for the year-ending 31 March 2019. This is to preserve the comparability of future assessment with the historic data the standards were based on.

We have made changes to reliability standards

X104 We have retained the quality standards based on reliability, as measured by the system average interruption duration index (SAIDI) and SAIFI. However, we have made the following changes (relative to DPP2):

X104.1 separating planned and unplanned reliability standards;

X104.2 setting the unplanned reliability standards at 2 standard deviations above the normalised historical average, and defining contraventions on an annual basis, rather than a ‘two-out-of-three’ year basis;

X104.3 setting the planned reliability standard at three times the historical average, and assessing it on a regulatory period basis;

X104.4 capping the inter-period (DPP2 to DPP3) movement in unplanned standards at ±5%; and

X104.5 implementing a new ‘extreme event’ SAIDI standard, set at either 120 SAIDI minutes or 6 million customer interruption minutes, and excluding specified events that we consider are predominantly caused by external factors.

X105 We have not set quality standards for other dimensions of service quality, or enhanced reliability standards (such as regional disaggregation).

X106 These changes are discussed in detail in Attachment L.

We have made refinements to revenue-linked reliability incentives

X107 We have retained the revenue-linked reliability incentive scheme. However, we are making the following changes to the scheme (relative to DPP2):

X107.1 applying the scheme to SAIDI only, to reduce complexity and to avoid double-counting the impact of SAIFI;

X107.2 setting the incentive rates with reference to value of lost load (VoLL) using a figure of $25,000/MWh so that consumer preferences are better reflected in the price/quality trade-off decisions distributors make;

X107.3 reducing the incentive rates by 76.5% to approximate a five-year retention of the benefits by distributors;

X107.4 reducing the incentive rate by a further 10% to account for the existing incentives created by quality standards (to $5,288/MWh);

X107.5 for planned interruptions, reducing the incentive rate a further 50% to reflect the fact that these are generally less disruptive to consumers (to $2,644 MWh); and

X107.6 for planned interruptions where certain notification criteria are met, reducing the incentive rate by a further 50% (to $1,322/MWh).

X108 These changes are discussed in detail in Attachment M.

Other changes for quality standards

X109 To better manage the impact that major events can have on reliability standards and incentives, we are proposing changes to the normalisation methodology we use:

X109.1 defining major events on a 24-hour basis, rolling in 30-minute intervals; and

X109.2 capping the assessed SAIDI or SAIFI value for any half-hour period within a major event at 1/48th of the boundary value.

X110 To improve our ability to assess compliance with the price-quality path, and to reduce the cost and uncertainty involved when a distributor contravenes its quality standards, we are proposing additional reporting requirements related to:

X110.1 major events; and

X110.2 the effects of and the circumstances which lead to a contravention of a quality standard.

X111 Given the importance to consumers of communications around planned interruptions, we have introduced an additional 'notified' level of planned interruption, with further reductions to the incentive rate (to $1,300/MWh) and to the impact on quality standards where certain conditions are met. In response to submissions, we have made significant changes to these conditions to avoid potential perverse incentives.

We will consider changes to the information we gather on other measures of quality during DPP3

X112 We have not implemented any new dimensions or measures of quality of service, or any detailed expansions of reliability standards or incentives (such as regional disaggregation or low voltage monitoring).

X113 This is not because we consider these measures unimportant. It is because we need to develop a better understanding of distributors' current performance before imposing any new price-quality path obligations.

X114 As such, we intend to consider these matters as part of ID, in a project to be undertaken in 2020, after the DPP3 setting process is complete.

X115 Our reasons for this, and the additional measures of quality we have considered are discussed in Attachment N.

Abbreviations used in this document

Abbreviation	Definition
ACOT	Avoided cost of transmission
ADR	Annual Delivery Report
AER	Australian Energy Regulator
AMP	Asset management plans
ARR	Asset replacement and renewal
BBAR	Building blocks allowable revenue
CAB	Customer advisory board
CGPI	Capital goods price index
CMA	Competition and Markets Authority
CPI	Consumer price index
CPP	Customised price-quality path
CPRG	Constant-price revenue growth
DER	Distributed energy resources
DPP	Default price-quality path
EGWW	Electricity, gas, waste, and water
ENA	Electricity Networks Association
ERANZ	Electricity Retailers Association of New Zealand
FCM	Financial capital maintenance
FENZ	Fire and Emergency Management New Zealand
GPB	Gas pipeline businesses
GSL	Guaranteed service level
HSWA	Health and Safety Work Act
HV	High voltage
ID	Information disclosure
IEEE	Institute of Electrical and Electronics Engineers
IM	Input Methodology
IPAG	Innovation and Participation Advisory Group
IPP	Individual Price-Quality Path
IRIS	Incremental rolling incentive scheme
LCI	Labour cost index
LV	Low voltage
MAR	Maximum allowable revenue
MBIE	Ministry for Business, Innovation, and Employment
MED	Major event days
MEUG	Major Electricity Users Group
NPV	Net present value

Abbreviation	Definition
PPI	Producers price index
QoS	Quality of service
RAB	Regulatory asset base
RBNZ	Reserve Bank of New Zealand
RS&E	Reliability, safety and environment
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
STPIS	Service target performance incentive scheme
TFP	Total factor productivity
VoLL	Value of lost load
WACC	Weighted average cost of capital
WTA	Willing to accept
WTP	Willing to pay

Chapter 1 Introduction

Purpose of this paper

1.1 This paper sets out the final default price-quality paths (DPPs) for electricity distribution businesses (distributors) from 1 April 2020 to 31 March 2025 (DPP3).

Resetting the current default price-quality paths

1.2 We are required to reset the DPPs for those electricity distributors that are subject to price-quality regulation under Part 4 of the Commerce Act 1986. Part 4 provides for regulation in markets in which there is little or no competition, and little or no likelihood of a substantial increase in competition.

1.3 Each distributor's DPP specifies the maximum allowable revenues and the quality standards that these distributors must comply with during a regulatory period. The current DPP was reset in 2015 and will expire on 31 March 2020. From 1 April 2020 the new DDP3 will come into effect until 31 March 2025.

1.4 15 distributors will be subject to these revenue and quality requirements. Two other distributors – Wellington Electricity and Powerco – are currently subject to customised price-quality paths (CPPs). These CPPs will end in 2021 and 2023 respectively. We have determined the quality standards that will apply to Wellington Electricity and Powerco if they transition back on to the DPP.[19]

The process we have followed

1.5 This section explains the process we have followed in arriving at the final decision and determination, and the relationship of the DPP3 setting process to the Input Methodology (IM) amendment process we have run in parallel.

Issues paper and initial stakeholder workshops

1.6 On 15 November 2018, we published an issues paper that explained our framework for considering changes when resetting the DPP and consulted on potential issues we identified in advance of the DPP3 draft decision.

1.7 In early 2019, we held two workshops with stakeholders to discuss specific issues relevant to the DPP3 reset:

1.7.1 The first workshop focused on quality of service issues and was held on 28 February 2019.

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[19] As discussed in Attachment I, we have the power under section 53X of the Act to determine starting prices for distributors transitioning from a CPP to the DPP, but this does not apply to quality standards. As such, we have determined quality standards as part of this reset.

1.7.2 The second focused on uncertainty and innovation and was held on 8 March 2019.

1.8 Distributors were entitled to apply for a discretionary shortening of asset lives (accelerated depreciation) before 28 February 2019. We received one application (from Vector Lines) and accepted comments on this application up until 22 March 2019.

Draft decision and updated draft decision

1.9 The draft decision was released on 29 May 2019. Additional models to support the draft decision were provided on 21 June 2019.

1.10 Submissions and cross-submission on the draft reasons paper and models were sought by 18 July 2019 and 12 August 2019 respectively.

1.11 An information gathering request (section 53ZD request) for information relating to quality of service was made on 28 June 2019. This was followed by a targeted quality workshop on 16 August 2019.

1.12 Updated draft models and an accompanying companion paper were released on 25 September 2019. Submissions and cross-submissions on the companion paper were sought during October 2019.

1.13 All the consultation material, along with submissions, are available on our website at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-price-quality-paths/electricity-lines-default-price-quality-path/2020-2025-default-price-quality-path.

Submissions not considered

1.14 To ensure a fair process for stakeholders, and to enable us time to properly consider matters raised in submissions, in the context of determining the DPP reset we have not had regard to submissions received:

1.14.1 after 16 October 2019 for matters raised in the updated models companion paper and 25 October 2019 for matters raised in the SAIFI consultation paper; and [20]

[20] These were the dates on which cross-submissions were due for the updated draft and SAIFI consultations respectively.

1.14.2 that was outside the ambit of consultation we had set for the updated models and the SAIFI consultation paper, unless it addressed a material element of our DPP reset decisions that was communicated for the first time in those publications.[21]

Process for amending IMs

1.15 Alongside the DPP3 reset process, we have also consulted on a package of amendments to the EDB IMs. These amendments fall into two broad categories:

1.15.1 changes we considered necessary to support implementation of incremental improvements to the way the DPP is set (such as new recoverable costs or reopeners); and

1.15.2 changes we considered to enhance certainty about the rules or correct errors ahead of the DPP reset (for example, correcting implementation errors in the IRIS drafting).

Process for DPP-related IM amendments

1.16 We issued notices of intention to amend the EDB IMs on 15 November 2018 and 16 May 2019, which set out the scope of the changes we were considering, and the indicative process we intended to follow.

1.17 Alongside the DPP3 draft decision, on 29 May 2019, we published a draft IM amendment decision, and a reasons paper setting out the reasons for our proposed changes. Submissions and cross-submissions on IM amendments were sought by 5 July 2019 and 19 July 2019 respectively.

1.18 In response to additional correspondence from the Electricity Networks Association (ENA) received on 5 September 2019, on 18 October 2019 the Commission published an open letter regarding our decision not to amend the IMs for cost of capital or asset valuation.

1.19 A final decision on the IM amendments necessary to implement the DPP was published on 26 November 2019.[22]

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[21] The scope of the consultation on the Updated Models Companion Paper was set out in: Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Updated draft models – Companion Paper" (25 September 2019), para 1.3. The scope of the SAIFI consultation was set out in: Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Recording of successive interruptions for SAIFI – Consultation Paper" (7 October 2019), para 3.

[22] Commerce Commission "Amendments to electricity distribution services input methodologies determination – Reasons paper" (26 November 2019).

1.20 All the consultation material for the IM amendments, along with submissions, are available on our website at: https://comcom.govt.nz/regulated-industries/input-methodologies/projects/amendments-necessary-to-implement-the-2020-electricity-distribution-default-price-quality-path.

Process for operating leases IM

1.21 As part of a separate but related process, we have made amendments to the EDB IMs to respond to changes in the accounting treatment of operating leases. We published a final decision on these changes on 13 November 2019. The relevant consultation material and submissions are available on our website at: https://comcom.govt.nz/regulated-industries/input-methodologies/projects/operating-leases.

What we have published alongside this paper

1.22 Alongside this paper we have published:

1.22.1 the suite of final financial and other models used to either determine final starting prices and quality standards or to inform the analysis in this paper; and

1.22.2 a final version of the EDB DPP determination.

1.23 Immediately prior to the publication of this paper, we have published:

1.23.1 final amendments to the EDB IMs necessary to implement our draft DPP3 decisions; and

1.23.2 a reasons paper explaining changes to the EDB IMs.

1.24 Finally, at the same time but as part of a separate consultation process, we have published a final decision on resetting Transpower's Individual Price-Quality Path (IPP).[23]

How we have structured this paper

1.25 The chapters of this paper:

1.25.1 summarise our decision;

1.25.2 explain the framework we have applied to reach these decisions and the context in which we are making them; and

[23] This material can be found on our website at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpowers-price-quality-path/setting-transpowers-price-quality-path-from-2020.

1.25.3 explain each of the key components that affect starting prices, revenue during the period, and quality standards.

1.26 The attachments to this paper explain our final decisions in detail and respond to submissions stakeholders have made throughout the consultation process and in our stakeholder workshops. We have structured the attachments into three parts:

1.26.1 Part 1 deals with decisions affecting starting prices for each distributor;

1.26.2 Part 2 deals with decisions affecting the revenue path during DPP3; and

1.26.3 Part 3 deals with decisions affecting quality standards and incentives.

Further inquiries and feedback on process

1.27 Inquiries on the final determination and its associated published documents should be addressed to:

Dane Gunnell (Manager, Price-Quality regulation)
c/o regulation.branch@comcom.govt.nz

Feedback on process for setting DPP3

1.28 In early 2020, we will invite feedback on the process we have followed to set DPP3, and on ways this process could be improved in future.

Chapter 2 Impact on allowable revenue

Purpose of this chapter

2.1 This chapter sets out the key decisions we have made and estimates their potential impact on distributors' allowable revenue and customers' lines charges.

2.2 It starts by briefly explaining the regulatory framework under Part 4 of the Commerce Act, and the role of price-quality regulation. It then explains the key decisions we have made as they relate to the price path.

Regulation of price and quality under Part 4

2.3 Part 4 of the Commerce Act provides for the regulation of the price and quality of goods or services in markets where there is little or no competition, and little or no likelihood of a substantial increase in competition.[24] For distributors, it sets out two forms of regulation:

2.3.1 Information disclosure (ID) regulation, under which regulated suppliers are required to publicly disclose information relevant to their performance.[25]

2.3.2 Default/customised price-quality regulation, under which price-quality paths set the maximum average price or total allowable revenue that the regulated supplier can charge. They also set standards for the quality of the services that each regulated supplier must meet. This ensures that businesses do not have incentives to reduce quality to maximise profits under their price-quality path.[26]

2.4 All businesses which provide electricity distribution services are regulated under Part 4 of the Commerce Act.[27] Of the 29 distributors, 12 are exempt from price-quality regulation because they are consumer-owned.[28]

2.5 The "non-exempt" distributors which are subject to either a DPP or a CPP are set out in the table and map below.

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[24] Commerce Act 1986, section 52.

[25] Commerce Act 1986, section 52B and 54F. As per section 54, information disclosure applies to all EDBs subject to Part 4.

[26] Commerce Act 1986, sections 52B and 54G. As per section 54G, default/customised price-quality regulation applies only to EDBs who do not meet the consumer-owned criteria set out in section 54D. EDBs subject to a default price-quality path have the option of applying for a customised price-quality path to better meet their particular circumstances (section 53Q).

[27] Commerce Act 1986, section 54E.

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

Figure 2.1 Map of distributors subject to price-quality regulation

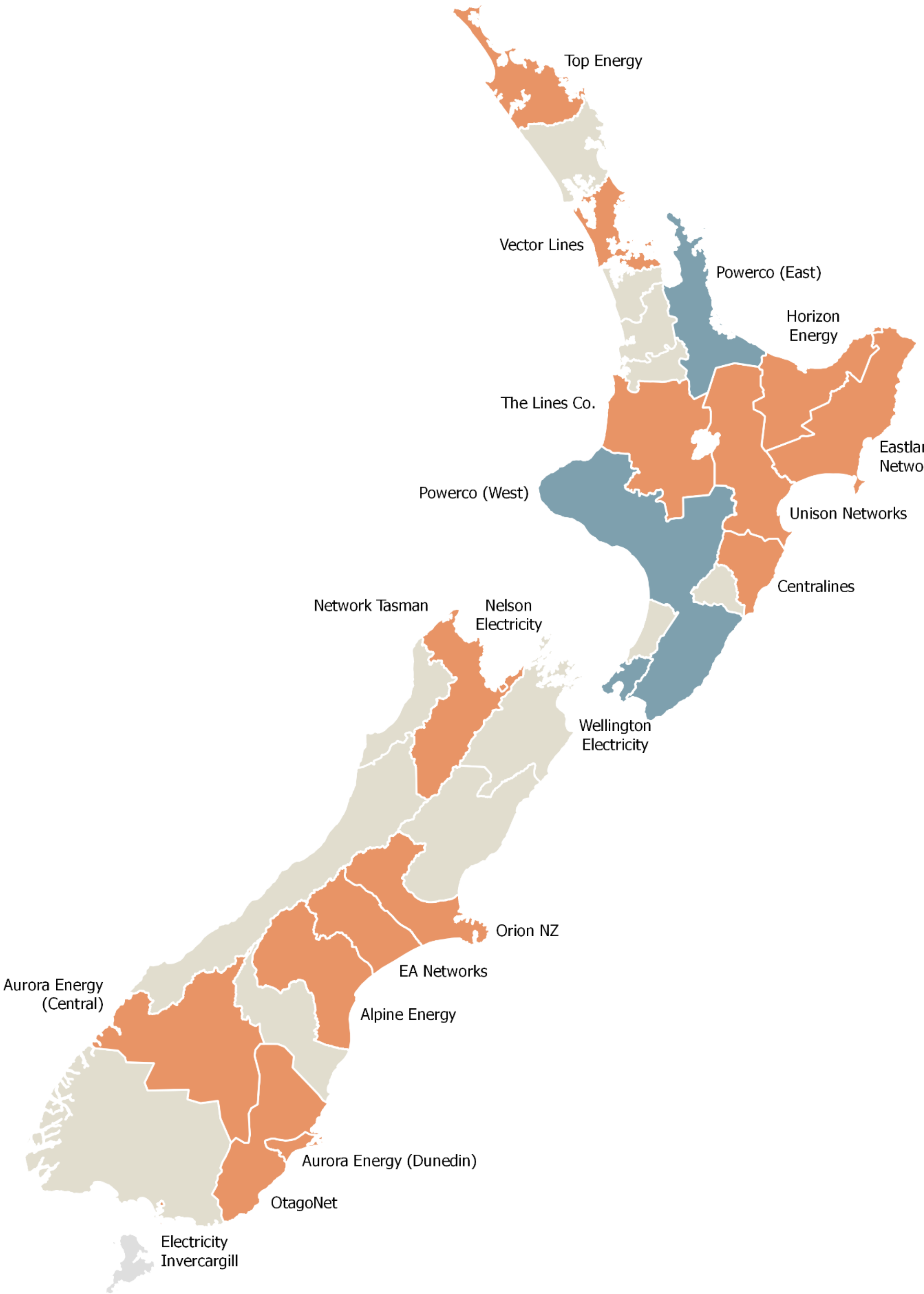

Table 2.1 Distributors subject to price-quality regulation

Distributors subject to the DPP			
Alpine Energy	Aurora Energy	Centralines	Eastland Network
EA Networks	Electricity Invercargill	Horizon Energy	The Lines Company
Network Tasman	Nelson Electricity	Orion NZ[29]	OtagoNet JV
Top Energy	Unison Networks	Vector Lines	
Distributors subject to a CPP			
Powerco (ends 2023)	Wellington Electricity (ends 2021)		

Decisions affecting the price paths

2.6 This section explains the key decisions we have made for distributors' price paths.

2.7 First, it briefly explains the terms we use to describe prices and revenues. Second, it sets out the starting prices we have set, and how these will change relative to current prices. Finally, it discusses some of the factors that are driving these changes – both the decisions we have made, and other factors.

'Prices' versus revenues—our terminology

2.8 The price path for DPP3 will apply to distributors as a 'revenue cap'. A revenue cap limits the maximum revenues a distributor can earn, rather than the maximum prices that it can charge.[30] For this reason, while the terminology in the Act refers to 'starting prices', in this paper we will generally refer to the 'allowable revenues' a distributor can earn.[31]

2.9 Allowable revenue may mean either:

2.9.1 'gross' allowable revenue, including pass-through and recoverable costs; or

2.9.2 'net' allowable revenue, excluding pass-through and recoverable costs.

2.10 Unless specified otherwise, references to 'allowable revenue' or 'revenue allowances' in this paper refer to net allowable revenue.

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[29] Orion NZ was subject to a CPP until 31 March 2019.

[30] The decision to move distributors from a price cap to a revenue cap was made as part of the IM review in 2016. Commerce Commission "Input methodologies review decisions – Topic paper 1 – Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016). The implications of this decision are discussed in more detail in Attachment H.

[31] The definition of "price" for the purposes of Part 4 means one or more of individual prices, aggregate prices, or revenues. When setting a price-quality path, we must specify prices as either one or both of prices or total revenues; Commerce Act 1986, sections 52C and 53M.

Price path

2.11 The price path is composed of three elements:

2.11.1 starting prices, expressed as maximum allowable revenue (MAR) for the first year of the period (2020/21);

2.11.2 the annual rate of change in revenues (CPI, plus or minus an 'X-factor'); and

2.11.3 pass-through and recoverable costs.

2.12 Our decision to set starting prices on the basis of current and projected profitability (discussed more in Chapter 5) will lead to a change in the net revenue each distributor can recover.

2.13 On top of this our decision on Transpower's IPP, the results of the incremental rolling incentive scheme (IRIS) efficiency incentives during DPP2, and other changes in pass-through and recoverable costs will affect the gross revenue distributors may recover from their customers.

Starting prices

2.14 Starting prices determine distributors' net allowable revenue in the first year of the DPP3 regulatory period. When combined with the rate of change, they also determine revenues in each subsequent year. Allowable revenues for the first year of the DPP3 period are set out in Table 2.2 below, and are discussed in more detail in Chapter 5.

Rate of change (CPI-X)

2.15 The rate of change in revenues (relative to CPI) for each subsequent year is also set out below, and is discussed in more detail in Chapter 6.

Table 2.2 Starting prices and rates of change

Distributor	MAR 2020/21 ($m)	Rate of change (relative to CPI)
Alpine Energy	42.65	0.00%
Aurora Energy	87.33	0.00%
Centralines	9.37	0.00%
EA Networks	33.26	0.00%
Eastland Network	24.03	0.00%
Electricity Invercargill	12.26	0.00%
Horizon Energy	23.91	0.00%
Nelson Electricity	5.50	0.00%
Network Tasman	26.45	0.00%
Orion NZ	158.50	0.00%
OtagoNet	25.78	0.00%
The Lines Company	34.71	0.00%
Top Energy	38.01	0.00%
Unison Networks	100.02	0.00%
Vector Lines	388.71	0.00%
Total	**1,010.49**	**-**

Allowance for pass-through and recoverable costs

2.16 In addition to the revenues we allow distributors to charge for electricity distribution services (expressed through starting prices and the rate of change) there are also a range of costs which we allow distributors to pass-through to their consumers. These are called 'pass-through costs' or 'recoverable costs' and are specified in the EDB IMs.[32]

2.17 These costs can have a material impact on changes in the total or 'gross' revenue distributors collect. Significant recoverable costs include:

2.17.1 Transpower's transmission charges;

2.17.2 efficiency incentive payments under IRIS; and

2.17.3 quality of service incentive payments under the revenue-linked quality incentive scheme.

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[32] Pass-through costs are costs that distributors have almost no ability to control. Recoverable costs are costs which distributors may have some limited ability to control. Under the current IMs, the revenue path treats both types of cost the same. Commerce Commission "Input methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper" (22 December 2010), pp. 195 to 197.

Drivers of net allowable revenue changes between DPP2 and DPP3

2.18 This section discusses changes in allowable revenue between the current DPP period (DPP2) and the next DPP period (DPP3). Changes between the draft DPP3 decision and the final DPP3 decision are discussed in the next section.

2.19 Changes in net allowable revenue are the result of:

2.19.1 decisions we have made (principally on opex and capex forecasts);

2.19.2 changes in other parameters we use in assessing current and projected profitability, but which are not part of our decision (principally in the weighted average cost of capital (WACC)) and the 'initial conditions' for each distributor; and

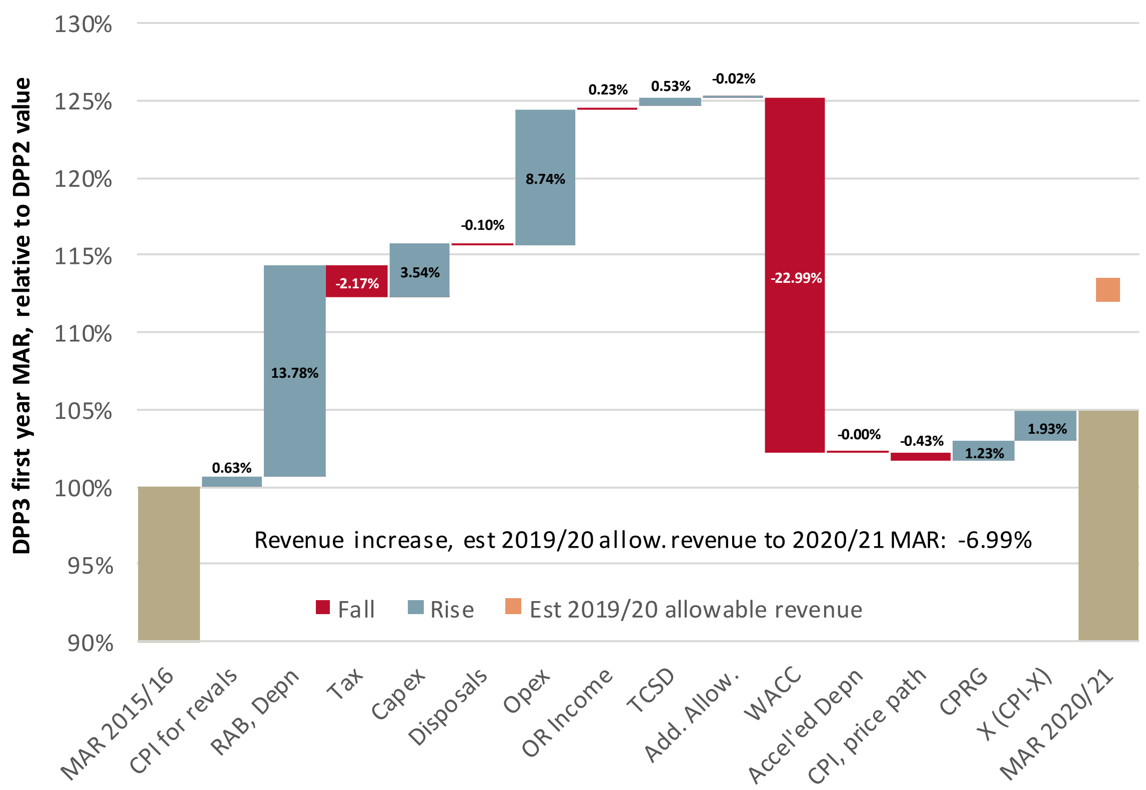
2.19.3 changes that have applied to allowable revenues during the DPP2 period (CPI, alternate X-factors, and changes in quantities).

2.20 Figure 2.2 below shows the drivers of changes in net allowable revenues for all distributors on the DPP between the DPP2 and DPP3 periods, in nominal terms.[33] This analysis is presented on a distributor-specific basis in Attachment O.

2.21 The figure begins with MAR in the first year of the DPP2 period (2015/16), and shows the progressive impact of changes in each variable used in our current and projected profitability modelling (the "financial model" that we have published alongside this paper), ending with MAR in the first year of the DPP3 period (2020/21).

[33] This excludes Powerco and Wellington Electricity, who are currently on CPPs, and Orion who was on a CPP until 2019/20, and for who we have no comparable DPP2 values.

Figure 2.2 Drivers of nominal change in net allowable revenues for DPP distributors [34]



2.22 The orange marker at the end of the chart is our estimate of allowable revenues in the final year of the DPP2 period. This differs from allowable revenue at the start of the period because of:

2.22.1 changes in CPI since 2015/16;

2.22.2 differences between the quantity growth we forecast at the start of DPP2 and actual quantity growth during DPP2;[35] and

2.22.3 for some businesses, the alternate X-factor we applied to spread large allowable revenue increases over the DPP2 period to avoid price shocks.[36]

[34] Total revenue across the 14 businesses subject to both DPP2 and DPP3, relative to 2015/16 allowable revenue.

[35] During DPP2, we limited the weighted-average prices distributors could charge (a price-cap). This exposed distributors to quantity growth risk, and required us to forecast revenue growth in constant prices (CPRG). Distributors who experienced higher than forecast CPRG were allowed to earn higher revenue than we forecast, and vice versa. Under a revenue cap, this will no longer apply.

[36] Alpine Energy, Centralines, Eastland Network, and Top Energy.

2.23 The cumulative effect of these changes is that total estimated net allowable revenues (for the 14 businesses analysed) in the final year of the DPP2 period (2019/20) are 5% higher than they were at the start of the DPP2 period. As a result, the estimated change in net allowable revenue between 2019/2020 and 2020/21 is a decrease of -7%.

Effect of our decisions

2.24 The change in our opex forecasts relative to our DPP2 forecasts directly impacts allowable revenues, as all opex is recovered in the year it is forecast to occur.[37] These changes account for a +9% change in overall revenue.

2.25 Changes in our capex forecasts, again relative to our forecasts for DPP2, have a lesser impact on starting prices than opex does.[38] This is because capex does not directly impact revenue, but rather impacts each distributors' forecast RAB, and is recovered over multiple regulatory periods. These changes account for a +4% change in overall revenue.

Effect of changes in other parameters

2.26 Changes in the WACC are the largest driver of changes in distributor revenue, accounting for a -23% overall change. The WACC value used to set starting prices for DPP2 was 7.19%. The estimate we have used for this decision is 4.57%.[39]

2.27 The financial model for the DPP depends on a set of initial conditions for each distributor. These initial conditions are sourced from each distributor's ID data, and reflect accumulated changes since the DPP was last reset in 2014. Changes in these initial conditions account for +14% of the overall change, with the majority explained by RAB growth over the DPP2 period.[40]

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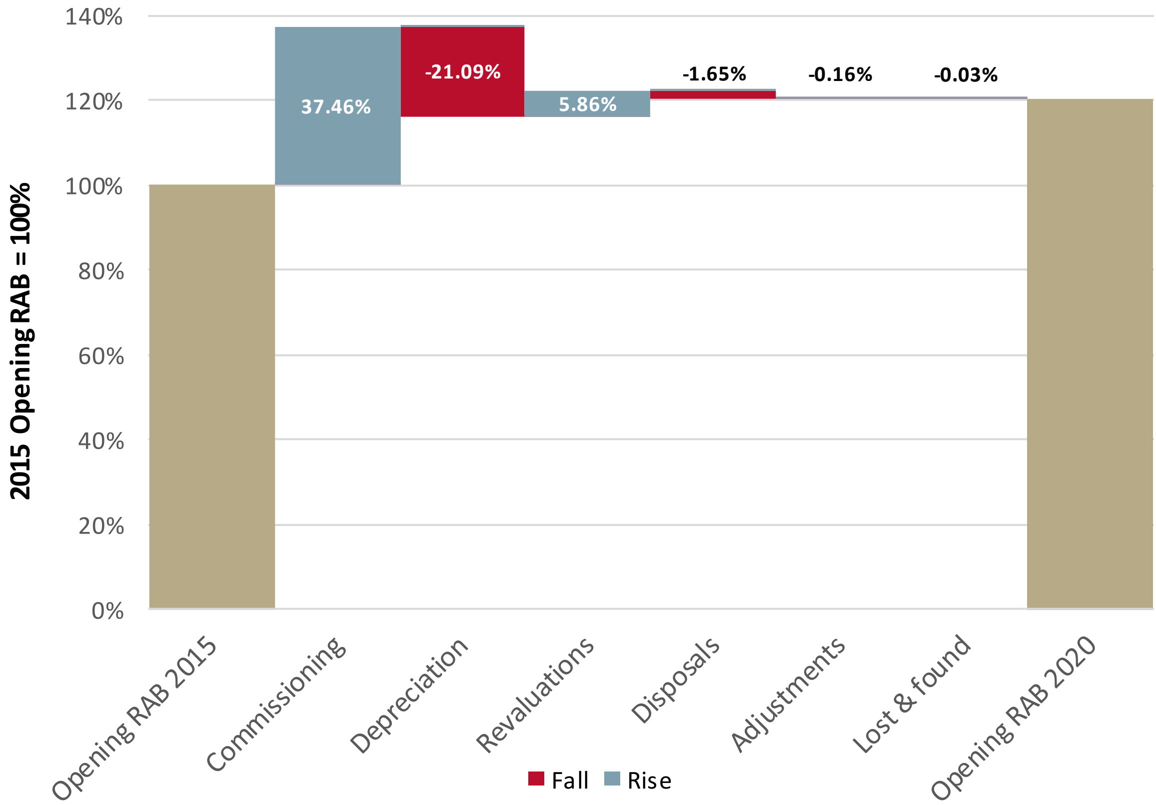
[37] Changes in *actual* opex relative to our DPP2 forecasts also have an impact on future gross revenues, however this is delivered through the opex IRIS mechanism. These effects are discussed in Attachment E.

[38] Changes in *actual* capex relative to our DPP2 forecasts also have an impact on future revenues, however this is delivered through the capex IRIS mechanism. These effects are discussed in Attachment E.

[39] Commerce Commission *Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path* [2019] NZCC 12 (25 September 2019).

[40] This increase includes spur assets purchased by some distributors from Transpower. These purchases have contributed approximately 2% of total commissioned assets for the period.

Figure 2.3 DPP distributors roll-forward of RAB from 2014/15 to 2019/20 [41]



2.28 This RAB growth is primarily caused by distributors commissioning new assets over the DPP2 period, added together with revaluation of assets, and partially offset by depreciation over the period.

2.29 Finally, there are factors that lead to allowable revenue in the final year of the DPP2 period being different from the allowable revenue we forecast at the start of the DPP2 period. These are:

2.29.1 changes in CPI since 2015/2016;

2.29.2 differences between the quantity growth we forecast at the start of DPP2 and actual quantity growth during DPP2;[42] and

2.29.3 for some businesses, the alternate X-factor we applied to smooth price increases over the DPP2 period.[43]

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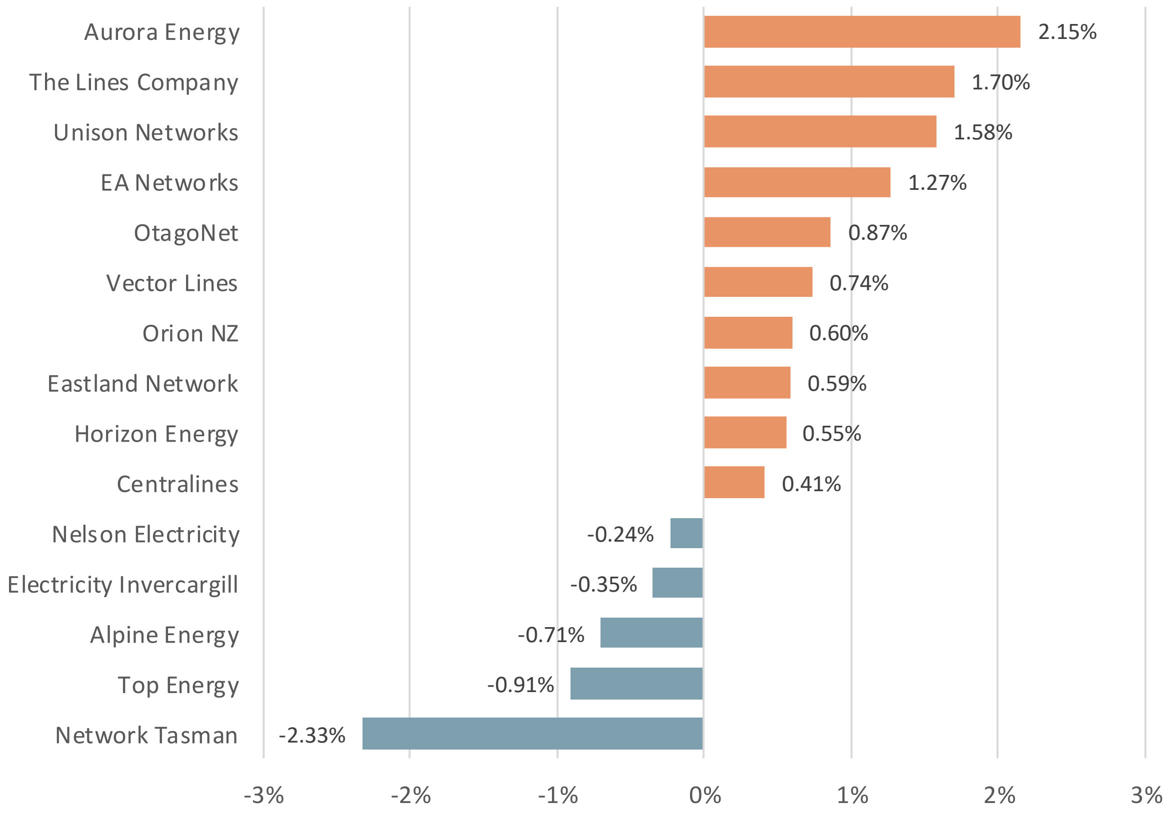
41 Excludes Orion NZ , Powerco, and Wellington Electricity. Opening RAB 2015 to closing RAB 2019.

42 During DPP2, we limited the weighted-average prices distributors could charge (a price-cap). This exposed distributors to quantity growth risk, and required us to forecast revenue growth in constant prices (CPRG). Distributors who experienced higher than forecast CPRG were allowed to earn higher revenue than we forecast, and vice versa. Under a revenue cap, this will no longer apply.

43 Alpine Energy, Centralines, Eastland Network, and Top Energy.

2.30 Of these, at an industry-wide level, difference in quantity growth is the most significant. Under a price cap, distributors are exposed to quantity growth risk, and receive the benefit (or face the disadvantage) of any difference in demand being higher than forecast. Our estimate of these changes is set out in Figure 2.4.

Figure 2.4 Changes in quantity growth (CPRG) over the DPP3 period [44]



Changes since the draft decision

2.31 The allowable revenue allowances we have set in this final decision differ from the allowances proposed in our draft decision; this section explains these differences, and the factors driving them, specifically:

2.31.1 changes to input data since our draft decision; and

2.31.2 changes in DPP3 policy decisions made in response to submissions.

2.32 Table 2.3 compares net allowable revenue in the first year of the DPP3 period (2021) from the draft and final decisions for each distributor. Figure 2.5 quantifies the impact of these changes at an industry-wide level.

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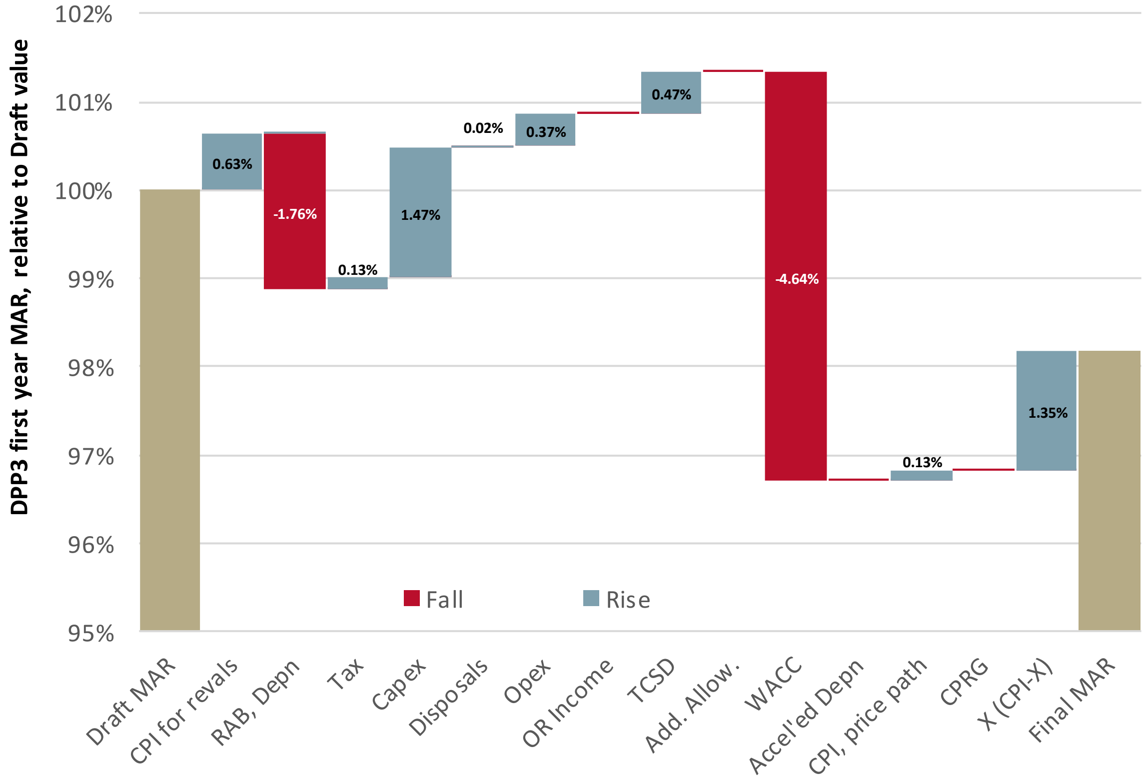
[44] Estimated annual constant-price revenue growth over the DPP2 period, based on DPP compliance statements.

Table 2.3 Comparison between draft and final allowable revenue

Distributor	Allowable revenue in 2020/21 ($m)	Draft allowable revenue 2020/21 ($m)	Change from draft decision ($m)	Change from draft decision (%)
Alpine Energy	42.65	45.36	-2.71	-5.97%
Aurora Energy	87.33	72.03	15.30	21.25%
Centralines	9.37	9.40	-0.03	-0.34%
EA Networks	33.26	37.70	-4.44	-11.77%
Eastland Network	24.03	25.06	-1.03	-4.10%
Electricity Invercargill	12.26	12.29	-0.03	-0.28%
Horizon Energy	23.91	25.01	-1.10	-4.38%
Nelson Electricity	5.50	5.59	-0.09	-1.55%
Network Tasman	26.45	28.78	-2.33	-8.09%
Orion NZ	158.50	161.17	-2.67	-1.66%
OtagoNet	25.78	25.08	0.69	2.77%
The Lines Company	34.71	33.94	0.76	2.25%
Top Energy	38.01	42.19	-4.17	-9.90%
Unison Networks	100.02	102.25	-2.23	-2.18%
Vector Lines	388.71	403.35	-14.64	-3.63%
Total	**1,010.49**	**1,029.20**	**-18.70**	**-1.82%**

Figure 2.5 Drivers of change in allowable revenue between draft and final decisions



Changes in input data

2.33 Because of changes in input data, in total for distributors on the DPP, allowable revenues are lower overall than in our draft decision.[45] These updated revenue allowances were first published in our updated draft decision on 25 September 2019.[46]

2.34 In the first year of the DPP3 regulatory period (2020/21), revenues are $18m or 1.75% lower because of these input data changes.

2.35 The main influences driving this change are:

2.35.1 a lower WACC estimate (resulting in a -4.64% change in allowable revenue);

2.35.2 a lower opening regulatory asset base (RAB) for the 2019/20 year than was forecast in our draft decision (-1.76%);

45 Values calculated at "an industry-wide level" are from the summation of the values for 15 EDBs that will be subject to the DPP3 determination. These EDBs exclude Powerco and Wellington Electricity which will continue to be subject to their CPP determinations.

46 Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Updated draft models – Companion Paper" (25 September 2019)

2.35.3 for capex, the use of 2019 AMP forecasts and 2019 actual data (+1.47%); and

2.35.4 for opex, use of updated cost escalator and base year data (+0.37%).

2.36 Input data changes since the draft decision are not uniform across all distributors. In particular, changes that affect opex and capex allowances, and changes in the opening RAB for each distributor result in significant differences.

Changes to DPP3 policy decisions

2.37 In addition to the changes in input data, changes in policy decisions since the draft have also affected revenue allowances. These changes relate to forecasts of opex and capex, and in one case, the X-factor we have applied.

2.38 For opex forecasts, the principle changes affecting revenue allowances are:

2.38.1 the removal of FENZ levies, pecuniary penalties and operating leases from forecast opex;

2.38.2 use of household growth forecasts, rather than population growth forecasts; and

2.38.3 updates to the elasticities for network and non-network opex.

2.39 For capital expenditure, the most material change is to how we calculate the 'fall-back' for suppliers where their AMP forecasts do not pass a gating test. Beyond that, our updated approach to system growth, and the introduction of dollar-amount caps on non-network and asset relocation capex affect certain suppliers' allowances.

Impact on consumer bills

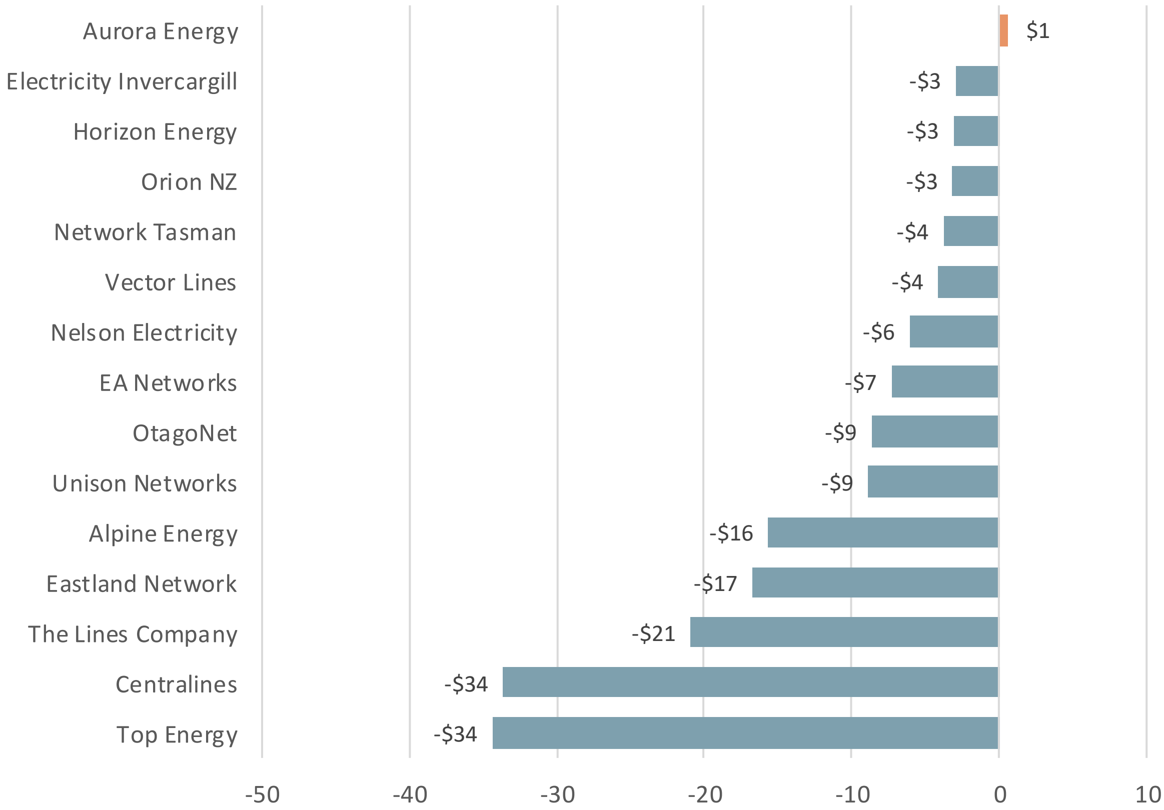
2.40 Our decision is likely to impact the prices that end-consumers will pay because of the effects on the revenues that distributors can recover. Electricity distribution charges compose 27% of an average consumer's bill, and electricity transmission charges compose a further 11%.[47] The combined effect on consumer bills of changes to distributor and Transpower allowed charges is estimated in Figure 2.6 below.

2.41 Note that this presents the change based on distributors' revenue allowances, not on the actual revenue they have been recovering. Where a distributor is pricing below its revenue cap, the change will be less significant.

[47] Electricity Authority "What makes up my power bill?" (as of 15 November 2019).

2.42 Finally, note that it is generally retailers who pass on distribution charges to consumers. As businesses operating in a competitive market, we would expect retailers to eventually pass on the lower cost of distribution and transmission charges. However, the Commission does not regulate the prices retailers can charge, and other factors influencing retail pricing may offset (or exacerbate) the indicative numbers below.

Figure 2.6 Indicative impact of the DPP and IPP resets on consumer bills ($/month)[48]



48 Estimated change in consumer bills, incorporating distributor and Transpower net revenue change, and the impact of the DPP IRIS.

Chapter 3 Framework

Purpose of this chapter

3.1 This chapter describes the high-level framework we have applied in making our DPP3 decisions. To do this, this chapter explains:

3.1.1 the requirements for setting DPPs under Part 4 of the Act;

3.1.2 the economic principles we have developed to aid in applying Part 4;

3.1.3 the incentives that give effect to these;

3.1.4 the low-cost DPP principles we use to help define the balance between DPP and CPP regulation; and

3.1.5 our framework for making decisions on DPP3.

3.2 It also summarises submissions on our draft decisions that were relevant to our regulatory framework, and responds to them.

Statutory purpose

3.3 Part 4 provides for the regulation of the price and quality of goods or services in markets where there is little or no competition, and little or no likelihood of a substantial increase in competition.[49] For electricity distributors, it sets out that regulation should apply in two forms:

3.3.1 ID regulation, under which regulated suppliers are required to publicly disclose information relevant to their performance.[50]

3.3.2 Default/customised price-quality regulation, under which price-quality paths set the maximum average price or total allowable revenue that the regulated supplier can charge. They also set standards for the quality of the services that each regulated supplier must meet. This ensures that businesses do not have incentives to reduce quality to maximise profits under their price-quality path.[51]

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49 Commerce Act 1986, section 52.

50 Commerce Act 1986, sections 52B and 54F. As per section 54, information disclosure applies to all EDBs subject to Part 4.

51 Commerce Act 1986, sections 52B and 54G. As per section 54F, default/customised price-quality regulation applies only to EDBs who do not meet the consumer-owned criteria set out in section 54D. EDBs subject to a default price-quality path have the option of applying for a customised price-quality path to better meet their particular circumstances (section 53Q).

3.4 To set a DPP, Part 4 specifies a number of requirements and limitations which we must follow:

3.4.1 the scope and application of the regulatory rules and processes, referred to as IMs, which we are required to set for Part 4 regulation;[52]

3.4.2 the content and timing of price-quality paths;[53]

3.4.3 what the determinations used to set DPPs must specify;[54]

3.4.4 requirements when resetting DPPs;[55] and

3.4.5 how we consider incentives and the avoidance of disincentives for energy efficiency, demand-side management, and the reduction of losses.[56]

3.5 We must also consider the Part 4 purpose and what default/customised price-quality regulation is intended to achieve when making our decisions.

Purpose of Part 4

3.6 Section 52A of the Act sets out the purpose of Part 4 regulation:

> (1) The purpose of this Part is to promote the long-term benefit of consumers in markets referred to in section 52 by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services—
>
> (a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and
>
> (b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and
>
> (c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and
>
> (d) are limited in their ability to extract excessive profits.

3.7 The key component of this statement is that we are to promote the long-term benefit of consumers, and this is our primary concern in achieving the purpose of Part 4. Section 52A guides us that this is to be achieved by promoting outcomes that are consistent with outcomes produced by competitive markets, and gives us four objectives to pursue that are considered consistent with those of competitive markets.

[52] Commerce Act 1986, section 52P(3).

[53] Commerce Act 1986, section 53M.

[54] Commerce Act 1986, section 53O.

[55] Commerce Act 1986, section 53P.

[56] Commerce Act 1986, section 54Q.

3.8 In practice, when setting a DPP, it is important to note:

3.8.1 We do not focus on replicating all the potential outcomes or mechanisms of workably competitive markets; we focus on promoting the section 52A outcomes.

3.8.2 None of the objectives listed in section 52A(a) to (d) are more important than the others, and they are not separate and distinct from each other, nor from section 52A(1) as a whole. Rather, we must balance the section 52A(1)(a) to (d) outcomes, and exercise judgement in doing so.[57]

3.8.3 When exercising this judgement we are guided by what best promotes the long-term benefit of consumers.[58]

3.9 In submitting on our issues paper, Meridian raised concerns that:

> the Issues Paper does not place sufficient emphasis on alignment of distribution sector outcomes with those occurring in competitive markets. The Issues Paper states the Commission will balance the section 52A(1)(a) to (d) outcomes and exercise judgment in doing so, but does not appear to acknowledge that each of those outcomes needs to be pursued to a degree consistent with that which occurs in competitive markets…
>
> … it is not enough, for example, that distribution businesses have some degree of incentive to pursue efficiency, or that they have some incentive to share efficiencies, or that they face some limitations in their ability to make excessive profits. [59]

3.10 In general, we agree with Meridian that it is important to highlight the importance of outcomes in workable competitive markets as a benchmark against which to measure the incentives we create for suppliers. However, we caution that this comparison cannot be done with precision in all cases, and that we must weigh the relative risks to the long-term benefit of consumers when faced with this uncertainty (for example, when considering the risk of under-investment – below a level which would be expected in a competitive market – and over-investment).

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[57] *Wellington International Airport Ltd & others v Commerce Commission* [2013] NZHC 3289, paras 684.

[58] See the discussion of our decision to adopt the 75th percentile for WACC in *Wellington International Airport Ltd & others v Commerce Commission* [2013] NZHC 3289, paras 1391-1492.

[59] Meridian Energy "2020-2025 Distribution default price-quality path – Issues paper" (20 December 2018), p. 2.

3.11 In its submission on the draft decision, Entrust focused on the investment limb of the purpose, saying:

> Care is needed to ensure Part 4 regulation does not inhibit needed investment: The Commission faces a difficult balancing act between operating Default Price-Quality Path (DPP) regulation in a low-cost manner, while recognising 'one size does not fit all'. Particular care is needed around elements of price-quality regulation which impact the extent lines companies can invest and maintain or improve network resilience and reliability.[60]

3.12 We share Entrust's view that promoting incentives for distributors to invest is important, and several of the decisions discussed later in this paper (such as provision for reopeners, our approach to capex forecasting, and quality incentives) have been made with this in mind. However, while the approach we take to setting the DPP should not be characterised as 'one-size-fits-all', there is a limit to the extent and materiality of distributor-specific circumstances we can account for under a DPP.

Purpose of DPP/CPP regulation

3.13 Section 53K of the Act sets out the purpose of default/customised price-quality regulation:

> The purpose of default/customised price-quality regulation is to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances.

3.14 We have taken this purpose to mean that:

3.14.1 DPPs are to be set in a relatively low-cost way, and are not intended to meet all the circumstances that a distributor may face; and

3.14.2 CPPs are intended to be tailored to meet the particular circumstances of an individual distributor.

3.15 To meet the relatively low-cost purpose of DPP regulation, we must take into account the efficiency, complexity, and costs of the price-quality regime as a whole when resetting the DPP. What this means in practice will vary over time and between sectors.

3.16 In the DPPs we have set since we determined the IMs, we have developed a combination of low-cost principles:

3.16.1 applying the same or substantially similar treatment to all suppliers on a DPP;

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[60] Entrust "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 1.

3.16.2 setting starting prices and quality standards or incentives with reference to historical levels of expenditure and performance;

3.16.3 where possible, using existing information disclosed under ID regulation, including suppliers' own AMP forecasts; and

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

3.17 In its submission on our issues paper, when discussing the relationship between DPPs and CPPs, Mercury Energy noted that "distributors are increasingly applying for CPPs which calls into question the effectiveness of the DPP regime".[61]

3.18 We do not agree with this framing of CPP applications. In some cases, distributors will face unique circumstances which require changes to the prices they charge their consumers, the quality they deliver (including how this is measured), or the incentives they face which we cannot properly assess under the DPP. In these cases, a CPP is the right outcome, and should not be considered a sign of regulatory failure.

3.19 This is demonstrated in the CPP applications we have received to date.

3.19.1 The CPP that applied to Orion was in direct response to the Canterbury earthquakes that had a catastrophic effect on its network in particular.

3.19.2 In the case of Wellington Electricity its CPP was to cater specifically for resilience preparedness, the timing and extent of which had a particular impact on the Wellington region, and for which we were able to implement specific mechanisms to incentivise the delivery of the programme of work.

3.19.3 Powerco's CPP application was to deal with a specific need to renew ageing assets while at the same time addressing specific rapid growth across its Eastern network, which involved a level of expenditure and price increase not proportionate to the scrutiny we can apply under a DPP.[62]

3.20 However, we agree that it is important to avoid unnecessary CPP applications which address issues that could be accommodated for under a DPP.

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61 Mercury "Default Price-Quality Paths for Electricity Distribution Businesses from 1 April 2020" (20 December 2018), p. 2.

62 The specific details of our CPP decisions in respect of these businesses can be found on our website at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-price-quality-paths/electricity-lines-customised-price-quality-path.

3.21 The ENA and its members, in their submissions on the draft decision, pointed to the balance between CPPs and DPPs when considering solutions to particular issues facing the sector:[63]

> ENA members have been considering there may be an intermediate way (between the DPP and a CPP) of bringing medium sized investment projects into the regulatory process without the expense and time involved in a CPP. Wellington Electricity showed the way with its earthquake readiness CPP, founded on a government policy statement. Responding to the government ICCC electrification policy seems like a similar situation, where an 'in-between' business case/project regulatory structure is established to leverage off the low-cost DPP process but avoid the expensive CPP process.
>
> The solution may fall under the existing DPP process, but the business case evaluation could take place at any time within a DPP timeline (not just at reset dates) providing the flexibility to EDBs to respond to government/NZ Inc policy objectives.

3.22 Vector noted:

> Equating the low-cost principle underpinning the DPP framework with applying a 'one-size-fits-all' approach to setting allowances – as the draft DPP3 decision appears to do – unfairly penalises EDBs that are facing circumstances like we are and have put significant effort into preparing their AMPs.[64]

3.23 Wellington Electricity expressed support for the decision-making framework (while at the same time noting instances where it thought the decisions could be improved):

> WELL supports the Commission's key goal of the Default Price/Quality Path (DPP) framework of providing a stable (consistent and predictable) regulatory platform by retaining the low cost approach by making incremental improvements to the DPP2 model.[65]

3.24 We have considered the ways the DPP can be improved to respond to these kinds of challenges. Examples of this include an expanded capex reopener, and the approach we have taken to assessing AMP capex, taking more account of distributor circumstances than in DPP2. However, there is a limit to our ability to do this without deeper scrutiny.

3.25 We do not agree with Vector's assertion that the DPP framework unfairly penalises distributors facing specific circumstances. Our consistent approach to DPP/CPP regulation – based on section 53K of the Act – is that CPPs are the appropriate tool for responding to circumstances that are specific to an individual distributor and that cannot be accommodated in a low-cost way. DPPs by contrast deal with issues facing distributors generally, in a relatively low-cost way and applying a generic approach.

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[63] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 39.

[64] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[65] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

3.26 A DPP is not intended to deal with circumstances that require significant scrutiny of costs and/or quality targets of a particular distributor. Where a DPP cannot be sufficiently tailored to meet specific distributor circumstances, two additional options already exist within the existing Part 4 regulatory framework to appropriately cater for these.

3.27 The first of these is a DPP quality reopener where a distributor believes it may not be able to meet the quality standards set under a DPP. The precise requirements for seeking a quality standard variation are set out in the existing regulatory framework.[66]

3.28 The second option is for a distributor to consider applying for a CPP. A CPP can be tailored to meet the specific needs of a distributor's customers, and also provides the flexibility to generally deal with uncertainties that an individual distributor may encounter.[67]

Our framework for making decisions on DPP3

3.29 In addition to the section 52A and 53K purpose statements, we use a decision-making framework and set of economic principles that we have developed over time to support our decision-making under Part 4. These have been consulted on and used as part of prior processes, and help provide consistency and transparency to support our decision making in giving effect to the statutory purpose.

Decision-making framework for DPP3

3.30 For this decision, we have in general retained approaches from the second EDB DPP (DPP2) where they remain fit for purpose.[68] We have made changes to the DPP2 approaches where those changes would:

3.30.1 better promote the purpose of Part 4;[69]

3.30.2 better promote the purpose of default/customised price-quality path regulation;[70]

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[66] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clauses 4.5.5.

[67] Commerce Act 1986, section 53Q

[68] These DPP2 approaches are discussed in the relevant attachments to this paper. However, a full discussion of the DPP2 decision can be found in: Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 – Main Policy paper" (28 November 2014).

[69] Commerce Act 1986, section 52A.

[70] Commerce Act 1986, section 53K.

3.30.3 better promote incentives for suppliers of electricity lines services to invest in energy efficiency and demand-side management, and to reduce energy losses (or better avoid disincentives for the same);[71] and

3.30.4 reduce unnecessary complexity and compliance costs.

3.31 This approach has been adapted from the 2016 IM review framework, and a similar framework was applied when resetting the DPP for gas pipeline businesses in 2017. We consider it will help ensure consistency with the low-cost purpose of the DPP.[72]

3.32 Submitters were generally supportive of this framework, and in particular the benefits it creates in terms of regulatory certainty.[73]

3.33 The ENA, while supportive of the framework overall, cautioned that we must not impose changes to quality standards without considering the impact on costs (and therefore revenues).[74]

3.34 Unison in its submission highlighted the importance of not only consistency, but of change in response to future circumstances:

> In general, we support the incremental approach being adopted – building on DPP2, and also note the constraints on the Commission looking at the detailed circumstances of each business under DPP Regulation…
>
> Overall, we think it is important that the reset is not just a mechanical application of models, but that where necessary adjustments are made to accommodate a reasonable forecast of the likely operating environment for EDBs in the 2020 to 2025 period and beyond.[75]

3.35 We agree with this sentiment, and as discussed in Chapter 4 below, our decisions have been made in many cases to respond to a changing industry context.

3.36 In addition to the above, we have also made changes that:

3.36.1 implement any required changes as a result of the 2016 IM review; and

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71 Commerce Act 1986, section 54Q.

72 Commerce Commission "Default price-quality paths for gas pipeline businesses from 1 October 2017 – Final reasons paper" (31 May 2017) paras 2.19-2.22.

73 Mercury "Default Price-Quality Paths for Electricity Distribution Businesses from 1 April 2020" (20 December 2018), p. 3; Fonterra "Consultation Paper EDB DPP3 Issue Paper" (20 December 2018); page 1.

74 Electricity Networks Assoc (ENA) "DPP3 April 2020 Commission Issues paper(Part One Regulating capex, opex & incentives)" (20 December 2018), p. 10.

75 Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018), p. 2.

3.36.2 where appropriate, carry across new approaches developed during the DPP we set in 2017 for gas pipeline businesses and for recent CPPs.[76]

3.37 Our goal when applying this framework to DPP3 has been to provide a stable regulatory platform within a changing industry context, while making incremental improvements to the way we regulate price and quality.

3.38 This includes revenue allowances set based on current and projected profitability and setting quality standards with reference to historical levels of performance.

3.39 In its submission on the draft decision, the ENA did not believe the decisions as presented in the draft "struck the right balance in the draft decision for this goal".[77]

3.40 We have recognised that substantial changes are occurring in the electricity sector. In part, this is driven by an increasing focus on decarbonisation and by the increasing affordability of technologies that provide both distributors and consumers with new opportunities. However, we recognise that there is uncertainty as to the extent, timing, and impact of these changes.

3.41 We have endeavoured to improve the balance between consistency and incremental improvement from the draft decision. Specific changes we have made are discussed in the relevant chapters and attachments of this paper.

Economic principles

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

3.42.1 Real financial capital maintenance (FCM): we provide regulated suppliers the ex-ante expectation of earning their risk-adjusted cost of capital (a 'normal return'). This provides suppliers with the opportunity to maintain their financial capital in real terms over timeframes longer than a single regulatory period. However, price-quality regulation does not guarantee a normal return over the lifetime of a regulated supplier's assets.

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

[76] Commerce Commission "Wellington Electricity's customised price-quality path – Final Decision" (28 March 2018); Commerce Commission "Powerco's customised price-quality path – Final Decision" (28 March 2018).

[77] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

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

3.43 We elaborated on each of these principles and how they should be applied in the context of price-quality regulation in our 2016 IM review framework paper.[78]

Incentives framework

3.44 When seeking to promote the statutory purposes and apply the DPP and economic principles above, the tools we have are the incentives the Part 4 regime directs us to create. These are set out in Table 3.1 below.

[78] Commerce Commission "Input methodologies review decisions: Framework for the IM review" (20 December 2016), pages 38-49.

Table 3.1 Incentive drivers for electricity distribution businesses

Incentive driver	Effects
Opex forecasts and IRIS	Provide a constant incentive for distributors to achieve operating cost efficiencies over a regulatory period. This is in the interests of consumers, as efficiency savings are shared with consumers. However, the revenue path may encourage over-forecasting and under-spending.
Capex forecasts and IRIS	Provides a constant incentive for distributors to achieve capital cost efficiencies over a regulatory period. This is in the interests of consumers, as efficiency savings are shared with consumers. DPP3 incentive rate is equal to opex IRIS, which should reduce incentive for distributors to favour capex solutions to investment needs.
WACC uplift	Mitigates the risk of under-investment due to any mis-estimation of the WACC. Our expectation is that this uplift may provide distributors with incentives to invest in assets and earn a higher than midpoint return, although because we cannot observe the actual WACC this incentive effect is unknown.
Quality standards	Encourages investment in, and maintenance of, the network to not let quality degrade below a certain level. Gives an incentive to provide a minimum standard of quality. The standard mitigates the broad expenditure incentives to let quality deteriorate over time.
Quality incentive scheme	Defines the range within which distributors can make marginal trade-offs between the quality and price of the services they provide. DPP3 standard is linked to VoLL, to approximate the value customers place on reliability, and a sharing factor that matches the IRIS retention factor, so benefits are shared between consumers and distributors.
Innovation allowance	Additional allowance that effectively reduces the incentive rate for innovative projects (passes some costs on to consumers, who we consider are more likely to benefit from certain kinds of innovation).
Reopeners	New measure to mitigate disincentive (created by IRIS) for distributors to undertake investment in response to new sources of demand and generation on their networks.
Revenue cap (new in DPP3)	Distributors have a revenue allowance over a DPP/CPP period that does not vary based on volume. This incentivises distributors to find solutions which reduce demand (and therefore capex) without putting revenue recovery at risk. Additionally, unlike a price cap, the compliance difficulties of introducing new tariff structures are lower.
Reporting requirements (ID)	Provides transparency to stakeholders on how the distributor operates its network and its performance. Encourages distributors to act as a prudent network operator.

Chapter 4 Responding to changes in the electricity sector

Purpose of this chapter

4.1 We recognise that substantial changes are occurring in the electricity sector, driven by an increasing focus on decarbonisation as well as increasing affordability of certain technologies that provide new opportunities to distributors and consumers. However, there is uncertainty as to the extent, timing, and impact of these changes. This was highlighted in a number of submissions on the issues paper, such as those from the ENA and Unison.[79]

4.2 This chapter outlines our consideration of these changes and the potential effects on distributors and our regulatory settings during the DPP3 period. Specifically, this chapter includes:

4.2.1 our view of electricity sector changes;

4.2.2 views from submissions on the issues paper;

4.2.3 consumer engagement in the changing electricity sector;

4.2.4 our response to the changing electricity sector, in terms of: uncertainty, innovation, and responses outside the DPP.

4.3 More detail on the relevant new mechanisms of the DPP reset are provided in the attachments to this paper.

4.4 The changes to the sector are also receiving focus from us outside of DPP resets, including our cooperation and collaboration with other agencies, such as the Ministry for Business, Innovation, and Employment and the Electricity Authority. This collaborative work is particularly focused on issues relating to distributors' involvement in contestable markets, and in better understanding the likely impacts of future industry changes.

4.5 The government has also noted in its response thus far to the Electricity Price Review that innovation in the electricity sector should be prioritised.[80]

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[79] ENA "DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)" (20 December 2018); Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018).

[80] MBIE "Electricity Price Review: Government Response to Final Report" (3 October 2019).

Our view of electricity sector changes

4.6 An increasing focus on decarbonisation will likely lead to an increase in the electrification of the transport and industrial sectors because of the low carbon intensity of electricity compared to fossil fuels. This change will be furthered by the increasing availability and affordability of relevant technologies, like electric vehicles.

4.7 The changes in demand patterns and potential increase in demand may require additional traditional investment in the networks. However, networks may also be able to meet some of these changes through more flexible solutions offered by smart grid technologies.

Submissions on the issues paper and draft decision

4.8 Many of the submissions on the issues paper and draft decision reasons paper discussed emerging technologies, such as electric vehicles, and some linked these changes to decarbonisation. Submissions raised emerging technology as both an opportunity (particularly for consumers) and a challenge (particularly for distributors). The main challenge raised from emerging technology was uncertainty, particularly uncertainty in demand forecasts.

4.9 For example, the ENA said:

> Emerging technology presents both uncertainty and opportunity for asset management and investment decisions by EDBs. The Commission should work in partnership with EDBs by providing incentives that support innovative and efficient approaches to asset management, system management and customer interfaces.[81]

4.10 Electricity Retailers Association of New Zealand (ERANZ) recognises the possibility of similar issues, saying:

> Some of this investment assumes that emerging technologies (distributed generation technologies such as solar PV systems and batteries, and electric vehicles) will be adopted en masse by consumers. Rapid adoption at scale - coupled with the uptake of applications enabled by emergent technology such as peer- to-peer trading, demand side response, and home energy management systems - would change traditional network demand patterns.[82]

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[81] ENA "DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)" (20 December 2018), p. 6.

[82] ERANZ "Submission on the default price-quality paths for electricity distribution businesses from 1 April 2020 (DPP) Issues paper" (21 December 2018), p. 3.

4.11 However, ERANZ also submitted that:

> Most businesses facing the risk of disruptive technology change operate in a competitive market and therefore bear the risks – both positive and negative - of investing for a future that may or may not eventuate. This is not the case for lines monopolies. Consumers will pay for network upgrades regardless of whether the demand forecasts underpinning those investments eventuate.[82]

4.12 Many submissions also addressed the new reopener and innovation incentive mechanisms that we proposed in the draft decision. Submissions generally supported the introduction of an innovation incentive mechanism but submitted that it needed to be scaled up to be effective. Submissions were also supportive of the new reopeners, but proposed increasing their scope.[83]

Consumer engagement in the changing electricity market

4.13 As new technologies and the progress towards decarbonisation make the electricity market more flexible and dynamic, the relationships and communication between the different parties will become increasingly complex and important. This means that both distributors and the Commission will need to do more work in engaging consumers.[84]

4.14 Facilitating a greater consumer voice in the electricity market is also clearly evidenced and supported in the final paper published by the Electricity Price Review.[85]

4.15 While we regularly receive useful input from some consumer parties and representatives like ERANZ, MEUG, and retailers, we have found that the views of end-use electricity distribution service consumers could be better represented in our regulatory processes. In part, this may be due to the complexity of the regulatory regime and competing priorities for consumers and their representatives. We will be working to improve this over time outside of this reset of DPP settings.

4.16 We also consider that transparency and accountability of distributors is an important part of our regulatory regime, that works alongside financial incentives, and supports consumer engagement. We consider that increased focus on the delivery of network investment and maintenance would be helpful in improving the performance of electricity distributors. This would help make them more accountable to their customers and better demonstrate how they are responding to changes in the sector. This is described further in Attachment N.

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[83] See for example: Powerco “Submission on EDB DPP reset draft decisions paper” (18 July 2019) and Vector “Submission on EDB DPP reset draft decisions paper” (18 July 2019).

[84] We note that the relationship between EDBs and consumers is complicated by the lack of commercial arrangement, with end-consumers generally only contracting to an electricity retailer.

[85] Electricity Price Review “Final Report” (21 May 2019)

Our response to the changing electricity sector

4.17 The remainder of this chapter explains:

4.17.1 our consideration of uncertainty from the changes in the electricity sector;

4.17.2 our view of innovation by distributors; and

4.17.3 potential regulatory responses outside of the DPP settings.

4.18 In consideration of uncertainty, we are introducing new reopeners for large system growth and new connection projects and programmes, which may increase in the near future due to decarbonisation initiatives. We are also including asset relocations in the reopener because asset relocations can be driven by external circumstances and thus cause significant uncertainty to the future level of expenditure required by distributors.

4.19 Innovation is specifically referred to in the purpose of Part 4.[86] The changes happening in the electricity sector are creating new opportunities for innovation with new technology, as well as requiring innovative responses to the new challenges faced by distributors. We are introducing a new recoverable cost to help incentivise ongoing innovation.

4.20 We have made these changes primarily through amendments to the input methodologies, so these changes are also explained in our reasons paper for the IM amendments that we have made to enable this DPP reset.[87]

4.21 Our regulatory responses outside of the DPP settings are likely to include performance analysis, compliance, and collaboration with other organisations.

Uncertainty

4.22 We recognise there are always uncertainties about what will happen during a regulatory period. However, changes in the electricity sector are meaning that there is an increased uncertainty in the level of electricity demand, distributed generation, new connections, and the way distribution networks will need to be managed.

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86 Commerce Act 1986, section 52A(1)(a).

87 Commerce Commission "Amendments to electricity distribution services input methodologies determination – Reasons paper" (26 November 2019).

4.23 One of the key issues for DPP3 is how steps taken to transition to a low carbon future will affect the networks. Distributors will need to allow for potentially large volumes of local generation (such as battery storage, solar and wind) and low carbon demand (such as electric vehicles and heat pumps) to connect efficiently and quickly.

4.24 Some of these may be large connection projects, such as a connection to enable conversion of a dairy plant from coal boilers to electric boilers.

4.25 Distributors have also submitted that asset relocation projects can be the cause of significant uncertainty.[88]

4.26 One of the concerns raised in submissions to our issues paper and draft decision reasons paper was the unknown impacts of increased demand with particular focus on the impact of electric vehicles.[89] There were a variety of suggestions and views on the best way to address these uncertainties.

4.27 Submissions on the issues paper raised the issue of the impact of demand uncertainty being greater because of the shift from a weighted average price cap to a revenue cap. For example, Alpine said:[90]

> We support the change to a revenue cap. However, we remain concerned around the form that the revenue cap will take. There is no mention in the issues paper of the mechanism for new growth for example.

Our consideration of uncertainty for DPP3

4.28 Prior to the amendments to the IMs published on 26 November 2019, the IMs and the settings for DPP2 already had a number of mechanisms to address uncertainty, particularly areas of uncertainty that significantly impacted distributors despite being largely outside their control.

4.29 There are reopeners available to distributors for:[91]

4.29.1 catastrophic events;

4.29.2 regulatory or legislative changes not accounted for when the DPP was set;

4.29.3 errors in setting the DPP;

4.29.4 major transactions;

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[88] See for example: Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019)

[89] See for example: Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018).

[90] Alpine Energy "Submission on EDB DPP3 Issues paper" (20 December 2018), p. 2.

[91] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clauses 4.5.1 to 4.5.7.

4.29.5 the provision of false or misleading information; and

4.29.6 quality standard variations that better reflect the realistically achievable performance of the distributor.

4.30 In 2016 we decided to set future EDB DPPs and CPPs as revenue caps rather than weighted average price caps.[92] Part of the rationale for this change was to reduce the impact of uncertainty in demand growth (and thus revenue growth), which the Commission was required to forecast under a weighted average price cap.

4.31 We note that costs treated as recoverable costs and pass-through costs are not an issue for distributors in terms of uncertainty because the distributor can recover the full costs without the application of IRIS, regardless of whether the costs are greater or smaller than expected. So any uncertainty in these types of costs, which are generally outside the control of the distributor such as levies, do not result in uncertainty in the distributors' profitability.

Large externally driven events

4.32 Significant, externally driven, and unforeseeable events are generally covered by the reopeners other within our DPP framework. However, while large consumer connections, system growth requirements, and asset relocations may also be significant, externally driven, and unforeseeable, none of the reopeners allow for them, prior to the IM amendments published on 26 November 2019.

4.33 Given there is limited ability for distributors to control the demand for this kind of capex, we consider that there is little incentive benefit in exposing them to this risk. The financial impact on distributors of these projects is potentially heightened given our increase to the capex IRIS retention rate.[93]

4.34 The impact of large individual consumer connections may also be greater in DPP3 because of the move to a revenue cap, which means that no additional revenue (outside of capital contributions) will be made available from unforeseen increases in demand.

[92] Commerce Commission "Input methodologies review decisions – Consolidated reasons papers" (19 December 2016).

[93] Our increase to the IRIS incentive rate for capex is explained in Attachment E.

We have introduced new reopeners for large new connections, system growth, and asset relocation projects

4.35 At our DPP workshop on uncertainty and innovation, one distributor raised the financial impact that it and other distributors face in facilitating large single consumer connections onto its network.[94] The concern is that this activity is often unforeseen at the outset of a DPP period, and can be particularly burdensome on smaller distributors where such costs represent a significant component of their overall revenue allowances. It was suggested that a specific reopener be considered to alleviate this uncertainty in DPP3.

4.36 We have introduced new reopeners in the IMs in line with the suggestion.[95] The reopeners are similar to the existing CPP 'unforeseen projects' reopener, but are targeted specifically at projects or programmes which require major capex for:

4.36.1 new connection (including alterations to existing connections);

4.36.2 system growth;

4.36.3 a combination of new connections (including alterations to existing connections) and system growth; and

4.36.4 asset relocations. [96]

4.37 The aim of the reopeners is to ensure, where possible, that distributors are able and incentivised to undertake the investment required to meet the one-off sporadic and changing needs of external stakeholders. In particular, this will ensure that distributors can connect and manage significant new demand and low carbon technologies as New Zealand increases its focus on decarbonisation, while maintaining network reliability and meeting the long-term interests of consumers. This is consistent with the Part 4 purpose, specifically in providing incentives for distributors to invest.[97]

4.38 The new reopeners, in applying to new connections, may also reduce any current incentive of distributors to encourage new connections to be arranged directly with Transpower despite connection to the distributor being a potentially more efficient option.

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94 Commerce Commission "Notes on EDB DPP3 Workshop on innovation and dealing with uncertainty" (8 March 2019)

95 Commerce Commission *Electricity Distribution Services Input Methodologies Amendments Determination (No.2) 2010* [2019] NZCC 20 (26 November 2019).

96 The 'unforeseen projects' reopener for CPPs and its application is described in 5.6.6 and 5.6.7(6) of the Commerce Commission "Electricity Distribution Services Input Methodologies Determination 2012, consolidated as of 31 January 2019" (31 January 2019).

97 Commerce Act 1986, section 52A(1)(a).

4.39 We do not intend for this mechanism to cover general growth in demand due to decarbonisation, such as high uptake of electric vehicles. Introducing a reopener for general demand growth would undermine the IMs, which require the use of a revenue cap rather than a weighted average price cap. Furthermore, we consider that the risk of out-turn network expenditure based on demand growth differing from forecast can be positive or negative, whereas a reopener would be asymmetric; the reopener would only result in a distributor potentially receiving more revenue allowance, not less.

4.40 While not included in our draft decision, Vector and Powerco also submitted that asset relocation projects have the same characteristics and should be added to the scope of the reopener that we proposed in our draft decision. [98] We accepted this in our final IM amendments decision, and have included asset relocation projects and programmes. Vector in particular sees this as a significant uncertainty and risk for them, explaining:[99]

> Driven principally by third-parties, relocations appear to meet the criteria articulated by the Commission for proposing a reopener for unforeseen major connections. Relocation activity is hard to forecast. Third-party plans such as Auckland Transport and the New Zealand Transport Agency tend not to coincide with AMP forecasting periods nor DPP setting. Activity driven by traffic authorities generally requires a standard capital contribution depending on the type of transport asset affected – however, the designation of transport assets can and do change which affects the contribution and network capex affected.
>
> Relocations could be significant over the upcoming DPP3 period given the volume of transport infrastructure development forecasted to occur. For Vector, the proposed Auckland Light Rail Transit corridor is expected to trigger a significant volume of cable relocations from 110 kV to 11 kV.

4.41 The addition of asset relocations to the reopeners was supported by Orion in cross-submissions on our draft decision.[100]

4.42 Our reopeners for large new connections, system growth requirements, and asset relocations would apply if the project, or increase in size of the project:

4.42.1 is not catered for in our forecasts of capital expenditure used to set starting prices;

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[98] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019); and Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

[99] Vector “Submission to Commerce Commission on changes to the input methodologies for electricity distributors and Transpower due 5th July” (5 July 2019).

[100] Orion “Cross submission on EDB DPP reset draft decisions paper” (12 August 2019)

4.42.2 is not covered through capital contributions, the approach taken to capital contributions is reasonable, and there is reasonable justification for the way in which the cost is going to be allocated to consumers;

4.42.3 requires additional expenditure (net of the capital contributions) by the distributor of at least 1% of revenue (excluding pass-through and recoverable costs) over the regulatory period or two million dollars per project or programme – whichever is less for the distributor; [101]

4.42.4 does not exceed the reopener cap of $30 million for additional expenditure; and

4.42.5 is evidenced as being required to a high degree of certainty.

4.43 While the new reopeners should help prevent unnecessary CPPs, we have also included a cap on the reopeners, which is important so that proportionate scrutiny can be given to larger changes in expenditure through the CPP process. We intend to reject reopener applications for which the cumulative additional expenditure is greater than the cap, even if the distributor has only applied to reopen its DPP for a portion of that expenditure.

4.44 Further detail on the requirements of the reopeners are provided in Attachment G, and are specified in the IM amendments determination.[102]

4.45 We note that the reopeners encompass increased capacity of existing connections. For example, the conversion of an existing dairy plant from coal boilers to electric boilers may be a substantial increase in capacity of the existing connection rather than a new connection.

We have set a regulatory period of five years

4.46 For DPP3 we have also considered whether we should set the DPPs to a four-year regulatory period because of the increased level of uncertainty, and the ability for us to adjust our policy settings sooner in response.[103]

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[101] 'Additional' expenditure refers to expenditure that is not required by the EDB in the absence of the connection project.

[102] Commerce Commission *Electricity Distribution Services Input Methodologies Amendments Determination (No.2) 2010* [2019] NZCC 20 (26 November 2019), clause 4.5.5A and 4.5.5B.

[103] Section 53M(4) of the Commerce Act 1986 states that the length of a DPP must be five years. However, section 53M(5) provides for the Commission to set a period of between four and five years, if we consider it would better meet the purpose of Part 4.

4.47 In our issues paper the option was put to stakeholders of transitioning to a four-year regulatory period. No potential compensation for impacts were raised in the paper, but, in practice, compensation would be considered for costs of additional hedging and swaps and we would likely include some mitigations to address stakeholder concerns. In our draft decision, we proposed retaining a five-year regulatory period.

4.48 None of the submissions on our issues paper expressed a preference for either a four-year or five-year regulatory period, and we received few submissions on the topic in consultation on our draft decision.

4.49 We specifically raised this topic at our second DPP3 stakeholder workshop in March 2019.[104] Attendees expressed no interest to move to a four-year regulatory period for the following reasons.

4.49.1 Changing the regulatory period creates increased interest rate hedging risk which is a major concern for distributors. A longer reset period provides more certainty for distributors in managing this risk as it is locked-in for longer. It would also require more resource to be allocated to this activity which will be conducted more frequently.

4.49.2 Distributors will find it harder to secure capital for long-term capex projects because creditors will have less certainty as to what settings will be in four- and ten years' time.

4.49.3 There are major concerns on the implications of how IRIS adjustments would be calculated and applied.

4.49.4 The WACC would need to be re-calculated, creating uncertainty.

4.49.5 Distributors require the certainty of a longer price control period to fully consider investing in longer term innovation projects during the period.

4.49.6 More frequent DPP resets would increase compliance costs.

4.49.7 In combination, the above factors are likely to result in more uncertainty for distributors and the wider electricity sector.

[104] Commerce Commission "Notes on EDB DPP3 Workshop on innovation and dealing with uncertainty" (8 March 2019).

4.50 MEUG submitted on our draft submission that a four-year regulatory period would help support their proposal to delay the introduction of any innovation incentive mechanism until DPP4. However, we consider that this minor potential benefit would not justify over-riding significant concerns raised in the workshop. Further, this benefit will not fully occur because we have introduced an innovation incentive mechanism for DPP3.[105]

4.51 Given the above reasons, we are not transitioning to a four-year regulatory period because we consider that any potential benefits are outweighed by the complications caused by applying a four-year regulatory period. At this stage, we do not consider a four-year regulatory period for DPP3 would better meet the purposes of Part 4 of the Act. In particular, our assumption is that distributors have in place swap contracts for the next regulatory period assuming a five-year term for the WACC, and that any change to a four-year regulatory period is likely to disrupt that process.

Innovation

4.52 We expect there to be more scope for innovation and its potential benefits now than in the recent past. Changes in technology have increased opportunities for electricity distributors to innovate as well as creating challenges that distributors may address through new practices. Innovation is an important consideration for us as it is one of the performance areas referred to in the purpose of Part 4.[106]

4.53 We consider innovation to be the practice of distributors putting technologies, processes, or approaches, which have not been used in similar circumstances in New Zealand by distributors before, into practice for the benefit of the electricity distribution service.

4.54 We accept there is some evidence that suggests the level of innovation is currently insufficient to realise all of the potential benefits, although this evidence is not completely clear and does not relate solely to electricity distributors. For example:

4.54.1 Only 7% of energy sector businesses are conducting research and development, which is much less than other sectors.[107]

4.54.2 Energy sector expenditure on research and development decreased between 2007 and 2016.[107]

[105] MEUG "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[106] Commerce Act 1986, section 52A(1).

[107] Vic Crone, Callaghan Innovation “Driving Clean, Smart Energy and Radical Services Integration” — presentation at Downstream 2018 conference.

4.54.3 For the 2018 regulatory year, distributors reported a total of less than $10m expenditure on research and development (compared to total lines charges of around $2.5b).[108]

4.54.4 New Zealand businesses focused solely on domestic markets are less likely to innovate and any innovation results in lower levels of productivity improvement.[109]

4.55 However, we also note that we have already seen several examples of beneficial innovative practices by distributors through our programme of distributor site visits and through the distributors' AMPs. For example, we noted the introduction of incipient fault waveform recognition technology as an innovative practice that could help distributors prevent interruptions.[110]

Our consideration of innovation in DPP3

4.56 While innovation can be very beneficial to consumers, it typically requires expenditure by the distributor, and may also require additional incentives that are ultimately paid for by consumers. It is difficult in practice to pinpoint the optimal level of expenditure on innovative practices, weighing up the costs and possible benefits. On balance, we consider that there is a material risk that the existing incentives for innovation are insufficient and that more expenditure on innovative practices would likely be in the long-term interests of consumers.

4.57 We received several submissions on innovation on our issues paper, held a workshop on 8 March 2019 to discuss the issues of innovation and uncertainty with stakeholders, and consulted on a proposed new innovation mechanism in our draft decision. The main points made in submissions on the need for stronger incentives for innovation were covered submissions from Unison, the ENA, and Vector.

[108] From information disclosure, although there may be under-reporting.

[109] Productivity Commission "Innovation and the Performance of New Zealand Firms—Staff working paper 2017/2" (November 2017).

[110] This innovative practice, along with others, was noted in the report: Commerce Commission "Observations from our review of Electricity Distribution Businesses' 2016 and 2017 Asset Management Plans" (31 July 2018).

4.58 Unison's submission explained its position that the incentives through IRIS are sometimes insufficient for innovation because the benefits may not be expected until future regulatory periods.[111] Vector and the ENA provided reports by consultants FTI Consulting and The Brattle Group respectively, which focused on incentives for innovation in overseas regulatory regimes.[112]

4.59 The Brattle Group report provides an overview of the relevant regulatory measures in Great Britain, Australia, New York, Illinois, and California. It reflects on the implications of these for the DPP reset in New Zealand. Specifically for innovation, the report explains that the additional mechanisms (particularly the use of additional pass-through cost mechanisms) in other jurisdictions suggests that the basic regulatory regime is insufficient to incentivise innovation, so an additional change should be considered. It also suggests that incentive equalisation for capital expenditure and operating expenditure is important too.

4.60 Similarly, the FTI Consulting report suggested that additional regulatory tools are required and provided case studies of tools used overseas. Great Britain and Norway were included as case studies of direct mechanisms for customers to fund innovation. In Great Britain, three pass-through cost mechanisms are in place with greater levels of scrutiny and complexity for the greater amounts of expenditure (including a competitive pooled fund). In Norway, a simpler limited pass-through cost, which requires external validation by an appropriate body, is in place.[112]

4.61 The FTI Consulting report concluded that we should:

> Consider introducing incremental targeted innovation-focused incentives (e.g. an allowance subject to cost-benefit analysis) in the short term, to support customer expectation of innovation but also to improve customer experience. Reserve more complex innovation tools (e.g. competition for funding) for the longer term, so that EDBs have time to prepare and to avoid undue regulatory disruption in the industry.[113]

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111 In its submission on the Issues Paper, Unison said "there are no incentives or compensation for EDBs to undertake research and development unless benefits can be realised within the regulatory period"— Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018), para 20.

112 FTI Consulting (commissioned by Vector) "Regulatory Blueprint to meet today's customer expectations, Final Report" (9 November 2018); The Brattle Group (commissioned by the Electricity Networks Association) "Incentive Mechanisms in Regulation of Electricity Distribution: Innovation and Evolving Business Models" (October 2018).

113 FTI Consulting (commissioned by Vector) "Regulatory Blueprint to meet today's customer expectations, Final Report" (9 November 2018), p. 11.

4.62 Meridian stated in its cross-submission on the issues paper that it does not accept the assertions that new innovation allowances may be needed.[114] Meridian's reasoning was that future needs should not distract from regulatory issues that are more certain and more of a priority.

4.63 We also received suggestions in submissions on the issues paper and at the workshop on 8 March 2019 that were outside the remit of the DPP reset, such as a suggestion that section 52A (the purpose of Part 4) should be amended to take into account issues like climate change mitigation. There was significant discussion in our workshop about the more technical details of what innovative projects might be, such as low voltage network monitoring.

4.64 Submitters also discussed the context giving rise to a greater need for innovation—particularly the need for climate change mitigation, the expected steep uptake of electric vehicles, and the increase of two-way flows on the networks from distributed energy resources including solar photovoltaics and batteries.[115]

There are several incentive mechanisms already available to promote innovation

4.65 There are several funding mechanisms already available to distributors for innovation investment, including:

4.65.1 increased returns through the IRIS mechanism from efficiency gains;

4.65.2 non-regulated income can be generated if an innovation can be sold to other businesses; and

4.65.3 external funds and support are also available (some would require partnering with other organisations), such as the Endeavour Fund, Callaghan Innovation funding and/or services, Research and Development Tax Credits, the Provincial Growth Fund, the Energy Efficiency and Conservation Authority, and the Green Investment Fund, and through the Energy Development Centre.

4.66 IRIS provides an incentive for distributors to innovate where innovation reduces capital or operating expenditure. We recognise that there are other incentives for distributors to innovate, including some outside of the regulatory regime.

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[114] Meridian Energy "2020-2025 Distribution default price-quality path – Issues paper" (20 December 2018).

[115] For example, in ENA "DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)" (20 December 2018).

4.67 There may also be some incentive for research and development and innovation from the ability for distributors to sell the intellectual property or resulting products and services in other contestable markets. However, we expect that the cost allocation rules will be correctly applied so that the consumers of distribution services are not paying for these benefits that accrue to others.

4.68 We note that if the innovative practices are developed by third parties supplying the distributor, then the income from future sales of the innovation are likely to accrue to the third-party rather than the distributor.

4.69 We expect that the introduction of a new innovation incentive mechanism may provide seed funding that supports innovative projects that gather finance and funds from the other sources listed above in addition to the recoverable cost.

4.70 We also consider that the move to a revenue cap, as decided in the 2016 IMs review, better promotes innovation for distributors. The change to a revenue cap means that distributors are not penalised through reduced revenues by implementing solutions that lower demand. The revenue cap will also simplify the process of tariff reform, allowing more innovation in pricing.

We are introducing a new recoverable cost for innovative expenditure

4.71 Despite the existing funding already available to distributors for innovation, they may be insufficient because in some instances the potential benefits of the investment may go to third parties, be uncertain, or may not eventuate until future regulatory periods.[116] Distributors may be more likely to invest in options (like traditional poles and wires investments) that have clearer benefits that can be more easily quantified.

4.72 This is particularly the case for small projects where the direct benefits are uncertain, but the greater benefit may be in the learning that can result. These greater benefits can be from the distributor introducing the innovative practice more extensively across its network and from other distributors introducing this practice. In such a situation, a lot of the greater benefits may not occur until later regulatory periods, and thus may not be recognised as greater returns for the distributors, particularly if the savings are from capital expenditure.

[116] In its submission on the Issues Paper, Unison said "there are no incentives or compensation for EDBs to undertake research and development unless benefits can be realised within the regulatory period—Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018).

4.73 Distributors may be less likely to envisage commercialising any benefits of innovation through selling to other distributors or other industries. This would result in lower incentives to innovate than if such opportunities were pursued. We expect that cost allocation rules would be correctly applied so that consumers only pay for the portion of expenditure that benefits the network service.

4.74 We are seeking to promote further innovation in a relatively low-cost way by introducing a new limited recoverable cost term as a change to the IMs. We consider that having some of the cost of a potential innovative practice covered by a recoverable cost will encourage greater innovation by distributors. We have decided to introduce this for DPP3 based on the range of factors outlined above.

4.75 The new recoverable cost term will:

4.75.1 target expenditure on innovative projects;

4.75.2 require a 50% contribution from the distributor;[117]

4.75.3 be limited to the amounts specified in Figure F1 in Attachment F, which adds up to approximately $6 million across all non-exempt distributors over the DPP3 regulatory period, excluding those currently on CPPs; and

4.75.4 require a report from an independent engineer or suitable specialist that the planned expenditure meets a simple list of criteria to show that the project is expected to be innovative and potentially benefit consumers.[118]

4.76 We received a number of submissions on our draft decision that our proposed limits on the recoverable cost were too low.[119] Vector also submitted that a two-tiered approach could be used with stricter regulation of the distributors that choose a higher level of innovation incentive.[120] The limits in the draft decision were similar to that in this final decision, except that we have set a minimum of $150,000 in our final decision, which increases the potential size of the recoverable cost for smaller distributors.

[117] The contribution from EDBs should be treated as regular capital or operating expenditure, while any capital expenditure under the recoverable cost will not enter the regulated asset base to avoid double recovery.

[118] The recoverable cost would be specified in the EDB IMs. The criteria we have set out here would be included in the EDB DPP determination.

[119] Such as Entrust "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

[120] Vector "Submission to Commerce Commission on changes to the Input Methodologies for Electricity Distributors and Transpower due 5th July".

4.77 We have considered these submissions, but still consider that it is best at this stage to introduce the new recoverable cost in DPP3 with a low limit and a requirement of substantial co-funding with regular operating or capital expenditure because of the substantial risks and downsides of the new recoverable cost.

4.77.1 The innovation recoverable cost may cover expenditure that would have happened without its introduction, resulting in a higher cost for consumers without any additional long-term benefit.

4.77.2 There is some compliance cost involved for independent assessment of projects, which may prevent uptake given the relatively small limit on the recoverable cost.

4.77.3 The innovation recoverable cost does not directly facilitate collaboration between industry participants.

4.77.4 Consumers will pay for a substantial proportion of the projects (up to a the recoverable cost limit plus the IRIS impact of regular capital or operating expenditure), even if the projects do not end up being successful, which is not consistent with the incentives present in competitive markets.[121]

4.78 ETNZ submitted that they "find it difficult to see how providing the incentives required by 54Q would in any way compromise the purpose of Part 4".[122] We disagree because of the risks explained above. For example, if the recoverable cost is used for expenditure that would have otherwise been undertaken anyway, it will increase the distributor's returns, which is contrary to the purpose of Part 4 of the Act. So, we have been required to balance the benefits and risks of introducing an innovation incentive mechanism in terms of the purpose of Part 4 of the Act.

4.79 In addition to submitting, like a number of others, that the limits of the recoverable cost should be significantly higher, the ENA also provided a useful explanation of how a larger scheme could be administered. The ENA's submission that such a scheme should be a pooled fund with competitive applications by distributors was supported by other submissions as well.

4.80 However, we have not chosen to implement the ENA's suggested approach because we are of the view that creating an external fund would be beyond the scope of a low-cost DPP framework, requiring significant administrative costs and oversight while adding complexity and risks to the DPPs and consumers.

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[121] We note that Meridian re-iterated this risk in its submission on our draft decision: Meridian "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

[122] ETNZ "Submission on EDB DPP reset draft decisions paper" (16 July 2019), p. 4.

4.81 A CPP may be more appropriate for a large innovative step change in a distributor's practices. While this would not initially benefit the other distributors directly, the learnings from the distributor on the CPP may be beneficial for other distributors in the longer term.

4.82 We also weighed up the submissions supporting a larger pooled fund against the submission from MEUG:[123]

> MEUG sees no reason why:
>
> a) EDB cannot continue to collectively pool resources under the banner of ENA, or any subset of EDB that see merit in collaborating, on further innovation projects using their discretion on how to allocate existing regulated revenue sources; and
>
> b) If the cost of future projects is substantially greater than work undertaken to date, then EDB could consider joint ventures with non-EDB parties and or seek funding from various government research grant schemes.

4.83 In its submission on the draft decision, MEUG explained that it did not support a new innovation incentive mechanism because there is insufficient evidence of under-investment in innovation to warrant it. We partially agree with MEUG on this point, acknowledging that there is weakness in the evidence base on innovation. However, we consider that it would be costly and impractical to collect such evidence, so it is reasonable to introduce an innovation incentive mechanism at a low level that we consider is likely to benefit consumers without risking a large additional cost.

4.84 We also note that part of the Open Access project of the Innovation and Participation Advisory Group and the Electricity Authority, and our own contestability project that is a joint project with the Electricity Authority (named Project Spotlight) is to look at the concerns of potential competitors that distributors may leverage their monopoly position to gain a competitive advantage in other competitive markets. This can include recovery of costs from consumers and we note that, although cost allocation rules should protect against this, they may be difficult to apply correctly in practice for research and development activities. The active work in this area means that there is less risk that any new additional incentives to innovate could result in less innovation by competitive market players.

4.85 Finally, we note that innovative projects could have benefits in terms of incentives to promote energy efficiency and demand-side management. New innovations in demand-side management technologies may allow distributors to reduce peak loads, and therefore avoid system growth capex investments. This has the benefit of increasing cost efficiency, but also helps promote the objectives considered under section 54Q of the Act.

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[123] MEUG "Cross-submission on EDB DPP reset draft decisions paper" (12 August 2019), p.2.

4.86 We note that we have also made a change to the input methodologies to remove the now-redundant scheme for compensating for demand-side management initiatives. The scheme is now redundant because the compensation was for the revenue impact of reductions in demand, but this will be nil during DPP3 because of the move to revenue caps (as opposed to price caps).

4.87 Further information on the recoverable cost for innovative practices is provided in Attachment F, including a description of the requirements, and the alternatives that we considered.

We are equalising capital and operating expenditure incentives

4.88 We are simultaneously equalising the incentive rates of efficiency savings from operating and capital expenditure to also help reduce an aspect of the risk of insufficient innovation. Our equalisation of incentive rates is described further in Attachment E.

4.89 The reason that equalising the incentive rates may remove a barrier to innovation is that some of the potential innovative practices that are made available by new technologies and business models involve additional operating expenditure to reduce capital expenditure. Without the equalisation of incentive rates, the distributor's profits could be reduced by innovative action that reduces overall costs.

Non-DPP responses to sector changes

4.90 Outside of this DPP reset we are continuing to work on better understanding emerging technology and how our regulatory settings can best support the opportunities and challenges from emerging technology.[124]

4.91 We have been cooperating with the Innovation and Participation Advisory Group (IPAG) of the Electricity Authority, which is looking at issues of open access, particularly in relation to changes to the electricity sector from emerging technologies. IPAG's final recommendations on open access were published in April.[125] We are also undertaking a related joint project with the Electricity Authority on emerging technology and open access to the networks.[126]

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[124] This work follows on from our consideration of the issue within the 2016 input methodologies review—Commerce Commission "Input methodologies review decisions – Consolidated reasons papers" (19 December 2016).

[125] Innovation and Participation Advisory Group (IPAG) "Advice on creating equal access to networks" (April 2019).

[126] Electricity Authority and Commerce Commission "Spotlight on emerging contestable services – a joint Electricity Authority-Commerce Commission project" (7 May 2019).

4.92 As new technologies offer new opportunities that may span the regulated and non-regulated markets, our cost allocation rules are increasingly important. We revised these rules in 2016 as part of the IMs review. We have also requested information from distributors on their investments in emerging technologies and how they have applied cost allocation rules. We have published this information on our website.[127]

[127] See: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/impact-of-emerging-technologies-in-monopoly-parts-of-electricity-sector?target=documents&root=100658.

Chapter 5 Starting prices

Purpose of this chapter

5.1 This chapter explains the starting prices we have set, how we have determined them, and our reasons for the decisions we have made. It also explains how these decisions have changed since the draft decision, our reasons for those changes, and how they affect allowable revenue. It is supported by the detailed material on our approach to forecasting, discussed in Attachments A to D.

Structure of this chapter

5.2 The first section of this chapter sets out the starting prices we have set, and explains our decision to set prices on the basis of current and projected profitability. The second section explains our building blocks approach to setting starting prices. The third section summarises the decisions we have made which affect starting prices.

Starting prices

5.3 The price path for DPP3 will apply to distributors as a 'revenue cap'. A revenue cap limits the maximum revenues a distributor can earn, rather than the maximum prices that it can charge.[128] For this reason, while the terminology in the Act refers to a 'price path' and to 'starting prices', in this paper we will generally refer to 'allowable revenues' a distributor can earn.[129]

5.4 Starting prices for each distributor are listed in Table 5.1 below.

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[128] The decision to move distributors from a price cap to a revenue cap was made as part of the IM review in 2016. Commerce Commission "Input methodologies review decisions – Topic paper 1 – Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016). The implications of this decision are discussed in more detail in Attachment H.

[129] The definition of "price" for the purposes of Part 4 includes "individual prices, aggregate prices, or revenues". When setting a price-quality path, we must specify prices as either or both of prices or total revenues; Commerce Act 1986, sections 52C and 53M.

Table 5.1 Net allowable revenue for 2020/21 ($m)[130]

Distributor	Allowable revenue in 2020/21 ($m)
Alpine Energy	42.65
Aurora Energy	87.33
Centralines	9.37
EA Networks	33.26
Eastland Network	24.03
Electricity Invercargill	12.26
Horizon Energy	23.91
Nelson Electricity	5.50
Network Tasman	26.45
Orion NZ	158.50
OtagoNet	25.78
The Lines Company	34.71
Top Energy	38.01
Unison Networks	100.02
Vector Lines	388.71
Total	**1,010.49**

‘Prices’ versus revenues—our terminology

5.5 The price path for DPP3 will apply to distributors as a ‘revenue cap’. A revenue cap limits the maximum revenues a distributor can earn, rather than the maximum prices that it can charge.[131] For this reason, while the terminology in the Act refers to ‘starting prices’, in this paper we will generally refer to the ‘allowable revenue’ a distributor can recover.[132]

5.6 Allowable revenue may mean either:

5.6.1 ‘gross’ allowable revenue, including pass-through and recoverable costs; or

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[130] Starting prices are expressed as maximum allowable revenue (MAR) in the first year of the DPP3 period, in nominal millions of dollars. Prices for Wellington Electricity and Powerco have not been included, as we do not propose setting starting prices for these distributors until their current CPPs end.

[131] The decision to move distributors from a price cap to a revenue cap was made as part of the IM review in 2016. Commerce Commission “Input methodologies review decisions – Topic paper 1 – Form of control and RAB indexation for EDBs, GPBs and Transpower” (20 December 2016). The implications of this decision are discussed in more detail in Attachment H.

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5.6.2 'net' allowable revenue, excluding pass-through and recoverable costs.

5.7 Under our approach to assessing current and projected profitability (discussed in more detail below) net allowable revenue in the first year of the period (starting prices) is determined by the present value of BBAR over the period, smoothed evenly over the period such that it increases by CPI-X. These MAR values for each distributor in each year of the DPP3 period, and the present value of this revenue over the period are listed in Table 5.2.

Table 5.2 Net allowable revenue in each year of the regulatory period ($m)

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25	PV[133]
Alpine Energy	42.65	43.48	44.36	45.25	46.16	197.66
Aurora Energy	87.33	89.04	90.84	92.66	94.51	404.73
Centralines	9.37	9.55	9.74	9.94	10.14	43.41
EA Networks	33.26	33.91	34.59	35.29	35.99	154.13
Eastland Network	24.03	24.50	24.99	25.49	26.00	111.35
Electricity Invercargill	12.26	12.50	12.75	13.00	13.26	56.80
Horizon Energy	23.91	24.38	24.87	25.37	25.88	110.82
Nelson Electricity	5.50	5.61	5.72	5.84	5.95	25.50
Network Tasman	26.45	26.97	27.51	28.06	28.63	122.59
Orion NZ	158.50	161.59	164.86	168.16	171.52	734.52
OtagoNet	25.78	26.28	26.81	27.35	27.90	119.47
The Lines Company	34.71	35.38	36.10	36.82	37.56	160.85
Top Energy	38.01	38.76	39.54	40.33	41.14	176.17
Unison Networks	100.02	101.97	104.03	106.12	108.24	463.52
Vector Lines	388.71	396.29	404.31	412.40	420.65	1,801.37

Revenue determined on the basis of current and projected profitability

5.8 We have determined revenue in the first year of the DPP3 period based on the current and projected profitability of each distributor. The Act also allows revenue to be set by 'rolling over' the revenues which apply at the end of the preceding regulatory period.[134]

5.9 Were current allowable revenues rolled over, distributors' revenues for the DPP3 period may not reflect their costs. In most cases, this would result in distributors earning excessive profits, while in others, it may hinder their ability to invest in their networks to provide services at a level which reflects consumer demand.

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[133] Present value at 1 April 2020 of MAR before tax over the regulatory period.

[134] Commerce Act 1986, section 53(P)(3).

5.10 Table 5.3 below compares distributor revenue over the DPP3 period based on current and projected profitability to our estimate of revenue over the period if revenues were rolled over.

Table 5.3 Estimated revenue over the DPP3 period ($m)

Distributor	PV of MAR	PV of MAR under roll-over	$ difference	% difference
Alpine Energy	197.66	234.45	36.78	19%
Aurora Energy	404.73	316.08	-88.65	-22%
Centralines	43.41	68.21	24.80	57%
EA Networks	154.13	175.04	20.91	14%
Eastland Network	111.35	131.43	20.08	18%
Electricity Invercargill	56.80	65.79	8.98	16%
Horizon Energy	110.82	111.36	0.55	0%
Nelson Electricity	25.50	32.08	6.58	26%
Network Tasman	122.59	133.30	10.71	9%
Orion NZ	734.52	788.10	53.58	7%
OtagoNet	119.47	128.28	8.82	7%
The Lines Company	160.85	192.62	31.77	20%
Top Energy	176.17	229.10	52.93	30%
Unison Networks	463.52	532.29	68.77	15%
Vector Lines	1,801.37	1,969.32	167.94	9%

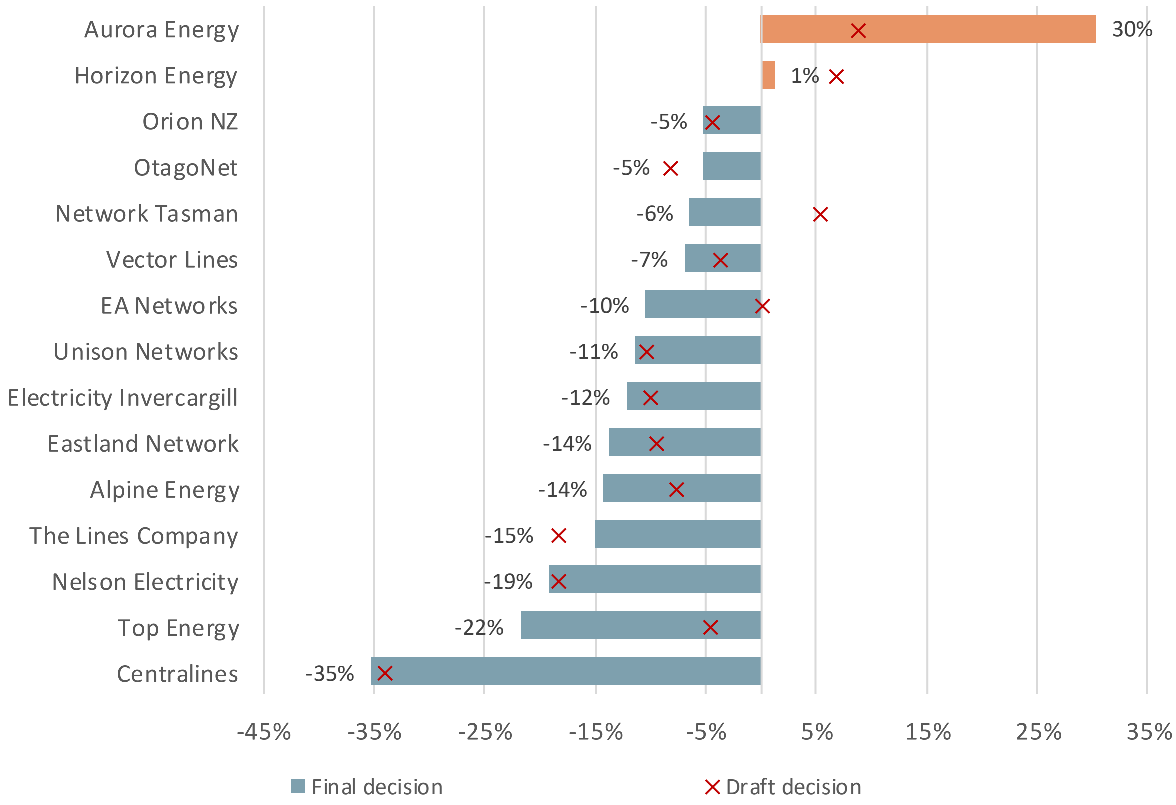
5.11 Because of our decision to set revenues on the basis of current and projected profitability, some distributors' allowable revenues for the year beginning 1April 2020 will change significantly relative to DPP2 allowable revenues.

5.12 Figure 5.1 presents this change on a year-on-year basis between 2019/2020 and 2020/2021.

5.13 Revenues are also affected by the rate of change relative to CPI (the X-Factor) we determine for the period. As discussed in Chapter 6 below, we have set an X-Factor of 0% for all distributors.

5.14 Our approach to determining these revenues in the first year of the DPP3 period is discussed in the next section. The decisions we have made as part of the decision that affect them are discussed in the final section.

Figure 5.1 Change in allowable revenue between 2019/20 and 2020/21



Our approach to setting revenue in the first year of the period

5.15 We specify the maximum revenues that distributors can earn over the regulatory period. The Act gives us a choice as to the 'form of control' which applies to each regulated supplier.[135] In the 2016 IM review, we changed the form of control for distributors from a weighted average price cap to a revenue cap with a 'wash-up' for over and under-recovery of revenue.[136]

5.16 This form of control sets annual maximum revenues a distributor can earn in a given year. Unlike a price cap, this maximum revenue is independent of demand. However, other than removing the need to forecast changes in demand, our approach to assessing current and projected profitability is substantially the same as it was in DPP2 under the price cap.

[135] Commerce Act 1986, section 53M(1)(a).

[136] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.1; Commerce Commission "Input methodologies review decisions: Report on the IM review" (20 December 2016), p. 78.

The limit on revenue provides incentives to focus on controllable costs

5.17 Setting price or revenue limits means that profitability depends on the extent to which distributors control costs. Actual costs may differ from forecasts for a variety of reasons, but the incentive to increase profits helps to create an incentive for suppliers to reduce costs. This incentive is a key to the way the DPP creates efficiency incentives, consistent with section 52A(1)(b).

5.18 There is a risk that suppliers may find these cost savings by reducing investment or maintenance. Quality standards (discussed in Chapter 7) play an important role in reducing the risk of this occurring. This maintains incentives to invest (consistent with section 52A(1)(a)) and to maintain quality of supply (consistent with section 52A(1)(b)).

5.19 Costs that suppliers have little or no control over are recovered through separate allowances for 'pass-through costs' and 'recoverable costs.' The items that qualify for these categories are set out in the IMs.[137] The changes we are proposing to recoverable costs are discussed in Chapter 6.

The revenue limit setting process

5.20 The DPP must specify allowable revenues and quality standards for each distributor for the regulatory period, as set out in section 53M of the Act. The gross revenue allowances each distributor can recover include an allowance for pass-through and recoverable costs. However, our BBAR analysis does not include pass-through and recoverable costs.[138] As such, the two main components of net revenue limits are:

5.20.1 the 'starting price' – revenue allowed in the first year of the regulatory period; and

5.20.2 the 'rate of change' relative to the CPI, that is allowed in later parts of the regulatory period.

5.21 When setting this starting price under a DPP, the Act provides for two approaches:

5.21.1 rolling over the prices applying at the end of the preceding regulatory period; or

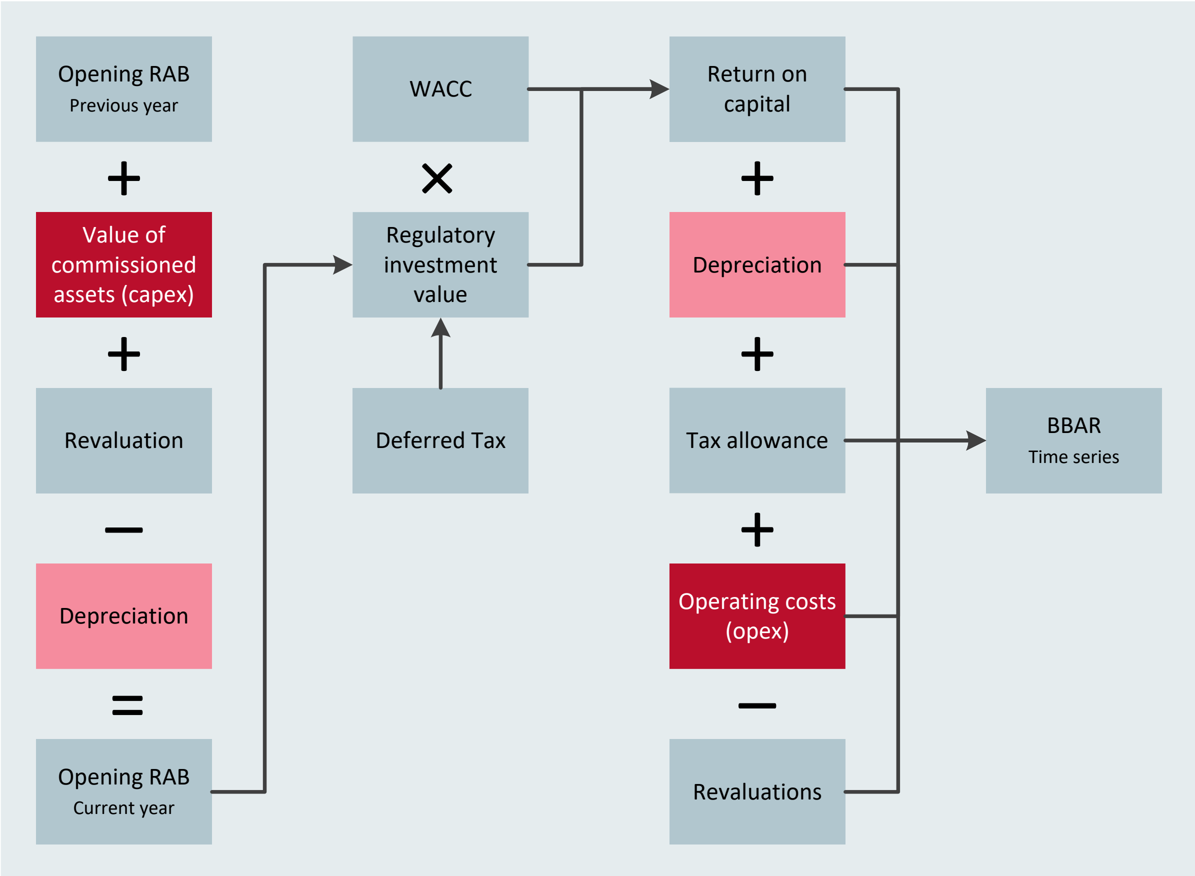
5.21.2 based on the current and projected profitability of each distributor, as determined by the Commission.

[137] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.3.

[138] Pass-through and recoverable costs are included as separate items in the revenue path formula. For a detailed discussion, see Attachment H.

5.22 To assess the current and projected profitability of each distributor, we use a 'building blocks' approach, which adds up the components of a distributor's forecast costs, and sets revenue equal to them.

Figure 5.2 Simplified model of how we calculate BBAR



The BBAR approach

5.23 The starting prices we set for each distributor are specified in terms of MAR, which is an amount that excludes pass-through costs and recoverable costs. We calculate the MAR amount through two key processes.[139]

5.23.1 Determining a building blocks allowable revenue (BBAR) for each year of the regulatory period. This process is represented in Figure 5.2 above.

5.23.2 Smoothing each of the BBAR amounts over the regulatory periods by CPI-X in present value terms. This represents the yearly changes to the revenue limit that are allowed over the regulatory period. This process is represented in Figure 5.3 below.

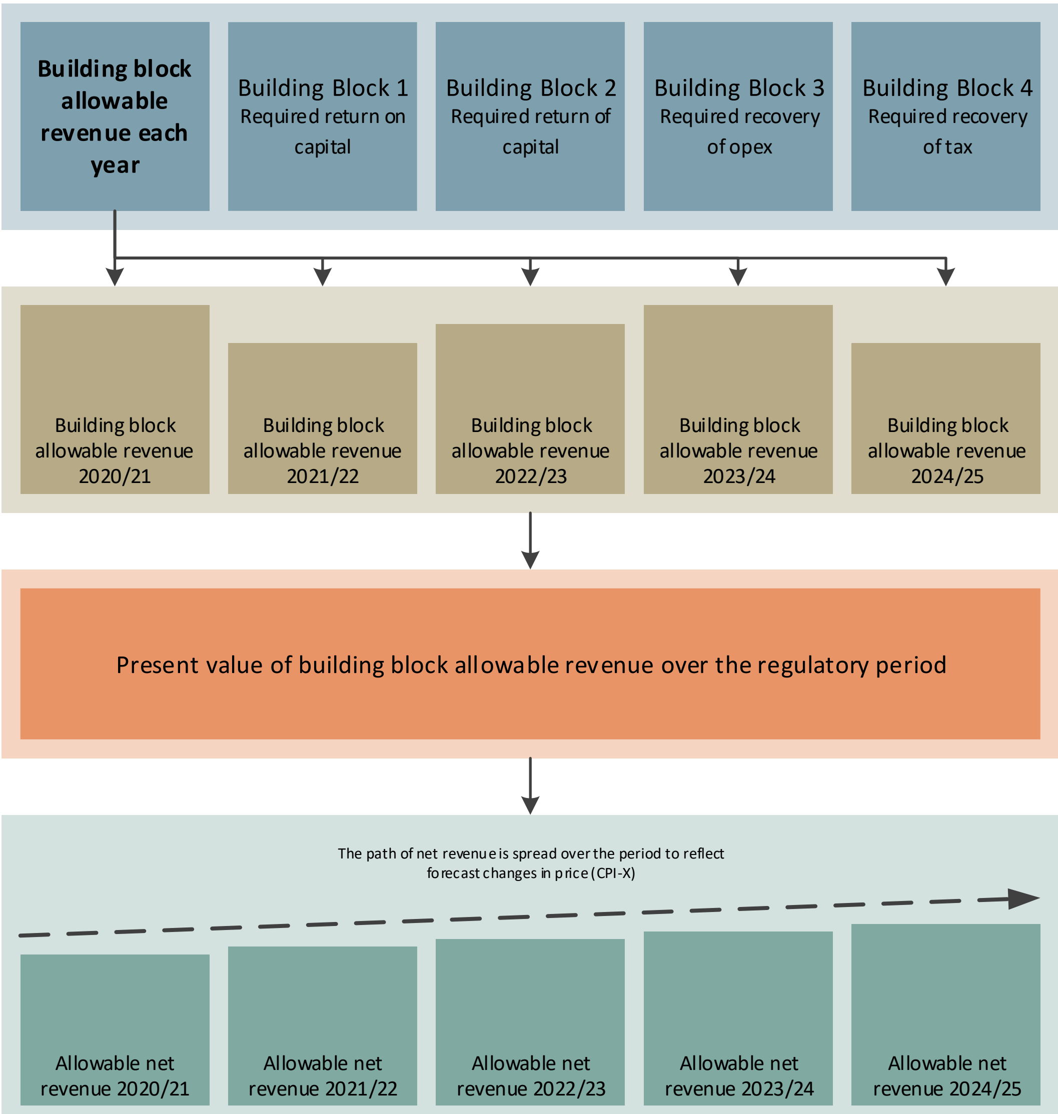
[139] In practice, these processes are calculated in the EDB DPP financial model, published alongside this paper.

5.24 The inputs highlighted in red (capital expenditure and operating expenditure) are those which we must forecast as part of the DPP, and which are not determined by the IMs. The item in pink (depreciation) is affected by our decisions on accelerated depreciation, but is predominantly determined by the IMs.

5.25 Our decisions on these matters are summarised in the next section of this chapter, and are discussed in detail in Part 1 of the attachments to this paper.

5.26 Some other inputs come from ID, while others are specified in the IMs. These ID and IMs inputs can have a material effect on allowable revenues. For example, the opening RAB is taken from ID, and the WACC rate is determined based on the IMs.

Figure 5.3 From BBAR to MAR



From building blocks to starting prices

5.27 The components in Figure 5.2 combine as building blocks to provide total BBAR for each year of the regulatory period. BBAR is then spread over the regulatory period into annual MAR figures, that increase at a consistent rate of CPI-X.

5.28 We do this in such a way that the present value of BBAR and MAR are the same. Figure 5.3 below illustrates this process.

5.29 A key difference between the price cap we applied in DPP2 and the revenue cap which we will apply for DPP3 is how the revenue smoothing shown in the final box in Figure 5.3 is calculated.

5.29.1 Under the price cap, revenues were spread out to reflect both forecast changes in prices (CPI-X) and forecast changes in quantities (CPRG).

5.29.2 Under the revenue cap, revenues are only spread out to reflect the forecast change in CPI-X.

Key decisions affecting allowable revenue in the first year of the DPP3 period

5.30 As shown in Figure 5.2 above, there are certain parameters of the BBAR model that we determine as part of setting the DPP. This section discusses these parameters, and changes to them since the draft decision. These parameters are:

5.30.1 opex forecasts;

5.30.2 capex forecasts; and

5.30.3 whether to allow distributors who have applied for it to accelerate the depreciation of their assets.

5.31 Additionally, there are other inputs to the financial model which can have a material impact on starting prices (for example, WACC or forecast CPI) but that we do not make decisions about as part of the DPP. These other inputs are discussed in Attachment C.[140]

Forecasts of opex

5.32 To forecast opex for each distributor, we have retained at a high level the 'base, step, and trend' methodology from the 2014 DPP2 reset. The opex allowances that result from our decision are set out in Table 5.4 below.

[140] We also received submissions on changes to the EDB IMs that would have changed the way these parameters are calculated. Our reasons for not making these changes are discussed in: Commerce Commission "Amendments to electricity distribution services input methodologies determination – Reasons paper" (26 November 2019), pp. 26-31 and 57-61.

5.33 Consistent with the DPP decision-making framework set out in paragraphs 3.29-3.30 in Chapter 3 above, we have retained the base-step-trend approach because we do not consider any alternatives (such as using AMP forecasts) would meaningfully improve the incentives distributors face in terms of section 52A, or would better promote the section 53K purpose of DPP/CPP regulation.

5.34 Our decision to retain the base-step-trend model is consistent with the low-cost DPP principles set out in Chapter 3 because it makes use of existing ID data that reflects each distributors' current level of performance, while at the same time making broad adjustments for distributor-specific differences in growth where reliable independent data is available.

5.35 Providing an opex allowance ensures that distributors have sufficient resources to fund recurring activities that are not capital expenditure. The opex allowance funds a variety of recurring activities that are essential for the operation of distribution networks, such as maintenance and planning activities.[141]

5.36 Opex has a direct effect on the starting price and the MAR. Opex represents approximately 44% of BBAR. From an efficiency point of view, the opex allowance we set is the baseline against which any opex IRIS gains and losses are measured.

[141] We would also generally expect distributors to fund innovation activities from this opex allowance or from the capex allowance discussed below. However, given incentives to avoid expenditure, and the risk that innovation will not deliver immediate efficiency or quality benefits (as discussed in Chapter 4), we consider that additional funding outside of the opex and capex allowances is in the long-term benefit of consumers.

Table 5.4 Opex allowances for DPP3 ($m)

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25
Alpine Energy	19.42	20.01	20.63	21.24	21.82
Aurora Energy	44.72	46.25	48.13	50.19	51.96
Centralines	4.23	4.33	4.45	4.56	4.66
EA Networks	11.82	12.22	12.63	13.06	13.49
Eastland Network	10.62	10.90	11.19	11.50	11.78
Electricity Invercargill	5.18	5.31	5.45	5.59	5.72
Horizon Energy	9.89	10.17	10.49	10.83	11.11
Nelson Electricity	2.25	2.32	2.39	2.46	2.54
Network Tasman	11.16	11.51	11.88	12.25	12.61
Orion NZ	64.15	66.49	68.93	71.32	73.63
OtagoNet	9.16	9.43	9.70	9.96	10.20
The Lines Company	14.91	15.30	15.71	16.11	16.48
Top Energy	16.02	16.54	17.05	17.57	18.06
Unison Networks	41.58	42.90	44.33	45.72	47.03
Vector Lines	127.35	132.45	137.80	142.97	148.02
Wellington Electricity[142]	n/a	36.79	37.97	39.17	40.32

5.37 Submitters on our draft decision generally supported the retention of the base-step-trend approach to setting an opex allowance, although several raised issues with individual components of the approach, in particular the decision to set a partial productivity factor of 0%. These issues and our responses are discussed in Attachment A.

5.38 The individual parameters (the base year, step changes, and trend factors) used to arrive at these forecasts are set out in Table 5.5.[143]

[142] The allowances for Wellington Electricity are indicative only, and will be updated when we determine starting prices for Wellington Electricity at the end of its CPP in 2020.

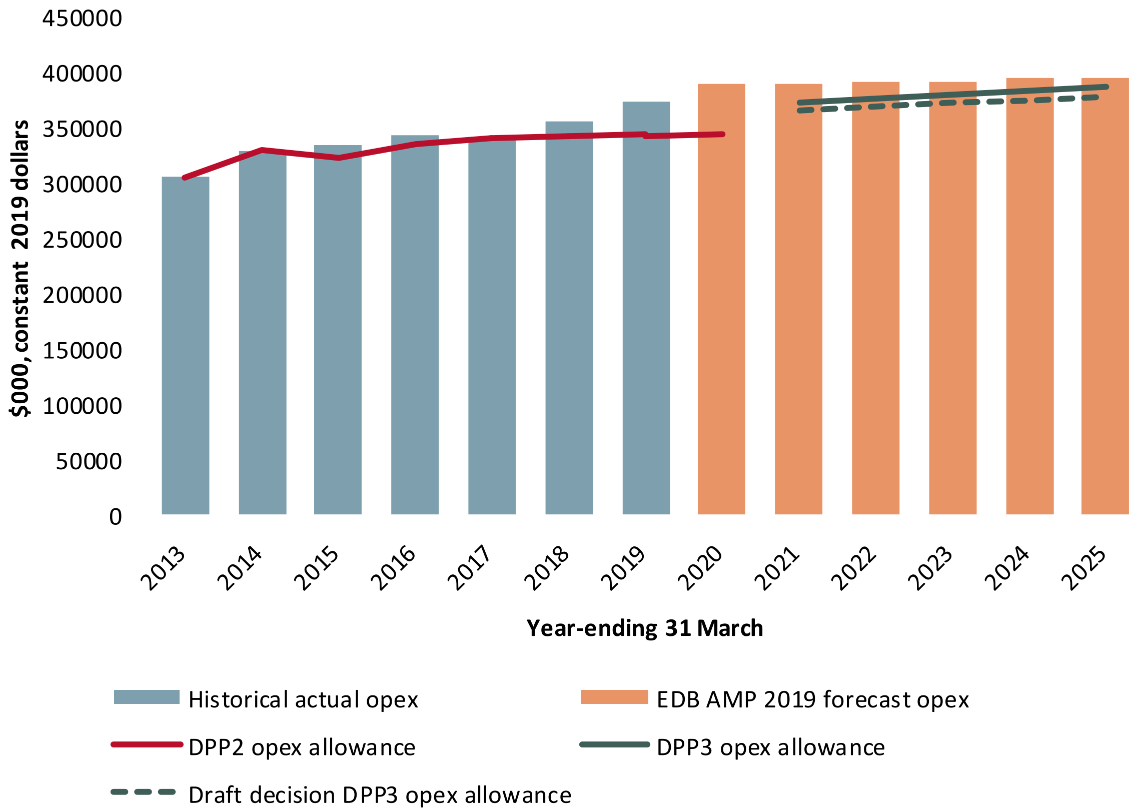
[143] We have shown the trend factors for 2018-2023 and 2023-2025 separately because of the StatsNZ forecasts of population growth for those periods. These two trends are also influenced by LCI and PPI trends, which are different in every year of the DPP3 period.

Table 5.5 Opex parameters for each distributor

Distributor	Total opex 2018/19 ($000)	FENZ levies 2018/19 ($000)	Pecuniary penalties 2018/19 ($000)	Operating leases 2018/19 ($000)	Operating leases 2021-2025 ($000)	Aggregate trend 2019-2023 (CAGR, %)	Aggregate trend 2023-2025 (CAGR, %)
Alpine Energy	18,296	-53	0	0	0	3.12%	2.84%
Aurora Energy	42,774	-28	0	0	-5,185	3.01%	3.90%
Centralines	4,020	-11	0	0	0	2.62%	2.34%
EA Networks	11,913	-27	0	0	-4,213	1.52%	3.35%
Eastland Network	10,079	-28	0	0	-15	2.73%	2.61%
Electricity Invercargill	4,938	-20	0	0	0	2.58%	2.45%
Horizon Energy	9,469	-48	0	0	-252	2.71%	2.95%
Nelson Electricity	2,146	-31	0	0	-40	3.11%	3.02%
Network Tasman	10,504	-41	0	0	-3	3.23%	3.02%
Orion NZ	59,678	-98	0	0	0	3.71%	3.36%
OtagoNet	8,660	-21	0	0	0	2.94%	2.56%
The Lines Company	14,173	-41	0	0	-19	2.68%	2.44%
Top Energy	15,409	-23	0	0	-1,470	2.60%	2.92%
Unison Networks	39,408	-66	0	0	-1,448	3.03%	3.00%
Vector Lines	121,961	-568	-3,575	1,461	-9,219	3.99%	3.64%
Wellington Electricity	34,017	-58	0	0	-2,543	2.83%	3.06%

5.39 Figure 5.4 compares the industry total opex allowances we have set for DPP3 with historical levels of opex, opex allowances during DPP2, distributor forecasts in their 2018 AMPs over DPP3, and our forecasts of DPP3 opex from the draft decision. This comparison is made on a 2019 constant-price basis.

Figure 5.4 Industry total constant-price opex series $(000)



5.40 Taken as a whole, we consider these opex allowances are reasonable because:

5.40.1 the base year provides a reliable indication of distributors' current level of efficiency;

5.40.2 the output trend factors allow costs to increase as networks increase in size, but at a lower marginal cost than the current average cost, delivering benefits to all consumers;

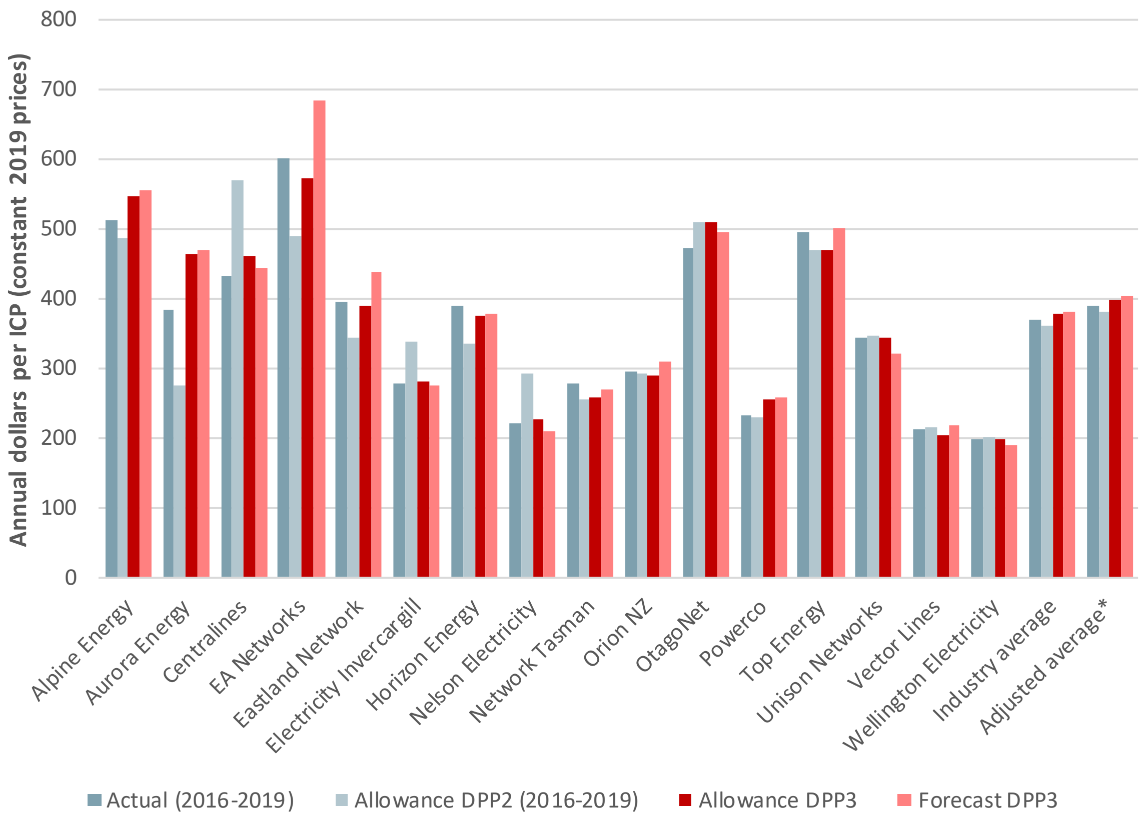
5.40.3 the input price inflators fairly reflect cost increases which are primarily beyond distributors' control, but that will reward distributors who can source inputs at a lower cost;

5.40.4 the partial productivity factor sets a baseline against which businesses who improve efficiency over the DPP3 period will be rewarded; and

5.40.5 the opex IRIS mechanism will distribute any combined gains between distributors and consumers at a rate that both rewards efficiency while at the same time sharing the benefits with consumers.

5.41 Given concerns in submissions that opex allowances would not adequately allow distributors to meet their efficient costs over the DPP3 period, for each distributor we have compared opex on a per-consumer basis between DPP2, DPP3, and distributor forecasts for DPP3. We consider our DPP3 allowances generally align with the sector's forecasts at a per-ICP level. These comparisons are set out below in Figure 5.5.

Figure 5.5 Annual average opex per ICP[144]



Opex base year

5.42 We have used data from the year-ending 31 March 2019 as the base year. While this is a change in the data we used, relative to the draft decision, it is not an explicit policy change. As we set out in the draft, the use of 2018 data for the draft decision was an issue of data availability.

5.43 Consistent with our approach of determining revenue and expenditure allowances based on each distributors' historic levels of performance, we consider it appropriate to use 2019 actual data, as it is the most up-to-date reflection of distributors level of opex expenditure and efficiency.

[144] Adjusted average excludes Powerco and Wellington Electricity.

5.44 To the extent that 2019 data is not fully representative of a distributor's current performance, the opex IRIS mechanism (specifically the base year adjustment term) accounts for this by sharing any temporary efficiency gains or losses between consumers and the distributor at the same uniform retention rate as savings in any other year of a DPP period.

5.45 Put another way, while increases or decreases in the opex base year affect the net allowable revenue we determine at the start of the DPP period, due to the IRIS mechanism they will have a reduced impact on the gross allowable revenue distributors can recover over the DPP3 period, with any reductions in base year opex offset by an increase in the opex incentive payments the distributor receives under IRIS.

Step changes

5.46 We have included three step changes in distributor opex allowances for DPP3:

5.46.1 an adjustment to account for FENZ levies now being treated as a recoverable cost;

5.46.2 the removal of pecuniary penalties from future opex allowances, to account for these no longer being treated as opex; and

5.46.3 the removal of operating leases from future opex allowances, as it will be classed as capex following a change in accounting standards.

5.47 Treating FENZ levies as a recoverable cost was first proposed in submissions on our issues paper. We have made this change because we consider FENZ levies meet the criteria we generally apply when determining what should be included as a recoverable cost (as discussed in Chapter 6), and that there is no incentive benefit to exposing distributors to any difference between forecast and actual FENZ levies.

5.48 As discussed in our draft decision and in the IM Amendments reasons paper, we considered that the current definition of operating costs may allow distributors to share the cost of any penalty with its consumers, rather than the distributor bearing the whole cost. In response to submissions, we do not to apply any adjustment to opex for the DPP2 period, consistent with our approach of not changing the underlying incentives distributors face after the fact. We have applied this adjustment on a forward-looking basis to ensure this issue is not repeated.

5.49 As discussed in our draft decision and in the IM Amendments reasons paper, we consider operating leases to be classed as capex instead of opex following the implementation of a new financial reporting standard – NZ IFRS 16.

5.50 Other proposed step changes that we have not implemented are discussed in Attachment A.

Trend factor – change in scale

5.51 As a distributor grows, the cost of maintaining and managing its network can also be expected to grow. We approximate this change using an econometric method, that compares historical expenditure on a distributor's network to a number of independent variables.

5.52 As suggested in submissions, we tested a range of potential options for drivers, and different levels of disaggregation for opex.[145] This analysis suggested that in terms of drivers, the best model used the change in the:

5.52.1 number of customers on a distributors network; and

5.52.2 total circuit length (for supply).

5.53 This is largely unchanged from our DPP2 approach. However, we have now also applied the circuit length driver to non-network opex.

5.54 The drivers we have used to forecast changes in network and non-network opex due to scale growth are set out in Table 5.6, along with the relationship between a difference in the driver and the difference in opex (the elasticity), and the overall explanatory power of the model (the R^2 value).

Table 5.6 Econometric drivers of opex scale growth

Opex category	Elasticity to ICP growth	Elasticity to circuit length growth	R^2
Network opex	0.4886	0.4470	0.905
Non-network opex	0.2185	0.6525	0.901

5.55 To forecast the change in circuit length, we have applied the same approach we applied for DPP2: projecting forward each distributor's historical growth.

5.56 To forecast changes in ICPs, we have used StatsNZ forecast of household growth instead of forecasts of population growth. This is a change from our draft decision, based on submissions that alleviated our concerns about data availability.[146]

[145] See for example: Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018), p. 5.

[146] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 25.

Trend factor – Input prices

5.57 The cost of the inputs that distributors require to deliver the outputs expected of them also changes over time. These changes are predictable and are largely beyond distributors' control. Put another way, the opex allowances we produce in constant-price terms must be converted to nominal dollars, to be incorporated into the financial model.

5.58 We have used the same weighted average inflation series used for DPP2:

5.58.1 NZIER's forecast of the all-industries labour cost index (LCI) (60%); and

5.58.2 NZIER's forecast of the all-industries producer price index (40%).

5.59 As suggested in submissions, we have considered whether an industry-specific sub-index (specifically StatsNZ's electricity, gas, waste, and water (EGWW) sub-index) would better predict changes in distributors' costs.[147]

5.60 Historically, over the medium term, there have not been substantial differences between the all-industries index and the EGWW sub-index.

5.61 Furthermore, a substantial proportion of the EGWW producer price index is composed of the cost of electricity distribution and transmission services, which both creates an endogeneity problem, and does not reflect distributors' input costs.[148]

5.62 We confirm that NZIER's forecasts of the LCI account for factors relevant to distributors. These include wage inflation in the public and private sector, employment rates, the increase in the minimum wage, an ageing workforce and business outlook.

5.63 Several distributors recommend that we reconsider using NZIER's forecasts. We investigated whether NZIER's forecasts are appropriate for distributors, by considering:

5.63.1 what factors NZIER forecasts include; and

5.63.2 other macroeconomic commentary and forecasts.

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[147] ENA "DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)" (20 December 2018), The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), and Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018) favoured the EGWW.

[148] 35% of the EGWW is composed of the cost of transmission and distribution services. Statistics New Zealand "Producers Price Index: March 2017 quarter – supplementary tables of new industry weights" (17 May 2017).

5.64 We engaged with NZIER to discuss what factors their forecast of LCI includes. We thought this was important following stakeholders' recommendations to seek advice and overall concern around NZIER's forecast of LCI. Distributors thought the draft forecast of LCI was too low for several macroeconomic reasons and some provided evidence of wage growth forecasts.

Trend factor – opex partial productivity

5.65 The final component of our trend methodology is a measure of the ratio between the outputs a distributor produces to the cost of the inputs it uses to do so – a measure called opex partial productivity.

5.66 We have retained a partial productivity factor of 0% for the DPP3 period.

5.67 NERA provides strong evidence to show that historic partial productivity is negative.[149] However, we remain unconvinced that declining productivity in the past is predictive of future declines. We consider improvements in productivity are achievable due to:

5.67.1 evidence of positive productivity in electricity distribution sectors across the world, including productivity studies which take quality of outputs into account;[150]

5.67.2 evidence of positive productivity in comparable sectors within New Zealand; and

5.67.3 a changing policy environment with a greater focus on innovation and technology.

5.68 The reason we do not set the partial productivity factor based on historic performance is because continually decreasing productivity is generally not associated with workably competitive markets. Adopting a negative growth rate may entrench declines in partial productivity and weaken incentives to improve efficiency.

5.69 Similarly, however, we do not consider it appropriate to use a high productivity factor to 'incentivise' distributors to find gains. This would have the effect of passing gains onto consumers in anticipation of their discovery, which is not the purpose of the productivity factor.

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[149] NERA Economic consulting on behalf of ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019)

[150] For example, customer minutes lost, interruptions, energy losses and customer satisfaction

Forecast of capital expenditure

5.70 To forecast capex allowances for each distributor, we have used an amended version of the DPP2 approach – still using each supplier's AMP as the starting point for our forecasts, but applying a series of caps and tests to supplier forecasts to assess whether the forecasts are reasonable.

5.71 In particular, the approach seeks to determine whether the AMP forecasts:

5.71.1 are internally consistent – for example, that a forecast increase in expenditure is supported by a corresponding increase in activity, and/or a realistic increase in costs;

5.71.2 identify large step changes in the planned level of investment, which may be more appropriate for us to consider under a CPP application or as part of a reopener.

5.72 We have made this change from our DPP2 approach because:

5.72.1 we think it meaningfully improves the incentives distributors' face to invest in replacing and upgrading assets, consistent with section 52A(1)(a); and

5.72.2 due to the scrutiny we apply and the change to the capex IRIS retention factor (discussed in Chapter 6), it maintains incentives for distributors to invest efficiently, consistent with section 52A(1)(b).

5.73 In terms of the DPP/CPP regulatory framework, our approach to forecasting requires a balance between:

5.73.1 on the one hand, accounting for distributor-specific circumstances where there is a low-cost way of doing so; and

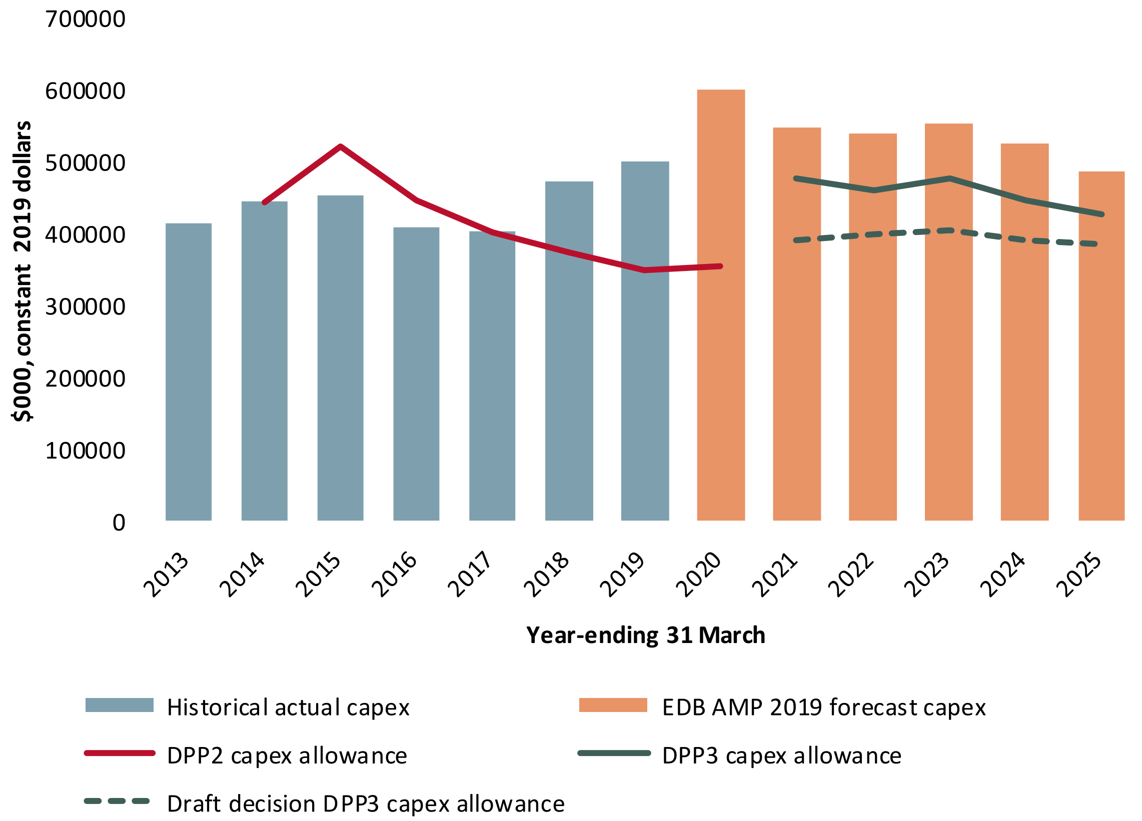
5.73.2 on the other hand, avoiding the excess cost of detailed scrutiny of individual distributors' forecasts where a CPP remains the appropriate solution.

5.74 The capex allowances which result from our forecasting approach are set out in Table 5.7. An industry-wide comparison of DPP3 allowances to DPP2 allowances, historical actual capex, and supplier AMP forecasts is shown in Figure 5.6. This comparison is in 2019 constant prices.

Table 5.7 Capex allowances for DPP3 ($m)

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25
Alpine Energy	16.66	16.98	15.38	14.67	14.15
Aurora Energy	50.95	50.75	48.25	38.77	43.21
Centralines	6.06	2.77	3.97	2.84	2.96
EA Networks	18.05	17.94	17.80	15.71	14.72
Eastland Network	9.68	10.14	8.98	9.38	10.05
Electricity Invercargill	4.66	5.05	5.57	5.58	5.13
Horizon Energy	8.32	6.72	8.08	8.52	8.57
Nelson Electricity	1.63	1.71	1.66	1.67	1.67
Network Tasman	10.29	12.26	9.04	10.07	8.47
Orion NZ	72.17	63.78	89.62	79.93	84.44
OtagoNet	13.99	13.50	18.00	23.07	13.93
The Lines Company	18.32	16.92	15.87	16.56	15.25
Top Energy	14.59	15.13	16.51	16.26	16.60
Unison Networks	46.75	52.52	50.53	46.85	48.04
Vector Lines	211.12	209.60	213.42	209.52	197.13
Wellington Electricity	n/a	35.51	37.68	39.91	42.08

Figure 5.6 Industry total constant-price capex series ($000)



Changes to capex forecasts since our draft decision

5.75 The most significant changes in capex forecasts are caused by our use of 2019 AMP and 2019 actual ID data. We consider it appropriate to use the most recent AMPs as the basis of our forecasts, as they represent distributors' most up-to-date view of the future needs of their networks.

5.76 In terms of policy changes, in response to submissions we have:

5.76.1 removed the historical forecast accuracy test;

5.76.2 changed our method for assessing system growth capex (as proposed in our updated draft decision);

5.76.3 changed the 'fall-back' forecasts we use where a distributor does not pass a gating test, from the historic average to the forecasts implied by the drivers we use; and

5.76.4 introduced dollar-value caps to our tests for minor capex categories.

Assessment of AMPs

5.77 As discussed in our issues paper, we still consider AMPs the appropriate starting point for our analysis, as distributors have better knowledge of factors such as:

5.77.1 current and future demand drivers for distribution services (both the quantities of demand, and the level of quality expected);

5.77.2 how to efficiently respond to this demand through conventional investment or through innovative approaches;

5.77.3 the current and future condition of their assets and the quality and safety risks these pose; and

5.77.4 the costs incurred in providing these services.

5.78 At the same time, we remain concerned about the possibility of capex forecasts being inflated in order to increase revenues during the DPP3 period, and the incentive benefits distributors would receive. As such, we have decided to apply a series of quantitative 'checks' to distributors' forecasts.

5.79 The structure of our analysis is set out in Figure 5.7, and each of the tests we have applied are summarised in Table 5.8. This is discussed in detail in Attachment B.

Figure 5.7 Flow diagram of capex assessment approach

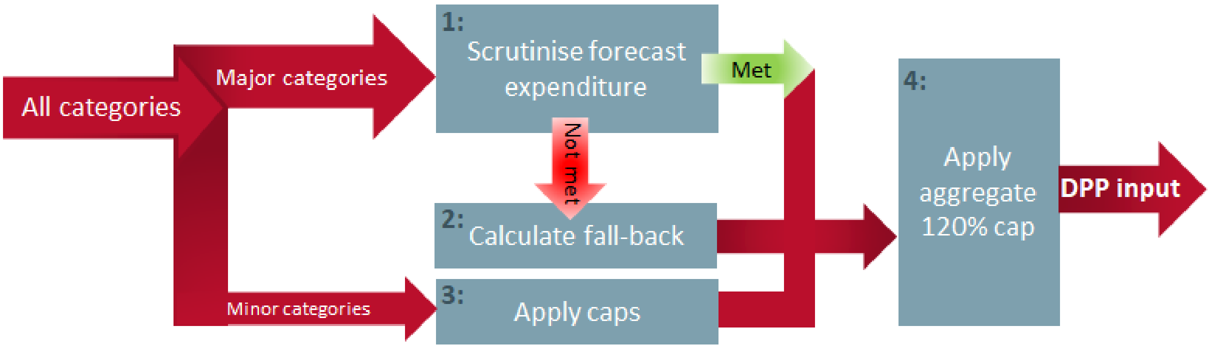
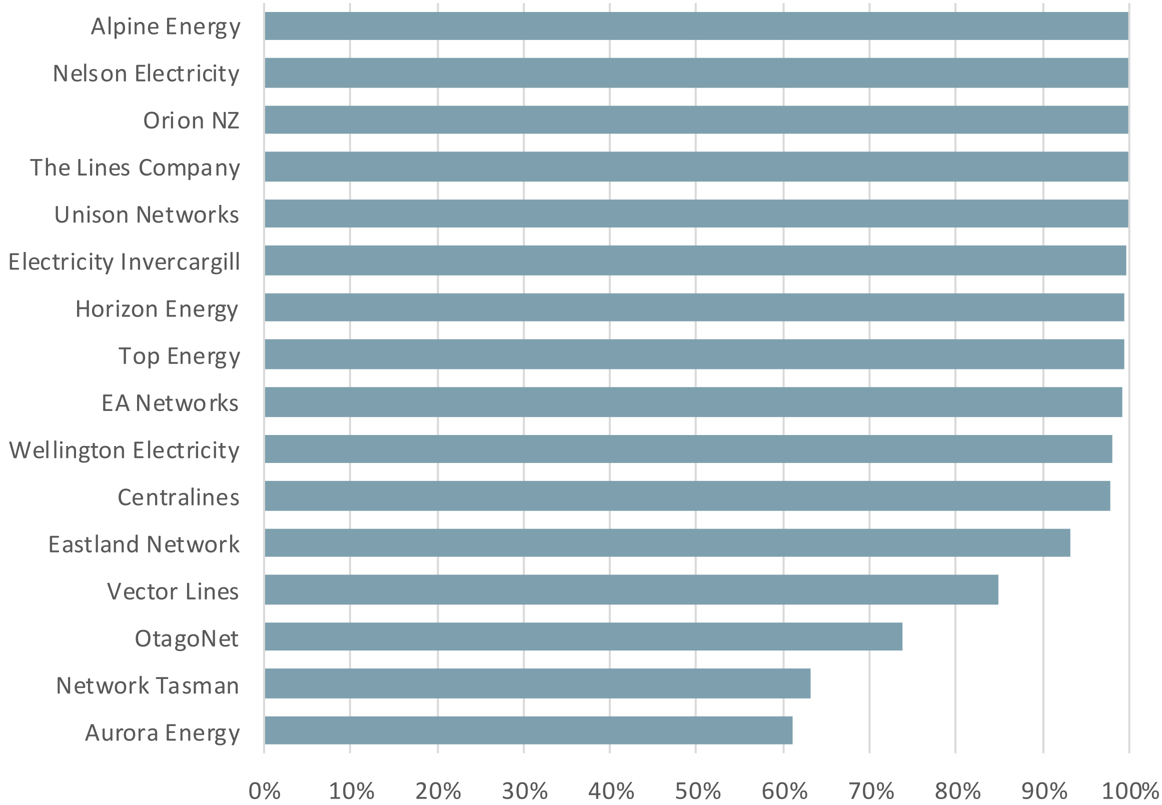


Table 5.8 Capex analysis tests

Test name	Category	Description
1: Residential connections	Consumer connection and system growth	Is the distributor forecasting growth in residential connections greater than both: 20% over their historical ICP growth, and forecasts of household growth for their area?
2: Per-connection expenditure	Consumer connection and system growth	Is the distributor's forecast per-connection spend increasing by more than 50%?
3: Renewal-depreciation	Asset replacement and renewal Reliability, safety, and environment	Is the distributor's combined ARR and RS&E expenditure more than 20% greater than their implied forecast depreciation?
4: Asset relocation cap	Asset relocation	Is forecast expenditure on asset relocations greater than $1 million per year on average over the DPP3 period, or their historical expenditure, on a sliding scale from 120% to 200%, depending on historical proportions of expenditure on asset relocations?
5: Non-network cap	Expenditure on non-network assets	Is forecast expenditure on non-network assets greater than $1 million per year on average over the DPP3 period, or their historical expenditure, on a sliding scale from 120% to 200%, depending on historical proportions of expenditure on non-network assets?

Figure 5.8 Overall capex acceptance rates by distributor



5.80 Taken as a whole, we consider these capex allowances are reasonable because:

5.80.1 distributors have access to the best information about the investments they need to make, which is reflected in their AMPs;

5.80.2 the category tests we apply help ensure any expenditure is justified by the needs of the distributors' networks and customers; and

5.80.3 the total capex cap ensures consumers do not see disproportionate price increases without the additional scrutiny available under a CPP or additional certainty about timing and quantum provided by a reopener.

Table 5.9 Capex acceptance rate by category

Distributor	Total capital expenditure (after 120% cap)	Consumer connection and system growth expenditure	ARR and RS&E	Asset relocations	Non-network expenditure	Scaling from 120% cap
Alpine Energy	100%	100%	100%	100%	100%	100%
Aurora Energy	61%	100%	54%	100%	20%	100%
Centralines	98%	97%	100%	100%	93%	100%
EA Networks	99%	98%	100%	100%	100%	100%
Eastland Network	93%	100%	100%	100%	100%	93%
Electricity Invercargill	100%	98%	100%	100%	100%	100%
Horizon Energy	100%	90%	100%	100%	100%	100%
Nelson Electricity	100%	100%	100%	100%	100%	100%
Network Tasman	63%	47%	100%	100%	100%	90%
Orion NZ	100%	100%	100%	100%	100%	100%
OtagoNet	74%	56%	100%	100%	100%	94%
The Lines Company	100%	100%	100%	100%	100%	100%
Top Energy	99%	98%	100%	100%	100%	100%
Unison Networks	100%	100%	100%	100%	100%	100%
Vector Lines	85%	100%	100%	55%	100%	90%
Wellington Electricity	98%	92%	100%	100%	100%	100%

Option to accelerate depreciation

5.81 As part of the 2016 IM review, we introduced a mechanism in our IMs allowing distributors to apply for a discretionary net present value-neutral shortening of their remaining asset lives. This mechanism allows distributors to elect new asset lives based on the expected economic lives of their assets, rather than their physical asset lives.[151]

5.82 This mechanism was introduced to address the risk that a network becomes economically stranded, rather than any risk of physical asset stranding.[152]

[151] Commerce Commission "Input methodologies review decisions: Topic paper 3: The future impact of emerging technologies in the energy sector" (20 December 2016), para 84-86.

[152] Commerce Commission "Input methodologies review decisions: Topic paper 3: The future impact of emerging technologies in the energy sector" (20 December 2016), paras 72 and 84.

5.83 We have decided not to apply an adjustment factor in response to Vector's application, based on weighing up our assessment of Vector's application against the formal IM requirements, the risk of economic stranding, section 52A of the Act and exercising our overall discretion. Having assessed Vector's application against our framework (which is set out below), we found that:

5.83.1 it was not clear to us whether Vector's application has met the criteria set out in clause 4.2.2 of our IMs because Vector did not explain how it had taken into account any issues raised in consultation, nor specified that no relevant issues were raised, however we did not have to resolve this because we declined Vector's application for other reasons;

5.83.2 we did not find evidence of a material risk to partial capital recovery with respect to Vector, which was the underlying purpose of the IMs providing for the adjustment factor;

5.83.3 we did not find that applying the adjustment factor Vector sought promoted the purpose of Part 4 of the Act; and

5.83.4 in considering our overall discretion we had regard to the interests of avoiding an initial pricing increase and not adding complexity

5.84 Our reasons for this decision are discussed in more detail in Attachment D.

Parameters we no longer need to forecast

Constant-price revenue growth

5.85 Given the move to a revenue cap, where supplier revenue is not dependent on changes in demand, we no longer need to forecast constant-price revenue growth (CPRG).

Other regulated income

5.86 As part of the move to the revenue cap, we have now included other regulated income as an item which is subject to the revenue wash-up. As such, we no longer need to forecast other regulated income.

Chapter 6 Revenue path during the period

Purpose of this chapter

6.1 This chapter explains ways in which distributors' revenues can change during the DPP3 regulatory period, and the policy decisions we have made which will affect them. This includes:

6.1.1 the rate of change that will apply during the period;

6.1.2 a brief description of the how the revenue cap with wash-up functions;

6.1.3 the incentives that will apply during the period;

6.1.4 newly introduced or modified recoverable costs;

6.1.5 circumstances in which the revenue path can be reopened;

6.1.6 how transactions between distributors will be treated; and

6.1.7 the dates for distributors to apply for CPPs.

Rates of change during the period

6.2 The revenues distributors can earn in the first year of the DPP3 period (before taking account of pass-through and recoverable costs) are determined by the starting prices we set, as described in Chapter 5. In the remaining years of the period, net allowable revenues are determined by the prior year's net allowable revenue and a 'rate of change'.

6.3 The rate of change is expressed in the form CPI-X, where 'CPI' reflects general inflation, and X is a percentage differential known as the 'X-factor'.

6.4 In determining the X-factor, we are required to determine a default rate of change in price that is based on the long-run average productivity improvement rate of distributors. We may consider the long-run average productivity improvement rate achieved by distributors in New Zealand and/or comparable countries.[153]

6.5 This rate of change will apply to each distributor, unless it is necessary or desirable to set an alternative rate of change, either to minimise any undue financial hardship to the distributor or to mitigate price shocks to consumers.[154]

[153] Commerce Act 1986, section 53P(6).

[154] Commerce Act 1986, section 53P(8)(a).

X-factor generally applicable to distributors

6.6 A default X-factor of 0% will apply to all distributors for the DPP3 regulatory period.

6.7 Based on our analysis of partial factor productivity in Attachment A we consider 0% appropriate.

6.8 Because starting prices are based on the current and projected profitability of each supplier, the rate of change will not affect the present value of revenue the distributor can expect to recover over the regulatory period.[155]

6.9 This is because we use the rate of change when setting expected revenues equal to expected costs over the regulatory period. The rate of change will affect the timing of revenue recovery over the period, or in other words the slope of the revenue path.

Alternative X-factors to avoid price shocks or financial hardship

6.10 We have not implemented any alternative rates of change for DPP3. We have assessed whether alternative rates of change were necessary based on:

6.10.1 whether a distributor's increase in allowable revenue – including any IRIS incentives – would otherwise exceed +10% in real terms; and

6.10.2 whether a decrease in a distributor's allowable revenue would cause financial hardship due to the change in cashflow profile between DPP2 and DPP3.

6.11 This is a change from the approach we took in the draft decision. In the draft decision, we assessed price shocks to consumers net of any IRIS effects. In its submission on the draft decision, Aurora Energy highlighted that once IRIS recoverable costs were accounted for, its change in allowable revenue would be much less significant.[156]

6.12 As the purpose of an alternate rate of change is to prevent either price shocks to consumers or revenue shocks to distributors, we agree that the need for an alternative rate of change should be assessed (to the extent possible) on a *gross* allowable revenue basis. As the IRIS incentive costs are known with certainty for Year 1 of DPP3, we have factored these into our assessment.

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[155] The relevance of the X-factor to setting allowable revenues under a BBAR model is explained well in Pat Duignan "Attachment - The role of the "X" in the EDB Default Price-quality Path decision" (20 December 2018).

[156] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 14.

6.13 In our companion paper to the updated draft, we sought feedback from distributors on whether the updated revenue allowances we proposed would create financial hardship.[157] No alternative rates of change were suggested in response to this.

6.14 Vector submitted that the we could "adopt a common X factor across all five years, spreading out any changes over the DPP period rather than leaving it in a single upfront hit."[158]

6.15 We interpret Vector's suggestion as each distributor having its own separately calculated X. We would calculate the X such that it would, along with changes in CPI, govern the change in net allowable revenue through five year-on-year changes in revenue. Those five changes would be the change in net allowable revenue from the last year of DPP2 to the first year of DPP3 and also the four CPI-X annual changes in net allowable revenue during DPP3.

6.16 While we agree that, where possible, minimising volatility in revenue and price is important, we have not adopted Vector's suggestion. If we were to adopt the suggestion of a single X for each of the five revenue changes for each distributor, then each distributor would have a different X. This would not be compliant with section 53P(5) of the Act. Applying a single X for each of the five revenue changes is effectively an approach we already consider for a single distributor to which section 53P(8)(a) applies.

Revenue cap with wash-up

6.17 As a result of the IM review in 2016, we changed the form of control for distributors from a weighted average price cap to a revenue cap, including a wash-up for over- and under-recovery of revenue.[159]

6.18 How the revenue cap will operate and policy decisions related to it are discussed in more detail in Attachment H.

[157] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Updated draft models – Companion Paper" (25 September 2019), p. 4.

[158] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019) paras 254 – 257.

[159] Commerce Commission "Input methodologies review decisions: Report on the IM review" (20 December 2016), p. 78.

How the revenue cap will apply

6.19 With the move to a revenue cap, we are now required to limit distributors' net revenues in a way that is independent of changes in demand for electricity distribution services. Distributors' forecast net allowable revenue for the period is set through starting prices at the start of the period, and then changes each year by CPI and the X-factor. It does not increase or decrease based on increases or decreases in demand, such as increased numbers of ICPs, or increases in volume of energy transported.

6.20 The wash-up mechanism is designed to make distributors or their customers whole for revenue under- or over-recovery due to differences between expected quantities when distributors set prices for a given year and when the revenue is actually recovered (forecast error). The wash-up works by allowing distributors to increase revenue in a subsequent year where it has under-recovered, or forces them to recover less revenue where they have over-recovered.

6.21 Because of the introduction of the wash-up mechanism, during the regulatory period distributors no longer have to recover the entirety of their revenue allowance *for* a given year *in* that year. Subject to the limitations discussed below, this allows distributors more flexibility to smooth the recovery of their revenue over the period.

6.22 Our DPP3 determination generally implements the revenue cap in the same way that the Powerco CPP did. Three exceptions to this are:

6.22.1 the introduction and application of a limit on how much a distributor's forecast allowable revenue can increase from one year to the next;

6.22.2 the application of a limit on the accrual of wash-up balances due to voluntary undercharging; and

6.22.3 The method of accounting for the residual 'pass-through balance' from the last year of DPP2.

Limit on the annual increase in forecast revenue from prices

6.23 We have applied a +10% limit on the annual increase in a distributor's gross 'forecast revenue from prices' (revenue including pass-through and recoverable costs). This limit will apply when distributors are setting prices in every year of the DPP period, except for the 2020/21 year.[160]

[160] The limit would not apply for the 2020/21 year as there will be no value of 'forecast revenue from prices' for the 2019/20 year in DPP2, and that value would be required for applying the limit.

6.24 The limit works in a present value-neutral way, with any under-recovery of revenue deferred to subsequent years of the DPP (or until the next DPP) via the wash-up mechanism.

6.25 The introduction of this limit requires an amendment to the EDB IMs. This amendment is discussed in more detail in Attachment H and in the accompanying IM amendment reasons paper.

6.26 In their submissions on the draft decision, Wellington Electricity and Vector proposed that the 'limit on the annual increase in forecast revenue from prices' only apply to forecast allowable revenue, rather than forecast revenue from prices.[161]

6.27 We have not implemented this change. The purpose of the limit is to mitigate the risk of price shocks to consumers. Excluding potential sources of such shocks would reduce the effectiveness of the limit and not be in consumers' interests. This decision is discussed in more detail in Attachment H.

We have not implemented the limit on an increase in revenue as a function of demand

6.28 We have not specified "an annual maximum increase in 'forecast allowable revenue as a function of demand." This control is provided for in s3.1.1(2) of the IM. We consider that this mechanism is not workable to implement in DPP3 in the event of certain price restructurings.

6.29 The 'function of demand' limit was intended to deal with price shocks to consumers caused by both changes in gross revenues and changes in quantities. While we have not been able to address price shocks arising from changes in quantities, we have addressed shocks arising from changes in gross revenues by implementing the limit on the annual increase in forecast revenue from prices.

Limit on voluntary undercharging

6.30 We have implemented a limit on distributors' ability to accrue a substantial wash-up balance as a result of charging below their revenue cap. The limit that we have implemented (termed the 'voluntary undercharging revenue floor') is the lesser of either:

6.30.1 90% of forecast allowable revenue; or

6.30.2 110% of the previous year's forecast revenue from prices.

[161] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019); Vector "Submission on IM amendments for DPP and IPP" (5 July 2019).

6.31 A distributor that prices below this limit permanently foregoes this revenue. Between the revenue cap and the undercharging floor, distributors will be able to roll over that revenue, and recover it in future years through the wash-up mechanism.

6.32 Under the price path for the current (DPP2) period, a distributor that charges below its price cap permanently foregoes that revenue.

6.33 Under the revenue cap with wash-up, distributors may carry forward under-recovered revenue in a wash-up account. Absent a mechanism to limit accumulation of the 'wash-up balance', a distributor that prices below the revenue cap may accrue a large balance, which could then create a price shock when it is passed through to consumers. To prevent this situation, we included a limit on this accumulation in the specification of price IMs.

6.34 The 90% limit was chosen to allow distributors some flexibility to smooth revenue recovery, while at the same time minimising the risk of future price shocks. The setting of the 'voluntary undercharging revenue floor' as described in paragraph 6.30 was included to allow for unusual situations where, because of the limit on the annual increase in forecast revenue from prices, a distributor would be 'forced' to price below the 90% limit.

6.35 We did not receive any submissions on the limit on voluntary undercharging and have not made any changes since our draft decision.

Revenue cap and incentives under 54Q

6.36 A key benefit to a revenue cap over a price cap is it removes any disincentives for measures to promote energy efficiency and demand-side management.[162] As distributors are no longer exposed to quantity risk, they can take steps to reduce demand (and therefore potentially defer capex) without incurring revenue losses.

6.37 Furthermore, moving to a revenue cap will allow distributors to restructure their prices to be more service-based and cost-reflective without the complexities of price restructures that are currently caused by the lagged prices in the compliance formula for weighted average price caps. Improved pricing may better support demand-side management.[163]

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[162] These benefits were part of our motivation for the change to the revenue cap when reviewing the input methodologies. Commerce Commission "Input methodologies review decisions – Topic paper 1 – Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016), pp. 24-25.

[163] Work on distribution pricing is currently being undertaken by the Electricity Authority, through its Distribution Pricing Review.

Incentives during the period

6.38 During the DPP3 period, distributors will be subject to explicit incentives that are intended to promote behaviour consistent with the long-term benefit of consumers. This section deals with two of these incentives:

6.38.1 incentives to improve efficiency (IRIS); and

6.38.2 incentives for innovation.

6.39 We have also retained a modified revenue-linked quality incentive scheme, which we discuss in Chapter 7.

Incentives to improve efficiency

6.40 For the DPP3, we have made changes to the IRIS mechanism. The most significant change is to the incentive rate for the capex IRIS. We have set a capex retention factor equal to the opex retention factor, or for the DPP3 period 23.5%.

6.41 We have also made minor amendments to the opex IRIS IMs, to ensure they are consistent with the original policy intent of the mechanism. These changes are discussed in Attachment E.

Retention factors for IRIS

6.42 Our regime provides incentives for distributors to improve opex and capex efficiency, and provides for these savings to be shared between distributors and consumers. To ensure these incentives are consistent throughout a regulatory period, we apply an IRIS mechanism, with a defined 'retention factor', which determines what proportion of any increase or decrease in efficiency is kept by the distributor.

6.43 Opex and capex are subject to different IRIS mechanisms. The retention factor for opex is defined by the IMs, and approximates a five-year retention of any savings or losses by the distributor. For the DPP2 period, this equated to a 34% retention factor. For capex, we determine the retention factor at each reset as part of the DPP determination. For DPP2, we determined a retention factor of 15%.

6.44 Because of the change in the WACC, the retention factor for opex for has reduced to 23.5%.[164] To ensure distributors have a consistent incentive to spend both opex and capex, and do not favour capital solutions over operating ones, we have equalised the capex retention factor with the opex one.

[164] For the draft decision, this amount was 26%. A further reduction in the final WACC for the DPP has resulted in it lowering further.

6.45 We also consider that this change will reduce or remove barriers to innovation. We do not want to disincentivise any potential emerging technologies from being used by distributors due to a lower capex incentive rate. Equalising rates will create a more level playing field to allow distributors to avoid spending capex through investing in innovative solutions using third parties.

Changes to IRIS incentives during DPP2

6.46 We have not made any distributor-specific changes to the IRIS incentives distributors faced during DPP2 (and which will affect allowable revenue during DPP3). This includes not making changes:

6.46.1 to the treatment of pecuniary penalties;

6.46.2 to deal with distributors that have priced below their allowable revenue during DPP2; and

6.46.3 to deal with additional opex related to spur assets purchased from Transpower.

6.47 The specific reasons for these decisions are discussed in Attachment E. In general, we have not made changes to DPP2 incentives because firstly, these changes have limited incentive benefits, as distributors cannot change past conduct. Additionally because such changes undermine the certainty the regime is intended to provide.

6.48 We have made a modification to deal with the change in the accounting treatment of operating leases. This change is distinct from the changes listed above because:

6.48.1 it affects most or all distributors on the DPP; and

6.48.2 it relates not to any conduct distributors have undertaken, but to a change in accounting rules that risks creating perverse outcomes.

6.49 This change is discussed in more detail in our operating leases final decisions paper.[165]

Incentives for innovation

6.50 We have introduced a targeted innovation allowance for distributors during the DPP3 period, in addition to the existing incentives for innovation created by the IRIS mechanism and the quality incentive scheme.

[165] Commerce Commission "Treatment of operating leases – Final decision" (13 November 2019).

6.51 As discussed in Chapter 4, possibilities for innovation in how regulated services are delivered (and the uncertainties it can create) are a major contextual theme for our DPP3 decision. We consider that the existing incentives in the DPP should be the main driver of innovation, specifically:

6.51.1 where adopting an innovative approach leads to lower costs, distributors will retain a portion of the savings (23.5%) and share the rest with consumers through the IRIS mechanism; and

6.51.2 where adopting an innovative approach leads to improved quality, distributors will keep a portion (23.5%) of the value of that improvement (as measured by the discounted VoLL we apply) through our quality incentive scheme.

6.52 However, as the benefits of innovation may be uncertain and may not be realised until future DPP periods, we consider that an additional incentive that enables distributors to undertake innovation projects could lead to better outcomes for consumers in the long term.

6.53 We have set the limit of the funding available at the greater of either 0.1% of allowable revenue or $150,000 over the period. We have set this conservatively, as there will be only limited scrutiny over how the allowance is spent. In response to submissions, we have introduced a dollar cap in addition to the percentage cap proposed in the draft decision.

6.54 Where a distributor seeks to make substantial innovations in the way it manages its network, and those innovations have a significant price or quality impact for consumers, a CPP is the more appropriate response. This will allow us to apply greater scrutiny, and to vary the way the price-quality path functions to account for innovative approaches.

6.55 The incentive will be given effect to via a recoverable cost, (discussed briefly below at paragraph 6.63), and be subject to a set of criteria discussed in Attachment F.

Allowance for pass-through and recoverable costs

6.56 The starting prices we determine through the BBAR methodology described in Chapter 4, and the net allowable revenues distributors can earn during the period, are determined 'net' of pass-through and recoverable costs.

6.57 Pass-through and recoverable costs are costs which distributors face that are substantially beyond their control, and are specified in the specification of price IMs. Distributors may pass on these costs to their consumers.

6.58 We are have introduced two new recoverable costs for the DPP3 period:

6.58.1 Fire and Emergency New Zealand (FENZ) levies; and

6.58.2 a recoverable cost to implement the innovation project allowance.

6.59 We have also made an amendment to clarify and extend the scope of the recoverable cost relating to charges payable by a distributor to Transpower in respect of a 'new investment contract' between those parties, or any equivalent contract with another provider. The amendment will allow a distributor to use a third-party option to finance the new investment contract between the distributor and Transpower (or equivalent contract with another provider). This amendment was proposed by Transpower in response to our draft DPP decision.[166]

6.60 All of these changes required amendments to the IMs, which are described in the IM amendments reasons paper which was published on 26 November 2019.[167]

Recoverable cost for FENZ levies

6.61 In submissions on the issues paper, the ENA identified FENZ levies as likely to change substantially in the DPP3 period, in a way that it is not possible to forecast.[168] We agree with this view, especially as the uncertainty involved may extend to the levies ceasing to apply altogether, one of the options which is currently under consideration.[169]

6.62 As payment of these levies is substantially beyond a distributor's control, we consider it appropriate for them to be moved from regular opex to a recoverable cost.

Recoverable cost to implement the innovation project allowance

6.63 As discussed above in paragraphs 6.50 to 6.53, we have implemented a new innovation project allowance. This will be given effect to by allowing distributors to pass on the cost of these innovation projects to their consumers through a recoverable cost. The criteria a distributor would have to meet to include this recoverable cost in their allowable revenue are specified in the DPP determination.

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166 Transpower "Submission on IM amendments for DPP and IPP" (5 July 2019).

167 Commerce Commission "Amendments to electricity distribution services input methodologies determination – Reasons paper" (26 November 2019).

168 Electricity Networks Assoc (ENA) "DPP3 April 2020 Commission Issues paper(Part One Regulating capex, opex & incentives)" (20 December 2018), p. 16.

169 Office of the Minister of Internal Affairs "Fire and Emergency New Zealand: a funding review" (released 25 March 2019).

Circumstances in which the price path can be reopened

6.64 To deal with certain unforeseeable changes during a DPP regulatory period, the IMs include provision for reopening a DPP. We have implemented new reopeners for 'major unforeseeable capex projects' and major foreseeable capex projects', as in certain circumstances they share relevant characteristics with existing reopeners.

6.65 Specifically, expenditure on major new connections (including alterations to existing connections), system growth, or asset relocations can be:

6.65.1 significant;

6.65.2 unforeseeable at the time the path is set;

6.65.3 beyond the control of distributors; and

6.65.4 not accounted for through other mechanisms.

6.66 Existing reopeners apply to situations like catastrophic events, legislative and regulatory change, or major transactions.

Reopeners for major capex

6.67 In submissions on the issues paper, parties identified major consumer connection capex as a material source of uncertainty, and suggested a 'listed projects' type mechanism to deal with this contingency.[170] Given decarbonisation efforts on the part of major energy consumers and the potential for increased distributed generation, or relocation of distribution assets to accommodate other infrastructure projects it is possible that there will be an increase in this type of activity in the future.

6.68 The specific conditions a distributor would have to meet to qualify for these reopeners are discussed in Attachment G. We have imposed these conditions to:

6.68.1 limit the number of applications over the period, to ensure the administration of the DPP remains relatively low-cost;

6.68.2 ensure the interests of existing consumers are protected;

[170] Electricity Networks Assoc (ENA) "DPP3 April 2020 Commission Issues paper(Part One Regulating capex, opex & incentives)" (20 December 2018) , pp. 17-18; Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018), para 13. We note that Transpower's listed projects mechanism covers replacement and renewal projects whose exact timing and cost is uncertain when the IPP is set, rather than consumer connection or system growth capex where the need is uncertain when the DPP is set.

6.68.3 enable a fast approval process, given the time constraints involved in such projects, including connected parties operating in competitive markets; and

6.68.4 to ensure the reopener is not used in circumstances where the higher level of scrutiny possible under a CPP is required.

6.69 In response to submissions on our draft decision, we have expanded the scope of these reopeners to include:

6.69.1 asset relocations; and

6.69.2 system growth projects or programmes.

6.70 We have also modified the threshold and limit for when the reopeners are available in response to submissions. Projects or programmes will qualify for the reopeners where they involve capex that is at least $2 million or 1% of a distributor's forecast net allowable revenue over the regulatory period – whichever is less.

6.70.1 We have also included a maximum cap of $30 million for the aggregate for all projects and programmes that can be applied for under these reopeners in any one disclosure year.

6.71 The other specific requirements for this reopener are discussed in Attachment G.

Transactions

6.72 When a distributor engages in a transaction where it transfers assets to another entity, and this transfer results in consumers no longer being served by the transferring distributor, an adjustment needs to be made to both the transferring and receiving distributors' price path.[171]

6.73 Where this transfer occurs by way of a complete amalgamation or merger of two price-quality regulated distributors, the IMs provide for their price-quality paths to be aggregated.[172] Where the transfer affects more than 10% of a distributor's opening RAB, the Commission may reopen the price-quality path (referred to as a 'major transaction').[173]

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[171] Another entity in this case could include: another price-quality regulated distributor, an exempt distributor, or a non-distributor purchaser, who – following the completion of the transaction – becomes a distributor.

[172] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.2.1.

[173] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 4.5.4.

6.74 Where a transaction is not an amalgamation, and affects less than 10% of a distributor's opening RAB, the DPP determination may specify how distributors are to adjust their revenue. To deal with these situations, which we refer to as 'transfers', we have adopted a principles-based approach to adjusting the revenue path and quality standards.

6.75 We did not receive any submissions on the treatment of transactions, and have made no changes from the draft decision.

Treatment of revenue path following a transfer

6.76 Our approach is one based on the principle that, in aggregate, consumers should be no worse-off, in terms of total revenue, than they would have been had the transaction not occurred.

6.77 Under this approach, distributors will have to agree an allocation of revenues to produce a new 'forecast net allowable revenue' and 'wash-up amount' for the transferring and receiving distributor. The amount transferred must be:

6.77.1 reasonable; and

6.77.2 supported by robust and verifiable evidence.

6.78 We have also adopted the requirement for distributors to notify the Commission of any transaction (amalgamation, merger, major transaction, or asset transfer) within 30 working days of the transaction occurring.

Treatment of quality standards and incentives following a transfer

6.79 We have taken a similar treatment for each of the parameters of the quality standards (for example: boundary values, reliability limits) and quality incentives (for example: targets and caps).

6.80 We note that when demonstrating whether adjustments to quality standards were reasonable, we would look to the ICP weighted-sums of SAIDI and SAIFI before and after the transactions, rather than the absolute amount of SAIDI and SAIDI.[174]

[174] Put another way, a distributor would need to demonstrate its reallocation was reasonable on a 'customer minute' basis, rather than a system average basis.

CPP application dates

6.81 Where a distributor considers that the DPP does not meet their particular circumstances, they have the ability to apply for a CPP. The Act requires us to specify in the DPP determination the date or dates by which a distributor may submit its CPP application. These dates are set out in Table 6.1 below, and are discussed in more detail in Attachment I.

Table 6.1 CPP application deadlines

CPP beginning	Final date for application
1 April 2021	Fri 12 Jun 20
1 April 2022	Fri 11 Jun 21
1 April 2023	Fri 10 Jun 22
1 April 2024	Fri 9 Jun 23
1 April 2025	Fri 29 Mar 24

Chapter 7 Quality standards and incentives

Purpose of this chapter

7.1 This chapter explains the changes we have made to the quality standards distributors must comply with and the quality incentives distributors will be subject to for the DPP3 period.

How we have structured this chapter

7.2 This chapter starts by explaining our high-level approach to quality by:

7.2.1 summarising the decisions we have made;

7.2.2 discussing the statutory requirements we must meet, and how we are promoting the purpose of Part 4;

7.2.3 setting out the reasons for our general 'no material deterioration' approach; and

7.2.4 discussing the importance in a changing environment of allowing distributors to make trade-offs where they are in the long-term interest of consumers.

7.3 The following sections then explain:

7.3.1 the quality standards we have set and our approach to setting these;

7.3.2 changes (relative to DPP2) to the revenue-linked quality incentive scheme;

7.3.3 updates to our approach for normalising major events;

7.3.4 the enhanced reporting requirements; and

7.3.5 how we have treated measures of quality other than reliability.

7.4 These topics, submissions we have received on them, and our responses to those submissions are explained in detail in Part 3 of the Attachments to this paper (Attachments J to N).

7.5 The determination that implements these standards and incentives can be found in Clause 9 and Schedules 3.1 to 4 of the accompanying DPP determination.[175]

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[175] Commerce Commission *Electricity Distribution Services Default Price-Quality Path Determination 2020* [2019] NZCC 21 (27 November 2019), clause 9.

High-level approach

Summary of our decisions

7.6 The quality standards we have set for DPP3 are based on the duration and frequency of interruptions on the distribution network that customers experience in aggregate. These are measured by 'SAIDI' and 'SAIFI' respectively. SAIDI refers to the average total duration of interrupted power supply in a year per customer in minutes. SAIFI refers to the average number of interruptions to power supply per customer in a year. Both SAIDI and SAIFI exclude interruptions originating on the low voltage portion of the network.

7.7 The DPP3 SAIDI and SAIFI limits for each of the quality standards for each supplier are set out in Table 7.1 below.

Table 7.1 Quality standard limits for DPP3

Distributor	Unplanned SAIDI (1-year)	Unplanned SAIFI (1-year)	Planned SAIDI (5-year)	Planned SAIFI (5-year)	Extreme event[176] (per event)
Alpine Energy	124.71	1.1970	824.87	3.4930	120 SAIDI
Aurora Energy	81.89	1.4687	979.80	5.5385	6 mil CIM
Centralines	83.61	3.1616	1064.46	5.8573	120 SAIDI
EA Networks	91.98	1.2826	1376.08	4.8939	120 SAIDI
Eastland Network	219.46	3.1525	1290.68	7.4745	120 SAIDI
Electricity Invercargill	25.86	0.6956	114.49	0.5183	120 SAIDI
Horizon Energy	194.53	2.3904	858.63	5.4415	120 SAIDI
Nelson Electricity	19.60	0.4277	180.11	2.3663	120 SAIDI
Network Tasman	101.03	1.1956	1129.14	4.9021	120 SAIDI
Orion NZ	84.71	1.0336	198.40	0.7481	6 mil CIM
OtagoNet	160.35	2.4172	2114.43	9.6212	120 SAIDI
Powerco	180.25	2.2684	772.50	3.5113	6 mil CIM
The Lines Company	181.48	3.2715	1331.68	8.7527	120 SAIDI
Top Energy	380.24	5.0732	1905.36	7.7526	120 SAIDI
Unison Networks	82.34	1.8152	625.79	4.4649	6 mil CIM
Vector Lines	104.83	1.3366	585.38	2.8783	6 mil CIM
Wellington Electricity	39.81	0.6135	69.70	0.5536	6 mil CIM

[176] These figures are indicative only. The extreme event standard is specified in either SAIDI minute and customer interruption minute terms. Distributors for which the customer interruption minutes is applicable we have converted to a SAIDI equivalent. This is discussed in more detail in Attachment L.

7.8 For the quality incentive scheme we have:

7.8.1 retained (from DPP2) revenue-linked quality incentives for both planned and unplanned SAIDI;

7.8.2 removed revenue-linked quality incentives for SAIFI;

7.8.3 set the SAIDI 'targets' (the point at which distributors are revenue-neutral) at the historical average of unplanned SAIDI and planned SAIDI over a 10-year, 2010-2019 period;

7.8.4 set the 'caps' (the limit on maximum losses) at the SAIDI limits;

7.8.5 set the 'collars' (maximum gains) at zero;

7.8.6 determined the incentive rate for unplanned SAIDI with reference to a VoLL of $25,000/MWh, discounted to 23.5% of VoLL to acknowledge the sharing of costs through the IRIS mechanism, and a further 10% to account for the existing incentives created by quality standards (21.2% of VoLL);

7.8.7 determined the planned incentive rate at 50% of the unplanned rate (10.6% of VoLL), and a further 50% (5.3% of VoLL) if certain notification conditions are met; and

7.8.8 set revenue at risk, endogenously but capped at 2% of revenue.

7.9 The relevant parameters for the incentive scheme for each supplier are set out in Table 7.2 below.

Table 7.2 Quality incentive scheme parameters

Unplanned SAIDI	Unplanned collar[177]	Unplanned target	Unplanned cap	Incentive rate[178]	Maximum loss[179]	Maximum gain
Alpine Energy	0.00	91.88	124.71	7,879	0.58%	1.63%
Aurora Energy	0.00	63.44	81.89	13,155	0.27%	0.92%
Centralines	0.00	62.83	83.61	1,071	0.23%	0.69%
EA Networks	0.00	71.65	91.98	5,394	0.32%	1.12%
Eastland Network	0.00	173.85	219.46	2,797	0.51%	1.94%
Electricity Invercargill	0.00	15.39	25.86	2,544	0.21%	0.31%
Horizon Energy	0.00	144.35	194.53	5,397	1.09%	3.13%
Nelson Electricity	0.00	9.53	19.60	1,417	0.25%	0.24%
Network Tasman	0.00	74.49	101.03	6,260	0.60%	1.69%
Orion NZ	0.00	66.47	84.71	31,686	0.35%	1.28%
OtagoNet	0.00	120.02	160.35	4,339	0.65%	1.94%
Powerco	0.00	151.96	180.25	47,908	0.46%	2.45%
The Lines Company	0.00	143.04	181.48	3,827	0.41%	1.52%
Top Energy	0.00	302.16	380.24	3,283	0.65%	2.51%
Unison Networks	0.00	67.81	82.34	16,185	0.23%	1.05%
Vector Lines	0.00	89.28	104.83	84,519	0.32%	1.87%
Wellington Electricity	0.00	31.20	39.81	23,215	0.21%	0.76%
Planned SAIDI	**Planned collar**	**Planned target**	**Planned cap**	**Incentive rate**	**Maximum loss**	**Maximum gain**
Alpine Energy	0.00	54.99	164.97	3,940	0.98%	0.49%
Aurora Energy	0.00	65.32	195.96	6,578	0.95%	0.47%
Centralines	0.00	70.96	212.89	535	0.78%	0.39%
EA Networks	0.00	91.74	275.22	2,697	1.43%	0.71%
Eastland Network	0.00	86.05	258.14	1,399	0.96%	0.48%
Electricity Invercargill	0.00	7.63	22.90	1,272	0.15%	0.08%
Horizon Energy	0.00	57.24	171.73	2,698	1.24%	0.62%
Nelson Electricity	0.00	12.01	36.02	709	0.30%	0.15%
Network Tasman	0.00	75.28	225.83	3,130	1.71%	0.86%
Orion NZ	0.00	13.23	39.68	15,843	0.25%	0.13%
OtagoNet	0.00	140.96	422.89	2,169	2.28%	1.14%
Powerco	0.00	51.50	154.50	23,954	0.83%	0.42%
The Lines Company	0.00	88.78	266.34	1,914	0.94%	0.47%
Top Energy	0.00	127.02	381.07	1,641	1.05%	0.53%
Unison Networks	0.00	41.72	125.16	8,093	0.65%	0.32%
Vector Lines	0.00	39.03	117.08	42,260	0.82%	0.41%
Wellington Electricity	0.00	4.65	13.94	11,607	0.11%	0.06%

7.10 The SAIDI and SAIFI major event boundary values for each supplier are set out in Table 7.3.

Table 7.3 Major event boundary values (24-hour)

Distributor	SAIDI boundary	SAIFI boundary
Alpine Energy	9.17	0.0671
Aurora Energy	5.69	0.0737
Centralines	6.79	0.1442
EA Networks	6.25	0.0729
Eastland Network	13.10	0.1765
Electricity Invercargill	4.13	0.0804
Horizon Energy	14.69	0.1170
Nelson Electricity	8.68	0.1430
Network Tasman	7.22	0.0688
Orion NZ	7.60	0.0668
OtagoNet	11.81	0.1776
Powerco	9.82	0.0628
The Lines Company	11.17	0.1596
Top Energy	27.92	0.2284
Unison Networks	4.48	0.0735
Vector Lines	4.83	0.0371
Wellington Electricity	2.16	0.0313

7.11 We have made the following changes to the way we normalise unplanned interruptions:

7.11.1 defining major events on a 24-hour rolling basis (assessed in 30-minute rolling blocks), rather than as calendar days;

7.11.2 setting the major event boundary value as the 1104th highest assessed rolled 24-hour period within the historical data set, rather than as the 23rd highest calendar day;[180]

7.11.3 replacing any half-hour within a major event that is above 1/48th of the boundary value with the 1/48th of the boundary value; and

[177] Collar, cap, and target values are in SAIDI minute terms.

[178] In $ per SAIDI minute terms.

[179] Estimated maximum incentive as a percentage of allowable revenue.

[180] This value is approximately equivalent to the 23rd highest calendar day approach applied in DPP2.

7.11.4 adjusting the major event boundary for distributors with smaller networks which can expect fewer major events each year.

7.12 Finally, we have:

7.12.1 introduced incentives for better notification of planned interruptions (as part of the reliability incentive scheme);

7.12.2 expanded major event reporting requirements;

7.12.3 introduced automatic reporting following any quality standard contravention; and

7.12.4 not introduced standards for other measures of quality of service.

Our approach to quality

The Act requires us to set quality standards

7.13 We are required by the Act to set quality standards that must be met by regulated suppliers when setting price-quality paths.[181] We may also set financial incentives for an individual supplier to maintain or improve its quality of supply.[182]

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

7.15 Where quality standards are not met, we may seek a range of remedies in Court against the distributor for that underperformance, including the imposition of pecuniary penalties, or an order that compensation be paid to parties that experienced loss or damage, under Part 6 of the Commerce Act. We may also bring secondary liability proceedings against directors, shareholders, or other entities associated with the business if their actions contributed to, or they were otherwise closely involved in, the quality standard contraventions.

Commission focus on quality

7.16 The quality of service provided by electricity distributors was one of the Commission's organisation-wide priorities for the 2018/19 year.

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[181] Commerce Act 1986, section 53M(1)(b).

[182] Commerce Act 1986, section 53M(2).

7.17 As we said in announcing those priorities:

> We will be consulting with stakeholders on the revenue limits and quality standards that should apply to electricity distribution networks for the five years from 1 April 2020, with our final decision due in November 2019. We continue to improve the efficiency and effectiveness of each reset. In the next reset we will consider whether 'no material deterioration' remains the appropriate basis for the minimum reliability standards. We will also consider whether other dimensions of quality should be monitored alongside the existing reliability measures, such as communication to customers during outages.
>
> In addition to this work, we will be seeking to better understand why some distributors have previously failed to comply with the minimum standards for network reliability and what this tells us about the state of their network.[183]

7.18 Submissions on our issues paper indicated that stakeholders did not agree on which quality measures should be implemented for DPP3. We received a submission from the ENA who convened a Quality of Supply Working Group,[184] but some distributors and non-distributor stakeholders disagreed with the recommendations put forward by the ENA.

7.19 Our decisions discussed below build on work undertaken by the ENA Quality of Service Working Group, and on analysis undertaken by NZIER on behalf of MEUG.[185] They are also the result of ongoing collaboration with industry stakeholders to develop a set of proposals that promote the Part 4 purpose, but that are also workable.

7.20 Given these priorities, and the areas for improvement in quality standards and incentives that we have identified through consultation, we consider that while the package of changes we are proposing is substantial, it is proportionate to the importance of the issue, and the scale of change in the industry as a whole.

No material deterioration

7.21 Consistent with the DPP principles discussed in Chapter 3 at paragraph 3.16, our starting point for a DPP is that distributors should at least maintain the levels of reliability that they have provided historically, all other things being equal. We refer to this principle as 'no material deterioration'.

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183 Commerce Commission "Priorities 2018/19" (8 August 2018), p. 3.

184 Electricity Networks Assoc. "ENA Working Group on quality of service regulation – Interim report to the Commerce Commission" (1 October 2018).

185 Major Electricity Users' Group "NZIER on behalf of MEUG EDB DPP reset issues paper" (21 December 2018).

7.22 The planned and unplanned reliability standards and targets we have implemented are based on distributors' historical performance, and are intended to give effect to the no material deterioration principle.[186]

7.23 The exception to this approach is the setting of the extreme event standard, which has been set at a fixed amount for all distributors. This is because, we consider that it is not possible to set a limit based on the reference period for an expectation of no material deterioration because of the infrequency of such events. This is not reason enough to avoid introducing an extreme event standard, although it has influenced us in introducing it at a with conservatively high level.

Reliability in a changing environment

7.24 While no material deterioration is the starting point for our approach to quality, we also acknowledge the need for distributors to make trade-offs about the level of quality they deliver, and the cost they incur in doing so. This consideration drives many of the changes we have made to the quality incentive scheme for DPP3 relative to DPP2.

7.25 Even in a relatively stable industry environment, it would be important for distributors to consider price-quality trade-offs at the margins, and to have the ability to move towards a level of quality that better reflects consumers' demands and the distributor's cost to serve those consumers.

7.26 However, as discussed in Chapter 4, we see potential for change over the DPP3 period, but with significant uncertainty about the scale of change. These future changes could be driven by:

7.26.1 changes in a distributor's cost to serve, driven by factors like improved technology or a changing climate;

7.26.2 changes in consumer expectations, whether that is a willingness to accept more interruptions, given the availability of self-supply (solar PV, batteries, microgrids) or a greater willingness to pay to avoid interruptions as more services (most prominently transport) depend on the grid; and/or

7.26.3 better understanding on the part of distributors about customer expectations from an improved level of customer engagement.

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[186] We used a reference period from 1 April 2010 to 31 March 2019 to assess against historical performance. However, we limit inter-period reliability movements of unplanned interruption parameters to 5%, as discussed in Attachment J.

7.27 This potential for changes makes it even more important that we give distributors some flexibility to change the level of reliability that they target, while we still protect consumers' interests by ensuring:

7.27.1 there are minimum standards beyond which greater scrutiny is required before changes are made;

7.27.2 the changes distributors make in some way reflect the value consumers place on reliability through a quality incentive scheme; and

7.27.3 consumers share in the benefits of either improved efficiency or improved reliability.

7.28 We consider distributors are best placed to make decisions around these trade-offs, so long as they are incentivised to act in a way that is aligned with the long-term interests of consumers. This is consistent with our approach to capex (discussed above in Chapter 5 at paragraph 5.77).

Quality standards

7.29 This section summarises the quality standards we have set, and briefly discusses our reasons for setting them. More detail on these standards, including submissions and our response to them can be found in Attachment L.

7.30 We have separated planned and unplanned interruptions for the purposes of standards and revenue-linked incentives. Separation eliminates the ability of distributors to avoid contravening their unplanned reliability standard by deferring planned work when it forecasts that it is otherwise likely to contravene. Separation better promotes the purpose of Part 4 because it does not create an incentive against investment at the most appropriate and efficient time and better reveals deterioration of network performance to be assessed against the quality standards.

Unplanned reliability standard

7.31 Given the network-wide aggregate nature of the SAIDI and SAIFI metrics used to assess reliability, setting an unplanned reliability standard at a level that perfectly reflects consumer preferences is not possible at this stage. In the absence of better information, we consider that an unplanned reliability standard should identify instances of material deterioration in overall reliability.

7.32 There was general support from submitters for the 'no material deterioration' standard, but diverging views on implementation (for example, reference periods, data adjustments, and normalisation). For example, the ENA submitted that "customer feedback to date strongly suggests that declining reliability standards are not generally acceptable".

7.33 This is consistent with our decision to base the quality standards on the historical average, with a buffer added to reduce the inherent risks due to random year-to-year volatility of the SAIDI and SAIFI metrics and to allow for moderate declines where it results in lower prices for customers via the revenue-linked quality incentive scheme.

7.34 With the decision to separate planned and unplanned interruptions for setting quality standards, an unplanned reliability standard is required to be specified for SAIDI and SAIFI. The unplanned reliability standard is:

7.34.1 assessed annually for unplanned SAIDI and SAIFI, removing the previous two-out-of-three-year rule; and

7.34.2 set with limits for unplanned SAIDI and SAIFI of 2.0 standard deviations above the reference period average, an increase from 1.0 standard deviation under DPP2.

7.35 Our decision is to replace the current two-out-of-three-year rule with a simpler annual limit for unplanned SAIDI and SAIFI. This decision is informed by other reliability standard settings (reducing the impact of major events and the buffer above the historical mean) that we consider are more effective means of reducing the risk of false-positives and false negatives.

7.36 We consider that using the historical mean with an additional buffer works well in capturing material deterioration in reliability. The current quality standards have resulted in contraventions that investigations have shown to be, at least in part, caused by failure of those distributors to act consistently with good industry practice. Conversely, we have not yet found contraventions of the quality standard in the current regulatory period to be caused only by random volatility.

Planned reliability standard

7.37 With the decision to separate planned and unplanned interruptions for setting quality standards, a planned reliability standard is required to be specified for SAIDI and SAIFI. The planned reliability standard is:

7.37.1 assessed once for the regulatory period for planned SAIDI and SAIFI (assessment is against a five-year total); and

7.37.2 set at three times the historical level of planned SAIDI and SAIFI.

7.38 Our decision to set the planned reliability standard over the full regulatory period will allow distributors to schedule planned works in a way that works best for their business and consumers, rather than to comply with an annual planned reliability standard. For example, previous settings may have incentivised distributors to inefficiently defer or bring forward work to avoid contravention. We consider that revenue-linked incentives are a better mechanism to encourage each distributor to manage its planned interruptions appropriately, allowing distributors to undertake planned interruptions for investment like replacement of aged assets where it is in the interests of consumers to do so.

7.39 We have implemented a large buffer for setting the planned reliability standard. We consider that a buffer of 200%, or triple the historical average, is appropriately less stringent than the quality standard set for DPP2 given the long-term benefits to consumers of the network investment and maintenance that is associated with planned interruptions.[187] It will also allow for some flexibility in work practices that may increase the impact of planned works on SAIDI or SAIFI, for example, changes in live lines working practices.

Extreme event standard

7.40 We have introduced a new 'extreme event standard' to deal with extreme one-off events that may cause serious inconvenience for consumers. The standard is set at the lower of either 120 SAIDI minutes or 6 million customer interruption minutes and it applies to events not caused by major external factors.

7.41 This is a change from our draft decision, where the extreme event standard was set at three times the major event boundary value. Submitters highlighted that this led to disproportionate outcomes for different distributors, given the different boundary values they faced. In response to this, we have set the extreme event standard at a consistent level across all distributors.

7.42 Normalising major events means that particularly large interruptions are unlikely to contribute to a contravention unless the assessed unplanned SAIDI or SAIFI is high enough for other reasons.

7.43 Major events are assessed on a statistical basis, rather than based on their causes. This means that with normalisation the unplanned reliability standard may miss large interruption events that are caused by not applying good electricity industry practice or under-spending on network maintenance and investment. Such interruption events can have a substantial impact on consumers and we consider that it is in the long-term interests of consumers to set a quality standard relating to extreme events.

[187] We note the revenue-linked incentives will also apply up to 200% above the target.

Quality incentive scheme

7.44 This section discusses changes (relative to DPP2) to the quality incentive scheme, and our approach to each of the parameters within the scheme, specifically the:

7.44.1 incentive rates;

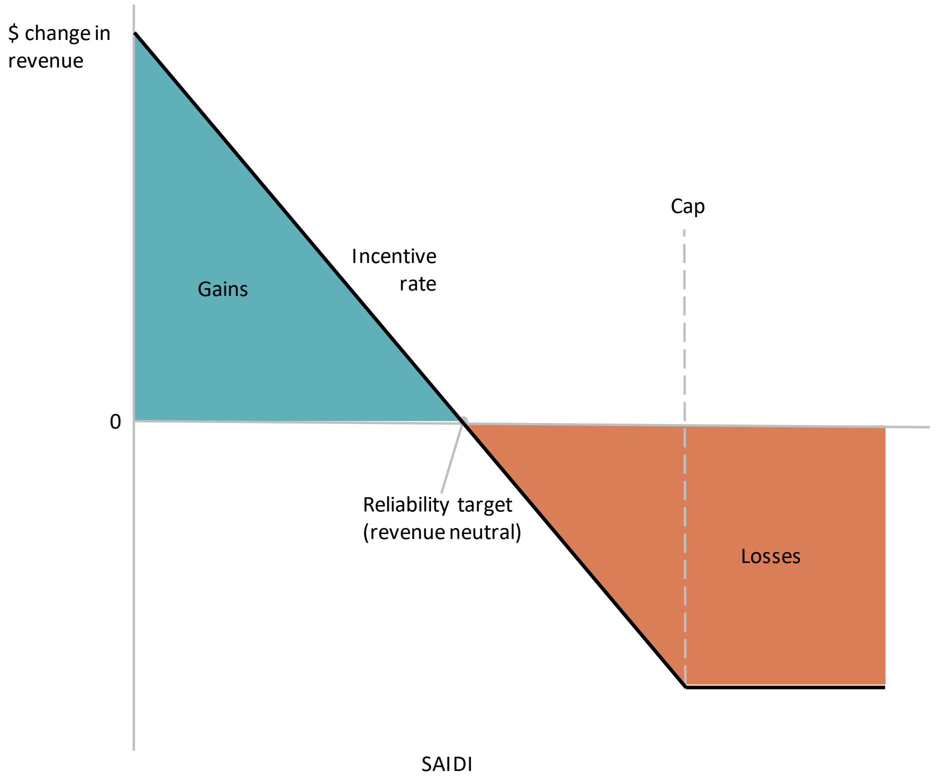
7.44.2 reliability targets;

7.44.3 caps and collars; and

7.44.4 level of revenue exposure (revenue at risk).

7.45 The relationship between these parameters is illustrated in Figure 7.1 below. The revenue-linked incentive scheme is discussed in more detail in Attachment M.

Figure 7.1 Relationship between parameters of our quality incentive scheme



We have retained the quality incentive scheme for planned and unplanned SAIDI

Retention of SAIDI incentives

7.46 As discussed above, we consider allowing distributors to make trade-offs about the level of reliability they deliver, and ensuring consumers share in the benefits of those trade-offs, is an important element of the DPP. For this reason, we have retained a modified version of the quality incentive scheme.

Removal of SAIFI incentives

7.47 Given the approach to the VoLL that we use for the DPP we were concerned that applying the scheme to both SAIDI and SAIFI risks double-counting the SAIFI impact. This is because SAIDI is a function of interruption frequency (SAIFI) and interruption length (CAIDI). Put another way, SAIDI is the product of SAIFI and CAIDI. We therefore considered that reducing or removing SAIFI from incentives was appropriate.

7.48 Our decision to remove SAIFI from the incentive scheme was driven by the following considerations:

7.48.1 SAIFI will still be subject to compliance standards;

7.48.2 SAIFI, as well as CAIDI, are indirectly captured through SAIDI incentives; and

7.48.3 SAIFI incentives may place undue priority on short-term mitigations rather than preventing long-term deterioration.

Improvements to the incentive rate

7.49 The incentive rates determine the level of financial exposure distributors have to a marginal change in reliability. The most material change we have implemented to the incentive scheme is to the incentive rates.

7.50 We have set SAIDI incentives rates that are informed by a VoLL of $25,000 per megawatt hour (MWh), and discounted to reflect expenditure incentives, quality standard incentives, and the different impact of planned and unplanned interruptions on consumers:

7.50.1 for unplanned interruptions, the discount is to 21.2% of VoLL, to reflect an IRIS-like five-year retention of the value of improvements or declines in reliability;

7.50.2 for planned interruptions, the discount is to 10.6% of VoLL (half the rate for unplanned interruptions), to reflect the lesser inconvenience planned interruptions cause consumers; and

7.50.3 for notified planned interruptions, the discount is to 5.3% of VoLL, to incentivise distributors to provide consumers with better notice of interruptions.

7.51 These decisions are largely unchanged from our draft decision. We have altered the percentage discount necessary to achieve a five-year retention of benefits by the distributor to reflect the change in the IRIS retention factor (to 76.5% from 74%). Since the draft decision, we have reduced the size of the additional discount we apply to account for the effects of the quality standard from 20% to 10%. This is to mirror the extension of the unplanned reliability standard buffer from 1.5 standard deviations to 2 standard deviations.

7.52 This is a significant change from DPP2, where the incentive rate was set endogenously. Consequently, for more reliable distributors, the narrower bands between caps and collars may have created incentives beyond that which consumers value. Conversely, less reliable distributors with wider bands had much weaker incentives. The quality incentives were up to five times stronger for the most reliable distributors as they were for the least reliable, a counterintuitive outcome we have corrected.

7.53 We have set a lower incentive rate for planned interruptions where additional notification criteria have been met, as discussed in Attachment M. This is to acknowledge that adequate notification of planned interruptions is important for consumers to mitigate the impact of the interruption. We consider these further incentives for planned interruptions that exceed the currently required 24 hours' notice for planned interruptions is an appropriate way to encourage better and meaningful notification for consumers.

7.54 In response to submissions that raised concerns about the workability of the definition of notified planned interruptions we proposed, and the perverse incentives that could result, we have made significant changes to the draft approach. These include:

7.54.1 removing the maximum notification window length;

7.54.2 allowing for the provision of alternative days; and

7.54.3 giving distributors the option of including particular planned interruptions as qualifying for this additional discount.

7.55 These are discussed further in Attachment L.

Quality targets

7.56 The quality target is the level of reliability performance at which the revenue impact of a distributor's performance is zero. Put another way, it is the point at which losses turn into gains and vice versa.

7.57 Consistent with the no material deterioration principle, we have set the target at the 10-year historical average level of SAIDI (normalised and limited to 5% movement between regulatory periods for unplanned interruptions). Absent of better information about the level of reliability consumers demand, we consider historical reliability, with prices determined with reference to historic levels of expenditure, provides an appropriate outcome for a default path.

7.58 This approach ensures that:

7.58.1 where reliability improves or declines over time, the distributor faces a proportionate incentive; and

7.58.2 where there is random variation in performance, over time these random variations can be expected to cancel out, leaving the distributor in a neutral position.

7.59 We have considered setting the target higher or lower than historical levels; in effect setting an 'improvement path' or a 'glide path'. However, we do not consider we have sufficient information about each distributors' customers preferences to do this at this point in the regime's evolution.[188]

Caps and collars

7.60 The reliability caps are the points at which no further incentive losses are applicable to the revenue-linked incentive scheme. Conversely, reliability collars are the point at which no further incentive gains are applicable.

Reliability caps

7.61 We have set planned and unplanned SAIDI caps equal to the applicable limit for compliance standards, subject to maximum revenue exposure of 2%. These are set:

7.61.1 2 standards deviations above the target for unplanned interruptions; and

7.61.2 triple the target for planned interruptions.

7.62 We consider that it is not appropriate to allow distributors to continue to make trade-offs beyond the minimum level of reliability determined by the quality standard, so a cap above the limit is inappropriate.

[188] We are unable to determine these levels by making comparisons between the performance of different distributors, given the prohibition on comparative benchmarking in section 53P(10) of the Commerce Act 1986.

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

Reliability collars

7.64 We have set planned and unplanned SAIDI collars at zero, subject to maximum revenue exposure of 2%. In other words, we have removed the collars in our incentive scheme. This means that financial incentives for reliability will always apply below the SAIDI limits.

7.65 As reliability improves, we expect the marginal cost of further improvements will increase. Rational distributors will look for the least-cost improvements in reliability before pursuing more expensive improvements. As SAIDI approaches zero, we anticipate that the cost of further improvement would far outweigh the conservative incentive rates we have set, and so do not consider this will lead to improvements beyond what consumers expect.

Asymmetry of caps and collars

7.66 With setting the reliability caps equal to the applicable SAIDI limit and the reliability collars at zero, at the extremes the revenue-linked quality incentive scheme is asymmetric. However, within a reasonable range we expect it is largely symmetric. For example, we would expect it would be rare for unplanned interruptions to fall more than two standard deviations below the annual target. We consider it appropriate that the cost-quality trade-off is always in place up to the applicable SAIDI limit.

Revenue at risk

7.67 Revenue at risk is the total pool of incentives a distributor may gain or lose based on its performance. It can be expressed in both dollar terms, and as a percentage of distributors' total revenue.

7.68 Given our decision to explicitly set SAIDI incentive rates and the SAIDI bounds for which incentives apply, the revenue exposure to the revenue-linked incentive scheme is set endogenously. In some cases, this may create an excessive level of exposure, so we have capped distributors' total exposure across planned and unplanned interruptions at 2% of allowable revenue each year.

7.69 This decision does not affect all distributors. Less reliable distributors will generally be exposed to a higher revenue at risk than more reliable distributors. However, we consider it appropriate that the least reliable distributors are subject to more revenue exposure, as they have the largest scope for improvements in reliability.

7.70 In theory, seven distributors could be impacted by the 2% cap on penalties. However, this is largely driven by the planned SAIDI cap being three times the historical average. Conversely, nine distributors could be impacted by the 2% cap on rewards, however, this would require a significant reduction in interruptions.

Approach to normalisation

7.71 This section discusses our approach to normalisation. It covers:

7.71.1 the reasons we apply normalisation;

7.71.2 changes to the definition of major events; and

7.71.3 changes to the treatment of major events.

Why we normalise reliability

7.72 SAIDI and SAIFI, particularly for unplanned interruptions, are highly volatile, and are strongly influenced by major individual interruptions.

7.73 For this reason, in DPP3 we have applied a filter both to historical reliability and to the way reliability performance will be assessed during the DPP3 period. This applies to both the unplanned reliability standards and to the incentive scheme for unplanned SAIDI.

Definition of major events

7.74 We have changed the definition of a 'major event' from a calendar day that is over a given boundary value, to a 24-hour rolling period that is over a given boundary value. The major event boundary is the equivalent of the 1104th highest 24-hour rolling period within the 10-year reference period.

7.75 The move to a rolling approach is driven by;

7.75.1 the arbitrary nature of calendar days when it comes to major events; and

7.75.2 the availability of sufficiently accurate recording of the start times of interruptions.[189]

7.76 For DPP2, we adapted the Institute of Electrical and Electronics Engineers (IEEE) methodology for normalisation. This methodology was based on the expectation of 2.3 major events per year. Over a 10-year period, this implied the 23rd highest day represented a reasonable boundary for a major event.

[189] This information was collected for the 2009-2019 period through a section 53ZD request issued in June of 2019. We anticipate that distributors will be able to continue recording this information on an ongoing basis.

7.77 Our intent is to retain this approach. However, because there are more rolling 24-hour periods that fixed 24-hour periods (days) in the reference period, we use the 1104^{th} highest as a reference point.

Treatment of major events

7.78 When a SAIDI major event or SAIFI major event is identified, the half-hours within the major event period that are over $1/48^{th}$ of the boundary value will be replaced with a SAIDI or SAIFI value that is $1/48^{th}$ of the boundary value.

7.79 This is a significant change from the draft decision, where any three-hour rolling period that was assessed as a major event would have been replaced with a pro-rated boundary value, based on the proportion of the day.

7.80 On balance, we considered that a change to replace identified major events with a reduced replacement value is appropriate given that:

7.80.1 expanded major event reporting requirements will provide more transparency and incentives around the main cause of these events;

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

7.80.3 the introduction of an extreme event standard will place further onus on distributors to minimise and respond appropriately to high impact events that are not caused by adverse weather or other external impacts; and

7.80.4 there are other incentives at play such as customer complaints and reputational risk when major events occur.

Updated reporting requirements

7.81 Consistent with our overall intention to provide for greater accountability of distributors for their performance, and in order to increase predictability for suppliers following the contravention of any quality standard, we have implemented two enhanced reporting requirements relating to:

7.81.1 quality standard contravention self-reporting; and

7.81.2 major event reporting.

7.82 The quality contravention self-reporting requirements are largely based on the information gathering (section 53ZD) requests sent to distributors who contravened quality standards in 2018, and are set out in Table 7.4.

Table 7.4 Information requirements following a contravention

Unplanned reliability standard
• Data on the unplanned interruptions. • Any existing independent reviews of the state of the network or operational practices. • Any investigations into significant individual interruptions or causes of the contravention. • Any analysis of trends in asset condition. • Any analysis of interruption causes. • Any analysis of the sufficiency of asset replacement and renewal. • Any analysis of the sufficiency of vegetation management. • Outline of any relevant analysis or investigation that would meet the categories above and is planned but not yet completed.
Planned reliability standard
• Data on the planned interruptions. • Any strategy for managing planned interruptions. • Any analysis or investigation of planned interruptions. • Outline of any relevant analysis or investigation that would meet the categories above and is planned but not yet completed.
Extreme event standard
• Data on the interruptions during the extreme event. • Any existing independent reviews of the state of the network or operational practices. • Any analysis of trends in asset condition. • Any investigation, analysis, or post-event review of the extreme event. • Any analysis of the sufficiency of asset replacement and renewal. • Outline of any relevant analysis or investigation that would meet the categories above and is planned but not yet completed.

7.83 For major events, the determination requires that, in addition to the cause of each major event, as previously required, a distributor must report for each interruption in its annual compliance statement:

7.83.1 the start date and time;

7.83.2 the end date and time;

7.83.3 the raw and replacement SAIDI and SAIFI values;

7.83.4 the location and equipment involved;

7.83.5 the cause and response; and

7.83.6 any mitigating factors that may have prevented or minimised the major event.

Other measures of quality

7.84 Our decisions on new measures of quality for DPP3 are:

7.84.1 that no new measures are introduced as part of the compliance quality standards applying in DPP3;

7.84.2 that no new measures are introduced as part of the revenue-linked quality incentive scheme in DPP3.

7.85 Additional quality standards that reflect consumer demands should be explored further during the DPP3 period and with a view to potentially considering them for future resets. As discussed further in Attachment N, we generally require a historic dataset of any new measure to set a standard against.

7.86 From 2020, we intend to consider changes to our ID requirements for distributors to report data that may be required for the future setting of additional quality standards.

7.87 These additional measures could include relate to its:

7.87.1 ordering and provisioning of new connections;

7.87.2 management and restoration of faults (including the number and duration of faults);

7.87.3 service performance, reflecting technical characteristics of the service such as voltage stability; and

7.87.4 customer service (such as the time taken to respond to customer complaints or enquiries).

Attachment A Forecasting operating expenditure

Purpose of this attachment

A1 This attachment explains the decisions we have made about opex allowances for the DPP3 period and responds to stakeholder submissions on these issues.

A2 It starts by explaining our high-level 'base-step-trend' approach to opex and the major decisions we have made. It then explains:

A2.1 the selection of the opex base year;

A2.2 decisions about opex step changes;

A2.3 trend factors to account for changes in scale;

A2.4 trend factors to account for changes in input prices; and

A2.5 trend factors to account for changes in partial productivity.

Table A1 Opex allowances for DPP3 ($m)

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25
Alpine Energy	19.42	20.01	20.63	21.24	21.82
Aurora Energy	44.72	46.25	48.13	50.19	51.96
Centralines	4.23	4.33	4.45	4.56	4.66
EA Networks	11.82	12.22	12.63	13.06	13.49
Eastland Network	10.62	10.90	11.19	11.50	11.78
Electricity Invercargill	5.18	5.31	5.45	5.59	5.72
Horizon Energy	9.89	10.17	10.49	10.83	11.11
Nelson Electricity	2.25	2.32	2.39	2.46	2.54
Network Tasman	11.16	11.51	11.88	12.25	12.61
Orion NZ	64.15	66.49	68.93	71.32	73.63
OtagoNet	9.16	9.43	9.70	9.96	10.20
The Lines Company	14.91	15.30	15.71	16.11	16.48
Top Energy	16.02	16.54	17.05	17.57	18.06
Unison Networks	41.58	42.90	44.33	45.72	47.03
Vector Lines	127.35	132.45	137.80	142.97	148.02
Wellington Electricity[190]	n/a	36.79	37.97	39.17	40.32

[190] The allowances for Wellington Electricity are indicative only, and will be updated when we determine starting prices for Wellington Electricity at the end of its CPP in 2020.

Final opex allowances

A3 The opex allowance for the sector for DPP3 is $2,293.68m. It has increased by $18.67m since the draft decision. This change is caused by the following updates since the draft decision:

A3.1 updating NZIER cost inflator data;

A3.2 updating the base year to 2019;

A3.3 making step changes for operating leases, FENZ levies and pecuniary penalties;

A3.4 incorporating 2019 ID data into circuit length growth forecasts in the scale factor;

A3.5 forecasting ICP growth using households in the scale factor; and

A3.6 updating the dataset used in the econometric model which calculates the elasticities.

Table A2 Changes in opex allowances relative to draft decision

Distributor	Opex allowance ($m)	Draft opex allowance ($m)	Change ($m)	Change (%)
Alpine Energy	103.11	100.51	2.61	2.60%
Aurora Energy	241.25	216.50	24.75	11.43%
Centralines	22.22	19.67	2.55	12.99%
EA Networks	63.21	72.29	-9.07	-12.55%
Eastland Network	55.99	57.14	-1.16	-2.03%
Electricity Invercargill	27.24	26.22	1.02	3.87%
Horizon Energy	52.49	59.44	-6.95	-11.70%
Nelson Electricity	11.96	11.27	0.68	6.05%
Network Tasman	59.41	64.16	-4.74	-7.39%
Orion NZ	344.53	327.43	17.10	5.22%
OtagoNet	48.45	42.19	6.26	14.83%
The Lines Company	78.52	70.37	8.15	11.57%
Top Energy	85.24	93.52	-8.27	-8.85%
Unison Networks	221.56	225.81	-4.25	-1.88%
Vector Lines	688.59	693.18	-4.59	-0.66%
Wellington Electricity	189.91	195.31	-5.39	-2.76%
Total	**2,293.68**	**2,275.01**	**18.67**	**0.82%**

High-level approach

A4 We have retained the base-step-trend approach to setting distributors' opex allowances for DPP3. The formula we use is shown in Box A1. This is consistent with the approach signalled in the Draft Reasons Paper.

Box A1: Formula for calculating opex

$$\text{opex}_t = \text{opex}_{t-1} \times$$

$$(1 + \Delta \text{ due to network scale effects}) \times$$

$$(1 + \Delta \text{ input prices}) \times$$

$$(1 - \Delta \text{ partial productivity for opex}) \pm$$

$$\text{step changes}$$

A5 It is appropriate to forecast opex in this way because most opex relates to activities that recur. As such, the expenditure is likely to be repeated regularly, and can be expected to be influenced by certain known and predictable factors.

Reasons for addressing this issue

A6 Providing an opex allowance ensures that distributors have sufficient resources to fund recurring activities that are not capex. The opex allowance funds a variety of recurring activities that are essential for the operation of distribution networks, such as maintenance and planning activities.

A7 Opex has a direct effect on the revenue distributors can earn. Opex represents approximately 40% of the BBAR, as forecast opex is recovered in the year it is forecast to be spent. From an efficiency point of view, the opex allowance we set is the baseline against which any opex IRIS gains and losses are measured.

Overall response in submissions

A8 Some submitters supported the retention of the base-step-trend approach to setting an opex allowance. However most had caveats that our draft allowance would not provide sufficient opex in DPP3. There were particular concerns around uncertainty and change, growth assumptions, input inflators, and partial productivity.[191]

[191] Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019) p. 3; Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019) p. 7; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019) p. 5; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019) p. 1; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019) p. 2.

A9 Others commented that the opex model can be inaccurate. This is due to differences between DPP2 allowances and actual opex, and differences between distributors' perception of forecasts and allowances.[192] The majority of distributors thought our draft allowance was insufficient to cover for further reductions in productivity, inflation, and costs unrelated to scale during DPP3.

A10 Orion's cross-submission reiterated its recommendation to use AMPs for forecasting.[193] Vector commented that significant effort goes into preparing AMPs, so it would be reasonable to use forecasts as a starting point or a cross-check at a minimum.[194]

A11 Vector also highlighted that it is important that the base step and trend method aligns with the capex allowance and quality standards. An inconsistency could result in distributors making decisions that are not aligned with customers' long-term interests. Consistent with our low-cost DPP framework, our decisions on opex, capex and quality standards are – in general – all based on distributors' current performance. Therefore, we have the ex-ante expectation that distributors will be able to earn a normal return while being able to fund their operations and investments. Our assumption is that the current relationships between these factors will persist.

Alternatives considered and analysis of those alternatives

A12 Instead of a base-step-trend approach, we also considered using opex forecasts disclosed from the latest AMP available to inform the DPP opex allowance.

A13 In assessing the two alternatives we have had regard to the principles discussed in our framework chapter. We have relied on the purpose of Part 4 as set out at paragraphs 3.5 and 3.6 in Chapter 3 above, and the purpose of DPP regulation which is set out at paragraphs 3.12 to 3.15 in Chapter 3 above.

A14 Relying on AMPs to set the opex allowance would have the following advantages:

A14.1 This approach would be consistent with our approach to setting capex allowances under the DPP and setting opex in the gas and transmission space.

A14.2 This approach would tailor opex allowances to the circumstances of individual distributors, rather than applying a blanket approach to all distributors.

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192 Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019) p. 7; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019) p. 2.

193 Orion "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019) p. 1.

194 Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 36.

A14.3 This approach is forward-looking so would potentially allow for changes in distributors' operating environment.

A15 Relying on historic opex performance to set the opex allowance would have the following advantages:

A15.1 The AMP-based approach may create perverse incentives to inflate costs. The risk of perverse incentives appears greater for opex than capex because opex recovery is more immediate than capex recovery. The base-step-trend approach mitigates that risk.

A15.2 Opex costs generally recur year-on-year so a method based on historical expenditure is likely to be a good predictor of future opex expenditure. Capex is more irregular and is not predictable from price reset to price reset which is why AMPs are more appropriate for forecasting capex expenditure.

A15.3 Any AMP-based approach would require more individual scrutiny than we consider is warranted. It would also be against our purpose of setting a DPP in a relatively low-cost way.[195]

A15.4 Our analysis at sector level (as shown in Figure A1 and Figure A2, below) indicates base-step-trend performed relatively well in DPP2, and that the DPP2 opex allowance was closer to actual expenditure than distributors' forecasts in their AMPs.

A16 Having regard to the above we have decided the base-step-trend approach is more appropriate for operating costs for the following reasons:

A16.1 We consider that the potential perverse incentives to inflate costs is contrary to the long-term interests of consumers, and more particularly the reference in section 52A(1)(b) of the Act to incentivising improved efficiency.[196]

A16.2 Opex costs are recurring and so a method based on historic expenditure is appropriate as we expect these costs to be incurred in the future. Our analysis at sector level indicates the base step and trend method had been a more accurate predictor of opex than distributors' forecasts in DPP2.

[195] See paragraph 3.13 in Chapter 3 above.

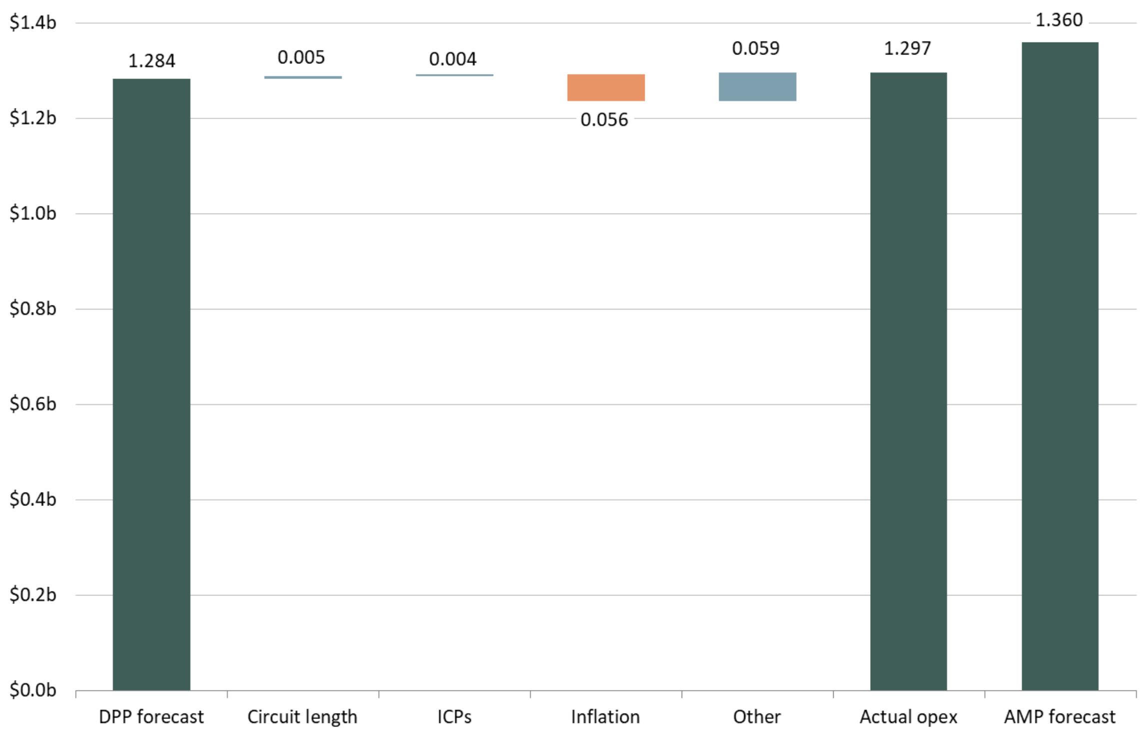
[196] See paragraph 3.5 in Chapter 3 above.

A16.3 The base-step-trend approach is more in line with our framework of applying the same or similar treatment to all suppliers on a DPP (which is contrary to the more tailored approach of the AMP approach) and setting expenditure with reference to historical levels of expenditure.[197]

A17 We have decided to apply different approaches to setting opex and capex because of two important distinctions. First, opex is more consistent year-on-year than capex, lending itself to step trend. Second, the perverse incentive to over-forecast is stronger for opex than capex, which factors against an approach relying on forecasts. Finally, we note that as part of implementing an opex IRIS for the DPP2 and DPP3 regulatory periods, we have committed to using a step and trend approach with year four of the five-year regulatory period as the base year for extrapolating opex.[198]

A18 Figure A1 below shows that the step and trend approach performed relatively well in aggregate, with only $59m unexplained after accounting for forecast errors relating to trend and price inflators between DPP forecast and actual opex. These costs are labelled 'other' in Figure A1.

Figure A1 Deviations between DPP allowance and actuals, 2016–2018 ($b)



[197] See paragraph 3.16 in Chapter 3 above.

[198] Commerce Commission "Amendments to input methodologies for electricity distribution services and Transpower New Zealand – Incremental Rolling Incentive Scheme – Final reasons paper" (27 November 2014).

A19 It should be noted that some of this unexplained difference may be accounted for by:

A19.1 productivity growth being lower than we forecast, or individual distributors becoming less efficient;

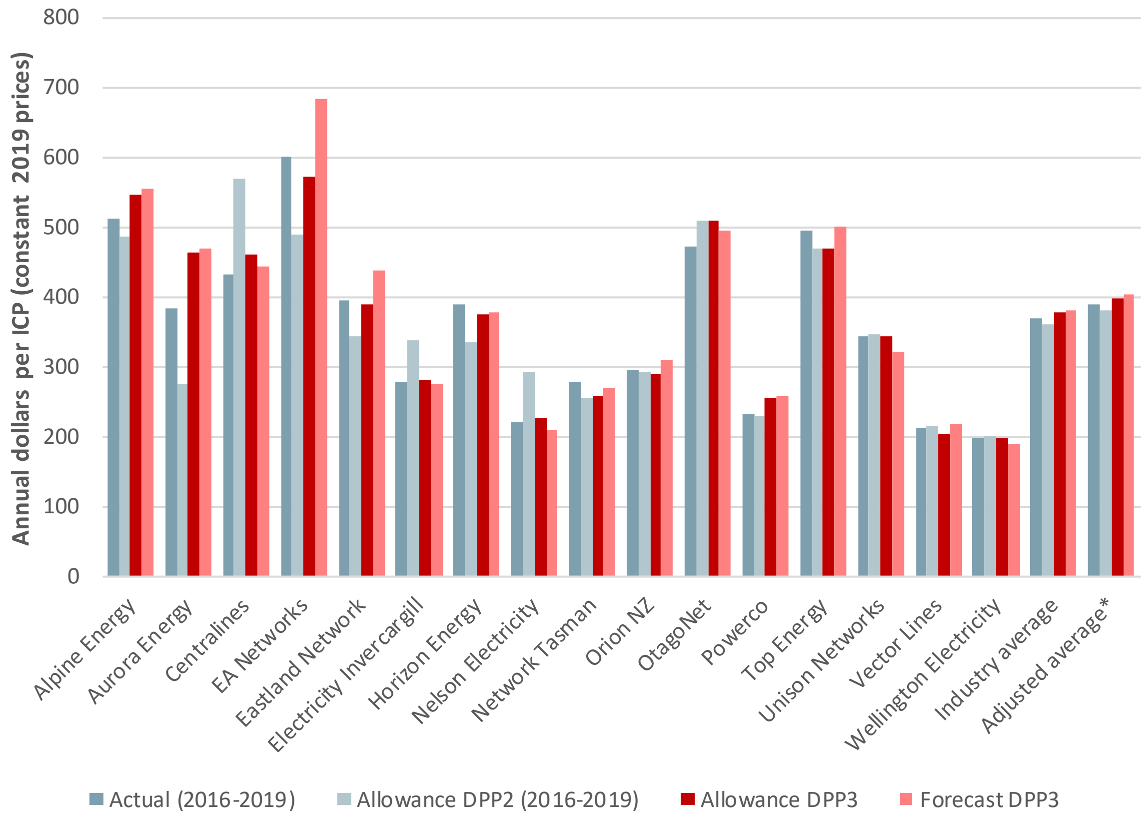
A19.2 econometric drivers deviating from actuals;

A19.3 any step changes not accounted for; and/or

A19.4 random variation in the level of opex.

A20 We have used distributors' actual and forecast opex per ICP as a cross-check against our allowances in Figure A2. We consider our DPP3 allowances align with the sector's forecasts at a per-ICP level. We note in Figure A1 and Figure A2 that accuracy is likely to be more variable at an individual distributor level and some differences may be related to specific distributor circumstances.

Figure A2 Annual average opex per ICP ($/ICP constant prices)



A21 The remainder of this attachment discusses the individual parameters of our opex forecasts in detail.

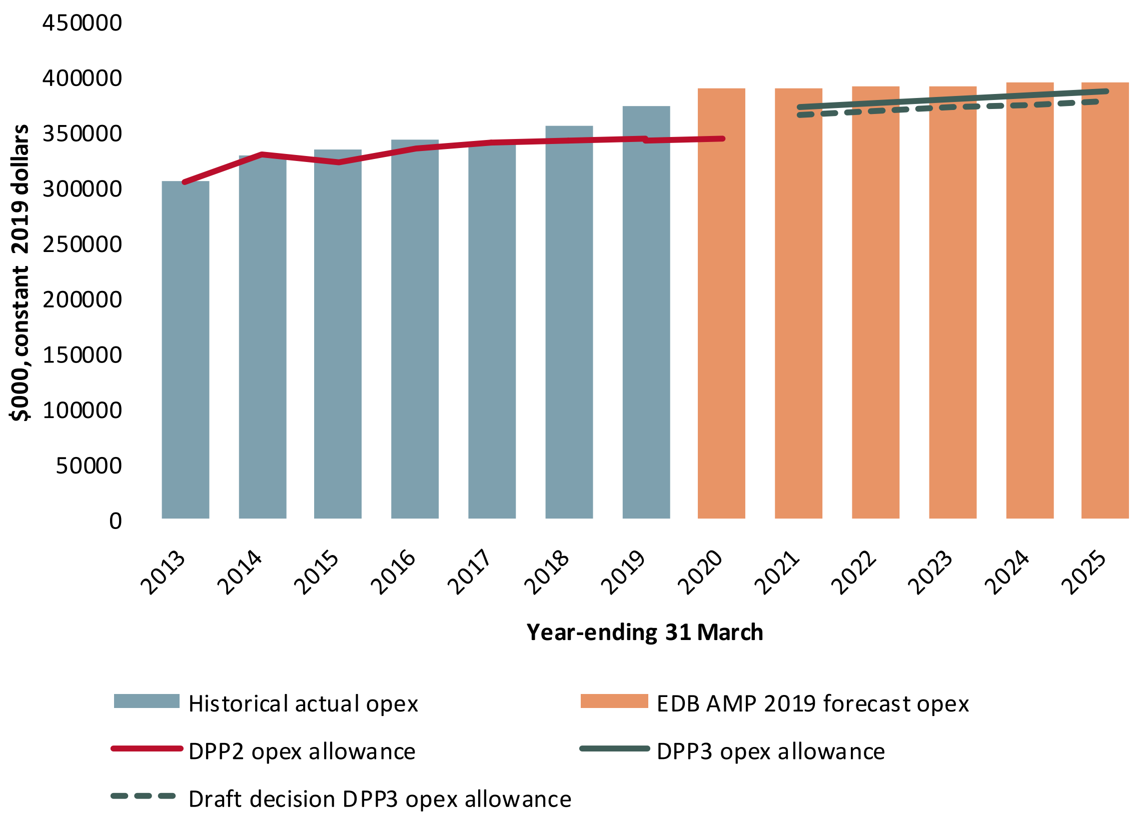
Opex allowances

A22 The remainder of this Attachment discusses the individual components of out base-step-trend methodology. The results of these decisions are set out in Table A3 below. The results of applying this approach are set out over time for the DPP distributors as a whole in Figure A3.

Table A3 Opex parameters for each distributor (nominal)

Distributor	Total opex 2018/19 ($000)	FENZ levies 2018/19 ($000)	Pecuniary penalties 2018/19 ($000)	Operating leases 2018/19 ($000)	Operating leases 2021-2025 ($000)	Aggregate trend 2019-2023 (CAGR, %)	Aggregate trend 2023-2025 (CAGR, %)
Alpine Energy	18,296	-53	0	0	0	3.12%	2.84%
Aurora Energy	42,774	-28	0	0	-5,185	3.01%	3.90%
Centralines	4,020	-11	0	0	0	2.62%	2.34%
EA Networks	11,913	-27	0	0	-4,213	1.52%	3.35%
Eastland Network	10,079	-28	0	0	-15	2.73%	2.61%
Electricity Invercargill	4,938	-20	0	0	0	2.58%	2.45%
Horizon Energy	9,469	-48	0	0	-252	2.71%	2.95%
Nelson Electricity	2,146	-31	0	0	-40	3.11%	3.02%
Network Tasman	10,504	-41	0	0	-3	3.23%	3.02%
Orion NZ	59,678	-98	0	0	0	3.71%	3.36%
OtagoNet	8,660	-21	0	0	0	2.94%	2.56%
The Lines Company	14,173	-41	0	0	-19	2.68%	2.44%
Top Energy	15,409	-23	0	0	-1,470	2.60%	2.92%
Unison Networks	39,408	-66	0	0	-1,448	3.03%	3.00%
Vector Lines	121,961	-568	-3,575	1,461	-9,219	3.99%	3.64%
Wellington Electricity	34,017	-58	0	0	-2,543	2.83%	3.06%

Figure A3 Opex time series (constant 2019 prices)



Choice of base year

Problem definition

A23 The base-step-trend methodology requires an initial level of expenditure (the 'base') which represents a distributor's current revealed costs.

Final decision

A24 For the final decision, we confirm using 2018/19 as the base year. For the draft decision, we used 2017/18 as the opex base year.

A25 We have used year four of the DPP2 period (2018/19) for the final decision is because this is the most recent available data. It is also consistent with the current opex IRIS IMs. We have updated the base year in the opex model using data received in September 2019. This section discusses the base year independently of any subsequent step changes made to the base year.

A26 The base year has increased by $26m which is a 7% increase across distributors from the draft to final decision.

Analysis

A27 The base year determines the initial level of opex that is trended forward. Any efficiencies or inefficiencies contained within the base year will therefore be captured in the baseline opex for DPP3.

A28 Because of the IRIS mechanism, using year four as the base year ultimately has no impact on the gross revenues a distributor will be able to recover over the DPP3 period: it only affects the balance between starting prices and the adjustment component of IRIS. The ‘base year adjustment term’ for the opex IRIS reverses out the net-benefit of any increases or decreases in opex in year four of the preceding period.

A29 To the extent that distributors make efficiency gains during the DPP period, they will retain a portion of these, and they are incentivised to do so. Using the most recent year as a base year means we are reflecting the distributors’ most recent level of efficiency and operating practices.

Stakeholder views

A30 Orion and Wellington Electricity supported the use of 2018/19 as the base year. Orion commented that using 2019 as the base year helps reflect distributors’ current operating environment. However, there were concerns that the base year does not capture unanticipated changes in costs during DPP3. We discuss these concerns in more detail under step changes.

Response

A31 Whichever year we use as the base year, the concerns about unanticipated DPP3 costs may be realised. However, there is a risk that customers would pay for inefficient expenditure with uncertain outcomes if we were to make an ex-ante adjustment. Distributors have ways to mitigate their risks via reopeners, applying for a CPP, passing on a portion of the cost to consumers through IRIS, and through the innovation allowance recoverable cost.

Step changes

A32 This section discusses step changes in opex. It starts by assessing the criteria we apply to considering step changes, then discusses some of the step changes we have considered in detail. It finishes by addressing all step changes raised in submissions.

Assessment criteria for step changes

Problem definition

A33 Setting opex allowances by trending forward the base year does not capture "step changes" in expenditure expected during the regulatory period. These step changes can have a material impact on distributors' revenue, and distributors have an incentive to seek the inclusion of as many (positive) step changes as possible. As such, we need to have a robust basis for considering whether to include them.

Final decision

A34 We have retained the step change criteria set out in the draft decision. We also clarify the rationale in the analysis.

A35 We require step changes to be:

A35.1 significant;

A35.2 robustly verifiable;

A35.3 not captured in other components of our projection (base year, trend factors, capex or recoverable costs);

A35.4 largely outside of the control of distributors; and

A35.5 be applicable to most, if not all distributors.[199]

Alternatives considered

A36 Submitters suggested in response to the issues paper that the criteria be altered to reflect a lower threshold for allowing a step change. Specifically, distributors took issue with the "robustly verifiable" criterion and suggested it be replaced with a lower threshold such as "reasonably likely".[200] In response to the draft paper, Wellington Electricity recommended allowing known cost increases that were suggested in response to the issues and draft paper.

A37 Wellington Electricity also recommended allowing step changes for individual distributors rather than the majority. This would relax the "applicable to most, if not all, distributors" criterion.[201]

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[199] These criteria have been developed to be consistent with the low-cost DPP forecasting principles set out in paragraphs 3.16.1 to 3.16.4 in Chapter 3 above.

[200] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), p. 13; Powerco "Cross submission on EDB DPP3 reset issues paper" (31 January 2019), p. 2; ENA "Cross submission on EDB DPP3 reset issues paper" (31 January 2019), p. 2.

[201] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 9.

A38 We also considered step changes for cumulatively material costs. Several submitters are concerned that new costs during DPP3 might be individually too small to justify a step adjustment or a reopener. There is a risk these costs could be cumulatively material and remain unfunded for.[202] We discuss these alternatives below.

Analysis

A39 Step changes are implemented to adjust distributors' opex allowances for additional expenditure they will incur (or will stop incurring) during the regulatory period. Each additional dollar of opex corresponds to approximately one additional dollar of allowable revenue.

A40 We have set a high threshold for evidence due to the information asymmetry over positive and negative step changes that are likely to occur during DPP3. Distributors are better placed to identify actual cost changes during DPP3 due to their understanding of how their networks work. However, there might be an incentive for distributors to only reveal step changes which result in higher allowances.

A41 In our decision to set a high threshold for evidence, we recognised that this risk is reflected by price resets in other jurisdictions. The Competition and Markets Authority (CMA) provided commentary on Ofwat's price determination. The feedback was given in response to Bristol Water appealing Ofwat's final determination to the CMA. The CMA commented that Ofwat's equivalent tool to a step change, a special cost factor, may act to the detriment of consumers if it is skewed towards companies' requests for upwards adjustments without considering whether there may be other offsetting areas where a company may have received a higher allowance than necessary. [203]

A42 The risk to consumers is twofold:

A42.1 if we accept a step change, and the expected event/driver does not materialise, consumers will overpay; and

A42.2 if we reject the step change, and the event does materialise, then distributors may reprioritise their expenditure to maintain profitability, and consumers will miss out on the benefits from expenditure that the distributor would have pursued had it been funded to do so.

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[202] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019) pp 7; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 14; Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019) p. 18; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019) p. 2.

[203] Bristol Water's final determination by the Competition and Markets Authority (October 2015), p. 46.

A43 The risk to a distributor is that it does not have sufficient opex and makes trade-offs between taking on additional risk (for example quality of service, operational, or regulatory risks), or bearing the extra expense. In the latter case, the IRIS mechanism should result in consumers bearing approximately three-quarters of the overspend.

A44 Distributors have other mechanisms to mitigate their risks:

A44.1 reopening the price path for legislative changes or catastrophic events;[204]

A44.2 applying for a CPP for material, business-specific changes;[205]

A44.3 incurring the expense and passing a portion of the cost onto consumers through the IRIS mechanism;[206] or

A44.4 expenditure could be included within the innovation allowance recoverable cost, which is discussed in Attachment F.

A45 In contrast, consumers do not have such options. In this context, a high threshold better promotes the long-term benefit of consumers.

A46 We have assessed step changes against criteria which align with the purposes of section 52A of the Commerce Act. [207] We describe the criteria and explain why we have set this standard below. We also give examples of the types of evidence which we could consider. It is important to note that distributors are not limited by these examples.

Significance

A47 We consider a step change to be significant if our allowances are insufficient to cover the costs without a step change. We would consider evidence to show that distributors have taken reasonable steps to control the cost. We only consider significant costs due to the principle that the DPP should be a low-cost regime.[208]

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[204] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 4.5.6.

[205] Commerce Act 1986, section 53Q.

[206] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.3.1.

[207] See paragraph 3.5 in Chapter 3 above.

[208] See paragraph 3.14.1 in Chapter 3 above.

Robustly verifiable

A48 For a proposed step change to be robustly verifiable, the evidence distributors have provided us must be such that we can establish whether the key elements of our criteria have been met with sufficient confidence. In particular, this includes knowing with reasonable certainty the quantity of costs involved.

A49 For example, distributors could provide third-party assurance or a range of quotes as evidence. We consider both the likelihood and efficiency of a step change to be important in relation to the purposes of Part 4 that suppliers are limited in their ability to extract excessive profits and that they are incentivised to improve efficiency, consistent with section 52A(1)(2).

Not captured in other components

A50 We consider whether costs are not captured elsewhere in our projection. An example could be a new cost which would not be captured in the base year. This is to prevent distributors from being remunerated twice for the same cost within their allowances. This criterion links to the purposes of Part 4 that suppliers are limited in their ability to extract excessive profits, consistent with section 52A(1)(4)

Outside the control of the distributor.

A51 We consider whether step changes are outside of management control and that are largely unavoidable. Examples include new legislation and macroeconomic factors. The reason we do not consider costs under management control is because distributors are able to choose how to spend their allowed revenue. This criterion relates to the purposes of Part 4 that suppliers have incentives to improve efficiency and share the benefits with consumers, consistent with section 52A(1)(3).

Applicable to most or all distributors

A52 This is in line with “applying the same or substantially similar treatment to all suppliers on a DPP.”[209] As mentioned above, there are other mechanisms for distributors to mitigate individual risks.

[209] See paragraph 3.16.1 in Chapter 3 above.

A53 For the final decision, we have not made any step change adjustments for cumulatively material costs. This is due to the lack of information around the significance and robustly verifiable criteria of individual small changes that might make up a cumulative step change. As well, we are not able to treat cumulatively material costs as step changes, reopeners or recoverable costs under the current IMs. At this stage we do not consider that it is proportionate to amend the IMs speculatively. If costs are cumulatively material, distributors are protected by the option of a CPP and are able to mitigate this risk through the options discussed above. We also note the prospect of offsetting downward cost pressures which suppliers are not incentivised to draw to our attention.

A54 We have not made individual adjustments to distributors' allowances either. This aligns with the principles we have adopted for setting DPPs. A key principle is "applying the same or substantially similar treatment to all suppliers on a DPP." We are also mindful that this change in approach would increase the compliance burden.

Step changes proposed for DPP3

Problem definition

A55 Given the above criteria, we sought reasons and evidence for likely step changes applicable to distributors as part of submissions on our issues paper. In response to the draft paper, we received further reasons and evidence from distributors around likely step changes.

Final decisions

A56 We have decided to make the following step changes:

A56.1 A negative step change to the base year for FENZ levies to account for the creation of a new FENZ levy recoverable cost.[210]

A56.2 A negative step change to the base year for pecuniary penalties, which will not be included in opex from 1 April 2020.

A56.3 A negative step change to DPP3 allowances for operating leases, which will not be included in opex.

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[210] ENA "DPP3 April 2020 Commission Issues paper(Part One Regulating capex, opex & incentives)" (20 December 2018), pp. 12-13; Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 4; Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 6; Orion "Submission on EDB DDP3 Reset " (20 December 2018) p. 5.

[210] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), pp. 13 and 38.

A57 The materiality of these step changes is shown in Table A4.

A58 We have not made any step changes in response to submissions. Submissions were largely qualitative, so we lacked information to show if step changes proposed by submitters met the significance or robustly verifiable criteria. We appreciated receiving cost evidence from Wellington Electricity and Vector as this helps build our evidence base. However, we were unable to tell whether these costs were efficient for the duration of DPP3.[211]

A59 We did not make step changes with respect to the following suggestions by submitters:

A59.1 health and safety (for example, reducing live lines work);[212]

A59.2 vegetation management regulation (tree regulations);[213]

A59.3 smart meter data, low voltage (LV) network monitoring, and ID enhancement;[214]

A59.4 FENZ levy changes;[215]

A59.5 guaranteed service levels schemes;[216]

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[211] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019) appendix A; Vector "Cross-submission on EDB DPP reset draft decisions paper" (12 August 2019) Attachment A.

[212] ENA "DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)" (20 December 2018), pp. 12-13; The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), pp. 4-5.

[213] ENA "DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)" (20 December 2018), p. 14; Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), p. 13; Powerco "Submission on DDP reset issues paper" (21 December 2018), p. 5.

[214] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), pp. 14-15; Powerco "Submission on DDP reset issues paper" (21 December 2018), p. 5.

[215] ENA "DPP3 April 2020 Commission Issues paper(Part One Regulating capex, opex & incentives)" (20 December 2018), pp. 12-13; Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 4; Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 6; Orion "Submission on EDB DDP3 Reset " (20 December 2018) p. 5.

[215] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), pp. 13 and 38.

[216] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), pp. 13 and 38.

A59.6 new pricing methodology;[217]

A59.7 preparation for the future state of the network;[218]

A59.8 labour skills shortages potentially exacerbated by the increased demand from Powerco's CPP capex programme;[219]

A59.9 customer service lines; [220]and

A59.10 the ongoing trend towards 'Software as a Service'.[221]

A59.11 regulatory requirements (from IPAG, EA, pricing reform and Part 4 requirements including meeting new quality standards);[222]

A59.12 cyber security costs;[223]

A59.13 insurance costs;[224]

A59.14 traffic management and congestion;[225]

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[217] The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), p. 5; ENA "DPP3 April 2020 Commission Issues paper(Part One Regulating capex, opex & incentives)" (20 December 2018), p. 12.

[218] Powerco "Submission on DDP reset issues paper" (21 December 2018), p. 5.

[219] The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), p. 5; Orion "Submission on EDB DDP3 Reset " (20 December 2018), p. 6.

[220] ENA "DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)" (20 December 2018), p. 13

[221] Powerco "Submission on DDP reset issues paper" (21 December 2018), p. 5.

[222] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019) p. 6; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 22; Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), pp 2-3.

[223] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 13; Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 34; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

[224] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17; Orion "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 3; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

[225] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 8; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17; Vector "Submission on EDB DPP reset draft

A59.15 maintaining assets as they reach the end of their lives;[226]

A59.16 Employment Relations Amendment Act;[227]

A59.17 climate change e.g. meeting Interim Climate Change Committee's electrification outcomes and responding to the climate change response amendment bill;[228]

A59.18 feasibility studies and trials;[229]

A59.19 new technology[230] and;

A59.20 adjustments for CPPs.

Stakeholder views

A60 All distributors who responded to our draft decision considered that our draft decision would undercompensate them during DPP3. Distributors recommended that we take account of a range of non-scale costs that they suggested are not accounted for in the draft opex allowance.[231]

decisions paper" (18 July 2019), p. 6; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 30.

226 Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

227 ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17.

228 Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 6; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17.

229 Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 3.

230 PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

231 Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 1; Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 4 and 7; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 14 and 17; Orion "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 3; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10; Vector "Cross-submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 18; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2; Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3.

A61 Submitters agreed with treating FENZ levies as a recoverable cost.[232] Distributors also commented about the treatment of pecuniary penalties incurred in the past.[233] In particular, Orion asked for clarification of the impact on past profit.[234]

Response

A62 In this section, we discuss the costs we have made step changes for, and those step changes where we consider a detailed response to the issue raised in submissions is warranted (either via a step change or another mechanism such as a future reopener) below.

A63 Our responses to the other suggested step changes and our reasons for not proposing to implement them are set out in the table at the end of this section.

Vegetation management (tree regulations)

A64 Vector, Powerco, and ENA submitted in response to the issues paper that changes to the Electricity (Hazards from Trees) Regulations 2003 are expected to drive higher vegetation management expenditure.[235]

A65 In response to the draft paper, the ENA, Unison, Wellington Electricity, Orion and Vector's cross-submission reiterate that a step change should be allowed for anticipated tree regulation changes.[236]

A66 As we set out in our draft decision:

> We consider that given that any change will stem from regulations that are yet to be promulgated, any step change would be speculative. It would be improper for us to pre-empt a decision yet to be taken by Cabinet.

[232] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 7; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 3; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 1.

[233] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23; Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 16.

[234] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 4.

[235] ENA "DPP3 April 2020 Commission Issues paper(Part One Regulating capex, opex & incentives)" (20 December 2018), p. 14; Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), p. 13; Powerco "Submission on DDP reset issues paper" (21 December 2018), p. 5.

[236] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 20; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 3.

> It is not certain that this change would increase opex costs in aggregate for distributors. Overall, the changes may lead to more efficient management of vegetation-related expenditure, with increased vegetation management expenditure more than offset by lower system interruptions and emergency expenditure.[237]

A67 While we do not consider this meets the criteria for a step change in opex because the change is not quantified, we suggest that reopening the price path could be considered if tree regulations change.

FENZ levies

A68 Our final decision is to introduce a new recoverable cost to cover FENZ levies. Given the level of uncertainty surrounding the changes we do not consider this is appropriate for an upwards step change in expenditure, as any forecasts could not in this case be robustly verified.

A69 However, because of this change, we have removed existing FENZ levy payments from distributors' base opex, based on information received in response to a section 53ZD information gathering request.[238]

LV line monitoring

A70 Greater visibility of the LV network is said to be increasingly important as it is likely to be the first part of the network impacted by emerging technologies, such as electric vehicles or battery storage. Submitters argue that accessing smart meter data to monitor these networks is likely to be a step change cost.[239]

A71 The ENA, Orion, Wellington Electricity and Vector reiterated that LV network monitoring should be a step change.[240]

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[237] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft reasons paper" (29 May 2019), p. 133.

[238] Commerce Commission, "Notice to supply information to the Commerce Commission under section 53ZD(1)(e) and 53ZD(1)(f) of the Commerce Act 2986" June 2019.

[239] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), pp. 14-15; Powerco "Submission on DDP reset issues paper" (21 December 2018), p. 5.

[240] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 9; Orion "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 3; Vector "Cross-submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 18.

A72 We do not consider LV monitoring satisfies the step change criteria. This is because we lack evidence to determine the significance, to robustly verify the expense, or to know how applicable this cost is to most distributors. We note that one distributor quantifies the costs in a confidential submission. However, given the uncertainties involved, we do not consider it appropriate to allow this (or any other amount) ex-ante.

A73 Where LV monitoring is achieved using methods or technologies that are innovative (in the New Zealand context) this expenditure is likely to qualify for inclusion within the innovation allowance recoverable cost, which is discussed in Attachment F.

A74 Furthermore, there are two cases where we may amend the DPP during the period to account for these costs, when the need, timing, and quantities are involved are more certain:

A74.1 where acquisition of smart meter data or other LV monitoring is required by a change to our ID regulations, we would have the option of a change event reopener to amend opex allowances (provided the 1% materiality threshold is met); or

A74.2 where the Electricity Authority makes regulatory changes to the terms on which distributors can access smart meter data from metering providers (as proposed by the Electricity Price Review), the Authority would be able to request the Commission reconsider the DPP under section 54V of the Commerce Act.

Cyber security costs

A75 Several distributors raised concerns about growing cyber security costs and threats.[241] Unison commented that it is only a matter of time before distributors are expected to meet the Voluntary Cyber Security Standards for Industrial Control Systems Operators (VCSS-CSO) which have been introduced this year.

A76 We do not consider that cyber security costs meet our step change criteria. This is due to lack of information if costs are robustly verifiable and if there will be significant increases. In addition, we expect some cyber security costs to be included in our allowances as cyber security costs are usual costs for any business.

[241] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 7; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2; Vector "Cross-submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 18; Orion "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 3.

A77 Vector suggested there is a benefit in having a shared resilience strategy rather than individual distributors adopting several different approaches. We acknowledge that there are public benefits to cyber security, and we support the sector sharing knowledge and working together in the long-term interests of customers.[242]

Adjustments for CPPs

A78 Wellington Electricity recommended updating their base year costs to include Wellington's earthquake readiness operating costs. These costs fall in the last two years of their CPP and after 2018/19. It is worth highlighting that we do not set a price path for Wellington Electricity and Powerco until their CPPs end. We will review Wellington Electricity's situation when we set their DPP next year.[243]

Penalties and fines not to be passed on

A79 We made a step change in the base year for penalties and fines. This means that opex allowances for DPP3 do not allow for future penalties and fines. Pecuniary penalties are fines or penalties imposed by a court, or by any other body with a statutory power to impose such fines or penalties. For the avoidance of doubt, on a forward-looking basis, we have amended the IMs to make it clear that fines and penalties do not qualify as opex for DPP purposes.

A80 Were these costs included in a distributors' ID opex, absent other changes, ~76% of the cost would be passed through to consumers via the IRIS mechanism. This is a perverse outcome; pecuniary penalties and fines are intended to penalise distributors (or other parties) for conduct contravening standards that apply to them. Penalties are also largely under a distributors' control, so it is appropriate that distributors bear the risk. There is no policy reason for these costs to be shared with consumers.

A81 Our final decision is that fines and penalties will not qualify as opex from 1 April 2020. IRIS rewards and penalties paid after 1 April 2020 which are based on profits made during DPP2 will not be retrospectively adjusted for pecuniary penalties incurred before 1 April 2020. For example, if a distributor incurred a pecuniary penalty during DPP2 before 1 April 2020, its IRIS payment in five years' time, after 1 April 2020 would not be adjusted to exclude those pecuniary penalties. This decision is a change from our IM reasons paper where we considered excluding pecuniary penalties from opex as a clarification. We thought it was implicit in the definition of operating costs that pecuniary penalties were excluded.

[242] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 34.

[243] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

A82 After considering the submissions received on our draft IMs reasons paper and to provide greater regulatory certainty, we felt that it is more appropriate that we amend the IMs and apply the changes from 1 April 2020 for the final decision. We consider that the possible long-term benefits of regulatory certainty outweigh the costs of making retrospective adjustments. Making a retrospective adjustment may reduce distributors' confidence in future regulatory decisions and could potentially hold up investment. A retrospective adjustment also adds complexity to the IRIS mechanism which could reduce its effectiveness.

A83 Our final decision means that distributors can pass on the costs of penalties incurred before 1 April 2020 via the IRIS mechanism. Vector's recent breaches of its quality standards resulted in a court-imposed penalty.[244] It is within Vector's discretion whether it chooses to pass on the costs of these pecuniary penalties to its customers.

A84 A full discussion of our reasons for this IM amendment are available in our final IM amendments reasons paper.

Operating leases

A85 We have made a step change in the base year for operating leases. This ensures that forecast opex does not include operating lease costs. This is an IM amendment which follows the implementation of a new financial reporting standard – NZ IFRS 16 where operating leases are treated as capex instead of opex.

Table A4 Analysis of step changes

Step change	Description	Assessment
Health and safety	Higher expenditure said to result from the Health and Safety and Work Act 2015. This relates to changes to work on electrified (live) lines.	Does not meet the significance or robustly verifiable tests as change is not quantified. In addition, past cost increases are already included in the base year.
Tree Regulations	Expected changes to the regulations governing vegetation management are said to result in higher expense.	Does not meet the significance or robustly verifiable tests as change is not quantified.
FENZ levies	FENZ are partially funded by a levy over certain insurance contracts. The government is in the process of reforming how the organisation is funded, including how this levy operates. This is likely to impact the amount distributors pay in insurance premiums.	FENZ levies are treated as a recoverable cost.
LV network monitoring	Increased information about LV networks is said to be important to understanding the impact of emerging. Collecting this data would involve a cost.	Costs are not able to be verified at the stage. May qualify for innovation recoverable cost.

[244] Commerce Act 1986, section 87.

Step change	Description	Assessment
Guaranteed service levels (GSL)	There is a possibility that in future distributors will be bound to provide compensation to customers when service falls beneath certain guaranteed levels.	Not necessary as we have not recommended a GSL scheme.
New pricing methodology	Distributors may need to restructure their pricing approach depending on changes from the EA's review.	Does not meet the significance or robustly verifiable tests as change is not quantified.
Labour skills shortages	There is said to be a shortage of skilled staff in certain areas (e.g., qualified line mechanics), with high demand across the sector further exacerbated by the demands of Powerco's capex programme.	Accounted for in input cost trend factor.
Software as a Service	The move towards Software as a Service results in higher opex instead of capex.	Does not meet the significance or robustly verifiable tests as change is not quantified. Existing software costs may be included in capex.
Customer engagement	Distributors have begun to take more active measures to engage consumers.	Does not meet the significance or robustly verifiable tests as change is not quantified.
Customer Service Lines	Some distributors are said to have concerns that customers are not maintaining their customer service lines, and that distributors may incur expense in doing so.	Customer services lines are currently excluded from the regulated service. A legislative change to include them as a regulated service may allow a reopener.
Regulatory requirements	Increasing regulatory requirements from IPAG, EA, pricing reform, Part 4 requirements including meeting new quality standards.	Does not meet the significance or robustly verifiable tests as change is not quantified.
Cyber security	Increasing cyber security costs and threats.	Does not meet the significance or robustly verifiable test as change is not quantified. Existing cyber security costs may be included in opex. Does not meet the significance or robustly verifiable test.
Insurance	Increasing insurance costs.	Existing insurance costs may be included in opex baseline. Costs provided by Wellington Electricity in their submission are not sufficiently significant.
Traffic management and congestion	Changes in traffic management requirements and increasing congestion in Auckland.	Does not meet the significance or robustly verifiable tests as change is not quantified. It is not appropriate to make distributor-specific step changes within the current DPP framework.
Employment relations amendment act	Recent legislative changes may increase costs.	Does not meet the significance or robustly verifiable tests as change is not quantified.
Climate change	Increased costs from the recommendation for "accelerated electrification" in the Interim Climate Change committee report and, the Climate Change Response Amendment Bill.	Does not meet the significance or robustly verifiable tests as change is not quantified.

Step change	Description	Assessment
Maintaining assets as they reach the end of their lives	Increased costs due to rising inspection and maintenance requirements before replacement.	These costs are within management control, do not meet the significance or robustly verifiable tests as change is not quantified and are likely to be captured in other components of our projection.
Feasibility studies and trials	Increased costs due to the emerging need for feasibility studies and trials.	These costs are within management control, do not meet the significance or robustly verifiable tests as change is not quantified and are likely to be captured in other components of our projection. We note that feasibility studies and trials related to innovative activities could qualify for innovation recoverable cost.
New technology	Increased technology costs e.g. hiring new appropriately skilled staff	These costs are within management control, do not meet the significance or robustly verifiable tests as change is not quantified and are likely to be captured in other components of our projection. May qualify for innovation recoverable cost.

Trend factor for changes in network scale

A86 This section discusses the first of our three trend factors: changes in scale growth. It starts by discussing the econometric model we use to forecast changes in opex, then discusses our approach to forecasting changes in circuit length and changes in ICP numbers.

Scale growth – econometric model

Problem definition

A87 To calculate the scale trend factor, the econometric model used historical data. In the draft allowance we used data from 2013-2018 and in September 2019 we received an additional year of data. We considered the trade-offs of incorporating this additional year of data.

Final decision

A88 We have:

A88.1 added 2019 data into the econometric model for network opex;

A88.2 not added 2019 data into the econometric model for non-network opex;

A88.3 updated the price inflators using NZIER's most recent cost inflators; and

A88.4 treated operating leases as opex in the dataset used to calculate the elasticities.

Analysis

A89 We have decided to incorporate distributors' most recent disclosures into the dataset used to calculate the elasticities for network opex. This is because network opex costs are consistent over time and using distributors' most recent data means the elasticities take account of distributors' current operating environment.

A90 We decided not to use distributors' most recent disclosure data in 2019 to calculate the elasticities for non-network opex. This is due to inconsistencies in the data which could cause potential bias in the elasticities.

A91 We could not remove FENZ levies and pecuniary penalties from non-network opex as we only had data for non-exempt distributors in 2019. If we deducted FENZ levies and pecuniary penalties from non-exempt distributors' non-network opex in 2019, this could have created an inconsistency between exempt and non-exempt distributors in 2019, and across all distributors over time. As the inconsistency is not random, this could potentially lead to bias in the elasticities.

A92 If we included FENZ levies and pecuniary penalties in non-network opex in 2019 this could also create bias in our elasticities. This is because there is a large penalty in 2019 for one distributor. We considered this penalty to be an anomaly and not representative of costs over time for most distributors.

A93 We have also decided to treat operating leases as opex in the econometrics dataset to ensure consistency over time and across distributors. This is because we do not have information on historic operating lease costs for exempt distributors.

A94 We acknowledge that the econometrics dataset includes operating leases, FENZ levies and pecuniary penalties and so the elasticities are calculated based on some costs which will not be part of opex in the future. We do not consider this to have a material impact on elasticities due to the size of these costs and our econometric testing shows that our models are robust to changes in the sample period and sample of distributors. This is as expected as opex costs, ICP numbers and circuit length numbers have a stable trend over time and we do not see a reason why they could change significantly over a short period of time.

Scale growth – selection of variables

Problem definition

A95 As a distributor grows, the cost of maintaining and managing its network can also be expected to grow. We approximate this 'output' change using an econometric method, and to do this we need to determine:

A95.1 what level of disaggregation in opex we use as the dependant variable(s); and

A95.2 what factors we use as the independent variables ('drivers' of the expenditure).

Final decision

A96 We retain the network and non-network level of disaggregation used in setting DPP2.

A97 For network opex we have retained the two current independent variables and have updated the elasticities using updated data as discussed above. The elasticities are shown in Table A4 below:

A97.1 change in circuit length, with an elasticity 0.4886 change in opex for every 1% change in circuit length); and

A97.2 change in ICP numbers, with an elasticity of 0.4470.

A98 For non-network opex, we use two independent variables:

A98.1 change in ICP numbers, with an elasticity of 0.6525; and

A98.2 change in circuit length, with an elasticity of 0.2185.

Table A5 Updated coefficients – removing outliers

Opex category	Elasticity to ICP growth	Elasticity to circuit length growth	R^2
Network opex	0.4886	0.4470	0.905
Non-network opex	0.2185	0.6525	0.901

Alternatives considered

A99 In terms of disaggregation, we have considered

A99.1 using total opex; and

A99.2 breaking network and non-network expenditure into one or more subcategories.

A100 In terms of drivers, we have considered:

A100.1 total circuit length (km);

A100.2 ICP growth;

A100.3 annual energy delivered (GWh);

A100.4 maximum coincident peak demand (MW); and

A100.5 overhead line length (km).

A101 The results of the econometric analysis are presented in detail below.

Analysis

A102 We looked at three things when comparing the results of our econometric analysis:

A102.1 whether the model had good explanatory value;

A102.2 evidence that the relationship between the variables is real, and not merely random/coincidental; and

A102.3 whether the relationship between the independent and dependant variables makes intuitive sense in terms of the way distributors manage their networks.

A103 In terms of explanatory power, the models we use explain approximately 90% of the variation in network and non-network opex.[245] Our analysis at the draft decision found that our models perform better on this measure than all other models we have analysed except one. The results are shown in Table A6 and Table A7 below. We tested models suggested by submissions and found our chosen models performed best using our updated dataset as well. We discuss in our response to stakeholder views below.

A104 A model which uses ICP growth and line length growth to explain total opex did result in a slightly higher R^2 value (it explained 94% of the variation in total opex). However, given the compositional differences between distributors network/non-network expenditure, we consider applying this model inappropriate.[246]

[245] For network opex, the combined line length-ICP model explains 90.5% of variation. For non-network, the combined line length-ICP model explains 90.1%.

[246] Network opex ranges from 24% (Unison) to 58% (OtagoNet) of total opex over the 2013-2018 period.

Table A6 Econometric analysis of opex – without removing outliers

Model	Elasticity					R^2
	Lines[247]	*ICPs*	*Delivery*[248]	*Peak*[249]	*Lines*[250]	
Total opex	0.3605	0.5342				0.9481
Opex categories						
Network opex	0.5276	0.4228				0.9034
Non-network opex	0.2095	0.6418				0.8924
Network opex						
SI & E[251]	0.5726	0.4353				0.8351
Veg. man.[252]					1.0552	0.7008
RCMI [253]			0.8843			0.6821
ARR[254] **(1)**	0.6472	0.3408				0.6001
ARR (2)		0.5385			0.3913	0.6355
Non-network opex						
Sys. operations[255]	0.2969			0.7442		0.8019
Bus. support[256]		0.7523				0.8525

Results are based on the dataset used for our draft decision

[247] Total circuit length (for supply).

[248] Total energy delivered to ICPs.

[249] Maximum coincident peak demand.

[250] Total overhead circuit length (for supply).

[251]Service interruptions and emergencies.

[252] Vegetation management.

[253] Routine and corrective maintenance and inspection.

[254] Asset replacement and renewal.

[255] System operations and network support.

[256] Business support.

Table A7 Econometric analysis of opex – removing outliers

Model	Elasticity					Adj. R^2
	Lines	*ICPs*	*Delivery*	*Peak*	*Lines*	
Total opex	0.3292	0.5564				0.9477
Opex categories						
Network opex	**0.4727**	**0.4514**				**0.8973**
Non-net. opex (1)	**0.2188**	**0.6520**				**0.9007**
Non-net. opex (2)		0.8069				0.8863
Network opex						
SI & E	0.5255	0.5207				0.8250
Veg. man.					0.8655	0.4717
RCMI			0.9377			0.7164
ARR (1)	0.6319	0.2201				0.5287
ARR (2)		0.4269			0.3975	0.5722
Non-network opex						
Sys. operations	0.2889			0.7030		0.8004
Bus. support		0.7983				0.8722

Models highlighted in orange are the ones we have used in our final decision (note data has been updated)

A105 Further disaggregation may better reflect the individual spends of each distributor (for example, accounting for variance in vegetation management spend for overhead vs underground lines). However, as our analysis in Table A6 and Table A7 shows, the explanatory power of these disaggregated models is weaker.

A106 For both our network and non-network models, the probability that there is no relationship between the dependent and independent values (the P_0) is zero, indicating that the relationship is real, and not mere coincidence.

A107 In terms of an intuitive connection between the driver and the expenditure, both models make sense.

A107.1 Our analysis of network opex indicates that there is a marginal cost both to adding additional customers and to physically growing the network, but that in both cases this marginal cost is less than 1% opex per 1% growth.

A107.2 As the activities involved relate both to the maintenance of physical assets and to service of customers, this relationship is reasonable. As distributors have a high fixed cost but low marginal cost structure, it is sensible that the elasticity is less than 1.

A107.3 Our analysis of non-network opex suggest a stronger relationship between customer numbers and opex than between circuit length and opex. As only a portion of non-network opex relates to the management of physical assets, whereas most of it relates to managing customers, this difference makes sense.

A108 This result is supported by the elasticities at the next level of disaggregation, where network support opex (which relates to the planning and management of the physical network) shows a stronger relationship to line length than business support opex, which is principally driven by the overall size of the business in customer terms.

Stakeholder views

A109 Wellington Electricity supported using ICP growth and change in circuit length as cost drivers to capture traditional network growth. It commented that the draft regression model shows these to be strong indicators.[257]

A110 However, some distributors are concerned that the econometric model does not capture all costs. Orion commented that opex is not always related to scale factors or historical performance and Unison stated that the model failed to account for any time dimension capturing the impact of non-scale variables on distributors' costs.[258] NERA considered that the econometric model persistently missed something, as evidenced by negative productivity growth for the last 16 years.[259]

A111 Alpine remarked that its growth involves an increasing size of connections rather than an increasing number of connections. This is due to dairy conversions and expansions. Alpine recommends using a measure to explain change in systems demand and transformer capacity instead of growth of circuit length and ICPs.[260]

Our response

A112 In response to distributors' concern that the econometric model does not capture all costs, it is important to state that the econometric model aims to explain recurring costs related to scale only. Non-scale costs are discussed under step changes.

[257] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 11.

[258] Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10.

[259] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 2; NERA Economic consulting on behalf of ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[260] Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 3-4.

A113 In response to Alpine, we have retained using ICP and circuit length growth based on the statistical results shown in the draft decision and the statistical results using a dataset that includes distributors' most recent information disclosures, and the relevance of these cost drivers to the majority of distributors' cost activities. Our econometric testing found that ICP and circuit length growth perform better in terms of the r-squared and significance of the coefficients than annual energy delivered (GWh) and maximum coincident peak demand (MW). This implies that distributors' opex costs are explained more by growth in the number of connections, rather than growth of the size of connections.

Forecasting circuit length growth

Problem definition

A114 Our results show there is a robust historical relationship between circuit length and opex growth (as discussed above). We then need a means of forecasting circuit length changes in the future.

Final decision

A115 We retain our DPP2 approach of forecasting future circuit length growth based on projecting distributors' historical line length growth into the future. We have updated our forecasts of circuit length growth using 2019 ID data.

Analysis

A116 Trends in circuit length growth (for most distributors) have been relatively stable over time, and we see no fundamental reason why this growth rate would change significantly over the DPP3 period. We received an additional year of circuit length data in September 2019 which shows the data continues to have a stable trend. ERANZ comments that over DPP2 circuit length and the number of ICPs has not materially deviated from expectations.[261]

A117 We did not consider requesting forecast data as an appropriate or proportionate option given the incentive for distributors to overestimate their forecast circuit length growth, the lack of a reliable metric to check the validity of their forecasts, and the regulatory costs to all parties.

[261] ERANZ "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3.

Stakeholder views

A118 Wellington Electricity was comfortable with projecting distributors' historic circuit length growth for DPP3 due to the cost of collecting the additional data to use distributors' forecasts. If there was not a cost to collecting additional data, Wellington would prefer using distributors' forecasts as they have local knowledge and expertise to develop accurate forecasts.[262]

Forecasting ICP growth

Problem definition

A119 Our results show there is a robust historical relationship between ICP growth and opex growth (as discussed above). We need a means of forecasting ICP growth in the future.

Final decision

A120 We forecast ICP growth based on StatsNZ forecasts of household growth in each distributor's network area. For the draft decision, we used StatsNZ forecasts of population growth.

Alternatives considered

A121 We considered retaining the use of StatsNZ population growth data as per the draft decision.

Analysis

A122 Growth in ICP numbers ultimately depends on new construction in a distributors' catchment.[263] As such, forecast of population growth and household growth, are in theory both sensible predictors of future ICP growth.

A123 Over the long-term, population has grown at a much faster rate than both households and ICPs as shown in Figure A4, since 2013.

[262] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 11.

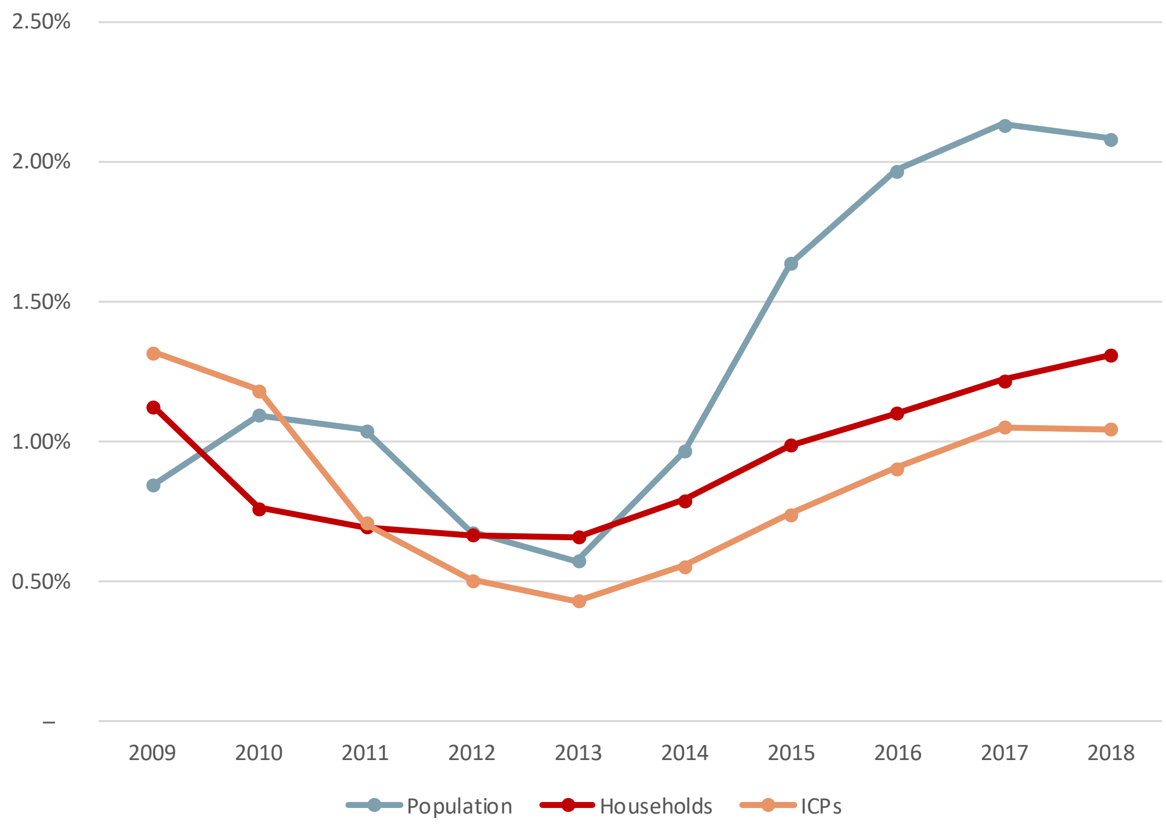
[263] While some ICP growth will relate to industrial and agricultural activity, these make up a small proportion of distributors total new connections. As the econometrics relate to total ICP growth, total growth in ICPs is what we are interested in.

A124 For the final decision, we have used household growth because:

A124.1 Household forecasts have historically mapped more closely to ICPs as shown in Figure A4. The trend between ICPs and population growth is less stable with greater historic fluctuations and a recent divergence in growth. Going forwards, we consider ICP growth is more closely related to household growth than population growth because not every individual has a connection.

A124.2 Our investigation found that it is more complex to map StatsNZ areas to distributors' service areas using household data. However, we did not consider this to cause significant inaccuracy in our household growth forecasts as the complexity only affects a minority of areas which are served by more than one distributor. For areas served by more than one distributor, we used population data to calculate the proportion of each area served by each distributor. This was because population data is available at a more disaggregated level than household data.

Figure A4 Comparison of national household, population and ICP growth 2009-2018



Stakeholder views

A125 Vector supported using household growth forecasts instead of population growth forecasts. This is due to household growth being more accurate as not every individual has a connection. Vector considered that any inaccuracy between mapping disaggregated household data to distributors' service areas is likely to be small. This is the case for Vector's service area. It commented on the risk of us incorrectly mapping Stats NZ areas to distributors' areas and this risk applies both to population and household data. We note that no distributor submitted on whether we map disaggregated StatsNZ data to the right service areas.[264]

A126 Wellington Electricity commented that household growth is a better predictor of ICP growth than population growth, but they would need a better understanding of how effective household growth is at predicting ICP growth on specific networks. We note that distributors are also protected by reopeners for large unforeseen new connections, as discussed in Attachment G.

Input price inflators

Problem definition

A127 The cost of the inputs distributors require to deliver the outputs expected of them also changes over time, for predictable reasons beyond their control. Put another way, the opex allowances we produce in constant-price terms must be adjusted for inflation, to be incorporated into the financial model.

Final decision

A128 We use a weighted average of two inflators:

A128.1 NZIER forecasts of the all-industries LCI (60%); and

A128.2 NZIER forecasts of the all-industries producer price index (40%).

A129 This is consistent with the approach taken in DPP2 and suggested in our EDB DPP3 issues paper. We have updated our draft forecasts using NZIER's most recent forecasts from August 2019.

[264] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 24-25 and 35.

Alternatives considered

A130 We have considered the following suggestions made in submissions in our analysis.

A130.1 Alpine suggested altering the weighting of LCI and PPI as the draft decision might not be appropriate for distributors experiencing load growth.[265]

A130.2 Making a specific adjustment for distributors or regions.[266]

A130.3 Centralines suggested using private sector wage inflation to inflate labour costs instead of LCI.[267]

A130.4 Seeking advice and reconsidering NZIER's forecasts for electricity distribution.[268]

Analysis

A131 The purpose of these inflators is to allow distributors the costs of changes in the real prices of inputs that are outside of their control. This ensures a nominal opex allowance that is suitably adjusted for price rises in future years.

A132 Alpine recommends placing more weight on PPI than LCI as distributors with increasing load growth will spend more on materials than labour.

A133 We did not alter the weighting of LCI and PPI as we considered the majority of distributors will experience growth of the number of the connections rather than growth at existing connections. Distributors with growth of number of connections are likely to incur a higher proportion of labour costs than those with increasing growth of existing connections. The latter can achieve economies of scale. For example, if a distributor increases its load at a connection, it does not necessarily need to increase its labour input by the same proportion. We currently lack the information to make an evidence-based adjustment to the weighting of cost inflators for this price reset.

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[265] Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3.

[266] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 35; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 16; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 12; Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 35.

[267] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 12.

[268] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 5 and 16; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 12; Orion "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 2.

A134 Several distributors suggested that labour costs are higher in particular regions. Vector provided evidence that labour costs are higher in Auckland relative to the rest of the country and PowerNet, Unison and Wellington Electricity highlighted that labour costs could be higher in the South Island due to a higher demand for labour by Aurora and other infrastructure demands.[269]

A135 We considered that the impact of regional labour costs can be largely mitigated by distributors hiring nationally and investing in their workforce. This is particularly applicable to non-network labour costs which are less bound by location than network labour costs. It is also not appropriate to make one-off adjustments under the DPP principle of “applying the same or substantially similar treatment to all suppliers on a DPP.”[270]

A136 Centralines suggested that private sector wage inflation is a more appropriate inflator than the LCI. This is because wage inflation takes account of the quality of employees which it suggests reflects that competency grows over time; whereas the LCI measures the change in the cost of labour that is required to produce the same quantity and quality of work.[271]

A137 We do not adopt the wage inflation index because the LCI already takes wage inflation into account. The LCI also measures other types of labour costs that employers incur such as non-wage labour costs like medical insurance, motor vehicles, annual leave and ACC employer premiums. We note that changes in costs caused by the quality of labour are reflected in the productivity factor, and changes in costs caused by labour cost growth are captured in the scale factor. Distributors also have a choice over the quality and quantity of labour they use. Our allowance for inflation aims to protect distributors only from labour cost inflation as this cost is largely outside of distributors’ control.

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[269] Vector “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 35; PowerNet “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 2; Unison “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 16; Wellington Electricity “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 12; Vector “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 35.

[270] See paragraph 3.16.1 in Chapter 3 above.

[271] Centralines “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 12.

A138 Several distributors recommend that we reconsider using NZIER's forecasts.[272] We investigated whether NZIER's forecasts are appropriate for distributors, by considering:

A138.1 what factors NZIER forecasts include; and

A138.2 other macroeconomic commentary and forecasts.

A139 We engaged with NZIER to discuss what factors their forecast of LCI includes. We thought this was important following stakeholders' recommendations to seek advice and the overall concern around NZIER's forecast of LCI. Distributors thought the draft forecast of LCI was too low for several macroeconomic reasons and some provided evidence of wage growth forecasts.

A140 We confirm that NZIER's forecasts of the LCI account for factors relevant to distributors. These include wage inflation in the public and private sector, employment rates, the increase in the minimum wage, an ageing workforce and the business outlook.

A141 Several distributors thought actual labour cost inflation for distributors would be higher due to a heavily unionised workforce.[273] Unions are not a new phenomenon and do not represent a change in circumstances compared to previous DPPs. The LCI covers all industries and all occupations except private households employing staff.[274] Therefore, NZIER's forecasts include the electricity distribution sector and other sectors with unions. An adjustment for unions has not been made in the past and distributors have been sufficiently compensated for labour cost inflation. For these two reasons, we do not consider that it is appropriate to adjust the LCI for unions in DPP3.

A142 We surveyed a range of macroeconomic commentary and forecasts to see how NZIER's macroeconomic outlook compared to other independent forecasts. Figure A5 shows NZIER's forecasts are in line with other forecasts of all sectors LCI from Infometrics and Westpac.

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[272] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 5 and 16; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 12; Orion "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 2.

[273] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 1; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 15; Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

[274] Stats NZ "Labour Cost Index Quarterly Data Collection".

A143 Westpac[275], ASB[276], ANZ[277], NZIER,[278] and Infometrics'[279] commentaries provide reasons why there will be slack in the labour market in upcoming years. For example, ASB comments that "With labour demand cooling as business confidence remains weak, the degree of slack may start to increase going forwards."[280] And Westpac "doubts unemployment will remain this low and it could rise over the coming year. There are signs of a softening labour market, with forward-looking indicators such as job ads falling in recent months. And now we face the prospect of an export downturn due to the escalating US-China trade-war which will affect employment in New Zealand."[281]

A144 It is also worth highlighting that BNZ, ANZ, and NZIER commented that labour market data typically lags other indicators. [282] Figure A4 displays a rolling average of inflation over time. It shows that LCI has historically lagged behind CPI inflation over a long time-frame. CPI has been persistently low over the past 5 years and the current policy target does not suggest future increases. The policy target is to "keep annual CPI inflation between 1% and 3% over the medium term, with a focus on keeping future inflation near the 2% per cent midpoint."[283]

A145 In summary, historic evidence and a variety of independent forecasts suggest there will not be significant increases in labour cost inflation over DPP3.

[275] Westpac "NZ labour market review, June quarter 2019" (August 2019), p. 2.

[276] ASB "Quarterly Economic Forecast" (August 2019), p. 3.

[277] ANZ "Labour Market Statistics – 2019Q1" (May 2019), p. 2.

[278] NZIER "Quarterly Predictions" (September 2019) pp 7.

[279] Infometrics "Cost adjusters 2019-2025 for the Commerce Commission" (September 2019), pp 2-3.

[280] ASB "Quarterly Economic Forecast" (August 2019), p. 2.

[281] Westpac "NZ labour market review, June quarter 2019" (August 2019), p. 2.

[282] BNZ "NZ's Bolshy Labour Market" (August 2019), p. 2; ANZ "Labour Market Statistics – 2019Q1" (May 2019), p. 2.

[283] Parliament "Monetary Policy and the Policy Targets Agreement" (March 2019).

Figure A5: Comparison of LCI and CPI from 1994-2024

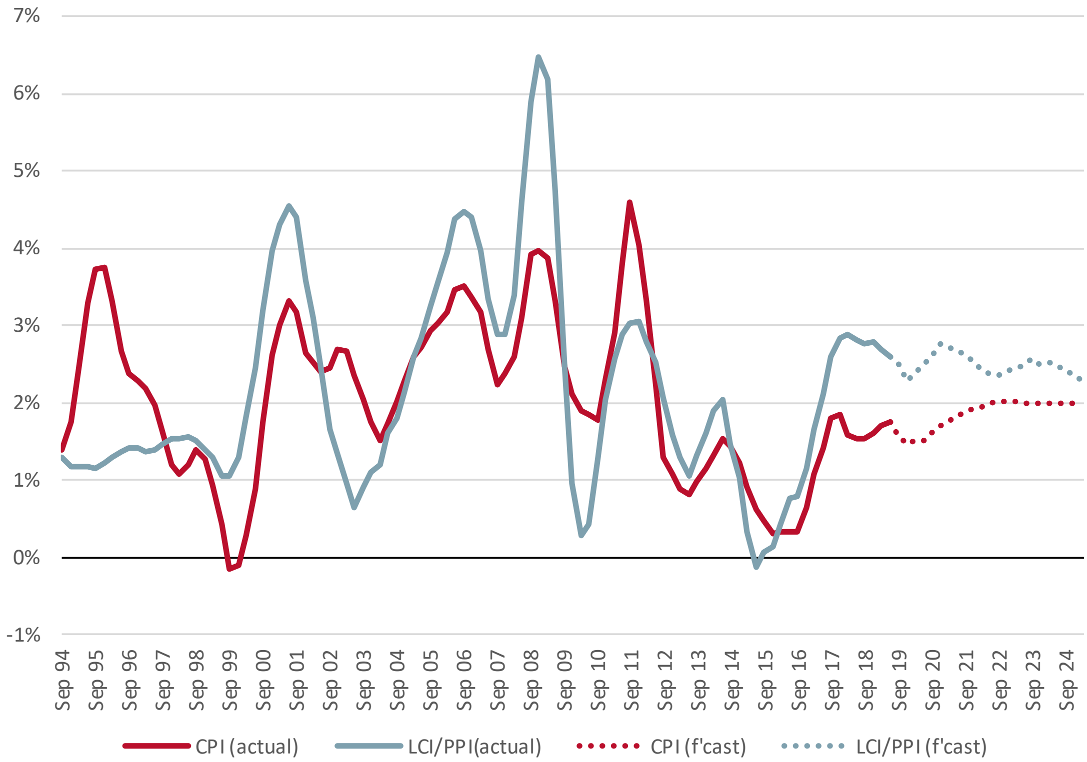
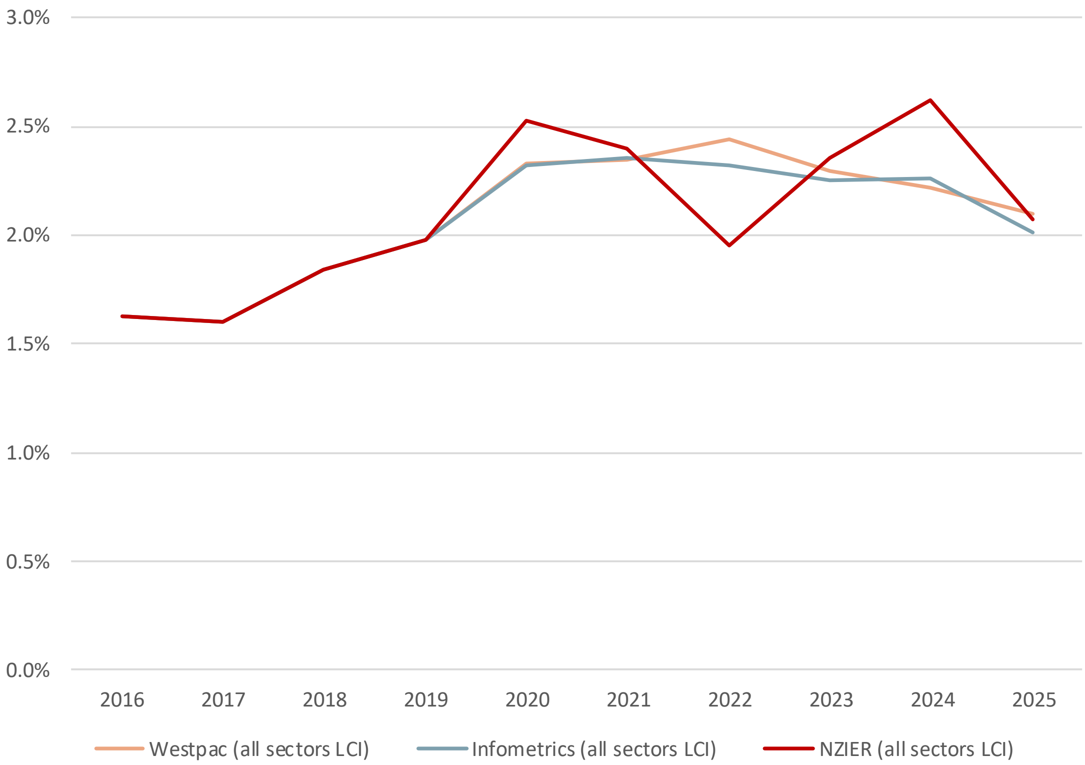


Figure A5 Comparison of all sectors LCI % changes from 2017 to 2025[284]



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[284] Westpac Economics Forecast Summary Spreadsheet (Oct 2019); NZIER forecasts (Aug 2019); Infometrics forecasts (Sep 2019).

Stakeholder views

A146 In relation to our method of forecasting labour cost inflation, some stakeholders showed support. Wellington Electricity supported using an independent agency such as NZIER and using LCI and PPI as a starting point.[285]

A147 There were few comments on our method for forecasting producer price input inflation. Centralines thought NZIER's forecast of PPI did not appear unreasonable.[286] However Alpine suggested that PPI should be given more weight for distributors that have steady or increasing load growth and that distributors could provide evidence of load growth to inform our decision.[287]

A148 Most stakeholders thought NZIER's forecast of labour cost inflation was too low after taking CPI into account. This was due to factors relating to distributors' operating environment such as high unionisation and wage pressures from infrastructure deficits and CPPs. Several distributors cited macroeconomic reasons such as an increase in the minimum wage, an ageing workforce, above average public sector wage settlements and the economy being at full employment. Stakeholders also submitted macroeconomic evidence to explain why labour cost inflation might be higher than forecast. Evidence was provided by submitters on wage growth, employment rates, participation rates and business outlook. We discuss our response in our analysis above.

Opex partial productivity factor

Problem definition

A149 Industry-wide changes in productivity can result in more (or less) output per unit of input. To reduce the risk of general productivity changes giving distributors windfall gains or losses, the opex allowance should be adjusted by a productivity factor.

Final decision

A150 We have set the opex partial productivity factor at 0%, based on an assessment of overseas productivity trends in electricity distribution, productivity trends in comparable sectors within New Zealand and a changing policy environment relative to DPP2.

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[285] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 12.

[286] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 5.

[287] Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3.

Alternatives considered

A151 We have considered the following alternative:

A151.1 Setting a productivity factor based on historic performance.[288]

Analysis

A152 We clarify that the 0% productivity factor we have set reflects our view that we expect distributors to improve their productivity during DPP3 relative to historic performance. We consider improvements in productivity are achievable due to:

A152.1 evidence of positive productivity in electricity distribution sectors across the world, including productivity studies which take non-scale variables such as quality of outputs into account;[289]

A152.2 evidence of positive productivity in comparable sectors within New Zealand; and;

A152.3 a changing policy environment with a greater focus on innovation and technology.

A153 We consider it is appropriate to compare New Zealand's electricity distribution sector to other electricity distribution sectors across the world such as the UK, Norway and Canada. These sectors have similar regulatory regimes to New Zealand and so they face similar incentives. They also have similar value chains and thus have similar inputs and outputs to distributors in New Zealand. It is important to note that this evidence only informs our decision as we acknowledge that international electricity distribution sectors are not perfect comparators. Further, much of the international productivity evidence available is based on total factor productivity (TFP) which does not distinguish between capex and opex.

A154 A recent long-term study by the Energy Policy Research Group at the University of Cambridge prepared for Ofgem in 2018 finds evidence of positive TFP growth of 1% p.a. from 1990/91 to 2016/17. Their analysis accounts for 'non-measurable' outputs including customer minutes lost, interruptions, energy losses and customer satisfaction. Their results align with other studies that find a positive TFP growth rate between 1 and 2% in the UK (Giannakis et al, 2005; Hattori et al., 2004) and with studies from other countries (Edvarsen et al., 2006; Senyonga and Berlgland, 2018; Ramos-Real et al., 2009).[290]

[288] See paragraph 3.16.2 in Chapter 3 above.

[289] For example, customer minutes lost, interruptions, energy losses and customer satisfaction.

[290] A report prepared by the Energy Policy Research Group at the University of Cambridge for OFGEM "Productivity growth in electricity and gas networks since 1990" (December 2018), p. 64.

A155 We also considered productivity from comparable sectors within New Zealand. These are largely competitive sectors which means firms not at the frontier would in theory be driven out of the market.

A156 Figure A6 shows that the Electricity, gas water and waste services sector lags significantly behind a selection of similar competitive sectors in terms of TFP. It is important to note that we are using TFP as an indicator of partial productivity.

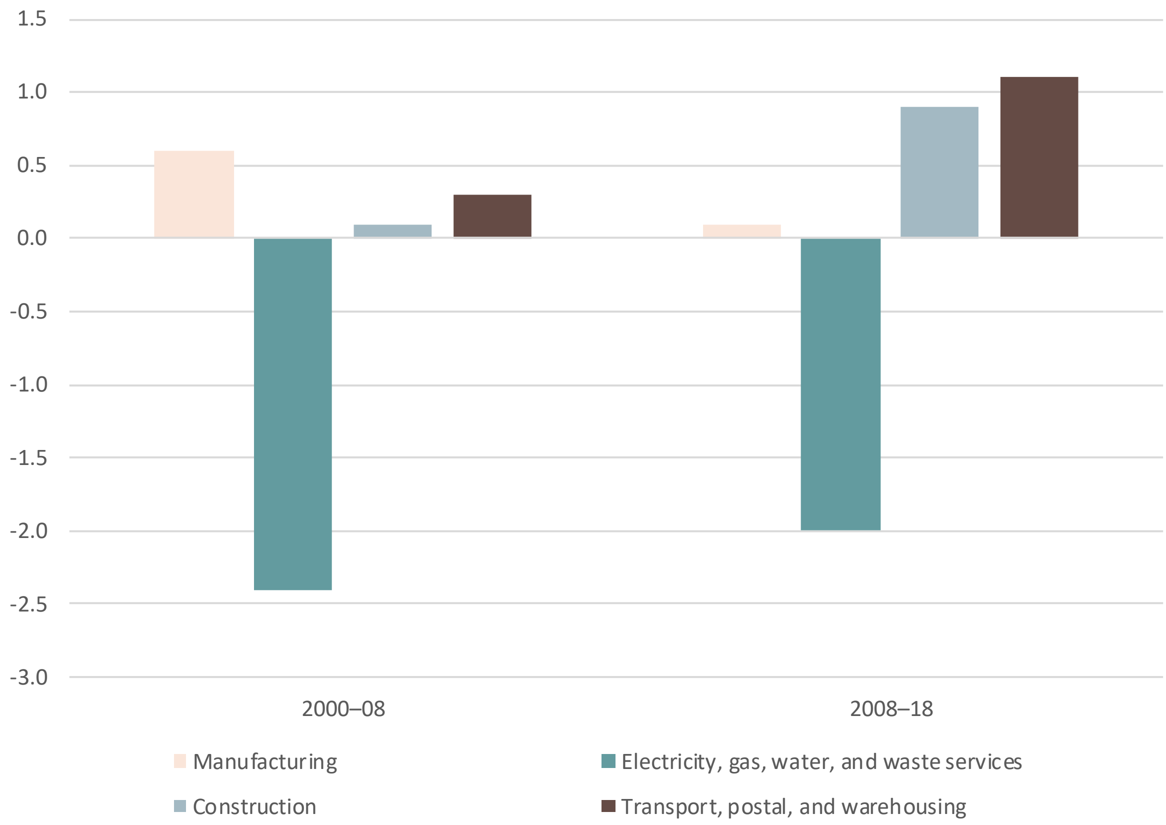
A157 We considered the manufacturing, construction and services sectors to be comparable to distributors because these sectors have similar inputs, operate and maintain a network or involve large scale equipment. These sectors align with several independent economic consultancies' views of comparable sectors to the water sector which is also a network utility.[291] Therefore, there are likely to be opportunities for distributors to adopt practices from these sectors to improve their productivity during DPP3.

A158 We have concluded that the value in relying on historic performance is outweighed by other considerations with respect to the productivity factor. By basing the productivity factor on the past behaviour of regulated suppliers, we risk creating perverse incentives which may undermine efficiency incentives in a way that is inconsistent with section 52A(1)(2) by compensating distributors for past efficiency losses, or effectively penalising distributors for efficiency gains, in subsequent periods.

A159 Lastly, the policy environment is different in DPP3 relative to DPP2 in light of the Electricity Price Review.[292] In addition DPP3 has a greater emphasis on innovation and technology as our innovation allowance aims to incentivise distributors to take up innovative activities.

[291] Europe Economics "Real Price Effects and Frontier Shift – Updated Assessment" (July 2019), p. 66-68.
[292] Electricity Price Review "Final Report" (May 2019).

Figure A6 Annual percentage change of TFP across comparable sectors



A160 Submitters provided evidence that there could be opportunities to achieve productivity improvements from innovating. ETNZ cites academic evidence from Wakeman (2017) which also found that in 2-3 years after receiving a grant, recipients experienced faster employment and labour productivity growth than non-recipients.[293] Similarly Contact Energy believes innovation is essential to boosting productivity and reducing the cost of network services over the long term. Examples of innovation opportunities include investment in LV monitoring, development of distribution system operator platforms to create third-party markets and programs trialling demand response programmes to contract third-party resources. Contact Energy also comments that there seems to have been a limited appetite to invest in innovation to date.[294]

A161 From a customers' perspective, there is also no reason why distributors' productivity should lag behind other sectors within New Zealand or distributors in other jurisdictions.

[293] ETNZ "Submission on EDB DPP reset draft decisions paper" (16 July 2019), p. 3.

[294] Contact Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

Stakeholder views

A162 All distributors who responded to the draft decision opposed the productivity factor being set at 0% and thought we should allow for non-scale factors that they consider will drive higher opex in DPP3.[295]

A163 Many of these distributors recommended a negative productivity allowance based on historic evidence from NERA which showed a negative long-term trend of productivity. Several distributors supported NERA's suggestion of reframing the productivity factor as the 'residual opex factor.'[296] This suggests a negative productivity factor does not necessarily mean negative productivity growth. Instead it is caused by the growth of unmeasured outputs such as resilience or quality, offsetting any productivity gains. For the reasons set out above, we do not consider it is appropriate to use historic performance to set the partial productivity factor.

A164 Only ERANZ thought 0% was too generous and provided little incentive for distributors to boost their productivity. ERANZ attributed distributors' decline in productivity from 2004-2014 due to growth in capital investment and provided evidence that one 'un-measurable output' has declined on average. They showed that SAIDI and SAIFI figures from 2013 and 2018 have deteriorated.[297]

A165 ENA's cross-submission asks for clarity over what the partial productivity factor allowance is for.[298] We address this in our analysis.

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[295] Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 8; Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 9; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 4; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3; Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 1; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 14; Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 35; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

[296] NERA Economic consulting on behalf of ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

[297] ERANZ "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 3-6.

[298] ENA "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 4.

A166 Going forward, Aurora noted that an approach that is objective and stable is needed.[299] MEUG suggested comparing performance relative to international best practice[300] and ERANZ thought we should move away from using historical studies in the same jurisdiction as this can create perverse incentives.[301] Wellington Electricity warned that overseas jurisdictions may not reflect New Zealand distributors' operating environment.[302]

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[299] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 8.

[300] MEUG "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 5.

[301] ERANZ "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[302] Wellington Electricity "Cross-submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 6.

Attachment B Forecasting capital expenditure

Purpose of this attachment

B1 This attachment outlines and explains our approach to forecasting capital expenditure (capex) for the DPP3 period.[303]

B2 Under the EDB IMs we must set a "forecast aggregate value of commissioned assets" for each distributor so that we can set starting prices and apply the capex IRIS incentive during the DPP3 period.[304] This forecast is material in determining the revenues distributors may earn; affecting their profitability, incentives to invest, and ability to deliver services.

B3 The EDB IMs provide that the forecast aggregate value of commissioned assets is equal to forecast capex for the relevant year as determined by us.

B4 The approach we have taken to forecasting capex reflects that the DPP is intended to be a relatively low-cost form of regulation catering for a wide group of businesses using a generic approach.[305] A DPP is not intended to deal with circumstances that require significant scrutiny of costs of an individual business. However, there are two mechanisms within the existing Part 4 regulatory framework to appropriately cater for the challenges distributors face in delivering to customer expectations.

B5 The first of these are reopeners. We have introduced a reopener that covers expenditure under three capex expenditure categories. This increases the flexibility available to distributors and reduces the potential for unintended consequences from a high-level approach.

B6 The second mechanism is CPP, which distributors can apply for if they consider an alternative price-quality path would better meet their particular circumstances. A CPP can be tailored to meet the specific needs of distributor and their consumers, and also provides the flexibility to generally deal with uncertainties that distributors may encounter.

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[303] Under the ID definitions, capital expenditure comprises 'expenditure on assets' plus 'cost of financing' less 'value of capital contributions' plus 'value of vested assets'. We outline our proposed treatment of all of these components within this attachment.

[304] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 4.2.5 defines "forecast aggregate value of commissioned assets".

[305] See the framework discussion under paragraphs 3.13 - 3.28.

B7 Increases in capex beyond what we have allowed for under a DPP have, and will likely continue to be, a primary driver of CPP applications from regulated suppliers. As such, the forecasts we set have wider implications for the workings of the price-quality regime.

B8 Our approach to forecasting capex for the DPP3 period draws on the approaches we have used in the past. This attachment will summarise the basic elements of those past approaches. It will then explain our approach, with reference to the discussion in the Reasons Paper supporting our draft decision, the Companion Paper to the Updated Models, and the feedback we received from submitters on both papers.

B9 We outline our approach first at a high level, illustrating how the different components of it are intended to work together, and outlining the key changes we have made since the draft decision. We then step through and discuss the details of our approach. This discussion is broken out into the following into three sections.

B9.1 The key design elements of our approach, which determine the extent to which we rely on distributors' own AMP forecasts of their capital expenditure in undertaking our capex forecasting.

B9.2 The tests that we have used to scrutinise distributors' AMP forecasts, and the caps on expenditure that we have applied.

B9.3 Other implementation issues.

B10 The capex allowances for each distributor that result from our approach are set out in Table B1.

Table B1 Capex allowances for DPP3 ($m)

Distributor	2020/21	2021/22	2022/23	2023/24	2024/25
Alpine Energy	16.66	16.98	15.38	14.67	14.15
Aurora Energy	50.95	50.75	48.25	38.77	43.21
Centralines	6.06	2.77	3.97	2.84	2.96
EA Networks	18.05	17.94	17.80	15.71	14.72
Eastland Network	9.68	10.14	8.98	9.38	10.05
Electricity Invercargill	4.66	5.05	5.57	5.58	5.13
Horizon Energy	8.32	6.72	8.08	8.52	8.57
Nelson Electricity	1.63	1.71	1.66	1.67	1.67
Network Tasman	10.29	12.26	9.04	10.07	8.47
Orion NZ	72.17	63.78	89.62	79.93	84.44
OtagoNet	13.99	13.50	18.00	23.07	13.93
The Lines Company	18.32	16.92	15.87	16.56	15.25
Top Energy	14.59	15.13	16.51	16.26	16.60
Unison Networks	46.75	52.52	50.53	46.85	48.04
Vector Lines	211.12	209.60	213.42	209.52	197.13
Wellington Electricity	n/a	35.51	37.68	39.91	42.08

How we have approached capex forecasting in the past

Approach we used in DPP2

B11 For EDB DPP2, we forecast capex by:

B11.1 relying on distributor constant-price AMP capex forecasts, subject to a cap based on historical expenditure;

B11.2 forecasting network and non-network capex separately;

B11.3 using a five-year 2010-2014 historical reference period;

B11.4 applying a uniform 120% cap relative to historic average network capex (assessed net of capital contributions);

B11.5 applying a linear 'sliding scale' cap relative to historic average expenditure for non-network capex, with a maximum cap of 200% where non-network capex was less than 5% of total capex, and a minimum of 120% where non-network capex was more than 25% of total capex;

B11.6 inflating constant-price capex forecasts to a nominal forecast series using NZIER's forecast of the all-industries capital goods price index (CGPI);

B11.7 including an explicit allowance for forecast cost of financing and forecast value of vested assets; and

B11.8 assuming forecast aggregate value of commissioned assets is the same as forecast capex as required in the IMs.[306]

Approach we used for the gas pipeline DPP in 2017

B12 The majority of gas pipeline businesses (GPB) (distribution and transmission businesses) are also subject to a DPP which requires us to produce capex forecasts. In forecasting capex for the 2017 GPB DPP reset, we took an approach which applied scrutiny to AMP forecasts. This approach is detailed in our GPB final reasons paper and included:[307]

B12.1 comparing category level AMP forecasts to a historical baseline;

B12.2 a series of quantitative and qualitative assessments of material contained in the AMP;

B12.3 an opportunity for GPBs to provide further information where the AMP did not justify the forecast expenditure; and

B12.4 the use of a 'fall-back' to historical levels of expenditure where the forecast expenditure could not be justified.

High-level overview of our approach for DPP3

B13 We have taken an approach to capex forecasting for DPP3 that draws on the approach we used in DPP2 and our experience with the GPB DPP in 2017.

B14 Our approach to capex forecasting utilises distributors' own AMP forecasts. However, it scrutinises those AMP forecasts, and calculates an allowance drawing on historical spending and an assessment of cost drivers where the AMP forecasts appear out of step with those cost drivers.

[306] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 4.2.5.

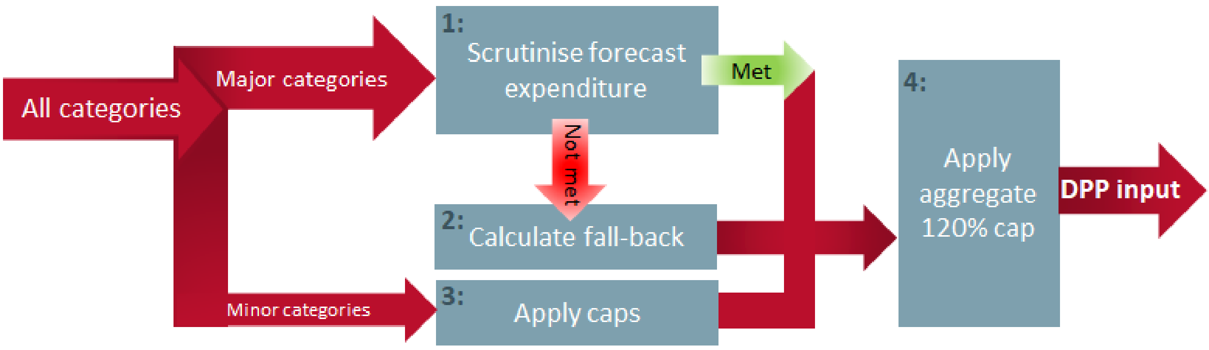
[307] Commerce Commission, "Default price-quality paths for gas pipeline businesses from 1 October 2017, Final Reasons Paper" (31 May 2017).

B15 Distributors have incentives to inflate forecasts, or to not apply rigorous practices when preparing their forecasts. As explained in attachment E, we have increased the capex incentive rate under the IRIS to equal the opex incentive rate (23.5%). This will increase the financial impacts for distributors from both over and under-spending relative to their price path.[308] However, by scrutinising distributors' capex forecasts, we ensure price paths better reflect the need and ability to deliver capex investments. This means consumers are less likely to pay for investments that do not proceed, and distributors are more likely to receive IRIS rewards only for genuine efficiency savings.

B16 The large number of electricity consumers justifies scrutiny of forecasts and the reasonableness of the expenditure. We have applied an approach that is similar in some respects to the 2017 gas pipeline DPP. However, our approach is less in-depth than what we used for the gas DPP because of the much larger number of distributors than GPBs, and the relatively low-cost requirement of the EDB DPP[309].

B17 Our approach to capex forecasting for DPP3 is demonstrated in Figure B1 and explained further below. We discuss our detailed considerations in forming each step of this approach, including views provided by submitters, later in this attachment.

Figure B1 Flow diagram of approach to capex forecasting for DPP3



[308] Refer to Attachment E – Incentives to Improve Efficiency.

[309] See the framework discussion under paragraphs 3.13 - 3.28.

B18 As shown in Figure B1, our approach consists of the following four main components:

B18.1 **Step 1 – scrutinise forecast expenditure:** Our approach scrutinises categories of capex within the current AMP forecasts, utilising the expenditure categories within ID. We have applied scrutiny to expenditure used for meeting growth—comprising 'consumer connection' and 'system growth' capex—and expenditure used to renew or improve existing capabilities—comprising 'asset replacement and renewals' (ARR) and 'reliability, safety and environment' (RS&E) capex. We have identified cost drivers for these bundled categories, and have assessed whether the expenditure for each category appears consistent with those cost drivers—within a tolerance commensurate with the high-level nature of the analysis.

B18.2 **Step 2 – calculate fall-back expenditure where necessary:** Where we concluded that the forecasts for the capex categories we have scrutinised do not reflect their cost drivers, we calculated an expenditure allowance for that category that is more consistent with those cost drivers.

B18.3 **Step 3 - cap 'other' expenditure:** We have capped the remaining, minor categories of expenditure—being asset relocations and non-network expenditure. We have used the higher of a dollar cap and a percent-based cap on growth over historic average expenditure. The percent-based cap uses the same 'sliding scale' that was used for expenditure on non-network assets in DPP2.

B18.4 **Step 4 – apply an aggregate cap:** As a final step, we have capped our aggregate capex forecasts for each distributor at 120% of its historical average expenditure. This is like DPP2 where we capped expenditure for network assets at 120% of historical average levels. This overall cap is intended to reflect the point at which we consider the cost impact on consumers justifies further scrutiny of expenditure.

B19 Our final decision does not include the forecast accuracy test that was proposed as part of our draft decision. We explain our decision to exclude that test in paragraphs B147 – B160.

B20 A key issue that we considered in forming our approach to forecasting capex was how to deal with instances where our analysis suggested distributors may be under-forecasting their capex requirements. We identified several instances of this, but recognised that:

B20.1 distributors do not have an incentive to under-forecast their expenditure; and

B20.2 providing distributors with a calculated amount based on cost drivers could result in us allowing them to recover revenue they may have no intention of spending.

B21 Therefore, our approach only focusses on distributors' incentive to over-forecast by scaling back expenditure that appears to be too high.

We have modified the approach put forward in our draft decision

We have maintained the significant features of the approach in our draft decision

B22 Our approach to capex forecasting is broadly consistent with the approach proposed in our draft decision and explained in the accompanying Reasons Paper. However, having considered submitter feedback, we have made some changes from the draft.

B23 Parties that submitted on the draft decision supported our approach at a conceptual level. Submitters particularly supported an approach that relied on the AMP forecasts. For example, Centralines stated:

> At a general level, Centralines is supportive of the Commission's approach, including its use of forward-looking Asset Management Plans.[310]

B24 Submitters generally accepted our approach of scrutinising AMP forecasts, though they considered our approach to scrutinising them needed refinement. For example, Unison stated:

> Unison supports the general approach, but recognises that the approach may require refinement over time as improved tests are developed to assess the reasonableness of expenditure projections.[311]

B25 Our approach to capex forecasting maintains the significant features from the draft decision. Specifically, we have disaggregated forecasts below the network and non-network level, applied scrutiny to the AMP forecasts, and capped the amount of uplift we'll allow relative to historic expenditure.

[310] Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 5-6; Also see: ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[311] Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17. Also see: ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18; PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Network Tasman "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 5.

We have adopted the proposal included in the Companion Paper to the Updated Models

B26 In our draft decision we proposed using a series of tests to scrutinise forecasts. We proposed a test for scrutinising system growth expenditure that utilised the supporting information in Schedule 12(b) of AMPs. That test sought to identify whether each distributor's forecast expenditure for zone substations for system growth implied cost increases for additional zone substation capacity of more than 20%.

B27 After considering feedback we received on that proposal, we subsequently proposed a different approach and sought feedback on that revised proposal in the Companion Paper to the Updated Models. Under the revised proposal, we would scrutinise system growth expenditure together with consumer connections expenditure.

B28 Most submitters on our Companion Paper to the Updated Models were broadly comfortable with us extending this test to system growth expenditure. For example, comments included:

> Overall we support the paper's adjusted approach to assessing system growth capex by treating system growth expenditure together with consumer connections expenditure. – Orion
>
> We support the proposed changes to the scrutiny test for system growth expenditure… There is a stronger relationship between system growth expenditure and population growth, coupled with historic ICP growth, when compared with the relationship to zone substation capacity, which makes the proposed test more suitable. - Aurora[312]

B29 However, submitters suggested some changes to the tests and/or that we should undertake qualitative scrutiny of AMPs where forecast expenditure exceeds the limits of the tests. For example, ENA stated:

> Therefore, we submit that a two-step gating test should be applied to system growth expenditure, as follows:
>
> Apply the system growth test against connections growth as proposed and accept the system growth forecasts for those EDBs which pass this test […]
>
> For those EDBs which fail the test, examine their AMPs, and assess whether the forecast system growth expenditure is adequately justified, based on the information presented in the AMP, and discussions with EDBs where necessary. - ENA[313]

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[312] Orion "Submission on EDB DPP3 Updated Draft Models Paper Sep19Final" (09 October 2019), p. 2; Aurora "2019 Aurora submission on Updated DPP3 draft - FINAL" (09 October 2019), p. 7.

[313] ENA "Submission on Updated draft DPP3 decision - 9 Oct final" (09 October 2019), p. 5.

B30 For our final decision, we have adopted the proposal that was put forward in the Companion Paper to the Updated Models with some changes. We discuss those changes in more detail and respond to comments in submissions later in this paper.

Key changes to the approach since the draft decision

B31 The key changes we have made from our draft decision are:

B31.1 We have removed the initial analysis scrutinising distributors' past accuracy in forecasting their expenditure.

B31.2 We have adopted the proposal made in the Companion Paper to the Updated Models to scrutinise system growth capex by bundling it in with consumer connection capex.

B31.3 We have made changes to the design of the analytical tools we have used in scrutinising forecasts, including:

B31.3.1 using household growth instead of population growth when scrutinising distributors' forecasts of new connections;

B31.3.2 including consistent thresholds of 120% above historic expenditure in all cases, except for consumer connection and system growth costs, which retains the threshold of 150% that was used in the draft decision;

B31.3.3 small technical changes that do not impact allowances.

B31.4 Where our scrutiny suggests a distributor's AMP forecast appears out of step with cost drivers, we have calculated an allowance based on those cost drivers, rather than relying purely on historic expenditure to determine an allowance.

B31.5 In addition to the percent-based caps that we applied to asset relocations and non-network expenditure, we have included a fixed dollar cap. This reflects that a per cent-based cap does not accommodate reasonable variations in expenditure where a distributor's historic expenditure under these categories has been low.

B32 We discuss submitters' comments on the specific aspects of our capex forecasting approach in the subsequent sections of this attachment.

The key design elements of our approach

B33 We have used distributor's 2019 AMPs as the starting point for our capex forecasts.

B34 Our draft decisions reasons paper stated our view that, given the relatively low-cost nature of the DPP regime and distributors' better knowledge of their own networks, their AMPs provide a better overall basis for capex forecasts than what we could derive ourselves. However, it also stated that allowing distributors to set their own capex forecasts creates a risk of inflated forecasts, investments that might not be delivered, and excessive prices for consumers.

B35 All submitters that commented on our draft approach to forecasting capex supported using distributor AMP forecasts. Submissions did not provide any information that would cause us to change our draft decision.

We have disaggregated forecasts into expenditure categories

B36 We can more accurately forecast capex and better scrutinise supplier AMPs by examining forecasts for disaggregated expenditure categories. Some categories of expenditure have relatively predictable drivers, and there are reliable external cross-checks available in some cases. However, disaggregating expenditure comes with more complex decisions around how to cap or limit expenditure in setting the capex forecasts.

B37 For our final decision, we have disaggregated forecasts into the following four categories;

B37.1 Growth – comprising consumer connection and system growth expenditure.

B37.2 Renewal and improvement – comprising asset replacement and renewal (ARR) and RS&E expenditure.

B37.3 Asset relocation expenditure.

B37.4 Non-network expenditure.

B38 This differs from our draft decision, in which we proposed disaggregating forecasts into the following expenditure categories:

B38.1 Consumer connection.

B38.2 System growth.

B38.3 ARR.

B38.4 RS&E.

B38.5 Other expenditure, comprising of asset relocations and non-network expenditure.

B39 For our draft decision, we sought to be selective in our level of disaggregation and focus our attention on the categories of capex (consumer connection, system growth and ARR), which have the most discernible cost drivers. Doing this limits the costs and risks involved with complex analysis. However, we also separated out RS&E because it is closely related to ARR in some instances—within the ID definitions, there is substantial scope for variation, and in many cases, expenditure may be undertaken for more than one purpose.

B40 Only two submitters commented on this aspect of our proposal, with both supporting the approach. Specifically, their comments were:

> WELL also supports the level of disaggregation applied. As outlined in the submission to the issues paper, WELL supports limiting disaggregation to the larger capital expenditure classes, (asset replacement, system growth and consumer connections) as this will help maintain a low cost approach. – Wellington Electricity[314]

> We do not oppose the proposed disaggregation of capital expenditure (capex) forecasts into five expenditure categories. We agree that this is an appropriate evolution of the light-handed scrutiny applied in DPP2. – Aurora Energy[315]

B41 However, we have changed the disaggregation given other changes to our approach to capex forecasting, as follows:

B41.1 We have adopted our proposal in the companion paper to the updated models to assess consumer connection and system growth expenditure together. This reflects that these categories are closely related and share an underlying cost driver. Therefore, we have bundled them together into a single category reflecting network growth.

B41.2 For consistency with that bundled approach, we have also bundled together ARR and RS&E expenditure into a single category reflecting network renewal and improvement.

B41.3 We have separated out asset relocations and non-network expenditure. Because asset relocations have been incorporated within a reopener provision (see attachment G), keeping the items separate gives a clearer delineation between what has and has not been captured within our capex allowances. Again, this is largely a technical change, and there is no effect on the quantum of our capex forecasts.

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[314] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

[315] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 8.

B42 There were no submitters that suggested we scrutinise forecasts beyond the category level using the detailed sub-category forecasts. We stated in the Reasons Paper supporting our draft decision that in scrutinising AMP forecasts, it may in some instances be appropriate to draw on ID information at that more detailed level. There is one instance where we did this for our final decision. In scrutinising consumer connection capex, we excluded capex associated with major consumers where we could identify them.

We have scrutinised the AMP forecasts and calculated default fall-back allowances

B43 Using supplier AMPs without challenge creates the risk of over-forecasting and/or under-delivering. Distributors have incentives to inflate forecasts, or to not apply rigorous practices when preparing their forecasts. We therefore must consider the risk that their forecasts may not be entirely reliable. Using a consistent approach from DPP to DPP increases this risk – as distributors could target their forecasts at the level of any uplift we allow, without going over.

B44 We therefore do not consider it appropriate to use distributor AMPs without some form of limit or scrutiny. Furthermore, the AMPs are important documents for our work, and for stakeholders. Scrutinising these documents signals to distributors the importance of developing AMPs of high quality.

B45 In the draft decision, we outlined the scrutiny framework we proposed to apply to scrutinise expenditure increases that distributors have forecast for key expenditure categories. Where a distributor's forecast did not come within the limits we applied, we proposed to base our forecast on their historical average expenditure, but noted the potential to alternatively derive an amount based on an external assessment of cost drivers (where available).

B46 The scrutiny we proposed was high-level, and we acknowledged that it was imperfect. We suggested this was appropriate to an extent, given the relatively low-cost nature of the DPP, though it also comes with a heightened risk of unintended consequences compared to a more in-depth approach.

B47 Our approach to scrutinising AMP forecasts was a key aspect of our proposal that attracted comments from submitters, and we have made changes to our approach having considered the issues that were raised.

B48 Several submitters suggested our approach may be too high-level. For example, comments included:

> We are concerned, however, that the blunt nature of proposed scrutiny will violate the purpose of DPP/CPP regulation by encouraging more distributors to apply for CPPs. - Aurora[316]
>
> The draft DPP3 decision rejects a large portion of that proposed expenditure by applying a range of somewhat arbitrary caps without further investigating whether that expenditure is prudent and efficient or otherwise satisfies the Section 52A purpose. That is a flawed approach as it does not consider whether consumers would benefit from it. - Vector[317]

B49 There were concerns that the outcome of our approach would have negative consequences for consumers. For example, comments included:

> When assessing forecast risk across the key elements making up the cost building blocks calculations, Centralines' assessment is that downside risk (potential for negative impact on returns) is much greater than upside risk. - Centralines[318]
>
> There is a concern that too much capex has been capped out for some EDBs, with detrimental long-term impacts on consumers. - ENA[319]
>
> If Network Tasman's current capex forecast is accurate (and we spend what we have forecast for DPP3) and the Commission retains its existing capex allowance for Network Tasman, Network Tasman would incur an average annual capex IRIS penalty of $3.2m in years 2-5 of DPP4. This is more than 10% of Network Tasman's revenue cap in period 5 of DPP3. – Network Tasman[320]
>
> We consider that any reduction in forecast capital expenditure would compromise the reliability improvements that we can achieve over the coming years, which would limit our ability to comply with the Commission's quality standards.- The Lines Company[321]
>
> If these tests are retained without the flexibility that we propose above, then there is a real risk that capex that is essential for our network is not funded by the regulatory regime – leading to difficult trade-offs being made that are unlikely to be in the long- term interests of our consumers. - Vector[322]

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[316] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 9.

[317] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 21.

[318] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3.

[319] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[320] Network Tasman "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

[321] The Lines Company "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3.

[322] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 29.

B50 Submitters also suggested the caps we applied on expenditure were arbitrary and unfair for small distributors. Comments included:

> We disagree with the proposal to limit each category's expenditure to the historical average when a distributor's AMP forecast is considered to fail scrutiny. While we agree some limitation should apply to failed scrutiny, we consider that capping the expenditure allowance at historical average:
>
> can lead to expenditure being capped well below levels that cost drivers would suggest is reasonable;
>
> can lead to a substantial reduction in the capex allowance for the category relative to forecast, even if the distributor only fails scrutiny by a small margin; and
> is a harsh penalty where scrutiny is imprecise in nature. - Aurora[323]
>
> The proposed cap on capex appears to be based on subjective judgement, rather than evidence and we consider it warrants further attention. - Entrust[324]
>
> The capital expenditure (capex) allowance for all EDBs, for instance, is capped at 120% of the historical average and further limited by various gates. Such tests may help reduce Commission effort in setting such allowances. However, given that their values are largely arbitrary they should not act as caps. - Vector[325]

B51 Submitters encouraged us to qualitatively analyse AMPs and other information that might validate the AMP forecasts. For example, comments included:

> Where the Commission has less than 100% confidence in an EDBs AMP forecasts the EDB be permitted to submit its capex forecasts to the Commission based on the principles in the customised price-quality path (CPP) IM. – Alpine[326]
>
> The ENA supports basing forecast allowances to some degree on AMP forecasts and providing the opportunity to EDBs to submit alternative methods and additional evidence to supplement the high-level scrutiny tests applied to capex. - ENA[327]
>
> If the current approach is retained, Network Tasman submits that the Commission should apply an overarching risk based assessment of its capex forecasts that includes an explicit assessment of not only the risk of distributor over-forecast error, but also of Commission over/under-forecast error. – Network Tasman[328]

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323 Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 9.

324 Entrust "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

325 Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

326 Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

327 ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18

328 Network Tasman "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 5.

Rather, if failed, they should trigger further investigation or at least allow an EDB to justify their expenditure as part of a second pass assessment. Otherwise the somewhat arbitrary gates and caps can lead to arbitrary allowances – which is not good regulatory practice and can undermine consumer interests. - Vector[329]

B52 Submitters also supported alternatives to capping forecasts at historic levels. Specifically:

If the proposed test is retained, then we consider that any distributor that fails the test should have expenditure capped at 125% of forecast depreciation. We note that the Commission suggests this alternative in its Reasons Paper. - Aurora[330]

Falling back to the historical average if a capex test is failed does not work for asset classes where work programmes are erratic or lumpy. The historic average is less likely to provide a sensible substitute for the AMP forecast. Alternatively, an EDB may have to invest in critically important asset replacements or respond to changes to meet quality standards, at a level of investment that is higher than the historic average. Reverting back to the historic average could result in necessary investments being foregone. As outlined in section 6.1, WELL recommends reverting back to the AMP until the capex tests are further refined. – Wellington Electricity[331]

WELL suggests that as the capex gates are refined and tested, a staged approach is taken to how they are applied:

Apply the first, overall forecasting accuracy test, as proposed. This will provide consumers with confidence that EDBs are delivering what they forecast.

Apply the proposed secondary gates and publish the results. However, don't revert to the historical average if an EDB fails.

A staged approach will allow the tests to be refined and for EDBs to adjust their internal process and forecast methods to the new gates. – Wellington Electricity[332]

B53 For our final decision, we have maintained an approach that relies on high-level analysis. However, we have made several changes to improve our approach, as summarised in paragraph B31 and explained in detail in the remainder of this attachment.

[329] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[330] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 12.

[331] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 16.

[332] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

B54 We acknowledge submitters' concern about paring back their expenditure forecasts based on high-level analysis, and their desire for us to qualitatively analyse AMPs or other material supporting forecasts. However as noted in Chapter 3, we consider that high-level scrutiny is appropriate for the DPP. The DPP is intended to be a relatively low-cost form of regulation that is designed to cater for a wide group of businesses using a generic approach. While there is potentially some scope within a DPP for tailoring where it can be done without significantly increasing cost, a DPP is not intended to deal with circumstances that require significant scrutiny of costs of a particular business.[333]

B55 We have analysed AMPs in developing our approach so that we understand what is driving outcomes and the results. Forecasts within AMPs should be internally consistent—ie, forecast expenditure increases should be explained by comparable forecast increases in cost drivers. Those documents are distributors' opportunity to explain and justify expenditure – not just to us, but to wider stakeholders. However, given variation in the quality and content of AMPs, it is not low-cost for us to undertake detailed scrutiny of the qualitative material in AMPs for the 15 distributors currently subject to a DPP.

B56 Further, we do not support providing distributors an opportunity to submit additional supporting information to justify their forecasts. This is the purpose of the AMPs. Furthermore, the issues paper signalled our intention to analyse the AMP forecasts for internal consistency. We would therefore anticipate that distributors will have prepared their 2019 AMPs with this in mind.

B57 Beyond testing AMPs for internal coherence, we have compared forecasts with independent drivers of investment. This provides greater assurance that the forecast expenditure is necessary.

B58 Given the difficulty in accounting for the variety in distributors' individual networks and circumstances through simple analysis, we have introduced a reopener that can cover three categories of capex—consumer connection, system growth and asset relocations. These categories can be particularly volatile and are often driven by consumer requirements. The reopener increases the flexibility available to distributors and reduces the potential for unintended consequences from our high-level approach.

[333] See the framework discussion under paragraphs 3.13 - 3.28.

B59 Submitters that responded to our Companion Paper to the Updated Models suggested that we should undertake detailed scrutiny of AMPs for distributors that do not come within the limits set by our high-level scrutiny approach.[334] We consider that the new reopener reduces the need for detailed scrutiny of AMPs and avoids us undertaking detailed scrutiny where it is not actually required or proportionate.

B60 Distributors also have the option of applying for a CPP if they consider it would better meet their particular circumstances than the DPP. A CPP can be tailored to meet the specific needs of distributor and their consumers, and also provides the flexibility to generally deal with uncertainties that distributors may encounter. For example, the standard CPP provisions provide for a 'contingent project' mechanism, which is intended to deal with projects with uncertain timing and cost.

B61 In this broader context, we consider our revised approach to scrutinising AMP forecasts is appropriate.

We have capped expenditure for asset relocations and non-network expenditure

B62 The minor categories of expenditure (asset relocations and non-network capex) do not have clear, quantitative drivers disclosed in AMPs, so scrutinising this expenditure would require qualitative assessment of the information in the body of the AMP. This would go beyond relatively low-cost scrutiny, and as these categories only compose 6% and 8% of capex respectively, it is not merited under our proportionate scrutiny approach.

B63 However, distributors could still inflate their forecasts of expenditure under these categories.

B64 In our Draft Decisions Paper we proposed to apply a linear ‘sliding scale’ cap for the more minor categories of capex, with a maximum cap of 200% where the expenditure is less than 5% of total capex, and a minimum of 120% where it is more than 25% of total capex.

B65 A ‘sliding scale’ cap has precedent in that it was used in DPP2 and is an approach that was supported by submitters.

[334] Orion “Submission on EDB DPP reset draft decisions paper” (17 July 2019), p. 2, ENA “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 5.

B66 Submitters were broadly supportive of the sliding scale cap for minor categories of expenditure. For example, comments included:

> We support the proposed approach of using a sliding scale cap of 120-200% for other categories of capex. We note that this approach is consistent with the approach taken in DPP2.- Aurora[335]

> WELL supports the Commission's approach to applying a sliding cap to the minor assets categories.- Wellington Electricity[336]

B67 However, submitters were also concerned that use of a percent cap limits reasonable variation in expenditure by distributors that have historically spent small amounts. For example, comments included:

> In Centralines' 2019 AMP we identify a required uplift in expenditure to build a new depot and administration building. These expenditures will push Centralines capital expenditure requirements above the 120% cap on total capex, and above the sliding scale cap on non-network capex expenditure. Centralines submits that the Commission needs to consider an alternative methodology that provides for smaller EDBs to reasonably undertake such activities without requirement to apply for a CPP. - Centralines[337]

> As noted in section 4.3 of our submission we are concerned regarding non-network capex where one off expenditure is incurred, such as a one in 50 year property rebuild required due to building code earthquake rating issues, where no material non-network expenditure has been incurred in the past. For non-network capital expenditure we recommend the approval of one off non-network capex without passing a gating test. A gating test simply cannot work effectively when past expenditure has been immaterial especially when a one off safety led investment in the region of 5% of RAB is encountered. Alternatively we recommend non-network expenditure is able to be treated as the basis of a reopener. - PowerNet[338]

B68 Vector also submitted that a cap on expenditure does not allow for consideration of the reasonableness of forecasts.[339] We refer to our discussion in the previous section in response to Vector's comment.

B69 We agree with submitters that a percent-based cap is unduly restrictive on distributors where their historic expenditure has been immaterial. Both asset relocations and non-network expenditure are categories where expenditure can be sporadic. We have therefore included a dollar cap for these categories of $1 million per year, as a secondary cap on expenditure. We would allow each distributor their AMP forecast amount for asset relocations and non-network expenditure up to the higher of $1 million or their sliding scale percent cap.

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[335] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

[336] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 16.

[337] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

[338] PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p.4.

[339] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 28.

B70 We acknowledge that this dollar cap is not a precise measure. We noted instances where forecasts for asset relocations and non-network expenditure categories appeared high relative to historic spending while being below the dollar cap. However, scrutiny of expenditure under these categories is not merited under our proportionate scrutiny approach.

B71 Given submitters' support for a sliding scale cap, we have retained the scale approach, even though a flat cap would be more straightforward and could be justified given the inclusion of a secondary dollar-based cap.

B72 Under our final decision, non-network expenditure is capped for two distributors, and asset relocations expenditure is capped for one distributor.

We have capped forecasts in aggregate at 120% of historical expenditure

B73 CPPs are the appropriate mechanism to address material business-specific step changes in investment and manage large price shocks for consumers.

B74 For our draft decision we proposed capping distributors' capex expenditure in aggregate at 120% of their historical expenditure levels to ensure large price shocks for consumers will only occur under the detailed scrutiny of the CPP process.

B75 The alternatives to applying a 120% cap to the aggregate forecast expenditure are to:

B75.1 not apply a final cap;

B75.2 apply a higher or lower cap than 120%; or

B75.3 apply a different form of cap.

B76 The scrutiny framework we discuss from paragraph B95 would have the effect of limiting expenditure increases where these do not appear consistent with supporting information. Therefore, we anticipate the potential for a distributor to have a forecast that appears relatively consistent with cost drivers based on high-level analysis, while still projecting a large increase in expenditure. Our scrutiny is necessarily high-level, and the tolerances we have applied in our analysis reflect the volatility of capex, variability in distributor circumstances, and forecasting challenges.

B77 We therefore consider it appropriate to include a final step in our approach that identifies any large steps-up in forecast expenditure that would result in price shocks for consumers that justify further scrutiny.

B78 We do not consider it appropriate to use the AMP forecasts without any overarching limit, as it may reduce the incentives to achieve efficiencies in capex. A distributor would be able earn an acceptable return without achieving efficiencies in the amount of capex incurred in providing electricity lines services.

B79 Furthermore, we consider a 120% cap applying across the five-year period has the advantage that it retains familiar aspects of the DPP2 approach, which submitters on the issues paper were broadly comfortable with.[340] This has been tried and tested and is straightforward to apply.

B80 Some submitters agreed with the approach of including an overarching limit. For example, Aurora stated:

> In principle, and assuming an absence of other information that the Commission might have to hand that it may rely on, we agree with the proposal to cap aggregate capex forecasts at 120% of historical expenditure. As a final scrutiny proxy, this remains consistent with the approach taken in DPP2. - Aurora[341]

B81 Others considered it arbitrarily limited expenditure. For example:

> Although less affected than other smaller EDBs we are cautious about the 120% cap on total capex and the sliding scale cap on more minor expenditure categories. There are some investments that are lumpy in profile and can create significant percentage movements. This is likely to disproportionately impact on smaller EDBs, but may also affect EDBs at Unison's scale. - Unison[342]

> WELL does not support the final adjustment of applying a 120% cap on the residual capex after all of the tests are applied. As outlined in WELL's submission to the Issues Paper, smoothing or limiting capital expenditure can produce sub-optimal investment decisions. Asset investment is timed with asset deterioration, customer connections with new developments and system growth with energy demand requirements. Limiting how much capital can be spent within a year or pricing period can result in assets being replaced too early or late, delays to new connections or the network not augmented to meet increasing capacity demands. – Wellington Electricity[343]

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[340] See For example: Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 11; ENA "DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)" (20 December 2018), p. 18; Orion "Submission on EDB DDP3 Reset " (20 December 2018), p. 8.

[341] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 8.

[342] Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 17.

[343] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 16.

> The Commission has capped any increase from past expenditure at 20%. That 'bright line' test is somewhat arbitrary – and it does not appear to be supported by any particular analysis of why it shouldn't be higher or lower than 20%. Moreover, it is hard to see how such a limit can possibly ensure consistency with the quality standard and / or deliver outcomes that consumers value because it was set without regard to those outcomes. - Vector[344]

B82 Further, as in the previous discussion, some submitters expressed that a percent-based cap unduly limits expenditure by small distributors because their expenditure is typically low. For example, comments included:

> For the small to medium EDBs projects like substation refurbishment, which is standard capex, could easily exceed the 120% cap if no similar sized projects were undertaken in the prior regulatory period. A cap of 120% could result in EDBs needing to apply to the Commission for a CPP for what is routine and expected expenditure… However, an increase in Capex of more than 120% is not necessarily indicative of a step change in Capex; rather it could simply be replacement of material assets on the network (e.g. sub-transmission assets) during the EDBs life cycle management. A CPP should be the exception and not the rule, particularly for foreseen asset replacement. - Alpine[345]

> Accordingly, when confronted with lumpy capital expenditure requirements which are invariant to EDB scale, small EDBs are disproportionately impacted and face the options of:
>
> Applying for a CPP; or
>
> Absorbing the excess in capex over the allowance; or
>
> Taking more risk by cutting back other areas of expenditure.
>
> Realistically, Centralines is not in a position to apply for a CPP (it does not have the resource capability to put together an application and Unison, Centralines Management Service provider, does not have the current capacity to provide this service), and very likely the costs of a CPP would exceed the reduced return under option 2. Option 3 would not be in the long-term interests of consumers, and is impractical, as Centralines could not temporarily lay-off workers while the one-off expenditures are being undertaken. - Centralines[346]

B83 We acknowledge submitters' concerns that a 120% cap cuts off expenditure they consider they may need.

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[344] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 22.

[345] Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[346] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

B84 A 20% increase above historic expenditure represents a significant uplift and should be sufficient for most businesses. Our approach does not prevent distributors from undertaking investment beyond 120% of historic expenditure. However, we do not consider it appropriate to approve full cost recovery for that kind of forecast expenditure uplift without more detailed scrutiny given the impact it could have on consumers. This may mean we seek greater assurances around the timing of an investment—particularly very large investment projects—or a distributor's ability to deliver it before we approve them charging consumers for it.

B85 As previously noted, there are other options available to distributors that consider their allowance is insufficient for them to fund necessary investment. This includes a reopener covering consumer connection, system growth and asset relocation capex, that we have introduced as part of this decision (see attachment G).

B86 We considered the potential to include a dollar-based cap on aggregate expenditure or take a different approach for small distributors. However, we consider that these concerns are significantly addressed by:

B86.1 incorporating dollar-based caps of $1 million per year on average for asset relocation and non-network expenditure; and

B86.2 a reopener for expenditure driven by customer demand.

B87 Further, consumers connected to a small distributor's network are in no better position to absorb large price increases than those connected to larger networks. We do not consider consumers should be presumed to absorb the consequences of distributors' decisions regarding the scale of their business.

B88 We therefore consider a percent cap remains appropriate.

We have used a historical reference period of 2013-19

B89 Our approach to setting capex forecasts requires an assessment of historical average expenditure.

B90 We have used the average of the years 2013 to 2019 as the historical reference period against which we have scrutinised and capped forecasts.

B91 Capex can be volatile in any given year (especially for smaller suppliers). This would preference using as long a historical reference period as possible.

B92 ID data at the expenditure category level is available from 2010. However, we decided to only use data from 2013 after considering submissions on our November issues paper. Those submissions suggested that data from before 2013 may not be comparable with forecasts in the 2019 AMP since it was prepared prior to the introduction of the current ID rules. We agreed with that concern.

B93 Aurora supported using a shorter historic reference period, stating:

> The use of an historic reference period is premised on the proposition that the most informative guide to future capex requirements is past capex requirements. However, the approach does not adequately capture cyclical changes in capital investment requirements. Specifically, in Aurora's case the use of a seven-year reference period significantly understates Aurora's future capex requirements. This is because of Aurora's low level of historic investment, which has resulted in deterioration of network assets that now requires remediation - Aurora[347]

B94 We do not agree with Aurora's statement. Aurora's current circumstances lead it to preference a shorter reference period. Aurora's circumstances are unlike other distributors, and we understand that it intends to apply for a CPP. More generally, the volatility of capex means that recent expenditure is not necessarily more representative of future expenditure. We consider that using the period from 2013 to 2019 for the final decision appropriately balances the priority of using consistent data, but as long a time series as possible to account for that volatility.

We have used three tests to scrutinise capex forecasts

Scrutinising distributors' forecasts of new consumer connections

B95 Distributors' capex requirements are affected by population and economic growth that causes new consumers to seek connection to, and use of a distributor's network.

B96 Distributors disclose forecasts of new connections in Schedule 12C of the EDB ID requirements.

B97 Our draft decision included a gating test in the EDB DPP3 reset that would check that forecast expenditure associated with consumer connections is not based on an assumed number of new connections that is greater than both a distributor's historical average connection growth and StatsNZ population growth statistics. In our Companion Paper to the Updated Models we proposed using this test to scrutinise both consumer connections and system growth.

B98 Having considered the feedback we received from submitters on both papers, we have applied this test for scrutinising system growth and consumer connection expenditure. However, we have made the following three amendments to the design of this test for the final decision:

B98.1 We have used Stats NZ projections of household growth instead of population growth. This change is discussed in detail in attachment A.

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[347] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

B98.2 We have allowed a 20% buffer on historic connections to account for reasonable variability in how a distributor might forecast connections and the expenditure driven by those connections.

B98.3 Where a distributor's forecast connections are higher than these comparative metrics, we have calculated an allowance commensurate with the higher of household growth or 120% of their historic connection growth.

B99 Submitters were broadly comfortable with this test as outlined in our draft decision. For example, comments included:

> We support the proposed scrutiny of consumer connection capex forecasts. When forecasts of population growth and historical ICP growth are combined with the per-connection expenditure test, a reasonably balanced view of the adequacy of the consumer connection capex forecast is obtained. - Aurora[348]

> WELL supports the Commission's approach of assessing per-connection expenditure. The 150% cap takes into account cost differences between different connection types. - WELL

B100 However, Unison suggested we should treat consumer connections as a pass-through cost. It stated:

> In Unison's view the balance of benefits and costs would suggest that customer capex should be treated more like a pass-through cost. There is strong public interest in EDBs connecting customers, so there should be no incentive for EDBs not to do so. Although we assume that the Commission would be concerned about the efficiency of customer capex expenditure under a pass-through or ex post washup scenario, the much greater interest is that consumers are connected without undue barriers. The current proposal leaves a gap. Unison submits that the Commission needs to give further consideration to mechanisms that compensate EDBs for the full costs of their customer connection capex (including mechanisms to recover un-spent allowances if customer demand does not materialise).[349]

B101 We acknowledge Unison's point. However, we consider that consumer connection expenditure should not be treated as a pass-through because:

B101.1 distributors do have some influence around consumer connection expenditure, and so it would be inappropriate to treat it as a full pass-through; and

[348] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10.

[349] Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18.

B101.2 distributors have flexibility in how they categorise expenditure—particularly noting the blurred line between consumer connection and system growth expenditure. Treating consumer connection expenditure as a pass-through cost could hence affect the incentives around how EDBs categorise expenditure.

B102 We also refer to Attachment G where we discuss the reopener provision that we included in our draft decision.

B103 PowerNet submitted that we should consider the unique circumstances that mean OtagoNet should not be subject to this test. It said:

> OtagoNet is also in a situation where it is competing with Aurora Energy in the Frankton (Queenstown) and Wanaka areas. Running a gate test for connection expenditure using past connection growth and forecast population growth cannot be applied to OtagoNet as OtagoNet chooses to compete with Aurora Energy for new connections.[350]

B104 As discussed in Attachment A, we have considered areas that are served by more than one distributor when determining household growth numbers. We also consider the reopener mechanism may suit OtagoNet's circumstances, given the number of connections it expects, and the potential need for a new GXP.[351]

B105 We suggested in draft decision that we were considering using Stats NZ projections of household growth rather than population growth. Wellington Electricity supported use of household growth:

> Population growth does not appear to be correlated with consumer connection growth and therefore would not be useful as an external driver. Local Government building consent applications or other indicators of new developments might be useful.[352]

B106 Vector also supported use of household growth, and suggested we assess all three metrics given neither metric is perfect. It stated:

> The Commission has understandably raised the concern that the household data available does not align exactly with EDB network areas – and so there is a risk that this reduces the accuracy of any household projections. This is a little short-sighted for two key reasons:
>
> The mismatch between the household data and EDB network areas is small in most cases – in our case, the two can be aligned almost entirely, with the only exception being about 6,000 households in the Papakura ward – and so any inaccuracy that results is likely to be small; and

[350] PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

[351] OtagoNet "Asset Management Plan Update 2019 – 2029" (March 2019).

[352] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

> Population growth itself is an imperfect predictor of connection growth – although the Commission has acknowledged this, it implicitly decides without robust analysis that that risk is palatable while the risk of a slight mismatch in EDB boundaries is not – which does not appear well-reasoned. - Vector[353]

B107 These submissions were echoed in those received in response to our revised proposal for scrutinising system growth, put forward in the companion paper to the update models.

B108 As discussed in Attachment A, we agree that household growth is a closer proxy to connection growth than population growth as it accounts for changes in occupancy rates. We have therefore replaced population growth statistics with household growth statistics in our final decision, based on Stats NZ's midpoint projection.[354] We have not included it as a third metric as Vector suggested, given its lower correlation with connection growth, and because it would not change the results of the test.

B109 For our final decision, this test:

B109.1 takes the total end-of-year connections in 2012, and cumulatively adds new connections in each year until 2024 to derive an approximate series of total connections (noting this ignores disconnections); and

B109.2 compares the compound annual growth rate that distributors have forecast in Schedule 12C(i) for the period 2020-2024,[355] with the compound annual growth rate:

B109.2.1 over the historical reference period of 2013-2019; and

B109.2.2 of households over the same future period, based on Stats NZ projections.

B109.3 Accepts any forecast new connection growth that is not greater than both household growth or 120% what has been observed historically.

B110 The results of this analysis are shown in Figure B2. It shows that seven distributors are forecasting growth above both metrics.

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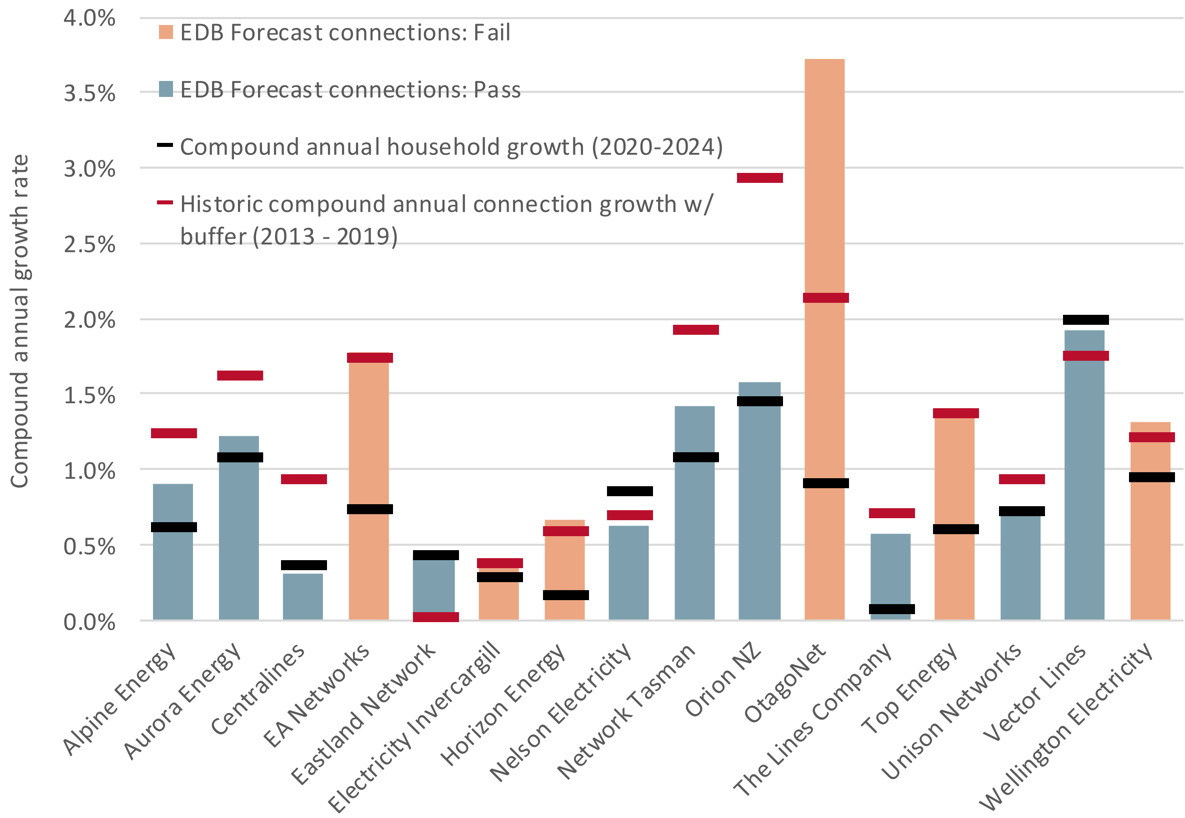
[353] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 25-56

[354] Vector also noted in its submission that Stats NZ projections are given as a range. We do not consider there is any rationale for using something other than a midpoint estimate.

[355] We note that we have used the period forecast 2020-2024 because EDBs only forecast this information out five years, so we are unable to assess the DPP3 period itself. As this test is a check of the quality of the forecast itself, rather than the expenditure per se, we consider this reasonable.

Figure B2 Forecast residential connections versus forecast population and historical connection growth



B111 In our draft decision, we proposed to scale back the consumer connection expenditure of any distributors with forecast new connections that did not meet our scrutiny, and that were forecasting higher consumer connection expenditure relative to recent history. We proposed we would scale them back to an amount equivalent to their historic average expenditure. However, our Reasons Paper supporting our draft decision suggested we may alternatively derive an amount commensurate with forecast population growth.

B112 For our final decision we have scaled back the consumer connection and system growth capex of all distributors whose forecast connections are greater than the comparative metrics to an amount that is the multiple of:

B112.1 the higher of household growth and 120% of their historic average new connections; and

B112.2 per-connection costs, as implied by their forecasts of expenditure on new connections subject to the scrutiny discussed in paragraphs B114 - B129.

B113 In our draft decision, we did not scale back the expenditure of distributors that were forecasting decreases in consumer connection expenditure, even where our scrutiny found it to be higher than suggested by our comparative metrics. However, we consider it would be inconsistent to provide some distributors with an allowance that we have assessed to be out of step with cost drivers, just because it is lower than what has historically been experienced. Therefore, for our final decision, we have scaled back the expenditure of all distributors whose forecasts are inconsistent with our comparative metrics.

Scrutinising distributors' forecast per-connection expenditure

B114 Each new consumer creates connection costs. Some of these are realised immediately from physically connecting them to the network. Some will be realised over time as the incremental effect of the associated demand requires increases in the network's capacity at various levels. Forecast expenditure should therefore reflect both the number of new connections and the incremental cost of those connections.

B115 Our draft decision included a test to assess each distributor's per-connection forecast expenditure for consumer connections against their historical average per-connection expenditure. The test assessed the implied price-aspect of the price-times-quantity equation that makes up consumer connection expenditure. The Companion Paper to the Updated Models also included a proposal to extend this test to system growth expenditure, which we have adopted following consultation.

B116 Submitters were broadly comfortable with using this proposed test for consumer connection expenditure. For example, comments included

> We note that the proposed 150% threshold (150% of historic per-connection expenditure (in real terms)) appears somewhat arbitrary; however, we agree that a wide tolerance is needed to account for variation in per-connection costs across different connection types. - Aurora[356]

> WELL supports the Commission's approach of assessing per-connection expenditure. The 150% cap takes into account cost differences between different connection types. – Wellington Electricity[357]

B117 Submitters that responded to the Companion Paper to the Updated Models had some concerns about this method of scrutinising system growth expenditure without further qualitative assessment.

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[356] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10.

[357] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 14.

B118 For example, ENA stated:

> We consider that the alternative proposal, to scrutinise both forecast customer connection and system growth expenditure against connection growth is a useful approach for an initial gating test. However, we do not think it is reasonable to rely solely on this test, because of the lumpiness of system growth expenditure. This would not be expected to line up with connections growth in the short to medium term.[358]

B119 Network Tasman considered that a 150% increase above historic expenditure would not allow reasonable increases in system growth expenditure. It stated:

> The Commission's test universally accepts any reduction in system growth expenditure – irrespective of the magnitude. For example, having recently completed an efficient major network investment programme it is reasonable for this distributor's system growth expenditure to fall by 2,000%. However, the test does not accept that a distributor heading into a comparable major capex programme could experience an increase in system growth expenditure of a similar magnitude.[359]

B120 We acknowledge the test is imperfect and may favour distributors that have recently been through a period of growth. However, the test is not intended to suggest expenditure beyond 150% of what has been spent historically is inefficient or should not proceed. Rather, it is intended to identify distributors that may be planning a large capex programme or project, and ensure that those investments receive a proportionate level of scrutiny.

B121 In its submission on our Companion Paper to the updated models, Network Tasman referred to Transpower's average capex spend during 2006-07 to 2011-12 as an example of a large investment programme that represented more than 150% growth compared to historic expenditure.[360] However, that investment programme received significantly more scrutiny than it would have under a DPP.

B122 A CPP is one option for scrutinising step changes in expenditure. However, we have also introduced a reopener as another option that may be available to distributors seeking approval to recover the costs of significant investments. This is discussed further in Attachment G.

B123 In isolation, we agree our high-level scrutiny could have unintended consequences for consumers on networks like Network Tasman that are experiencing growth. However, in combination with the other changes we have made as part of this decision, we consider any such unintended consequences are mitigated.

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[358] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4-5.

[359] Network Tasman "DPP3 updated draft paper submission" (09 October 2019), p. 1.

[360] Network Tasman "DPP3 updated draft paper submission" (09 October 2019), p. 3.

B124 Given this, we consider it appropriate to adopt the proposal put forward in the Companion Paper to the Updated Models of using this test of per-connection costs to scrutinise system growth and consumer connection expenditure together.

B125 For our final decision, this test compares the average per-connection expenditure (i.e. total consumer connection and system growth expenditure divided by the number of connections) that each distributor has incurred historically, with the implied per-connection expenditure that is forecast for the period 2020-2024.[361] We retain a threshold for the expenditure we would allow of 150% of historic expenditure in real terms.

B126 We also exclude from the analysis any connection costs associated with major consumers where these affected whether a distributor exceeded the 120% threshold, and we could readily identify them.[362] We note that only excluding them where the limit is exceeded means that some distributors that have had major new connections in the past are more likely to come under the threshold than they might be if we were to exclude them routinely. However, it is not possible to consistently identify these connections from the data in ID, so it is not possible to exclude it routinely without introducing inequity into the results.

B127 We have made one technical change to the test since the draft decision. This is to leave capital contributions in the expenditure data series. This reduces double-counting of costs when excluding major connections, given major connections are likely to contribute significant capital contributions. It also avoids any influence that different capital contributions policies, and any changes to those policies over time, may have on the analysis.

B128 Figure B3 shows the results of the analysis. It shows that Centralines' and Network Tasman's forecasts exceed the tolerances included in this test of per-connection costs.

B129 For the draft decision, we scaled distributors back to their historic expenditure if their forecasts exceeded the limits of our test and they were forecasting an increase in consumer connection expenditure relative to their historic average. For the final decision, we have altered the fall-back allowance we provide.

[361] We note that we have used the period 2020-2024 because EDBs only forecast this information out five years, so we are unable to assess the DPP3 period itself. As this test is a check of the quality of the forecast itself, rather than the expenditure per se, we consider this reasonable.

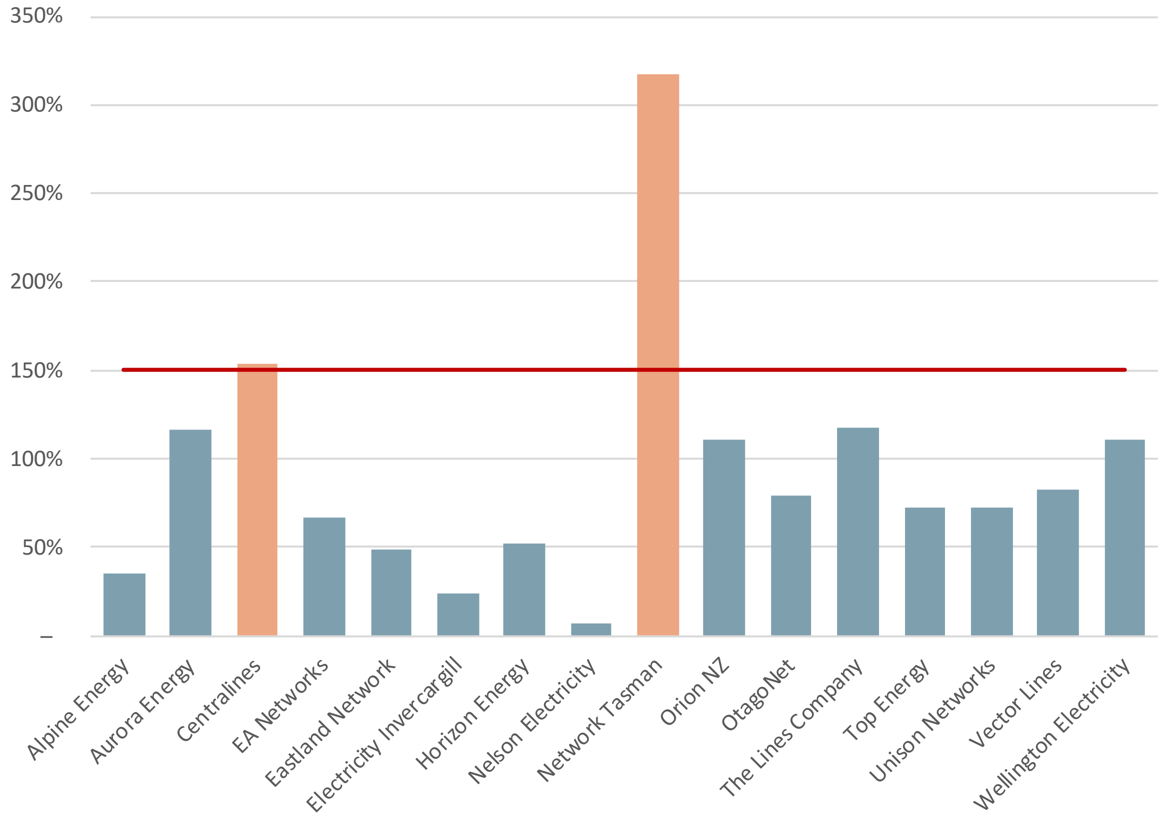
[362] This was only the case for The Lines Company.

B130 The revised fall-back allowance scales back the expenditure of all distributors whose forecasts exceed the limits of the test by:

B130.1 the proportion of forecast new connections determined reasonable under the number of new connections test, discussed previously in paragraphs B97 - B112; and

B130.2 150% of their historic per-connection expenditure.

Figure B3 Per-connection expenditure – forecast versus historic



Reasonableness of combined results of consumer connection tests

B131 The distributors whose consumer connection expenditure is impacted by these two tests applied to consumer connection and system growth expenditure in combination are:

B131.1 Centralines (97% of consumer connection and system growth forecast);

B131.2 EA Networks (98% of consumer connection and system growth forecast);

B131.3 Electricity Invercargill (98% of consumer connection and system growth forecast);

B131.4 Horizon Energy (90% of consumer connection and system growth forecast);

B131.5 Network Tasman (47% of consumer connection and system growth forecast);

B131.6 OtagoNet (56% of consumer connection and system growth forecast);

B131.7 Top Energy (98% of consumer connection and system growth forecast); and

B131.8 Wellington Electricity (92% of consumer connection and system growth forecast).

B132 For Centralines, EA Networks, Electricity Invercargill, Horizon Energy, Top Energy and Wellington Electricity, the impact is moderate and/or consumer connections is a small component of total expenditure, and we consider the acceptance rate of their forecasts—both for consumer connections and in total—is reasonable.

B133 The impact for both Network Tasman and OtagoNet is more significant. Both are forecasting signficant increases in expenditure for network growth. We consider the scale of those increases justifies greater scrutiny than what is appropriate under a DPP.

Scrutinising distributors' forecast ARR and depreciation

B134 ARR is the largest capex category, and so we want to be sure that the expenditure in this area is reasonable.

B135 In our draft decision we proposed conducting a test to check that forecast ARR expenditure is not substantially greater than the rate of depreciation of existing assets. Where that was the case, we suggested it may indicate catch-up investment more appropriate to a CPP. That test was based on a view that, over the long-term, ARR expenditure should be broadly proportional to depreciation, with new investment roughly matching the rate of degradation and retirement of existing assets.

B136 The extent to which distributors are investing to maintain the quality of their assets has been a focus for the Commission in recent times, particularly following the issues that have arisen with Aurora Energy.[363] One of the metrics we have been tracking to gauge whether investment appears sufficient is the ratio of ARR to depreciation, and we drew on this same analysis to set this test.

B137 In the Reasons Paper supporting our draft decision we acknowledged that there are significant limits to the assumption that ARR and depreciation should approximately correspond with one another. This is because of the cyclic nature of replacement and renewal, long-life of the assets, and 'snapshot' nature of the AMP forecasts.

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[363] WSP "Aurora Energy, Independent Review of Electricity Networks – Final report" (November 2018).

B138 Asset replacement and renewal expenditure is driven by asset condition (disclosed in Schedule 12a of ID) and, specifically, the forecasts of assets requiring replacement within the next five years. In the Reasons Paper we stated that we would ideally compare forecast ARR expenditure against that data. However, the data is detailed and challenging to work with, and does not readily translate into a metric that we can scrutinise. We were therefore unable to devise a simple test that would reasonably assess the legitimacy of the forecast expenditure. However, we asked for stakeholder views as to how this could best be done.

B139 Few submitters commented on this test. Submitters were likely unexercised about the imperfections of the test given most distributors passed it. Wellington Electricity stated:

> WELL supports using a capital expenditure/depreciation ratio with a 125% cap, to scrutinise asset replacement and renewal and reliability, safety and environment investment. The 125% cap applied to the capital expenditure/depreciation ratio provides enough flexibility to capture differences between an asset's economic book life and its actual useful life, as assessed by EDBs' asset health indices.[364]

B140 Orion disagreed with our suggestion that the draft results of the test may imply under-investment by distributors. Specifically, it noted different approaches to categorising expenditure, and that the depreciation figures include non-network assets when assessing the reasonableness of investment in existing network assets only.[365] We acknowledge Orion's points, and note that this largely reinforces that the test is likely to be conservative.

B141 Aurora—the only distributor whose forecast expenditure exceeds the limits under this test— stated:[366]

> …we support the Commission's comments on the weakness of this test… We suggest that a qualitative assessment of asset condition could be undertaken, as a second gating test, to assess any distributors who failed the initial test comparing ARR expenditure against forecast depreciation.

B142 For our final decision, we have maintained this test largely as it was proposed in the draft. As discussed in paragraphs B45 – B61, we do not consider that detailed scrutiny of a distributors specific circumstances can be undertaken within the relatively low-cost constraints of the DPP. We note Aurora's circumstances lend themselves to a higher level of scrutiny than is appropriate under a DPP.

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[364] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 16.

[365] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 6.

[366] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 12.

B143 For our final decision, this test of expenditure on renewals:

B143.1 Is applied to a bundled category of ARR and RS&E**.** Investments in ARR can often also support RS&E purposes. Therefore, RS&E and ARR expenditure can be interchangeable to an extent, and different distributors have different practices around how they allocate expenditure within these categories. We therefore summed forecast ARR and RS&E, and divided this by forecast depreciation.[367]

B143.2 Includes a 120% tolerance. We would not expect distributors to maintain a ratio of 100%. For example, networks that have recently invested a lot in new assets will have high depreciation and potentially lower future investment requirements. Similarly, networks with lots of assets beyond their accounting lives may have very low depreciation. In such situations, the ARR can reasonably be somewhat lower or higher than depreciation, and looking at this as a ratio can give the misleading impression that a new network is under-investing, while an old one is over-investing. To avoid capturing these situations within our test, our test only identifies distributors with forecasts where ARR and RS&E that is more than 120% of depreciation. We reduced this from 125% in our draft decision for greater consistency with the other limits we've applied. This change has no effect on our final capex forecasts, as Aurora is affected by the 120% aggregate cap regardless.

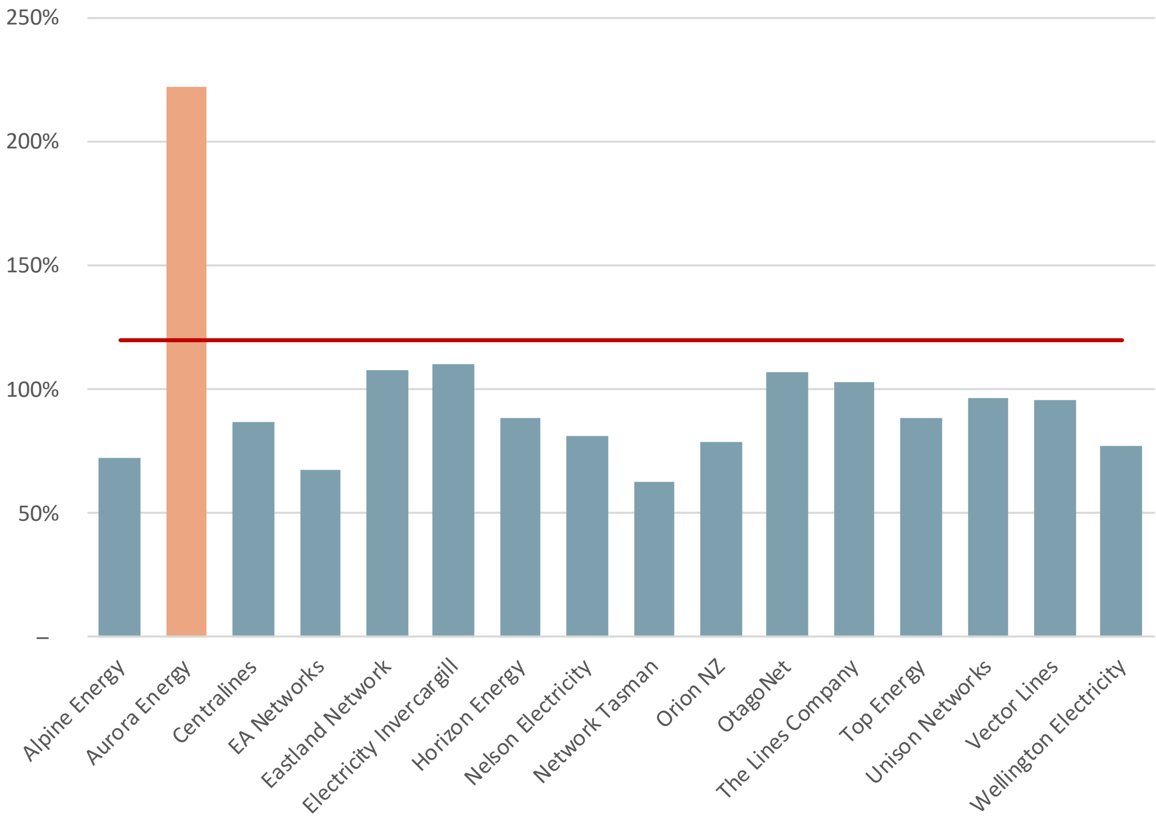
B144 We have made a minor technical change to the calculations for this test. As with the test of per-connection costs, we have kept capital contributions in the expenditure data series, as we do not consider the source of funding is relevant to the issue of whether the expenditure is proportionate.

B145 The results of this test are shown in Figure B4.

B146 For our draft decision we proposed scaling back the expenditure of distributors whose forecast expenditure exceeded the limits of this test to match their historic average expenditure. For our final decision, we have instead capped the combined ARR and RS&E at 120% of forecast depreciation—the maximum expenditure we would have allowed.

[367] Distributors do not forecast their own depreciation. Rather, we used the DPP3 financial model to prepare forecast depreciation figures for this test. This was done by replacing the 'value of commissioned assets' figures for the years 2021–2025 with the corresponding EDB 2018 capex forecasts.

Figure B4 ARR and RS&E relative to depreciation



Scrutinising distributors' past forecast performance

B147 Distributors' AMP forecasts provide a good starting point for our capex forecasts because distributors have access to the best information on their networks and circumstances. However, our November 2018 issues paper noted persistent over-forecasting of capital expenditure by regulated and exempt distributors collectively.[368] At an individual level, over-forecasting may result in those distributors earning excessive profits.

B148 In our draft decision, we proposed using a test that identifies whether the distributor has a track record of forecasting their total capex expenditure, on average, within 125% of actual in real terms.

B149 If we are to use AMP forecasts for our capex forecasts, we should be doing so on the basis that they are a reasonable reflection of likely expenditure.

B150 In the Reasons Paper supporting our draft decision we explained why we considered our proposed test appropriate, despite a similar assessment of forecasting accuracy being ultimately dismissed for DPP2.

[368] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Issues Paper" (15 November 2018), paras B22-23.

B151 We stated our view that we have a sufficiently long and robust sample size from which to assess the performance of distributors' forecasts. The specific analysis we proposed for this test used data from the 2014 to 2019 AMPs. All these AMPs were prepared under the IM requirements. We proposed excluding the 2013 forecast on the basis that it was the first year, and distributors would likely have been establishing their forecasting processes at that time.

B152 We also considered that distributors could have reasonably expected that their forecasts would be used for this purpose, as we had made it clear during the DPP2 reset that we would carefully look at performance against AMPs when setting future DPP prices. We referred to our DPP2 decision paper, which stated:

> Despite some concerns outlined by submissions we are still of the view that evaluating asset management plans against out-turn expenditure could serve a useful purpose in assessing distributor performance.
>
> Although in theory it could lead to some distortion of pure cost minimisation objectives, this has to be considered against the benefits from improving forecasting accuracy across non-exempt distributors. Our draft decision also permitted a relatively high difference between the forecast and out-turn expenditure before applying the lower capital expenditure cap.[369]

B153 Consistent with that comment, our proposed test allowed some tolerance in terms of the level of accuracy required—assessing if forecasts were within 125% of actual expenditure on average over time.

B154 Some submitters were comfortable with our proposed test. For example, comments included:

> "We support the proposal to test distributors' forecast accuracy within a broad boundary. We consider that if a distributor fails this test, some multiple of historical average expenditure should be used as a fall-back for all expenditure categories where the distributor is forecasting a relative increase in expenditure. We believe this approach provides a reasonable gateway test that incentivises improvement in forecast accuracy." - Aurora[370]
>
> WELL also understands the Commission wanting to scrutinise the capital expenditure forecast and supports the general approach of first applying a test of overall forecast accuracy, before cost driver based tests are applied to the major capex categories. – Wellington Electricity[371]

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[369] Commerce Commission, "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 - Low cost forecasting approaches", (28 November 2014), para 4.39.

[370] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10.

[371] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

B155 Each of the distributors that were impacted by the test submitted that they should not be captured by it. For example, their comments included:

> The key reason for the variance in prior period forecasts is the transmission asset purchase. We relied on Transpower information when preparing our AMPs prior to 2015, when we acquired the asset. It was only once we had acquired the assets and completed our own evaluation of them that we were able to prepare more realistic forecasts. Our actual capex is more closely aligned to these later forecasts. - Eastland[372]

> Network Tasman submits that the Commission should remove the costs of constructing the GXP from its assessment of Network Tasman's forecasting performance… Network Tasman's deferral of the GXPs construction has been the economically efficient thing to do. – Network Tasman[373]

> Including 2019 actual capital expenditure (as is intended in the final decision) results in TLC passing the Gate 1 test, and as a result, no scaling should be applied to TLC's capital expenditure… Following the implementation of the governance and management changes in 2017-18, we have been steadily improving the delivery of our works programme.– The Lines Company[374]

B156 Some submitters further suggested the test would result in perverse outcomes. They stated:

> The lower actual capex than the capex that Transpower had planned for the assets is a significant efficiency benefit which is in the long-term interests of consumers. As the decision stands, Eastland Network is penalised for deferring this expenditure. This is inconsistent with the regulatory purpose. - Eastland[375]

> Those members with higher historical forecast variance are classified as poor forecasters and their capex is adjusted down as a result rather than undergo scrutiny. Those members with lower forecasting variance are scrutinised at the capex category level. - ENA[376]

> The Commission's DPP3 capex allowance represents a 43% reduction from what Network Tasman spent in DPP2… Network Tasman would be relatively comfortable if this reduction was in response to an objective assessment of Network Tasman's capex needs... It is not. Rather, the driver of this change is the Commission's assessment of Network Tasman's ability to accurately forecast its capex spending. – Network Tasman[377]

> In the event Network Tasman, or any other distributor failing the Commission's capex forecast test, now produces more accurate capex forecasts, the Commission's approach to capex forecasting would still scale back that forecast, based on historical forecasting performance. – Network Tasman[378]

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[372] Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[373] Network Tasman "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[374] The Lines Company "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3 and 8.

[375] Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[376] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18.

[377] Network Tasman "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3.

[378] Network Tasman "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

B157 Our expectation remains that distributors' capex forecasts should be accurate to within 125% over time. Performance beyond this level likely indicates that a distributor takes few, if any, risks on the forecasting 'unders' compared to the 'overs', with those risks instead falling on consumers.

B158 We agree with Network Tasman that deferring investments can be efficient and in the long-term benefit of consumers. However, we note that deferring assets is one way distributors can game forecasts. Further, we question whether deferring forecast expenditure that was based on prudent peak demand forecasts (as Network Tasman suggests it does) can practically be considered efficient deferral for these purposes, since, by definition, there is a low probability it will be required when forecast.

B159 Despite this, we have decided *not* to include the forecasting accuracy test when setting capex allowances for DPP3. Our reasons for this are as follows:

B159.1 We acknowledge that large one-off investments can overwhelm forecasting performance, as well as Eastland's point that it relied on information from Transpower when forecasting expenditure for the asset it purchased. Were we to keep the test, we consider it would be appropriate to exclude transmission asset purchases from the data. However, untangling these purchases from past forecasts would have been difficult.

B159.2 We consider that our other tests, in combination with a cap on aggregate expenditure, adequately limits expenditure.

B159.3 The consequences of exceeding our forecast accuracy limits were significant—particularly for Network Tasman because it was forecasting a change in expenditure focus (i.e. decreases in expenditure under some categories that were accepted and increases that were not). Further, we are no longer falling back on historic expenditure under our other tests.

B159.4 The test did not account for improved forecasting over time, and Figure B4 in the Reasons Paper supporting our draft decision showed Network Tasman's forecasting accuracy has improved (though still tends to be high).

B159.5 We determined that including all years of the 2014 AMP forecasts in the test would be inappropriate, as DPP2 was set based on those forecasts and distributors may have reasonably revised their expenditure plans in line with their DPP2 allowance. Excluding this AMP would have seen all distributors come within the 125% limit if the test was otherwise unchanged.

B160 For these reasons, we no longer intend to include this analysis as a test within our approach to setting capex forecasts. However, we still consider there is value in providing transparency around forecasting performance, and we intend to monitor distributors' forecast performance over time.

We have retained the DPP2 approach for several implementation issues

Using CGPI to escalate costs into the future

B161 Our assessment of AMP forecasts and any caps are applied on a constant-price basis. However, the DPP itself requires forecasts set on a nominal basis. As such, we need to determine a cost escalator to derive them.

B162 For DPP2 we used the all-industries CGPI forecasts from NZIER. The issues paper discussed how differences in the cost of distributors' inputs contributed $31 million of the $119 million difference between our DPP2 forecasts and distributors' actual expenditure to 2018.[379] However, despite this, we consider a nation-wide all-industries CGPI forecast from an independent source (e.g. NZIER) is the preferred option for converting the constant-price capex forecast series to a nominal series.

B163 The alternative options we considered in the issues paper were:

B163.1 using an all-industries CGPI forecasts from another provider;

B163.2 using an industry- or region-specific index (for example, EGWW);

B163.3 using the CPI;

B163.4 using distributors' own implied inflation from their AMPs.

B164 Few submitters commented on this issue. Wellington Electricity supported our approach stating:

> WELL supports the Commission's proposed approach of using all-industries CGPI to forecast capital expenditure cost inflation. Consistent with our view of which operating cost inflators to use, all industry forecasts are less volatile than the industry or regional specific forecasts. – Wellington Electricity[380]

B165 Conversely, Centralines stated:

[379] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Issues Paper" (15 November 2018), pp. 73-75.

[380] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p 17.

> Centralines does not consider that this is likely to be a credible pattern of CGPI movements because around 50% of capital works are comprised of labour costs… Centralines submits that the Commission should seek updated forecasts for the Final Decision and make a specific request of NZIER to consider the factors impacting on the labour market confronting EDBs.[381]

B166 For our final decision we have retained the use of NZIER's CGPI forecasts for inflating capex allowances. We refer to our detailed consideration of this issue discussed in Attachment A under 'input price inflators'.

Excluding capital contributions from capex forecasts

B167 Capital contributions are a substantial part of many distributors' expenditure on assets. In previous DPPs, we have set capex forecasts as forecast expenditure on assets net of capital contributions, and not applied any scrutiny to the level of contributions suppliers are forecasting. However, changes in the forecast level of contributions can have a material effect on forecast capex.

B168 In our draft decision, we proposed to explicitly consider capital contributions when assessing the capex forecasts, as we had done in DPP2.

B169 The issues paper considered two broad options for DPP3: continuing to assess all capex net of distributors' forecasts of capital contributions, and including capital contributions within the scope of our analysis.

B170 This issue attracted little comment from submitters. Aurora Energy stated:

> We support the proposal to not independently scrutinise capital contribution forecasts. Separate scrutiny would, in our view, increase the likelihood of forecast error. In addition, our experience is that capital contributions are difficult to forecast with precision and are impacted by external factors over which distributors have limited control. – Aurora[382]

B171 While total contributions vary widely year-on-year, for each distributor and within in each expenditure category, the portion of expenditure covered by contributions is relatively consistent over time. As such, we would only have concerns where a distributor is forecasting a much lower portion of forecast expenditure to be covered by contributions, relative to historical levels.

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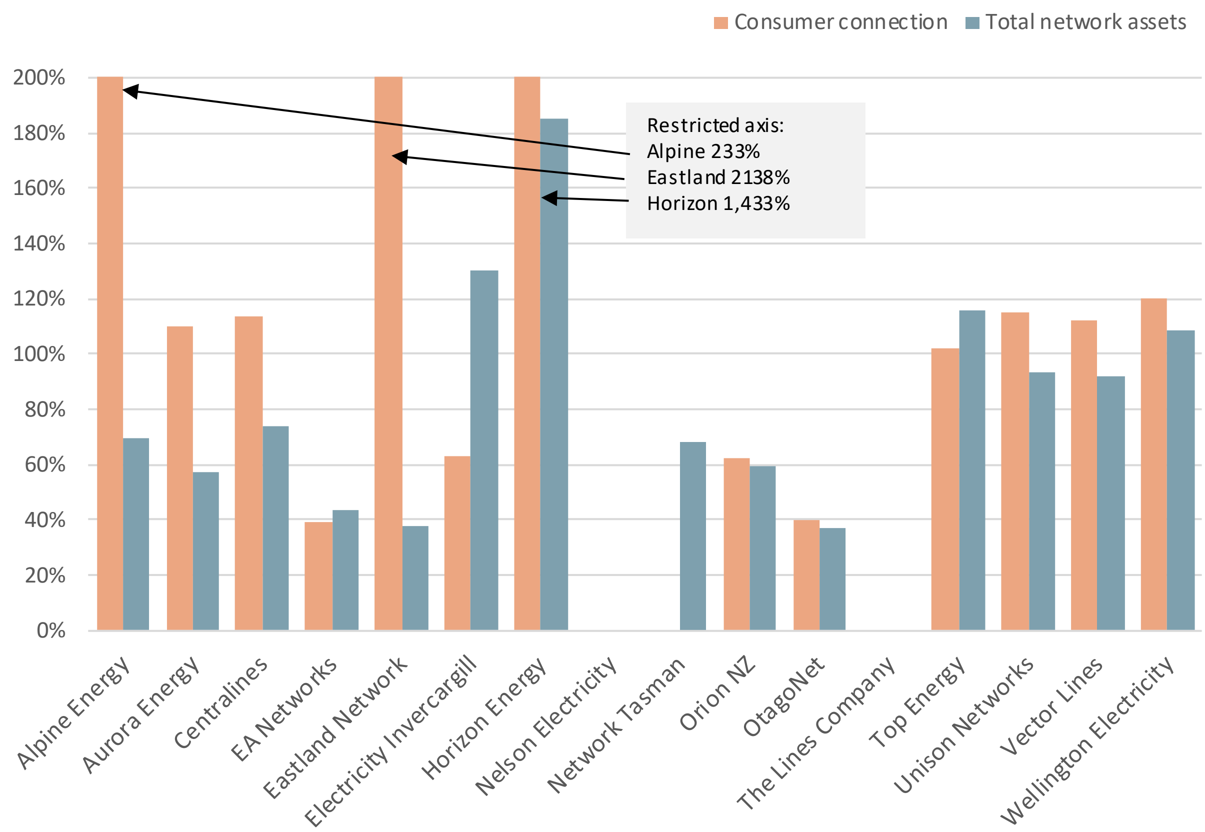
[381] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 15.

[382] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

B172 Figure B5 shows the percentage change in forecast capital contributions as a proportion of total expenditure on assets. It shows the forecast proportion of expenditure on assets covered by capital contributions during the DPP3 period compared to the historical average proportion for each distributor. It is shown for the consumer connection category—which, for most distributors, is the major and most predictable source of capital contributions—and for total expenditure on network assets. A value above 100% suggests capital contributions would fund more expenditure than they have historically, and vice versa.

Figure B5 Capital contributions as a proportion of expenditure on assets—forecast versus historical average



B173 Figure B5 suggests that distributors are variously forecasting that capital contributions will fund a similar, higher or lower proportion of expenditure as they have historically. Any under-forecasting is more significant for total network assets than for consumer connections, for which capital contributions are more predictable.

B174 These results suggest some distributors may be being conservative in their approach to forecasting capital contributions. However, we did not consider that it was consistent with our low-cost approach to setting DPPs to further develop this analysis as part of the DPP3 reset.[383]

Allowance for forecast cost of financing and vested assets

B175 In our draft decision we proposed to explicitly consider the cost of financing works under construction when assessing the capex forecasts, and providing for the value of any vested assets.

B176 We proposed retaining the approach used in DPP2, where we included distributors' forecasts of these components in our forecasts. However, we proposed that where we apply a cap or some other limit to capex, we would scale back cost of financing by a proportional amount—as we did in the 2017 gas DPP.

B177 Aurora was the only submitter that commented on this topic, and supported our approach.[384]

B178 For our final decision, we have maintained this approach as proposed, given there were no issues raised by submitters on this issue, and it is simple for us to implement following our experience with DPP2 and the 2017 gas DPP. Practically speaking, this means that a distributor's cost of financing is impacted by how they perform under our approach to scrutinising forecasts, including the 120% cap we apply on expenditure in aggregate. However, we have not applied any scaling to the value of vested assets.

Using forecast capex as a forecast of commissioned assets

B179 To set the revenue cap over the DPP period, our financial model relies on a forecast of distributor's aggregate value of commissioned assets, and the "capex" incentive mechanism also works by comparing forecast with actual commissioned assets. The EDB IMs direct us to forecast commissioned assets as equal to capex for the relevant year.[385]

[383] Refer to 3.13.1 of framework chapter.

[384] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

[385] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 4.2.5.

B180 The issues paper highlighted some rare instances that cause our assumption that forecast aggregate value of commissioned assets can be proxied through a forecast of capex to break down. These are when a distributor acquires assets from related parties or other regulated suppliers. We asked distributors to identify if they were contemplating making such transactions in the next five years, so that we could assess the materiality of this issue.

B181 There were no comments from submitters on this issue. Distributors did not flag that they would be acquiring any assets from related parties or regulated suppliers in the next five years. Therefore, for our final decision we have maintained the approach of forecasting commissioned assets using capex for the relevant year, with no further adjustment.

Treatment of spur asset purchases

B182 On occasion, Transpower has sold 'non-core' transmission grid assets (referred to as spur assets) to the distributor that connects to these assets. For our draft decision we proposed retaining the approach we used in DPP2 for dealing with these transactions, which involved:

B182.1 A 'transmission asset wash-up adjustment' recoverable cost in the IMs, which allows us to include spur asset purchases in capex forecasts, but also allows the return on/of these assets to be removed from distributor revenue if the purchase is cancelled.

B182.2 Excluding this transmission asset capex from our assessment of forecast capex, as the scale of the purchase and future maintenance costs represented a significant increase above historical levels.

B183 Submitters did not comment on our proposed approach to forecast purchases. We note that no distributor has indicated that it intends to undertake transmission asset purchases during the DPP3 period. Therefore, we see no reason to depart from this approach in theory.

B184 The Reasons Paper supporting our draft decision also considered our treatment of historical transmission asset purchases. For the draft decision, we did not capture transmission asset purchase expenditure for two reasons.

B185 Firstly, we lacked a complete dataset of historical capex associated with transmission asset acquisitions, so we were unable to make a full and accurate accounting of it within our forecasting approach.

B186 Secondly, we needed to further consider the extent to which we excluded these purchases from our assessment of forecast capex. We note that two of the issues we were contemplating as to how to capture transmission assets are no longer relevant because our final decision:

B186.1 Does not include a test scrutinising distributor's forecast accuracy. Removing these purchases from forecasts would have been difficult, but also necessary—the combination of which largely contributed to our reasons for excluding the test in the final decision.

B186.2 Includes a different approach to scrutinising system growth expenditure. Our draft approach focused on only a subset of system growth expenditure, and considering transmission asset purchases reasonably within that approach would have required a detailed breakdown of the allocation of those purchase costs within subcategories.

B187 The remaining issue we discussed in the Reasons Paper remains relevant to the final decision. Specifically, we considered whether the expenditure should be excluded from the historical expenditure series where we 'fall-back' on this because of our scrutiny tests, or cap aggregate expenditure at 120% of historical levels.

B188 Submitters did not comment on this issue. Prior to our final decision, we asked stakeholders to confirm whether they had purchased transmission assets since 2013 and provide data on those purchases where necessary. For our final decision we have drawn on that data to:

B188.1 exclude transmission asset costs during the year of acquisition from historic and forecast expenditure series when scrutinising expenditure;

B188.2 exclude transmission asset costs during the year of acquisition from historic and forecast expenditure series when scaling and capping forecasts; and

B188.3 add back in any costs during the year of acquisition of a transmission asset for inclusion in the final allowance.

B189 This approach reflects that the transmission asset purchases can distort the historic expenditure series of distributors, given their magnitude. Removing them for scrutinising and capping forecasts is appropriate, as not doing so would imply greater historic expenditure than would be representative of expenditure going forward and cloud our ability to scrutinise their business as usual expenditure. Further, these purchases represent an expansion of the network, so it is appropriate to add the associated expenditure back in to the final allowances.

Attachment C Forecasts of other inputs

Purpose of this attachment

C1 This attachment explains the inputs to the financial model we must include in addition to our forecasts of opex and capex discussed in the preceding attachments. It discusses:

C1.1 the WACC estimate we have used to set the DPP decision;

C1.2 the forecast of CPI we have used for the revaluation rate and as an element of the price path; and

C1.3 forecasts of disposed assets.

High-level approach

C2 The inputs discussed in this attachment are primarily determined in accordance with the EDB IMs (specifically the cost of capital and asset valuation IMs).[386] As such, our high-level approach to these issues is to apply the relevant EDB IMs. Our decision not to amend these IMs is discussed in Chapters 3 and 4 of our IM amendment reasons paper.[387]

Cost of capital estimate

C3 For the final DPP decision, we have used a WACC of 4.57%. This figure was determined as at 1 September 2019.[388] Figure C1 below sets out changes in the WACC since prices were last reset in 2014.

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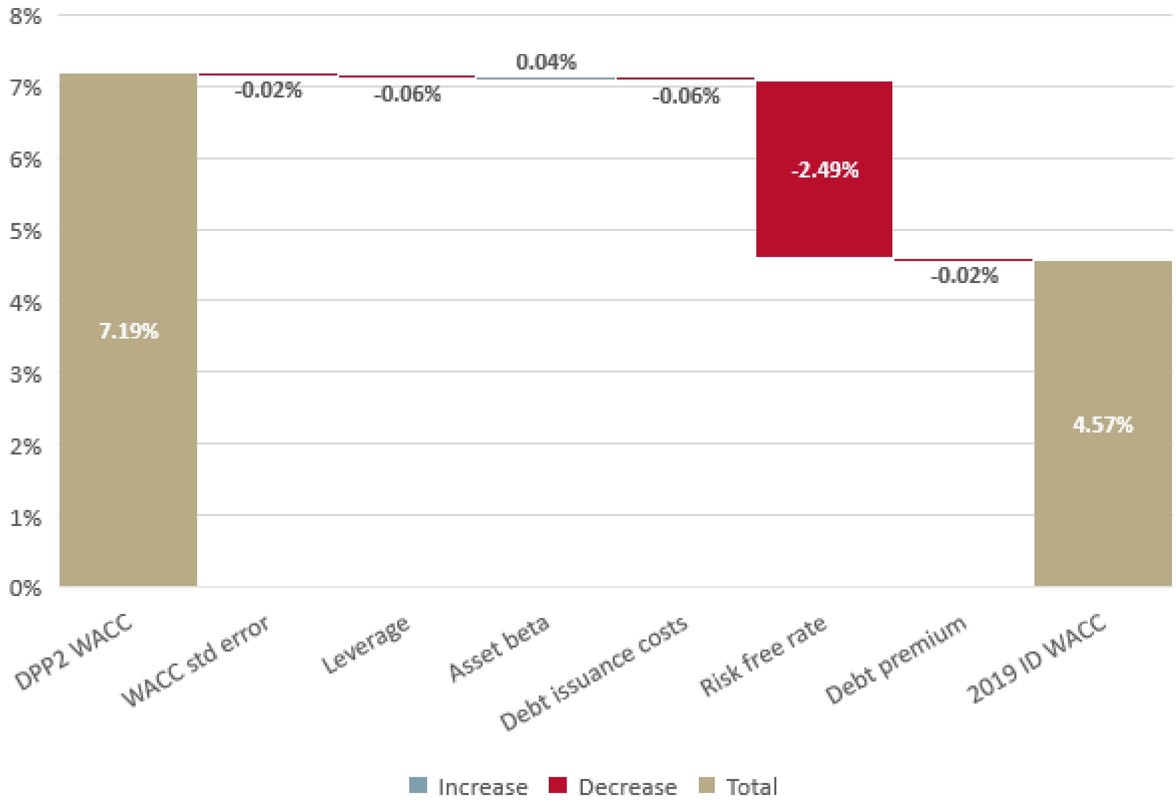
[386] The exception is our approach to forecasting asset disposals. These are discussed separately at the end of this attachment.

[387] Commerce Commission "Amendments to electricity distribution services input methodologies determination – Reasons paper" (26 November 2019).

[388] Commerce Commission *Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path* [2019] NZCC 12 (25 September 2019).

Figure C1 Cumulative effect of changes in WACC



CPI forecasts

Problem definition

C4 The revenue path is determined on a nominal basis (consistent with the CPI-X DPP/CPP regime outlined in Subpart 6 of the Act). When using a BBAR/MAR model to determine starting prices, we require a forecast of CPI to project annual revenues for each year of the DPP3 period. Because the asset valuation IM requires the RAB to be revalued at the rate change of CPI, we also require a forecast of CPI to determine BBAR.

Decisions

C5 The approach we must use is determined by the EDB IMs.[389] As discussed in Chapter 3 of the IM amendments reasons paper, we have decided not to amend these IMs.[390] In support of this decision, we have also analysed whether the forecasts of CPI we use seem unreasonable relative to other available forecasts, and the relationship between CPI and the LCI/PPI inflation indices we use to forecast operating expenditure.

C6 For both the rate of change of forecast CPI for RAB revaluations and the rate of change for the price path calculation, the forecasts are based on the Reserve Bank of New Zealand's (RBNZ) forecasts of inflation issued as part of the Monetary Policy Statement immediately prior to the determination of the WACC for the DPP.[391] The results of this approach are set out in Table C1 below.

Table C1 Forecasts of CPI

Pricing year ending in calendar year	CPI used for revaluations	CPI element of the price path	CPI used for revaluations (Draft decision)	CPI element of the price path (Draft decision)
2019	1.48%	1.69%	1.60%	1.72%
2020	1.70%	1.52%	1.70%	1.45%
2021	1.90%	1.75%	2.10%	1.98%
2022	2.00%	1.95%	2.10%	2.07%
2023	2.00%	2.02%	2.07%	2.07%
2024	2.00%	2.00%	2.03%	2.03%
2025	2.00%	2.00%	2.00%	2.00%

Analysis

C7 We have analysed how RBNZ's forecasts of inflation compare to other forecasts from trading banks, government departments, and independent economic experts. These results are presented in Figure C2 below.

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[389] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019) clauses 3.1.1(8) and 4.2.4.

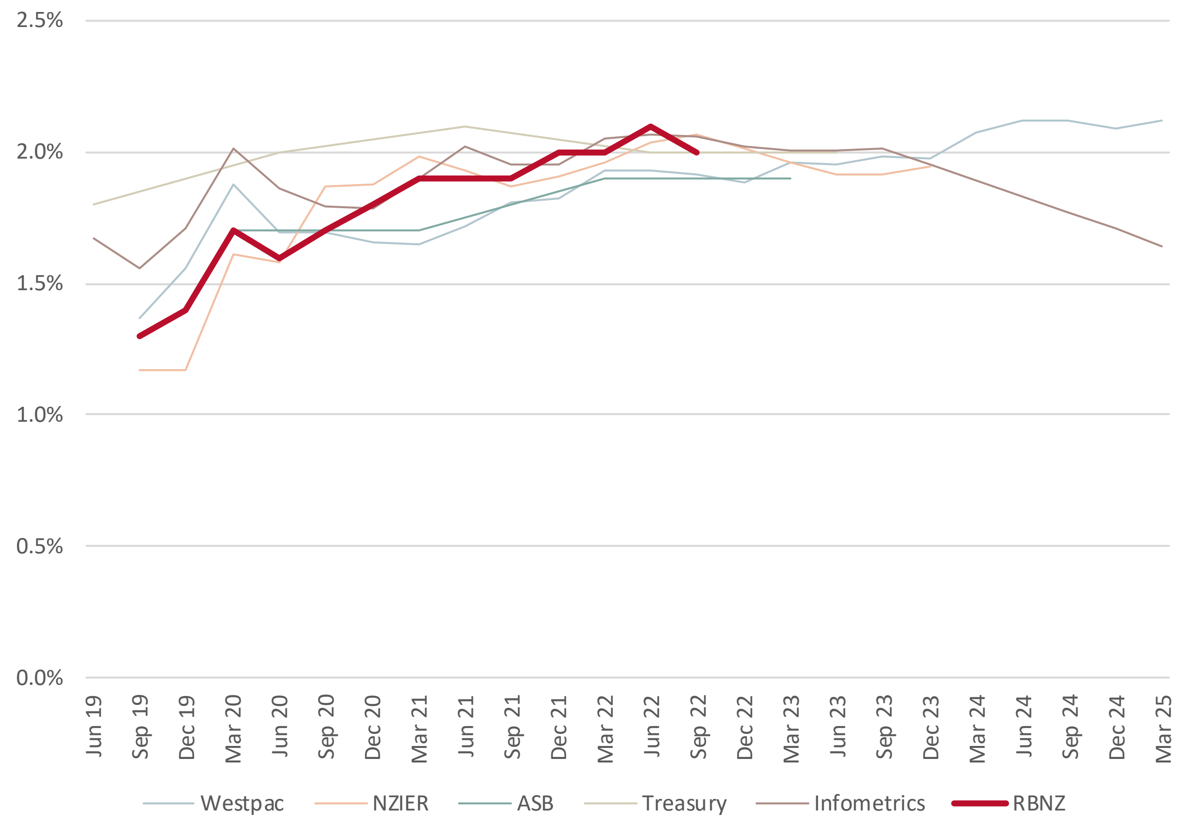
[390] Commerce Commission "Amendments to electricity distribution services input methodologies determination – Reasons paper" (26 November 2019), pp. 26-31 and 57-61.

[391] Reserve Bank of New Zealand "Monetary Policy Statement August 2019" (7 August 2019); Commerce Commission *Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path* [2019] NZCC 12 (25 September 2019).

C8 To the extent that there are inaccuracies in CPI forecasts for revaluation purposes, the use of CPI forecasts consistent with market expectations of inflation at the time the WACC for the DPP is determined provides a ‘natural hedge’ against forecast error – to the extent that CPI (and therefore revaluations) are over-forecast, the WACC (and therefore the return on building block) will also be higher.

C9 Based on the results presented in Figure C2, we do not consider the RBNZ forecasts we have used are unreasonable or out of line with the inflation expectations of other forecasters.

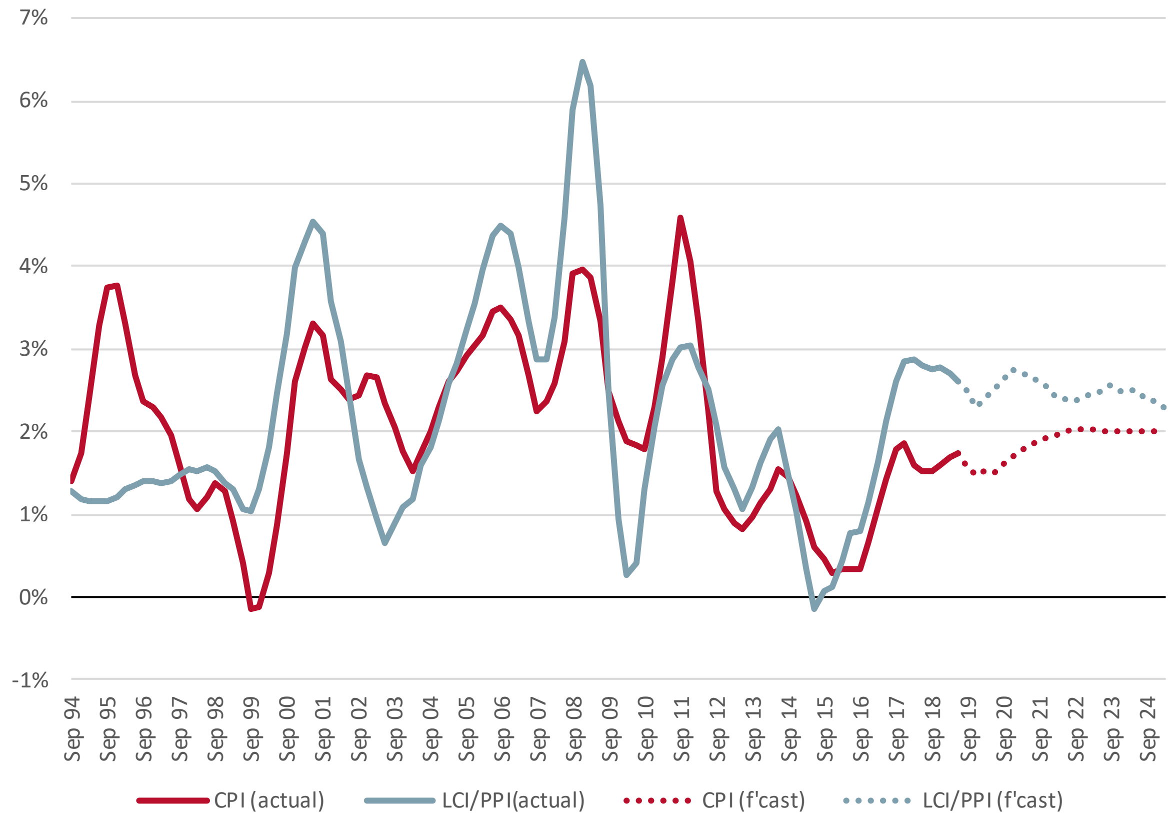
Figure C2 Comparison of CPI forecasts



C10 For price path purposes, to the extent that CPI is over-forecast, the input price inflators (LCI, PPI, and CGPI) we use to determine opex and capex allowances will also likely be over-forecast, providing a partial offset to the lower revenues distributors will receive as a result.

C11 This correlation between CPI and opex input prices has been consistent historically, as shown in Figure C3. We note that over the DPP3 period, we are forecasting input cost growth above the rate of inflation, and consequently higher opex and capex allowances.

Figure C3 Comparison of CPI and LCI/PPI inflation



Forecasts of disposed assets

C12 A disposed asset is an asset that is sold or transferred, or irrecoverably removed from a distributor's possession without consent (but is not a lost asset). We are required to forecast disposed assets because disposed assets are removed from the RAB when rolling forward the RAB value.

C13 To reach our final decision, the forecast value of disposed assets in each year of the regulatory period has been forecast in real terms as equal to the historical average real value of disposals. The real forecast time series has then been converted to a nominal time series by adjusting for forecast CPI changes. These results are set out in Table C2 below.

C14 We did not receive any submissions on the accuracy of our forecasts of disposals, except for submissions from Orion and Vector noting extraordinary disposals in 2016 and 2017.[392] Issues raised about the treatment of gains or losses on disposals (as other regulated income) are discussed in Attachment H.

[392] Vector "Submission on companion paper to updated models" (9 October 2019), p. 6; Orion "Submission on companion paper to updated models" (9 October 2019), p. 3.

Table C2 Forecasts of disposed assets ($m)

Distributor	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Alpine Energy	0.13	0.13	0.14	0.14	0.14	0.14
Aurora Energy	0.29	0.30	0.30	0.31	0.31	0.32
Centralines	0.03	0.03	0.03	0.03	0.03	0.03
EA Networks	1.08	1.10	1.12	1.15	1.17	1.19
Eastland Network	0.18	0.18	0.19	0.19	0.19	0.20
Electricity Invercargill	0.12	0.12	0.13	0.13	0.13	0.14
Horizon Energy	0.28	0.28	0.29	0.30	0.30	0.31
Nelson Electricity	0.07	0.07	0.07	0.07	0.08	0.08
Network Tasman	0.55	0.56	0.57	0.58	0.59	0.61
Orion NZ	1.72	1.75	1.79	1.82	1.86	1.90
OtagoNet	0.29	0.29	0.30	0.30	0.31	0.32
The Lines Company	0.51	0.52	0.53	0.54	0.55	0.56
Top Energy	0.03	0.03	0.03	0.03	0.03	0.03
Unison Networks	2.63	2.68	2.73	2.79	2.84	2.90
Vector Lines	10.77	10.97	11.19	11.42	11.65	11.88

Attachment D Accelerated depreciation

Purpose of this attachment

D1 Vector provided the Commission with a notice on 28 February 2019 proposing an adjustment factor under clause 4.2.2(5) of the electricity distribution business IMs for an accelerated rate of depreciation.

D2 This attachment provides a brief background, explaining that we introduced in our 2016 IM review a mechanism allowing distributors to apply for a discretionary adjustment factor reflecting the net present value-neutral shortening of their remaining asset lives to mitigate risks of partial capital recovery and outlines our consideration of Vector's application and reasoning for choosing not to apply an adjustment factor.

High-level approach

D3 Clause 4.2.2 of the Input Methodologies provides that the Commission may apply an adjustment factor for accelerated depreciation on the application of a party.

D4 We have decided not to apply an adjustment factor in response to Vector's application, based on weighing up our assessment of Vector's application against the formal IM requirements, the risk of economic stranding, section 52A of the Act and exercising our overall discretion. Having assessed Vector's application against our framework (which is set out below), we found that:

D4.1 it was not clear to us whether Vector's application has met the criteria set out in clause 4.2.2 of our IMs because Vector did not explain how it had taken into account any issues raised in consultation, nor specified that no relevant issues were raised, however we did not have to resolve this because we declined Vector's application for other reasons;

D4.2 we did not find evidence of a material risk to partial capital recovery with respect to Vector, which was the underlying purpose of the IMs providing for the adjustment factor;

D4.3 we did not find that applying the adjustment factor Vector sought promoted the purpose of Part 4 of the Act; and

D4.4 in considering our overall discretion we had regard to the interests of avoiding a price increase (or reduction in the price decrease) and not adding complexity

Background

D5 As a result of our 2016 IM review, we introduced a mechanism in our IMs allowing distributors to apply for a discretionary net present value-neutral shortening of their remaining asset lives. This mechanism allows distributors to apply for new asset lives based on their assets' expected economic lives, rather than their physical asset lives.[393]

D6 In 2018, we made further IM implementation changes to better give effect to our 2016 IM review decision.[394]

D7 No later than 13 months prior to the commencement of DPP3, distributors may apply to us for 'an adjustment factor'.[395]

D8 On 28 February 2019 Vector submitted a notice to us requesting that we apply a 0.85 adjustment factor under our IMs.[396] On 14 March 2019, we sought feedback on Vector's application, and we received comments from several interested parties.[397]

D9 On 29 May 2019 we made the draft decision to decline Vector's application for accelerated depreciation. We received submissions on our draft decisions, including five submissions that specifically referred to our draft decision on Vector's application from the following parties:[398]

D9.1 Major Electricity Users Group (MEUG);

D9.2 Contact;

D9.3 Entrust;

D9.4 ERANZ; and

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[393] Commerce Commission "Input methodologies review decisions: Topic paper 3: The future impact of emerging technologies in the energy sector" (20 December 2016), para 84-86.

[394] Commerce Commission *Electricity Distribution Services Input Methodologies (Accelerated Depreciation) Amendments Determination 2018* [2018] NZCC19 (8 November 2018).

[395] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 4.2.2(5).

[396] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019)

[397] ENA "Vector – Accelerated depreciation application" (29 March 2019); MEUG "Vector – accelerated depreciation application" (28 March 2019); Mercury "Vector – Accelerated depreciation application" (1 April 2019); Meridian Energy "Vector – Accelerated depreciation application" (29 March 2019); Powerco "Comments on Vector's application for accelerated depreciation" (29 March 2019) Vector "Vector – Accelerated depreciation application" (29 March 2019).

[398] MEUG "Submission on EDB DPP reset draft decisions paper" (18 July 2019); Contact Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019); Entrust "Submission on EDB DPP reset draft decisions paper" (18 July 2019); ERANZ "Submission on EDB DPP reset draft decisions paper" (18 July 2019); and Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

D9.5 Vector.

D10 Vector's submission on our draft decision did not sufficiently clarify the basis of suggesting that there is a heightened risk of partial capital recovery in the future or otherwise persuade us to alter our position. While the submission from Vector and its major shareholder Entrust disagreed with our draft decision to decline its application, the other submissions above supported our draft decision. The specific points raised in these submissions are responded to throughout this attachment.

Our framework for assessing adjustment factor applications

D11 The Commission has overall discretion in deciding whether to accept an application to apply an adjustment factor at what level because the input methodologies state that "…the Commission <u>may</u> apply adjustment factors…". In exercising that discretion, we have considered the following factors:

D11.1 Our assessment of whether the application has met the specified criteria set out at clause 4.2.2(5) of the IMs;

D11.2 Our assessment of whether there is a material risk of partial economic recovery, by which we mean a situation in which the level of demand or willingness to pay for distribution services across its network means that the distributor is unable to fully charge up to the level of revenue allowed for under its price path;

D11.3 Whether making the adjustment factor applied for would advance the purpose of Part 4 as set out in section 52A[399]; and

D11.4 Whether as a matter of overall discretion the Commission should approve the adjust factor applied for.

Criteria specified in the IMs

D12 The first factor that we consider is whether the application for an adjustment met the specific IM requirements. To meet those requirements, a distributor must submit a notice meeting each of the requirements in clauses 4.2.2(5)(a)(i), 4.2.2(5)(a)(ii) and 4.2.2(5)(a)(iii) of the EDB IMs; namely:

D12.1.1 proposing an adjustment factor of not lower than 0.85, nor higher than 1, as required under clause 4.2.2(5)(a)(i) of the EDB IMs;

[399] Our framework for decision making for the DPP, particularly through consideration of the purpose of Part 4 of the Act, is described in Chapter 3.

D12.1.2 explaining why applying an adjustment factor of the level proposed would be consistent with section 52A of the Act, as required under clause 4.2.2(5)(a)(ii) of the EDB IMs; and

D12.1.3 describing any consultation it has undertaken with interested persons on the proposed adjustment factor and, if relevant, explaining how it has taken into account any issues raised, as required under clause 4.2.2(5)(a)(iii) of the EDB IMs; and

D12.2 we must not have previously applied adjustment factors, as specified in clause 4.2.2(5)(b) of the EDB IMs.

Material risk of partial economic recovery

D13 In assessing whether there is a material risk of partial economic recovery we mean a situation in which the level of demand or willingness to pay for distribution services across its network is such that the distributor is unable to fully charge up to the level of revenue allowed for under its price path (which we call economic stranding, in contrast to physical stranding).

D14 It was economic stranding that our accelerated depreciation IM changes were intended to address. We explained its purpose in the 2016 IMs review reason paper:

> We have decided to implement a 'net present value (NPV) neutral' risk mitigation measure. We consider that the best way to reflect the higher uncertainty attached to the magnitude and direction of the risk of partial capital recovery is to allow EDBs to apply for a discretionary NPV-neutral shortening of their remaining asset lives. This would happen at the time of the DPP reset.[400]

D15 We were specific that the IM mechanism was to address the risk of economic stranding, rather than any risk of physical asset stranding:

> The IMs allow for assets to stay in the RAB even though they have ceased to be used (ie, become physically stranded). Therefore, physical asset stranding is not the risk under consideration. Rather, it is the risk that the network becomes economically stranded. That is, the risk is that at some future point enough consumers elect to disconnect from EDBs' networks such that the revenue EDBs are able to recover from the remaining customer base is insufficient to allow them to fully recover their historic capital investment (hence the title 'risk of partial capital recovery'). This is because prices to those remaining consumers would need to rise beyond their willingness to pay given their economic alternatives (or beyond politically acceptable levels).[401]

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[400] Commerce Commission "Input methodologies review decisions - Consolidated reasons paper" (20 December 2016), p. 576

[401] Commerce Commission "Input methodologies review decisions - Topic paper 3: The future impact of emerging technologies in the energy sector" (20 December 2016), paras 72 and 84.

D16 In its comments on Vector's notice, ENA indicated that adjustment factors should be used "wherever it is needed to mitigate stranding risk and to maintain investor confidence".[402] In our draft decision, we explained that we agreed with this framing.

D17 However, MEUG disagreed with this in its submission on our draft decision, submitting that "Using "wherever" is too absolute given future stranding risk and investor confidence is uncertain and should be considered in a probabilistic range of possible outcomes".[403] We accept MEUG's submission, and as such point and reiterate that we assess applications for accelerated depreciation against the risk of economic stranding, not physical stranding.

D18 While our consideration is that of the risk of future partial recovery of capital to support an ex-ante expectation of real financial capital maintenance, we also note that we explained in the IMs reasons paper that we did not intend for the mechanism to eliminate all risk of partial capital recovery in the IMs reasons paper.[404]

Promote the purpose of Part 4

D19 In exercising our discretion under clause 4.2.2(4) of the EDB IMs, we must consider whether applying any adjustment factor (and if so, what level of adjustment factor) would promote the outcomes specified in section 52A of the Act, where suppliers of regulated goods or services:

D19.1 have incentives to innovate and to invest, including in replacement, upgraded, and new assets;[405]

D19.2 have incentives to improve efficiency and provide services at a quality that reflects consumer demands;[406]

D19.3 share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices;[407] and

D19.4 are limited in their ability to extract excessive profits.[408]

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[402] ENA "Vector – Accelerated depreciation application" (29 March 2019), p. 1.

[403] MEUG "Submission on EDB DPP reset draft decisions paper" (18 July 2019), paragraph 28.

[404] Commerce Commission "Input methodologies review decisions - Consolidated reasons paper" (20 December 2016)

[405] Commerce Act 1986, section 52A(1)(a).

[406] Commerce Act 1986, section 52A(1)(b).

[407] Commerce Act 1986, section 52A(1)(c).

[408] Commerce Act 1986, section 52A(1)(d).

Overall discretion

D20 In exercising our overall discretion, we will look at whether there are any other factors (outside the IM criteria, the risk of partial economic recovery and the purpose of Part 4) that means we should or should not make an adjustment.

D21 An example of a factor we may consider in applying our overall discretion is pricing impact, which is in line with our statement at the time of the IM review that "We will then review this proposal, giving consideration to its impact on pricing."[409]

General comments on the application

D22 Overall, we consider that despite a relatively low level of evidence being required given the low-cost nature of the DPP, Vector did not include sufficiently convincing evidence in its application.

D23 In its application, Vector's key reasoning for the appropriateness of an adjustment factor was its view of a material risk of partial economic recovery. However, the application did not include the basis of the scenarios which it modelled. Given that it is the outputs of this scenario modelling that was provided as evidence of the risk, the application should have laid out the basis of the different scenarios to show whether they are at all likely and whether actions by the distributor could avoid these scenarios (such as through pricing reform). It also should have included the numeric outputs of the modelling.

D24 Also, as described above, Vector's application did not clearly state whether any specific issues were raised in consultation and if so, what these issues were.

Our assessment of Vector's application against the specific IM requirements

D25 This section describes how Vector's application generally met the specific requirements of the IMs for applications for accelerated depreciation, consisting of:

D25.1 *Adjustment factor:* The application must propose an adjustment factor of not lower than 0.85, nor higher than 1, as required under clause 4.2.2(5)(a)(i) of the EDB IMs;

D25.2 *Consistency with Part 4 purpose:* The application must explain why applying an adjustment factor of the level proposed would be consistent with section 52A of the Act, as required under clause 4.2.2(5)(a)(ii) of the EDB IMs; and

[409] Commerce Commission "Input methodologies review decisions: Report on the IM review" (20 December 2016), paragraph 94.

D25.3 *Consultation:* The application must describe any consultation it has undertaken with interested persons on the proposed adjustment factor and, if relevant, explaining how it has taken into account any issues raised, as required under clause 4.2.2(5)(a)(iii) of the EDB IMs; and

D25.4 *Previous adjustment factor:* We must not have previously applied adjustment factors, as specified in clause 4.2.2(5)(b) of the EDB IMs.

D26 However, we note that it was difficult to completely assess whether all of the consultation requirements have been met.

Adjustment factor

D27 To meet clause 4.2.2(5)(a)(i) of the EDB IMs, Vector must have proposed an adjustment factor of not lower than 0.85, nor higher than 1.

D28 Our decision is that Vector has met clause 4.2.2(5(a)(i) as it has proposed in its notice an adjustment factor of 0.85.[410]

Consistency with Part 4 purpose

D29 To meet clause 4.2.2(5)(a)(ii) of the EDB IMs, Vector must have explained why applying an adjustment factor of 0.85 would be consistent with section 52A of the Act.

D30 Our decision is that Vector has met clause 4.2.2(5)(a)(ii) of the EDB IMs as its notice provides an explanation of why it considers that applying an adjustment factor of 0.85 would be consistent with section 52A of the Act. It has described each of the outcomes that Part 4 of the Act promotes and has explained why it considers that its adjustment factor proposed is consistent with those outcomes.[411] For the avoidance of doubt, we note that by deciding that Vector has met clause 4.2.2(5)(a)(ii) we are not providing any indication on whether an adjustment factor would be consistent with section 52A of the Act.

D31 In paragraphs D58 to D83, we identify the text Vector has used to explain why it considers that the adjustment factor it has proposed is consistent with the outcomes that Part 4 of the Act promotes.

D32 Section 52A(1)(a) of the Act promotes an outcome where suppliers of regulated goods or services have incentives to innovate and to invest, including in replacement, upgraded, and new assets.

[410] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), p 3.

[411] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), paras 73-84.

D33 Vector has said that:

> As discussed above, applying the depreciation adjustment lever will provide confidence for EDB investors to make investments in long-life physical assets with the expectation that NPV=0 and FCM will be adhered to. Otherwise replacing long-life physical structures cannot be financed economically if this expectation does not hold. This is especially important where greater technology adoption is anticipated to compromise capital recovery.[412]

D34 Section 52A(1)(b) of the Act promotes an outcome where suppliers of regulated goods or services have incentives to improve efficiency and provide services at a quality that reflects consumer demands. Vector has said that:

> The Notice notes a significant driver for capital programs is the prescribed regulatory quality standards applied onto EDBs. Accordingly, it is important for these standards to reflect customer expectations and for investment to ensure standards are indeed a fair reflection of customer expectations. EDBs are at risk of quality regulations becoming out-of-step with customer expectations especially in an era of energy technology change. Therefore, investing to meet quality regulations does increase the risk for EDBs, as has been shown from quality regulations applied in NSW and QLD, discussed later in this notice, where reliability standards were found to be out-of-step with customer expectations.[413]

D35 Section 52A(1)(c) of the Act promotes an outcome where suppliers of regulated goods or services share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices. Vector has said that:

> The use of the depreciation adjustment lever is NPV neutral, however we demonstrate in this Notice the application of the lever will deliver intergenerational equity for customers at a time when technology adoption may cause price increase for customers and so will moderate any price increase from technology scenarios where this occurs. The use of the lever will also deliver greater fairness between customers as deprivation from new technology adoption where current technology trends continue is expected to exacerbate over time. Therefore, the lever will moderate the extent of any bifurcation between technology adopters and customers unable to access the new options.[414]

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[412] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 84(a).

[413] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 84(b).

[414] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019) para 84(c).

D36 Section 52A(1)(d) of the Act promotes an outcome where suppliers of regulated goods or services are limited in their ability to extract excessive profits. Vector has said that:

> As noted above, the use of the depreciation adjustment lever is still consistent with the Part 4 concept of NPV=0 which ensures EDBs can earn no more than a normal return on their investment. Rather the use of the lever will ensure greater inter-generational equity and fairness across customers to moderate the impact technology change is expected to have on network cost recovery.[415]

Consultation

D37 To meet clause 4.2.2(5)(a)(iii) of the EDB IMs, Vector should have described any consultation it has undertaken with interested persons on its proposed adjustment factor and, if relevant, explained how it has taken into account any issues raised.

D38 Vector has described the consultation it has undertaken with interested persons on the proposed adjustment factor in its application. However, Vector's notice has not identified any issues raised by interested persons as part of its consultation, making it difficult to determine:

D38.1 whether any relevant issues were raised by interested persons on the proposed adjustment factor; and

D38.2 whether Vector has taken into account any relevant issues raised by interested persons on the proposed adjustment factor.

D39 Vector's application describes:

D39.1 how it raised the topic of our depreciation adjustment factor with its customer advisory board (CAB), where the CAB "recognised the merits of the technology risk to capital recovery and acknowledged the Vector case for lodging a Notice";[416] and

D39.2 how it undertook a customer survey focused on the residential customer segment of Vector's network, representing over 85% of ICPs,[417] which:

D39.2.1 asked customers to determine their views on whether:

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[415] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 84(d).

[416] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 106.

[417] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 109.

"a) New technology was creating more uncertainty for future demand for networks and if they agreed this was increasing the risk for network investment; and

b) They would be prepared to pay more for their electricity network now to support the intergenerational equity for networks."[418]; and

D39.2.2 found that 66 percent of respondents agreed that investing in networks is riskier than before;[419] and

D39.2.3 found that 68 percent of respondents were prepared to pay more for the network today to avoid intergenerational inequity".[420]

D40 Clause 4.2.2(5)(a)(iii) of the EDB IMs also requires, "if relevant", an explanation in the notice of how the applicant "has taken into account any issues raised" by interested persons during the proposed adjustment factor consultation.

D41 Vector's notice has not identified any specific issues raised by interested persons as part of the consultation summarised in paragraphs D32.1-D33.2, nor confirmed whether no relevant issues were raised. This makes it difficult to determine:

D41.1 whether any relevant issues were raised by interested persons on the proposed adjustment factor; and

D41.2 whether Vector has taken into account any relevant issues raised by interested persons on the proposed adjustment factor.

D42 If relevant issues were raised by interested persons on the proposed adjustment factor, Vector's notice would have needed to explain how it had taken those issues into account.

D43 Given the lack of detail provided by Vector, we found it difficult to assess this criterion. We are inclined to the view that the applicant has not established that clause 4.2.2(5)(a)(iii) is satisfied. However, we do not find it necessary to reach a final conclusion given our conclusions on the other factors.

D44 Vector outlined concerns in its submission on our draft decision about our expectations for applications:

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418 Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 107.

419 Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 109.

420 Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 109.

> we are concerned with the lack of clarify about what is required to support an accelerated depreciation application. Given that that option is intended to operate under the low cost DPP framework, preparing such an application should also be low cost and the Commission's consideration of it should reflect that.[421]

D45 We appreciate Vector's concerns and intend to issue further guidance on the matter on the future.

Previous adjustment factor

D46 To meet clause 4.2.2(5)(b) of the EDB IMs, we must not have used clause 4.2.2(4) of the EDB IMs to apply adjustment factors for Vector.

D47 As we have not used clause 4.2.2(4) of the EDB IMs to apply adjustment factors for any distributor, our decision is that this requirement is satisfied.

Assessment of whether there is a material risk of partial economic recovery

D48 We have considered the material in Vector's notice and the submissions received following our consultation and draft decision. This material has not convinced us that there is a sufficient risk of partial economic recovery to warrant application of accelerated depreciation now.

D49 In Vector's notice it suggests that:

D49.1 network stranding puts financial capital maintenance at risk; and

D49.2 only partial capital recovery is likely on the basis of its scenario modelling.[422]

D50 Based on the information provided in Vector's notice and subsequent consultation, our decision is that there is insufficient evidence to demonstrate that Vector faces a material risk of economic stranding.

D51 Vector's customer technology scenario modelling is essential to providing evidence for its assertion that its adjustment factor should be applied. The modelling evidence needs to be reasonably persuasive that network stranding is a sufficiently established risk.

[421] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), paragraph 42.

[422] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 74-83.

D52 Paragraphs 83, 99 and 101 of Vector's notice provide some of the key outputs of the scenario analysis. They are that:

> The modelling shows multiple scenarios where partial capital recovery is likely.
>
> The review found that three scenarios produced significant year-on-year price increases for customers. The price rebalancing by accelerating depreciation would provide some reprieve to the sustained price increases expected by customers in some scenarios.
>
> Importantly, the review found the magnitude of the expected sustained price will not be adequately rebalanced by the depreciation adjustment factor capped at a maximum of 15 percent.

D53 There is no support in Vector's notice for the statements of key outputs quoted above. There is no quantification of any partial capital recovery, no quantification of price rises, or what an adequate rebalancing would be.

D54 When we commenced work on our IM review that was completed in 2016, there was much discussion of the risk for distribution networks of many disconnections as consumers go off-grid. This reduction in use of the assets could result in a price for use that becomes greater than consumers' willingness to pay, exacerbating the exodus or requiring a reduction in price below that which results in a normal return. It was in that context that we consulted on and implemented the adjustment factor provision in the IMs.

D55 The industry emerging view would now seem to be that distribution networks will continue to be essential for most consumers, and that the prospect of high market share for electric vehicles reinforces this. However, the nature of the use of electricity distribution services may change for some consumers, increasing the importance of tariff reform towards cost-reflective and service-based pricing.

D56 It is not clear from Vector's notice or from its AMPs how its network would become economically stranded in this wider context.

Our assessment of Vector's application against the purpose of Part 4

D57 Our assessment of Vector's notice and the submissions received following our consultation and draft decision is that applying an adjustment factor would not promote the outcomes specified in section 52A of the Act.

Would applying an adjustment factor for Vector promote the outcome specified in section 52A(1)(a) of the Act?

D58 Section 52A(1)(a) of the Act specifies an outcome where suppliers of regulated goods or services have incentives to innovate and to invest, including in replacement, upgraded, and new assets.

D59 In Vector's notice it suggests that:

D59.1 network stranding puts financial capital maintenance at risk; and

D59.2 only partial capital recovery is likely on the basis of its scenario modelling.[423]

D60 Accordingly, Vector's rationale under section 52A(1)(a) is to assert the risk of economic stranding.

D61 As explained in paragraphs D48-D56, it is our view that Vector has not provided evidence to show sufficiently increased risk of partial economic stranding, so we have not found this to contribute to promoting the outcome specified in section 52A(1)(a).

D62 In its submission on our draft decision, Vector also suggested that we should consider the financeability of the planned network investment in assessing whether accelerated depreciation would better support the purpose of Part 4 of the Act.[424]

D63 We disagree that accelerated depreciation should be applied to support financeability because we consider that the primary incentives for investment through the price path remain through time and changes in investment levels. We expect that the ex-ante expectation of normal returns enables sufficient financing of the business.

D64 The Commission does not consider that enabling distributors to maintain a relatively constant level of equity in absolute terms is required to support the purpose of Part 4 of the Act. Consistent with businesses in competitive markets, we expect that an ex-ante expectation of a real return is sufficient to garner finance and that the business may choose to increase equity (for example through reduced dividend payments) or debt.

D65 If faced with lumpy investment profiles, it is not uncommon for businesses to raise additional capital, through debt or equity, to fund that investment rather than being able to finance it solely from operating cash flows. If an individual distributor's unique situation requires means that a regulatory response to financeability is instead required, we consider that a CPP would be a more appropriate instrument.

[423] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 74-83.

[424] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

D66 In terms of financial structuring, we note that we seek to incentivise distributors to maintain an investment grade credit rating (by estimating our debt premium with reference to an investment grade bond), and distributors can adopt any financial structuring approach that is consistent with that.

D67 Accordingly, we do not consider that Vector's notice demonstrates that applying an adjustment factor for Vector promote the outcome specified in section 52A(1)(a) of the Act.

D68 We have also considered whether accelerated depreciation would better promote the other limbs of the section 52A of the Act, as explained below.

Would applying an adjustment factor for Vector promote the outcome specified in section 52A(1)(b) of the Act?

D69 Section 52A(1)(b) of the Act specifies an outcome where suppliers of regulated goods or services have incentives to improve efficiency and provide services at a quality that reflects consumer demands.

D70 In its notice, Vector suggests that an adjustment factor is needed, in part, because of the risk that quality regulation becomes "out-of-step with customer expectations", where investing to meet quality regulations increases the risk for distributors.[425] In Vector's view, examples from Australia (New South Wales and Queensland) indicate that investment is needed "where reliability standards were found to be out-of-step with customer expectations."[426]

D71 Based on the information provided in Vector's notice and subsequent consultation, our decision is that applying an adjustment factor would not promote an outcome of Vector having:

D71.1 incentives to improve efficiency; and

D71.2 incentives to provide services as a quality that reflects consumer demands.

D72 While we must always remain wary of imposing quality standards that lead to inefficient levels of investment, as we discuss in Attachment L, we have implemented several measures in setting quality incentives to avoid this.

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[425] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 84(b).

[426] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 84(b) and 111-118.

D73 Furthermore, the examples cited from the Australian context concern deterministic grid planning standards (akin to those used by Transpower), and not the outcome-based measures of reliability we use for the DPP, we do not consider this risk applies.

D74 We also consider that the Part 4 framework offers the flexibility to deal with specific circumstances that a distributor may encounter that cannot be catered for under a DPP approach. This includes the option of applying for a CPP or a variation of its quality standards where this would be a more appropriate response to delivering the long-term interests of consumers. However, this is a decision that each distributor will need to make based upon its own circumstances and specific needs of its business and the long-term interests of its consumers.

D75 Accordingly, we do not consider that Vector's notice demonstrates that applying an adjustment factor for Vector promote the outcome specified in section 52A(1)(b) of the Act.

Would applying an adjustment factor for Vector promote the outcome specified in section 52A(1)(c) of the Act?

D76 Section 52A(1)(c) of the Act specifies an outcome where suppliers of regulated goods or services share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices. According to Vector:

> The use of the depreciation adjustment lever is NPV neutral, however we demonstrate in this Notice the application of the lever will deliver intergenerational equity for customers at a time when technology adoption may cause price increase for customers and so will moderate any price increase from technology scenarios where this occurs. The use of the lever will also deliver greater fairness between customers as deprivation from new technology adoption where current technology trends continue is expected to exacerbate over time. Therefore, the lever will moderate the extent of any bifurcation between technology adopters and customers unable to access the new options.[427]

D77 We do not consider that intergenerational equity or fairness in respect of customer deprivation from new technology adoption are relevant to our consideration of whether applying adjustment factors would promote an outcome of Vector sharing with consumers the benefits of efficiency gains in the supply of electricity lines services, including through lower prices.

D78 Our position on intergenerational equity not being relevant is supported by ERANZ's submission on our draft decision.[428]

[427] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019) para 84(c).

[428] ERANZ "Submission on EDB DPP reset draft decisions paper" (18 July 2019)

D79 We note that the assumptions in Vector's scenario quoted above depend on pricing structures that reflect current volumetric charges. As noted in our discussion on innovation in Chapter 4, the Electricity Authority and distributors are currently undertaking work to examine how pricing structures may need to change in the future. Such changes may be as or more effective at mitigating these risks than accelerated recovery of assets.

D80 Based on the information provided in Vector's notice and subsequent consultation, our decision is that applying an adjustment factor would not promote an outcome of Vector sharing with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices.

Would applying an adjustment factor for Vector promote the outcome specified in section 52A(1)(d) of the Act?

D81 Section 52A(1)(d) of the Act specifies an outcome where suppliers of regulated goods or services are limited in their ability to extract excessive profits. Vector states that:

> As noted above, the use of the depreciation adjustment lever is still consistent with the Part 4 concept of NPV=0 which ensures EDBs can earn no more than a normal return on their investment. Rather the use of the lever will ensure greater inter-generational equity and fairness across customers to moderate the impact technology change is expected to have on network cost recovery.[429]

D82 As noted above, we do not consider that intergenerational equity and 'fairness' between customers are relevant to the limitation of excessive profits.

D83 While Vector's point that the adjustment is net present value neutral means that it would not be contrary to the purpose of limiting Vector's ability to extract excessive profits, nor would it promote that purpose.

D84 Based on the information provided in Vector's notice and subsequent consultation, our decision is that applying an adjustment factor would not promote an outcome of Vector being limited in its ability to extract excessive profits.

[429] Vector "Notice to Commerce Commission for Accelerated Depreciation Adjustment Factor" (28 February 2019), para 84(d).

Our overall exercise of discretion

D85 In its submission on our draft decision to not apply an adjustment factor, Entrust said that it "considers that Vector provided strong and compelling evidence, specific to Auckland's circumstances, which justify accelerated depreciation".[430] We disagree that Vector has provided strong and compelling evidence, as explained in the remainder of this attachment.

D86 Our view is that applying an adjustment factor would not provide long-term benefit to consumers. On the contrary, we consider there is a risk that it might be to the detriment of consumers, because it may lead to:

D86.1 a short-term relative increase in prices for consumers; or

D86.2 increased complexity of the regulatory settings.

D87 Vector did not provide a forecast of the effect of its proposed adjustment factor on its prices. However, our initial estimates were applying the maximum accelerated depreciation (ie, using a factor 0.85) would initially increase a distributor's prices by 4% to 7%. We consider that such an immediate price increase for consumers is against their interests in a direct sense, which we have considered against any potential benefits of an adjustment factor.

D88 We explicitly noted in our issues paper on DPP3 that reducing unnecessary complexity and compliance costs is a consideration for our decision making. We consider that the application of an adjustment factor to a distributor's assets will create additional complexity, which is a relevant for our consideration of Vector's application. For example, it could make performance analysis of the distributors (particularly comparative analysis) more difficult.

[430] Entrust "Submission on EDB DPP reset draft decisions paper" (18 July 2019), page 5.

Attachment E Incentives to improve efficiency

Purpose of this attachment

E1 This attachment sets out our final decisions relating to expenditure incentives under the IRIS.

Summary of our decisions

E2 Our decisions for expenditure incentives are summarised below:

E2.1 the capex incentive rate be equalised with the opex incentive rate.[431] Based on the WACC used for DPP3 (as calculated at September 2019),[432] the opex incentive rate will be approximately 23.5% (updated from draft decision);

E2.2 not introduce any additional opex smoothing mechanisms to the current mechanism in the EDB IM to smooth opex incentive payments (unchanged from draft decision);[433]

E2.3 not neutralise the impact of the IRIS adjustments for distributors who have purchased transmission assets (for which they have received avoided cost of transmission (ACOT) incentive payments) (unchanged from draft decision); and

E2.4 no change be made from DPP2 on how we treat deliberate undercharging in lieu of future expenditure incentive payments with the introduction of the undercharging 'banking' mechanism in the revenue cap for DPP3 (unchanged from draft decision).

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[431] The opex incentive rate is based on an EDB being able to retain the benefit of any efficiency saving for 5 years. This has not changed from DPP2, but the incentive rate will reduce with a lower WACC because the NPV value of 5 years of savings will be lower as a proportion of the NPV of the total value of the saving.

[432] Commerce Commission *Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path* [2019] NZCC 12 (25 September 2019).

[433] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.3.2(2)(b)(i).

IRIS IM amendments

E3 We have made amendments to the EDB IMs to give effect to the original policy intention of the opex IRIS mechanism. These drafting changes include a correction to the time value of money adjustment applied when smoothing the opex IRIS adjustment term.[434] We have also amended the language in clause 3.3.2 of the EDB IM.[435] This amendment is detailed in the IM changes reasons paper.

Analysis of expenditure during DPP2

E4 We consider it is important to present and analyse distributors' historical performance against opex and capex allowances to gain an understanding of how the industry is performing and how this may influence our decision making. This may give us an indication on how the current incentive settings in place during DPP2 for opex and capex are impacting suppliers.

E5 Figure E1 shows for each distributor the opex under- and overspends for the 2015-2020 regulatory period. We have included distributors' forecasts from AMPs as a proxy for Year 5 of the period (2020).

E6 Figure E2 shows how the under- and overspends accumulated to date translate to revenue impacts for the next regulatory period (including distributors' 2020 AMP forecast). This demonstrates that generally there is no clear trend as to whether distributors have under- or overspent in comparison to the opex allowances. There are, however, a few large individual negative IRIS revenue adjustments from distributors that have overspent during DPP2.

[434] The formula error came to light after releasing the final determination for the Wellington Electricity and Powerco CPPs. The issue relates to the adjustment made to accommodate for the time value of money resulting in the correct retention factor under the IRIS mechanism.

[435] Clause 3.3.2 of the EDB IMs references the 'DPP regulatory period' instead of 'regulatory period'. Amendments were included in the CPP determinations for Wellington Electricity and Powerco to correct for this.

Figure E1 Actual opex vs. allowance for period

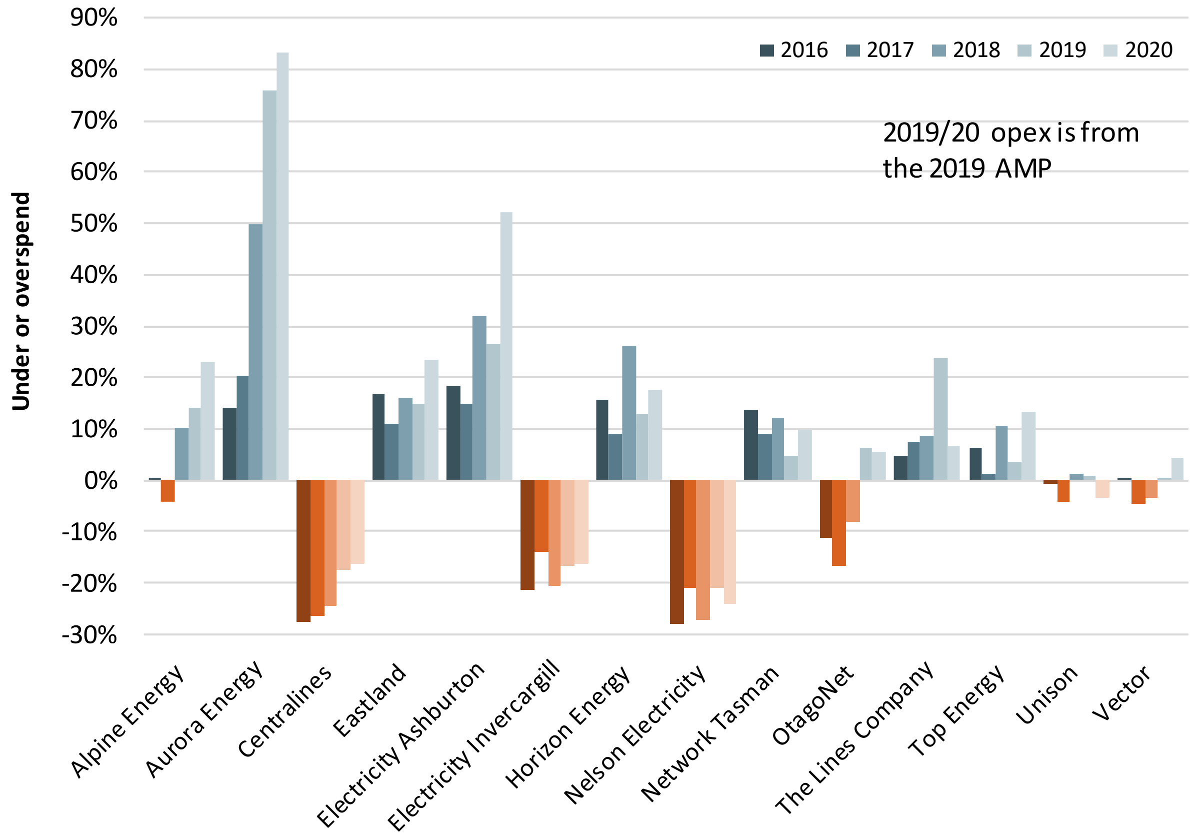
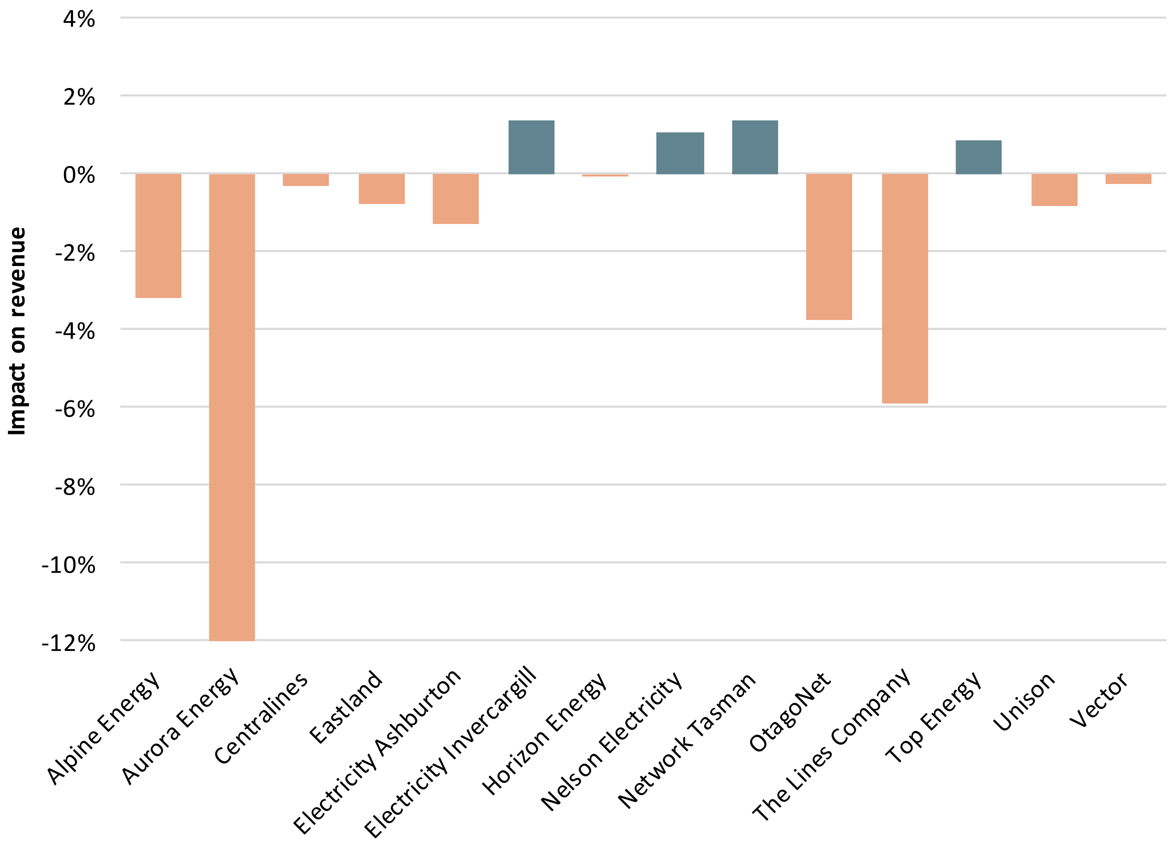


Figure E2 Opex IRIS impact on revenue (over the DPP3 period)



E7 Some of the values from Figures E1 and E2 may not be intuitive and are a result of how the IRIS mechanism works. The IRIS mechanism's adjustments are based on the timing of spending in the regulatory period. If there are greater underspends early in a period (compared to the latter years of the period), negative IRIS adjustment terms are required in the subsequent period to ensure that the distributor retains 34% of underspends over the life of the savings. The model analyses incremental changes between years to estimate which savings are permanent and temporary in nature.

E8 For example, we can look at Centralines as an example. In the first year of DPP2 Centralines makes cost savings in comparison to its allowance. This results in a positive opex IRIS carry-forward amount from Year 2 for a total of 5 years. However, from Year 2 onwards it makes incremental negative savings (ie, the savings made in Year 1 are reversed in comparison to the allowance). This results in negative opex IRIS carry-forward amounts for the remainder of DPP2, and results in an overall negative revenue adjustment over DPP3 as demonstrated in Figure E2.[436]

E9 The calculation of the capex incentive amount is complicated by the fact that capital expenditure is recovered over time through the return on and of capital. Consequently, in calculating the required adjustment, it is important to correct (or 'wash up') for the difference between;

E9.1 the revenue we allow, over the regulatory period, based on the forecast of capital expenditure relied on when setting the price-quality path; and

E9.2 the revenue required, over the regulatory period, based on the supplier's actual capital expenditure after the price-quality path started.

E10 By first calculating the adjustment required to wash up for this difference, the penalty/reward is more straightforward to calculate. In particular, after the wash up, the penalty/reward is simply the capex retention factor that we set multiplied by this difference.[437]

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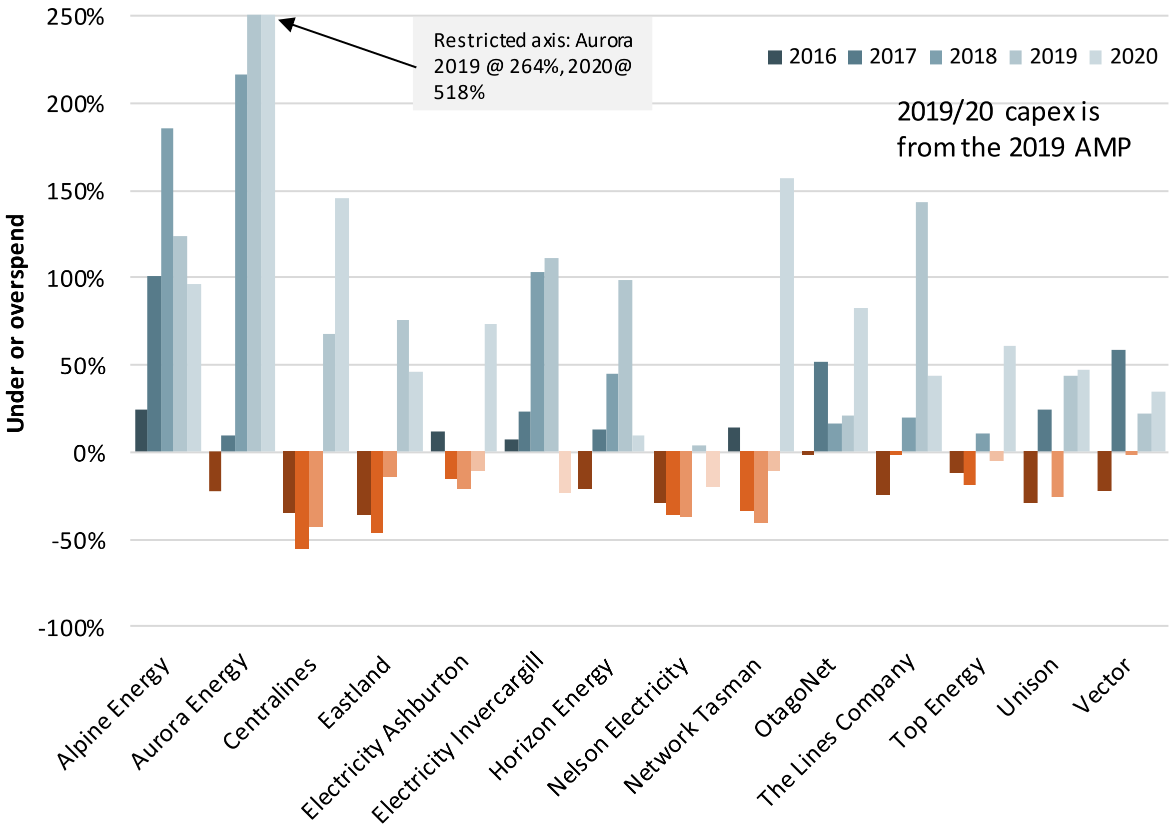
[436] This amount does not include the amount that Centralines will recover during DPP2 from the savings below the DPP2 opex allowance.

[437] This is explained in more detail in: Commerce Commission "Amendments to input methodologies for electricity distribution services and Transpower New Zealand Incremental Rolling Incentive Scheme" (27 November 2014), Chapter 6.

E11 Figure E3 shows for each distributor the capex under- and overspends accumulated in the regulatory period to date, including distributors' 2020 forecast from distributors' 2019 AMPs. There is a mix of distributors over- and under-spending the capex allowances. The general trend across most EDBs is overspending the capex allowance towards the end of DPP2 (regardless of whether the distributor has over- or underspent in previous years of the regulatory period).

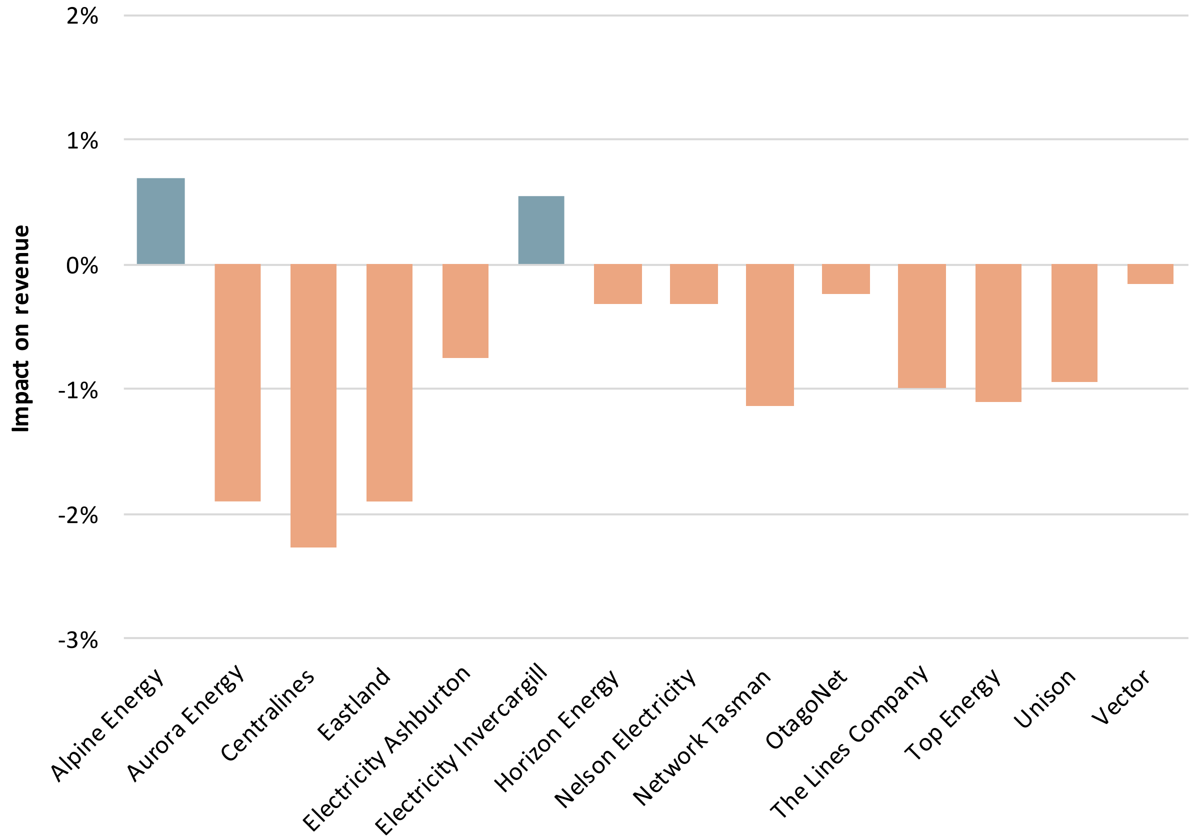
E12 Figure E4 shows how the under- and overspends accumulated to date translate to revenue impacts for the next regulatory period (including forecast AMPs). This demonstrates that, on average, for most distributors there will be negative revenue adjustments from the capex IRIS.[438]

Figure E3 Actual capex vs. allowance for period



[438] It is worth noting that the capex IRIS adjustment has two different factors: the wash-up amount, and the retention factor adjustment.

Figure E4 Capex IRIS impact on revenue (over the DPP3 period)



E13 As well as looking at individual suppliers, we consider it is useful to analyse how distributors on the DPP as a whole is performing against DPP2 opex and capex allowances. We have weighted suppliers by proportion of total opex and capex allowances across the industry.[439] From the above Figures it is clear that Aurora is a clear outlier in the last three years of DPP2 (2018 to 2020), and therefore we have removed it as an additional measure to gauge how the rest of the industry has performed.

E14 Figure E5 displays the aggregate weighted opex actuals against allowances across DPP2. Figure E6 displays the aggregate weighted capex actuals against allowances across DPP2.

[439] The proportions were calculated as the total opex (and capex) allowances over DPP2 as a portion of the total opex (and capex) allowances of all EDBs in the analysis over DPP2.

Figure E5 Opex – actual vs allowance

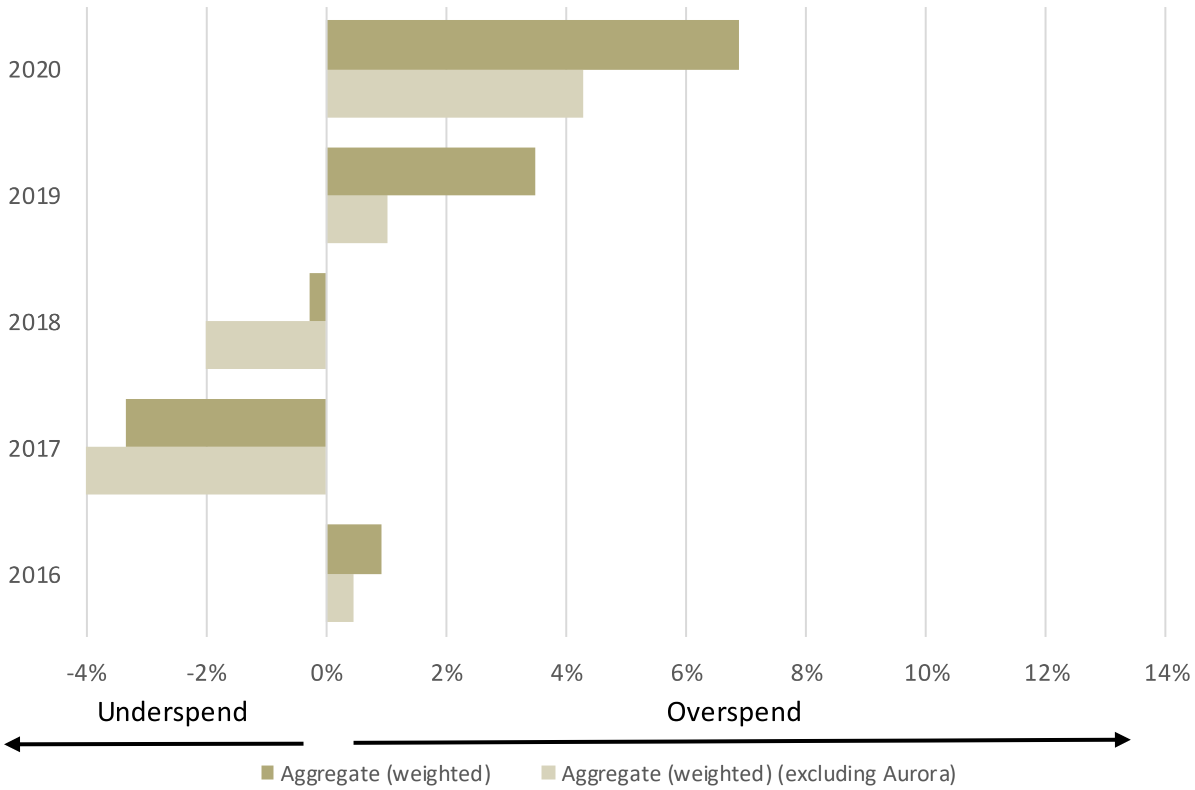
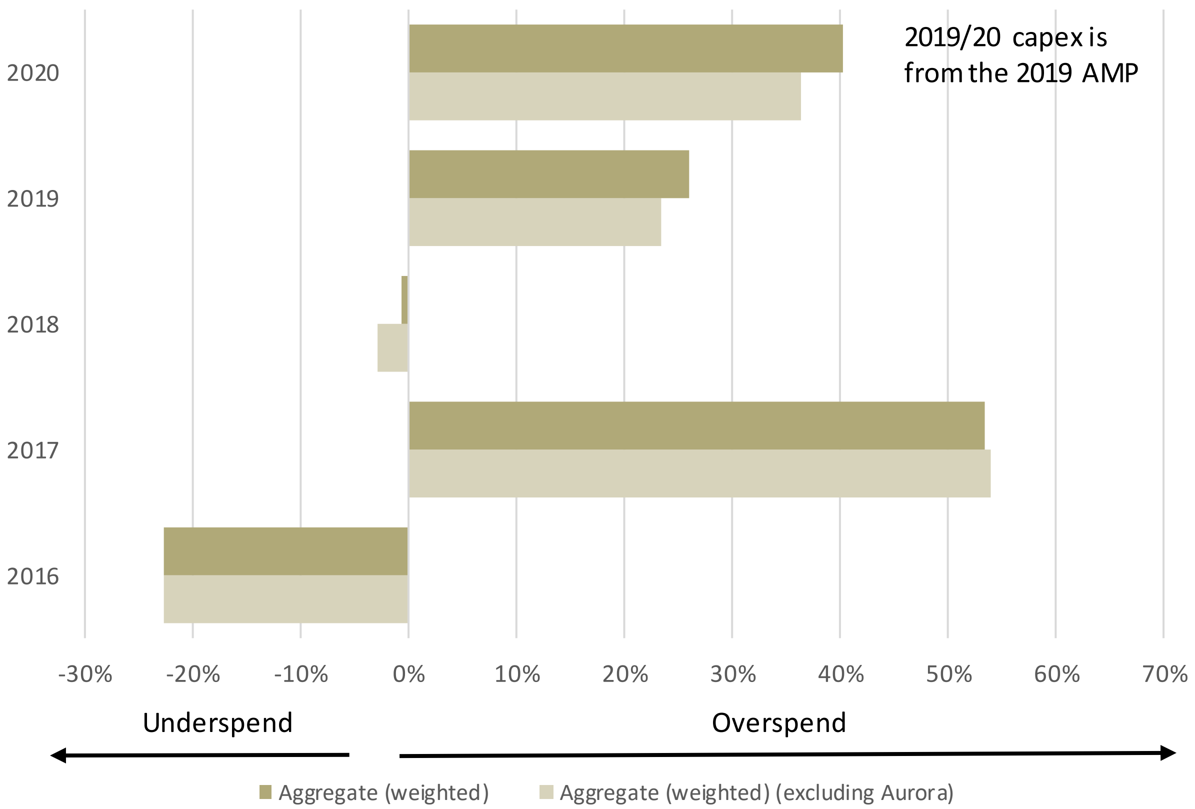


Figure E6 Capex – actual vs allowance



E15 At an aggregate level it appears that the industry is approximately neutral in terms of opex spend compared with allowances over DPP2. There was greater under-spending across the industry earlier in the period with subsequent overspends in the latter years. This may indicate that distributors have tried to find efficiencies early in the period but were required to spend more later in the period to cover necessary costs.

E16 On the capex side there has generally been overspending of allowances by distributors during DPP2. This could be due to a number of factors (increases in unexpected costs through the period, setting of DPP2 allowances etc) and could indicate that the weaker incentive rate was not leading to efficiencies being created.

E17 There are also a number of external factors that can lead to a preference for spending capex over opex (such as preferring to build or replace assets, as this has historically been the solution, rather than maintaining current assets or contracting a third-party solution).

Setting the expenditure incentive rates

E18 The expenditure incentives for opex and capex are part of a suite of incentives that may impact on distributors' expenditure and quality decision-making processes. The expenditure incentives are closely related to incentives on distributors to maintain or improve quality through the quality incentive scheme and to meet their associated quality standards enforceable under the Act.

E19 Our regime provides incentives for distributors to improve opex and capex cost efficiency and provides for these savings to be shared between distributors and consumers.

E20 To achieve this, we set incentive rates for opex and capex, which determine the proportion of any cost savings (or efficiency losses) that the distributors can retain (or bear in the case of a reduction in efficiency). Consumers benefit from improved efficiencies through lower network prices in future regulatory control periods.

E21 Under DPP2, the incentive rate that applied to opex differed from the incentive rate that applied to capex. The opex incentive rate is determined in the EDB IMs and is derived from the length of retention of cost under- or overspends and the WACC value.[440] This is based on the distributor's ability to retain the saving for five years (equivalent to the length of the regulatory period), with savings being discounted at the current WACC rate over the life of the saving.

[440] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.3.2.

E22 The capex incentive rate is determined as part of a DPP reset and is outlined in the EDB DPP determination.

E23 The opex incentive rate that applied under DPP2 was approximately 34%. The incentive rate for capex under DPP2 was 15%.

E24 Equalising the opex and capex incentive rates can help to provide distributors with equal incentives to find efficiencies regardless of whether these are through opex or capex solutions. Many submissions on our Issues and Draft Decisions paper called for the differential in incentive rates between opex and capex to be reduced or eliminated.[441] Some distributors also agreed with our proposal to equalise incentive rates conditional on receiving appropriate expenditure allowances.[442]

Reasons for addressing this issue

E25 We have an IRIS to ensure constant incentive rates for distributors to pursue opex and capex efficiencies over the regulatory period. By setting the incentive rates in advance, suppliers have certainty around the strength of the marginal incentives on efficiencies achieved. Consumers will share any benefits from any under- or overspends through lower or higher network prices in future regulatory control periods.

E26 As we noted in the issues paper, applying different incentive rates for opex and capex may create a preference or bias towards the type of expenditure that is subject to the lower incentive rate.[443] In addition to different incentive rates, there may be other factors which contribute to a preference towards particular types of expenditure.[444]

E27 In DPP2 there was a significant differential between the incentive rates applying to opex and capex, and this asymmetric treatment of opex and capex savings may contribute to a capex bias. This may have distorted decisions such as whether to consider non-wire (opex) solutions. Reducing or removing this differential will reduce this distortion.

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[441] For example, see: Contact Energy “Default price-quality paths for electricity distribution businesses from 1 April 2020 “ (18 December 2018), p. 1; Unison “Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper” (21 December 2018), p. 5; and MEUG “MEUG to CC EDB DPP3 reset 18 Jul 19” (18 July 2019), p. 5.

[442] For example, see: Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 6 and Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 15.

[443] Commerce Commission, “Default price-quality paths for electricity distribution businesses from 1 April 2020 – Issues Paper” (15 November 2018), para E23.

[444] For example, Frontier refer to a number of factors that could result in a capex bias, including a WACC uplift; company culture where capex solutions are favoured; and a preference to control assets rather than contracting with third parties. Frontier Economics “Total expenditure frameworks: a report prepared for the Australian Energy Market Commission” (December 2017), section 4.3.3.

E28 Also relevant to this topic are other workstreams such as the level of scrutiny applied to capex forecasts, the strength of any quality incentive scheme, incentives for innovation, and mitigating uncertainty.

Opex incentive rate

Decision

E29 Our decision is to not make a change to how the opex incentive rate is determined.

Background

E30 To provide distributors with an incentive to pursue efficiency savings through the period, the incentive rate that suppliers retain or bear from making efficiency gains (or efficiency losses) is set in the EDB IMs.[445] The opex incentive rate is derived from the length of retention of cost under- or overspends and the WACC value. This is based on the distributor's ability to retain the saving for five years (equivalent to the length of the regulatory period), with savings being discounted at the current WACC rate over the life of the saving.

E31 As previously noted, the opex incentive rate is derived from the length of retention of cost under- or overspends and the WACC value. This is based on the distributor's ability to retain the saving for five years (equivalent to the length of the regulatory period), with savings being discounted at the current WACC rate over the life of the saving.

What we said in our issues paper and draft decision

E32 In our issues paper we considered that the IRIS mechanism used in DPP2 to determine the operating expenditure incentive rate for DPP3 was appropriate because we considered that there was no substantial reason to deviate from the methodology that applied to DPP2.[446]

E33 We noted that our intended approach for DPP3 was to use the IRIS mechanism using the DPP3 WACC value, so that the distributors have certainty around the retention factor applied to operating expenditure efficiencies achieved throughout the regulatory period.

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[445] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.3.2.

[446] As part of the input methodologies review, we decided not to amend the DPP IRIS. Commerce Commission "Input methodologies review decisions: Report on the IM review" (20 December 2016), Chapter 9 and Chapter 17.

E34 In our draft decision we reiterated how the opex incentive rate is calculated and demonstrated how EDBs had performed against their allowances during DPP2.

Stakeholder views

E35 In a personal submission on our draft decision, Pat Duignan considers that the opex incentive rate in DPP2 has not been high enough to elicit opex efficiency savings during DPP2.[447]

E36 In its cross-submission, ENA responded to Mr Duignan's submission rejecting the assertion that the opex incentive scheme has been ineffective during DPP2.[448]

Our view

E37 As Figure E5 demonstrates, at an aggregate level it appears that distributors are approximately neutral in terms of opex spend compared with allowances over DPP2. In comparison to the capex outcomes from DPP2 (which had a lower incentive rate of 15%), EDBs have performed better against allowances for opex (with a DPP2 incentive rate of 34%).

E38 The opex incentive rate is one of the factors that influences EDBs' expenditure decisions during a period. Other factors such as the opex allowance that we set, projects that arise, level of substitutability, for example, can affect the level of opex savings. There is not likely to be an 'optimal' opex incentive rate that will result in savings to all suppliers (without putting reliability and necessary maintenance at risk for consumers).

E39 We consider that the methodology for determining the opex incentive rate, as specified in the EDB IM, is appropriate and reflects the time value of money (and external financial conditions) through our WACC estimate.

E40 As part of the 2016 input methodologies review we decided not to amend the DPP IRIS.[449] We can consider whether the current method for setting the opex incentive rate is appropriate during the next IM review.

Capex incentive rate

Decision

E41 Our decision is to set the capex incentive rate at the same rate as the opex incentive rate (which is based on the WACC and the length of the regulatory period).

[447] Pat Duignan "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp 3-4.

[448] ENA "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 3.

[449] Commerce Commission "Input methodologies review decisions: Report on the IM review" (20 December 2016), Chapter 9 and Chapter 17.

E42 Our decision is not to have different incentive rates for different types of capex in the IRIS mechanism.

Background

E43 To provide distributors with an incentive to pursue efficiency savings through the period, we determine a capex incentive rate that sets the proportion of any efficiency gains (or efficiency losses) that distributors can retain (or bear). The capex incentive rate is required to be determined by the Commission at each DPP reset. Distributors therefore have certainty that the incentive rate will be specified in advance of any efficiency improvements being achieved throughout the regulatory period.

E44 During DPP2 there was a significant differential between the opex and capex incentive rates. This differential can create incentives to increase capex spend and reduce opex, as the proportion of any opex savings that are retained by the distributor is more than twice that of any capex savings (34% incentive rate versus 15%). This potential preference for increasing capex may also result from other external factors.[450]

E45 Reducing the differential in incentive rates between opex and capex can have an impact on reducing any disincentive to consider non-wire (opex) solutions.

What we said in our issues paper and draft decision

E46 In our issues paper we considered whether the reasons for setting the capital expenditure retention factors at 15% in DPP2 remain valid for DPP3. For the capex IRIS incentive rate, we noted that the incentive rate should be broadly similar to the opex incentive rate, except where there are good reasons to prefer different values.

E47 We therefore reviewed the reasons that led us to set a lower capex incentive rate in 2014, to see if those reasons remain valid for DPP3 and sought views on what the applicable capex incentive rate should be.

E48 In our draft decision we considered having a 'blended incentive rate' approach based on the ENA's submission stating that not all categories of capex are substitutable with opex.[451] The ENA considered that there should be different incentive rates applying to different types of capex; system growth capex could face a 34% incentive rate (as the ENA consider that there are greater opportunities for substitution) and the rest of capex could face the current 15% rate.

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[450] External factors that may lead to a preference for capex solutions outside of our regime may include EDBs preferring to own their assets rather than procuring through a third party or the status quo of using capex solutions without considering opex alternatives.

[451] ENA "DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)" (20 December 2018), p. 19.

E49 In response to the suggestion of having different capex incentive rates for different capex categories we noted that this could lead to an 'intra-capex bias' where distributors prefer certain types of capex over others based on the applicable incentive rates.[452] We also noted that there is a grey area in how some types of capex projects can be classified, for example, certain projects could be classified as multiple capex categories. This could lead to gaming of the incentive rates based on how projects are classified.

E50 In our draft decision we proposed equalising the capex incentive rate with the opex incentive rate. We considered that increasing the capex incentive rate was appropriate given our proposal to increase the level of scrutiny applied to distributor capex forecasts. This mitigates concerns that a higher capex rate might encourage distributors to over-forecast capex (whether deliberate or not).

E51 We noted that unless rates are equalised across opex and capex, there could be incentives to favour one type of expenditure type over another.

Stakeholder views

E52 A number of distributors did not support the proposed equalisation of the capex incentive rate with the opex rate (which is determined in the IMs based on the WACC and length of the period).

E53 Wellington Electricity does not support the increase due to the risk of penalising distributors for genuine capital expenditure, for example, additional capex costs during the period that do not come within the capex allowance.[453]

E54 Powerco does not support the increase in capex rate because there is no evidence that the current IRIS settings are creating a problem and may incentivise distributors to defer network investment at a time when it is needed. Powerco also note that tying the capex incentive rate to the opex incentive rate (which varies with WACC) introduces inter-regulatory period inconsistency for capex (ie, $1 capex avoided in one period to be worth more or less than $1 avoided in a different period).[454]

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[452] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft reasons paper" (29 May 2019), E38 to E43.

[453] Wellington Electricity "Cross-submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 17.

[454] Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 20.

E55 Some submitters noted that there is currently a bias towards capex due to the different incentive rates,[455] and submissions generally supported our draft decision to equalise rates.[456]

E56 Unison supports neutralising trade-offs between opex and capex, as increasingly non-wire alternatives will become available to distributors which can effectively substitute opex for capex. Unison suspects that it is necessary to move to a totex regime to fully achieve this and note that the current settings of the allowances continue to favour capex over opex because opex is based on historical performance whereas capex is forward-looking.[457]

E57 ENA notes that members are not yet persuaded that the simple equalising of the proportion of NPV benefits addresses the concern that distributors do not face a neutral trade-off between opex and capex and suggests that this may only be addressed through a totex approach.[458]

E58 A number of distributors were supportive of equalising incentive rates conditional on receiving appropriate opex and capex allowances.[459]

E59 ERANZ support the equalisation of rates but raise the question as to whether the draft decision incentive rate of 26% was high enough. ERANZ states:[460]

> We support the equalisation of the rates and believe that it is a useful change to aid in aligning incentives on decisions of capital and operational spending.
>
> However, we raise the question as to whether the retention rate of 26% should be higher. In our judgement, the 26% retention rate does not give a large incentive for an EBD to become more efficient. A higher retention rate may incentivise greater productivity growth in the sector by rewarding underspending and penalising overspending to a greater degree.

E60 Mr Duignan considers that the capex incentive rate should be increased because the effective capex incentive rate is reduced by the WACC uplift.[461]

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455 For example: Contact Energy “Default price-quality paths for electricity distribution businesses from 1 April 2020 “ (18 December 2018), p. 1; ENA “DPP3 April 2020 Commission Issues paper (Part One Regulating capex, opex & incentives)” (20 December 2018), p. 19; and Unison “Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper” (21 December 2018), p. 5.

456 IEGA "Submission on EDB DPP reset draft decisions paper" (05 July 2019), p. 2; MEUG "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 5.

457 Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 19.

458 ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 20.

459 Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 6.

460 ERANZ "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 7-8.

461 Pat Duignan "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 5.

E61 In its cross-submission, ENA responded to Mr Duignan's submission on the effect of the WACC uplift on the capex incentive rate stating:[462]

> In effect, it is assumed that EDBs regard the 50th percentile WACC as representing their true cost of capital. ENA members submit that this assumption is erroneous. ENA members consider that a WACC of 5.13% (real return of 3.13% that is dropping and likely to be around 4.7%, 2.7% real, in the final decision) is not in any way, an incentive for investment, given the long-term risks of the business.
>
> At these levels of WACC, (where the real risk-free rate is now negative) there is strong risk of incentivising under-investment during this regulatory period. We note Duignan's comment that with a low risk-free rate, EDBs would be more incentivised to invest. We can assure the Commission that the situation is very much the opposite!

E62 Some distributors considered that the Commission should consider different incentive rates applying to different categories of capex. Unison suggested that:[463]

> As variations in customer capex are likely to be driven more by the volume and size of customers seeking connections, than variations in efficiency in connecting customers, we question the validity of the 26% capex IRIS adjustment. It is unclear what policy reason exists that either EDBs or existing customers should bear the volume/size risks on customer capex, compared with an approach of simply providing a wash-up that makes EDBs and existing customers neutral to the volume/size of customer connections.

E63 Powerco also suggest removing consumer connection, system growth and asset relocation expenditure from capex IRIS calculations to remove incentives for distributors to alter the timing and quantum of customer-initiated capex so that customers connections are not distorted.[464]

Our view

E64 As previously noted, unless rates are equalised across opex and capex, there could be incentives to favour one type of expenditure over another because of the incentive rate settings. Our decision is to equalise incentive rates so that distributors have generally consistent incentives to choose solutions and make savings that are most efficient for consumers, rather than preferring one type of expenditure over another.

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[462] ENA "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019), p. 3.

[463] Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), para 57.

[464] Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18.

E65 We note Unison's submission suggesting that a totex regime may be necessary to fully achieve substitutability between opex and capex. Our decision to equalise rates reduces the differential between types of expenditure for DPP3, and we will consider the option of moving to a totex approach in the future.[465]

E66 We note points from Vector stating that some types of capex have limited substitution with opex.[466] However, attempting to identify all capex categories with the potential to be substituted for opex could be arbitrary and may not be consistent across distributors.

E67 Some distributors submitted on our issues paper and draft decision that the capex incentive rate should not be increased because of uncertainty around the expenditure allowance and the risk that the incentive rate settings could encourage distributors to defer necessary capex investment.[467]

E68 The setting of the capex incentive rate is linked to how we set capex allowances - the higher the incentive rate, the higher the incentive to inflate forecasts. Given the constraints of a low-cost DPP, our capex allowances are our best estimate of required costs over the period and so this is the baseline to compare actual capex costs to.

E69 Our approach to forecasting the capex requirements of the distributors starts with the distributors' AMP forecasts, and then applies the scrutiny tests described in Attachment B. This can help mitigate the risk that distributors are over-rewarded for over-forecasting capex (whether deliberate or not) through the capex IRIS.

E70 We have also included additional reopeners specifically for certain types of projects, as set out in Chapter 4. This mitigates some of the concerns that distributors have expressed in terms of uncertainty as a reason to not support equalising of rates.

E71 Another issue is around promoting emerging technologies and innovative solutions to network problems. We do not want to disincentivise any potential emerging technologies from being used by distributors due to a lower capex incentive rate. Equalising rates will create a more level playing field to allow distributors to avoid spending capex through investing in innovative solutions using third parties (these solutions will generally be through opex).

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[465] We note that a move to a full totex approach would be a significant change in regulatory approach for EDBs. According to advice prepared by Frontier Economics for the AEMC, the transition to a totex framework would require significant development work and would likely take two to three years. See Frontier Economics "Total expenditure frameworks" (December 2017), p. 80.

[466] Vector "Key issues for DPP3" (21 December 2018), p. 12.

[467] For example, see: Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

E72 For example, the ENA Energy Efficiency Incentives Working Group also noted in 2014 that inconsistent incentives for capital expenditure relative to operating expenditure are: [468]

> particularly relevant to efficiency options that involve greater operating expenditure relative to traditional solutions. For example, EDBs may prefer capital expenditure solutions such as expanding substation capacity, over operating expenditure solutions such as contracting for demand-side response if there is a greater incentive to undertake capital expenditure.

E73 Some distributors have expressed concerns around increasing the capex incentive rate.[469] We note that with the opex incentive rate expected to fall for DPP3 (based on the lower WACC value), this could partially mitigate concerns around distributors having to bear proportions equal to the current 34% rate. As noted above, the opex incentive rate is 23.5%, based on the DPP3 WACC.

E74 In the DPP2 reset, one of the reasons for setting a low capex incentive rate (15%) was because distributors had significantly underspent capex allowances. It appears from the analysis at the beginning of the Attachment (see Figure E3) that this is not such a concern for the DPP3 reset with distributors expected to overspend their capex allowances on average over DPP2.

E75 In response to the inter-regulatory inconsistency raised by Powerco for the capex incentive rate, we note that the opex incentive rate varies between periods to reflect the time value of money reflected in the WACC being updated between regulatory periods.

E76 The changing discount rate is intended to reflect financial conditions during the period (and subsequently impacts the retention factor). In principle it may be desirable to maintain a constant capex incentive rate between periods so there exists no incentive to inefficiently defer (or move forward) expenditure between periods.

E77 However, this would come with a loss of flexibility for the rate to change between periods based on how distributors appear to be reacting to incentives or external financial conditions (as reflected in the WACC). Maintaining a constant capex rate between periods would also lead to the same issue of the capex rate being inconsistent with the opex rate as previously discussed.

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[468] ENA Energy Efficiency Incentives Working Group "Options and Incentives for Electricity Distribution Businesses to Improve Supply and Demand-Side Efficiency: Report to the Commerce Commission" (April 2014), p. v.

[469] For example, Aurora Energy "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018), p. 10; and Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 4.

E78 We note the submission from Mr Duignan suggesting that the capex incentive rate should be increased because the IRIS benefit will be partially offset by the WACC uplift.[470] We agree that this is one factor that will impact the effective incentive faced by distributors to reduce capex costs. There are also a number of other factors (some also mentioned in Mr Duignan's submission) such as the effect of quality incentives and quality standards that may impact the effective incentive to make capex savings.

E79 We are not trying to set the capex rate to mathematically take every relevant factor into account as it will likely be impossible to include all relevant factors and may differ between conditions affecting different distributors. We are aiming to reduce the differential in incentives for opex and capex as is currently the case and provide a general equalisation of incentive rates for distributors.

E80 We have a WACC uplift to take into account the asymmetric risk of providing suppliers with a WACC that is too low. Therefore, adjusting for this in the capex incentive rate and essentially providing distributors with an even greater incentive to reduce capex seems counterintuitive and against the original purpose of the uplift.

E81 As noted previously, we consider that introducing different incentive rates for different categories of capex would introduce further complexity to a mechanism that is already complex. We also note that there is a grey area in categorisation of different types of capex, so having different incentive rates could introduce an intra-capex bias. Having a zero-incentive rate for certain categories of capex could lead to inefficiency where costs are controllable and issues of categorisation of capex.

Smoothing of opex incentive payments

Decision

E82 Our decision is to not introduce any additional smoothing adjustments to opex IRIS amounts.

What we said in our issues paper and draft decision

E83 In our issues paper we considered it is possible that 'opex incentive amounts' could be sufficiently large to cause price shocks to consumers and/or revenue shocks to distributors.

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470 Pat Duignan "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 5.

E84 In our draft decision we considered whether the IRIS opex incentive amounts themselves could be smoothed over the period. We decided that this would involve distributors forecasting the incentive amount values for the remainder of the period and smoothing to ensure NPV neutrality and would require an IM change and introduce additional complexity to the regime. Therefore, we decided not to pursue the option.

E85 Our draft decision was not to propose any additional smoothing adjustments to the opex incentive amounts. We noted that the current mechanism in the EDB IMs smooths the 'base year adjustment term' which is calculated in year 2 of the DPP period.[471] This mechanism smooths this lumpy adjustment term in the IRIS between periods.

E86 As part of our draft decision on the revenue cap we proposed a smoothing mechanism for the overall revenue path that limits the change in revenue from year to year. This would help control any significant volatility from IRIS incentive payments throughout a period.

Stakeholder views

E87 Wellington Electricity supported the concept of a net present value (NPV) neutral smoothing mechanism if the mechanism is low-cost to implement and operate.[472] The Lines Company and Orion also agreed.[473]

E88 Aurora supported the proposal in principle subject to understanding the detail of the proposal, agreeing that it could help alleviate price shocks for consumers.[474]

E89 We received no submissions on this point on our draft decision.

Our decision

E90 We consider that the current mechanisms in place to smooth certain IRIS amounts as well as general revenue smoothing are appropriate to reduce the risk of price shocks to consumers or revenue shocks to distributors.

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[471] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.3.2(2)(b)(i).

[472] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 21.

[473] The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), p. 11; and Orion "Submission on EDB DDP3 Reset " (20 December 2018), p. 9.

[474] Aurora Energy "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018), p. 10.

Purchased transmission assets

Decision

E91 Our decision is to not allow any IRIS adjustments from opex costs in DPP2.

Background

E92 Eastland and Wellington Electricity have raised issues relating to how the IRIS interacts with transmission asset purchases.[475]

E93 Eastland and Network Tasman both purchased assets on 31 March 2015. As part of our process for setting the 2015-2020 DPP, distributors submitted that they should retain the 5 years of ACOT charges provided for in the IMs as an incentive to purchase transmission assets and receive an allowance for capex and opex associated with the transmission assets over the period.[476]

E94 In DPP2, distributors are able to recover, for a period of five years, the value of transmission charges that are avoided by purchasing an asset from Transpower.[477] We adopted this for DPP2 as we considered that the intention of the ACOT incentive mechanism was to cover the costs of asset purchase and any subsequent capital expenditure on the transferred asset until the next regulatory reset.[478] At the next reset any such expenditure will enter the RAB. We also noted that there would be no specifically identified allowance for operating expenditure associated with purchased assets.[479]

E95 We previously considered that if the distributors retain the ACOT payments as well as the allowances under opex and capex for the assets they would likely be overcompensated.

[475] Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 6; Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 13.

[476] Eastland Network "Default price-quality paths from 1 April 2015 for 17 electricity distributors" (29 August 2014), paras 27–31; and PwC "Submission to the Commerce Commission on Proposed Default Price-Quality Paths for Electricity Distributors From 1 April 2015 – Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), para 69.

[477] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clauses 3.1.3(1)(b) and 3.1.3(1)(e).

[478] Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main Policy Paper" (28 November 2014), para D38.

[479] Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main Policy Paper" (28 November 2014), paras D44-D48.

E96 In our final DPP2 reasons paper we provided a view on providing distributors an opex allowance for the transmission (spur) assets in addition to the ACOT payments:[480]

> Including an additional adjustment for operating expenditure associated with spur assets would likely over-compensate distributors. This expenditure would not therefore meet the objective of avoiding double-counting as it is captured in other components of the price-quality path. We were also not able to robustly verify the information provided by distributors on their additional expenditure for spur assets. It is therefore not clear whether the suggested amount reflects efficient expenditure.

E97 During the DPP2 reset, Network Tasman stated that they acknowledge that any shortfall in opex should be adequately covered through the ACOT payments:[481]

> "…we acknowledge the 5 year avoid cost allowance within recoverable costs under the IMs may provide adequate offset…"

What we said in our issues paper and draft decision

E98 In our draft decision we noted the decision we made in 2015 to not include the operating costs in the opex allowances of the distributors as we considered that distributors were already compensated through the capex allowance and ACOT payments.[482]

E99 As we did not allow the operating costs associated with the transmission assets into the distributors' opex allowances in DPP2, the decision for the DPP3 reset is whether we should neutralise the impact of the IRIS adjustments for distributors who have purchased transmission assets (for which they have received ACOT incentive payments).

E100 We sought views from stakeholders on whether we should neutralise the impact of the opex IRIS adjustments for distributors who have purchased transmission assets (for which they have received ACOT incentive payments).

[480] Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020" Low cost forecasting approaches" (28 November 2014), paras 3.51-3.52.

[481] Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main Policy Paper" (28 November 2014), para D49.2.

[482] Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main Policy Paper" (28 November 2014), Attachment D.

Stakeholder views

Submissions on the issues paper

E101 In its submission on our issues paper, Eastland stated that the operating costs of these transmission assets are considered under the IRIS scheme to be an inefficiency and revenue losses will be incurred.[483]

E102 Wellington Electricity also suggested in its submission that the IRIS mechanism should be adjusted to exclude any expenditure relating to the operation of a newly purchased transmission asset.[484]

Submissions on our draft decision

E103 Eastland consider that the opex IRIS penalties are overstated because they include penalties for opex which was deliberately excluded from the opex allowance. Eastland considers that the implementation of the DPP opex IRIS scheme, after the ACOT incentive scheme had been in operation for some time, retrospectively changed the operation of the ACOT scheme, and is not consistent with the policy intent of the IRIS or ACOT incentives. Eastland states that it is of concern that one incentive should be used to offset the benefits of another.

E104 Network Tasman considers that if an aspect of regulation overcompensates distributors, then the Commission should modify that aspect of the framework directly rather than tinker with other aspects of the regime. Network Tasman considers that we have already ring-fenced opex costs relating to transmission investments. Rather, Network Tasman suggests that the Commission could amend the opex allowance specified for IRIS to include newly acquired transmission assets.

E105 Horizon and ENA also suggested that we neutralise the impact of the opex IRIS adjustments.

Our decision

E106 We consider that the purpose of the ACOT payments is to cover the costs of the transmission assets (ie, the opex costs and the return on and of capital).[485] We want distributors to purchase transmission assets where it is more efficient for the distributor to own than Transpower.

[483] Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 6.

[484] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 13.

[485] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft reasons paper" (29 May 2019), para D38–D48.

E107 We decided that opex costs of transmission assets should be funded through the recoverable costs of the ACOT payments (but not included in the opex allowance). In DPP2 we decided that opex IRIS adjustments from transmission assets to not be accounted for.

E108 The additional opex spent on transmission assets will become part of the baseline opex level, so will form part of forecast opex for future periods. Therefore, there will only be an opex IRIS adjustment for one regulatory period and these will be reflected in future forecasts. We have also allowed a capex allowance on top of the ACOT payments.

E109 Overall, we consider that distributors will be compensated appropriately, and if we allowed an opex allowance on top of the ACOT payment this would likely overcompensate distributors – we consider that this is not in the best interests of consumers.

E110 Based on analysis undertaken as part of the DPP3 reset, for Eastland the ACOT payments more than covered the operating costs during DPP2 and the opex IRIS adjustments combined. Eastland receives ACOT payments of $3,746,000 for each year in DPP2.[486] The ACOT payments for DPP2, less the operating costs and future opex IRIS adjustment result in a remainder of approximately $6 million for Eastland.

E111 ACOT is a relatively unsophisticated mechanism, which is intended to cover the avoided transmission costs. Making changes to this mechanism requires amendments to the IMs rather than changing the determination of the DPP3.

E112 Taking the value of the transmission assets out of the opex IRIS mechanism could set a precedent for other requests to ringfence expenditure outside of the IRIS mechanism. The original intent of the IRIS was to be a mechanism that we set and do not adjust during the period unless we need to.

E113 The Commission has a general policy for not making retroactive changes to the incentives that distributors face during a period. Allowing for distortions to incentives after savings (or overspends) have been incurred reduces certainty and the intention of the incentive regime.

Undercharging

Decision

E114 Our decision is not to make an adjustment for the capex or opex IRIS outcome from undercharging.

[486] These can be found on Eastland's disclosures on its website under 'Pricing Methodology'.

Background

E115 Under the current price cap for DPP2, distributors cannot recover any undercharging relative to its MAR. This means that to the extent a distributor chooses to bring forward any IRIS payments due to consumers in the next regulatory period through lower prices in the current regulatory period, the distributor will still be subject to IRIS payments in the next regulatory period. This arises because the IRIS effectively assumes that distributors charge up to their allowance when calculating the incentive adjustments.

E116 The implication is that distributors will not recover some revenue from consumers (undercharging) for which they would have been entitled to, and then essentially pay a refund to consumers which had not been paid for in the first place (ie, for revenue that had not been collected). Distributors bear a proportion of this 'refund' through the IRIS and cannot recover these costs in subsequent years under the current price cap methodology.

E117 This issue has been raised by Centralines who have undercharged consumers during DPP2.[487]

E118 In assessing voluntary undercharging in DPP2, we considered that a retroactive change was not appropriate. We considered that it should be known what rules were in place during DPP2, so any undercharging should have been undertaken anticipating the incentive outcome. In the case of Centralines, we cannot be sure there was a direct link between the undercharging and lower capex spend, or whether the undercharging was for other reasons.

What we said in our draft decision

E119 In our draft decision we considered that the introduction of the revenue cap undercharge 'banking' mechanism addressed most of the concerns around any future undercharging by allowing IRIS payments to consumers to be brought forward.

[487] Centralines underspent its capex allowance by approximately 50%.

Stakeholder views

E120 Centralines submitted that in its case, the lower expenditure has been more than matched by pricing significantly under the allowed DPP price path (while network performance has consistently been within SAIDI and SAIFI limits). According to Centralines, it will have to reduce revenues below the level required to deliver a reasonable return in DPP3.[488] Centralines would effectively have to make refunds to customers in DPP3 for money that it has not collected from consumers during DPP2.

E121 Centralines submits that the Commission's approach is inconsistent with the long-term interests of consumers, suggesting that our draft decision focused on implementation of rules rather than the genuine long-term interests of consumers.[489]

E122 Centralines submits that:[490]

> … the only reasonable outcome is to adjust Centralines' revenue allowance to offset the capex IRIS adjustment. We note that the Commission has stated that it would make a step change adjustment for any EDB that has included pecuniary penalties in opex to ensure that the opex IRIS mechanism does not allow the EDB to pass-through 74% of the penalty to consumers – an outcome that it considers would be perverse (para A60). Centralines submits that it would be similarly perverse for the Commission to insist Centralines provides refunds to consumers for money it has not actually collected. A step change should therefore be provided on the same basis.

E123 Centralines submitted that this is not the intended outcome from the IRIS, and that this would be inconsistent with the Commission's FCM principle.

Our view

E124 For future voluntary undercharging, the introduction of the revenue cap undercharge 'banking' mechanism provides flexibility to distributors for any future undercharging by allowing undercharged amounts (up to a certain limit) to be recovered in the future. This is implemented through a timing adjustment for the value of undercharging. This is explained further in Attachment H.

E125 Under the current price cap, distributors that voluntarily undercharged could not recover the undercharge amount in subsequent periods. Consequently, there may have been a potential disincentive to undercharge consumers without such a mechanism to allow recovery (up to a certain level) of undercharging.

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488 Centralines "Submission on DPP Reset Issues Paper" (21 December 2018), p. 1.

489 Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 16.

490 Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 16.

E126 In the case of Centralines undercharging its price cap during DPP2, this is a retrospective issue. The rules in place on undercharging and the impact on IRIS have not changed during DPP2.

E127 Centralines are requesting that we provide a step change to its revenue allowance to offset the capex IRIS adjustment. We cannot identify what the undercharging was due to (efficiency, deferred expenditure, or inflated forecasts), and therefore making a retroactive adjustment for this under-spending would undermine the credibility of the incentive regime. Any change to revenues for capex IRIS adjustments would also need to apply to other distributors that have undercharged their price cap in DPP2, which impacts all distributors to varying degrees.

E128 We want distributors to continue to undercharge their allowable revenue where it is in the best interests of consumers and the wider community. However, distributors looking to undercharge should consider the IRIS impact when considering the level of undercharging.

E129 In response to Centralines' submission point around comparisons to pecuniary penalties in the opex allowance, we note that our approach is consistent. We have not adjusted DPP2 incentives for either undercharging or for pecuniary penalties.

E130 On the other hand, undercharging is undertaken voluntarily by the supplier (benefitting consumers) but leads to loss of incentives to achieve efficiency savings throughout the period. If we provide Centralines with additional revenue to offset the IRIS adjustment, it would be very difficult to disentangle any efficiency savings from the amount undercharged.

E131 We note that our decision on undercharging is consistent with our decision on pecuniary penalties. Pecuniary penalties will only be excluded from the application of the IRIS mechanism in future periods, as we consider consumers should not bear a proportion of these costs. The treatment of undercharging is consistent with pecuniary penalties in that it does not involve retrospective adjustments to the IRIS carry-forward adjustments (as the IRIS adjustments in DPP3 are based on values from DPP2).

E132 We consider that our decision will provide guidance which should help ensure that if a distributor wishes to underspend, that it takes the IRIS impact into account when doing so. As previously noted, the Commission has a general policy for not making retroactive changes to the incentives that distributors face during a period. Allowing for distortions to incentives after savings (or overspends) have been incurred reduces certainty and the intention of the incentive regime.

Other technical issues raised in submissions

IRIS model

E133 As part of the DPP2 reset we published an 'illustrative' model that was simplified to give an indication of how the capex IRIS model works. We understand that some distributors are using this illustrative model to calculate what their IRIS adjustments will be for the following period.

E134 As part of our draft decision package we published a comprehensive capex IRIS model for stakeholders to engage with.[491]

E135 We will publish an updated IRIS model prior to DPP3 beginning to assist distributors in complying with its obligations. We note that Vector and ENA have raised some minor technical corrections which we will take into account in the final model.[492]

E136 The ENA also noted that the remaining life values in the IRIS model published with our draft decision contained a minor calculation error.[493] We consider that the application of the remaining asset lives in the IRIS model published with the draft decision is appropriate and consistent with our DPP2 and DPP3 financial model, and any change to these values would create an inconsistency between the capex IRIS adjustments and suppliers' RABs.

E137 Vector and the ENA have also raised concerns around including actual asset lives for commissioned assets in the capex IRIS model.[494] We consider that this is an important step in calculating the capex IRIS incentive amounts to be consistent with the IMs, but do not consider that including the template for this in the formal capex IRIS model is appropriate. We want to provide distributors with flexibility to apply actual asset lives, in line with the IMs, using its own systems and asset profiles to calculate the correct capex IRIS retention.[495]

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[491] See: https://comcom.govt.nz/__data/assets/excel_doc/0028/155836/Calculations-of-IRIS-recoverable-costs-for-DPP3-EDB-DPP3-draft-21-June-2019.xlsx.

[492] Vector "Submission on companion paper to updated models" (9 October 2019), para 110; ENA "Submission on companion paper to updated models" (9 October 2019), p. 9.

[493] ENA "Submission on companion paper to updated models" (9 October 2019), p. 9.

[494] Vector "Submission on companion paper to updated models" (9 October 2019), p. 5-6; and ENA "Submission on companion paper to updated models" (9 October 2019), p. 9-10.

[495] We note that this would involve EDBs inputting the asset lives of newly commissioned assets into the capex IRIS model to calculate the capex incentive amount.

Discount factor used in IRIS model

E138 Mr Duignan considers that the midpoint level of the WACC (50th percentile) should be used rather than the 67th percentile for the discount rate used in calculating the strength of the relevant IRIS and WACC incentives.[496]

E139 We agree that technically the 50th percentile WACC could be an appropriate discount factor to be used to present value cash flows in the IRIS mechanism. This is a wider issue than just the IRIS calculation and would impact a range of different models. Introducing different WACCs for different purposes within the regulatory regime may introduce confusion.

E140 Mr Duignan also suggested that the Commission provide a view on whether a post-tax WACC should be used (rather than the vanilla WACC that we currently use) as the relevant discount rate in the opex IRIS:[497]

> It is possible, depending on the exact way tax is treated in the operation of the Opex IRIS, that the post-tax WACC rather than the vanilla WACC could be the relevant discount rate to use in assessing a distributor's incentives regarding expenditure decisions. I hope that the Commission will provide its view on this issue.

E141 The WACC is used in the opex IRIS only as a discount rate to calculate the retention factor between distributors and consumers to reflect external financial conditions. We apply a vanilla WACC to calculate the opex retention factor to be consistent with how the retention factor has been applied in DPP2 as well as for the opex incentive rate and base capex incentive rate for Transpower. As part of the IM review we can look at whether a post-tax WACC is more appropriate for discounting in terms of IRIS.

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[496] Pat Duignan "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

[497] Pat Duignan "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 2.

Attachment F Incentives for innovation

Purpose of this attachment

F1 This attachment explains the details of our new mechanism to further incentivise innovation.

F2 Our reasoning for introducing this new mechanism is provided in Chapter 4.

Recoverable cost for expenditure on innovative projects

F3 We have introduced a recoverable cost term in the EDB IMs and specified the criteria and limits in this DPP so that the recoverable cost:

F3.1 is targeted for expenditure on innovative projects;[498]

F3.2 requires at least 50% contribution from the distributor;[499]

F3.3 is limited to the amounts specified in Table F1, which was calculated as the higher of 0.1% of our forecast of allowable revenue (excluding pass-through and recoverable costs) or $150,000 over DPP3;

F3.4 requires a report from an independent engineer or other suitable specialist that the planned expenditure on the project meets the set of criteria for it to be considered an innovation project and potentially benefits consumers.

[498] Innovation project means a project that is focussed on the creation, development or application of a new or improved technology, process, or approach in respect of the provision of electricity lines services in New Zealand.

[499] The contribution from the EDB should be treated as capital or operating expenditure of the contributing EDB, while any capital expenditure treated under this mechanism as a recoverable cost would not enter the regulated asset base.

Table F1 Recoverable cost limits for the innovation project allowance

Distributor	Cumulative limit ($000)
Alpine Energy	222
Aurora Energy	454
Centralines	150
EA Networks	173
Eastland Network	150
Electricity Invercargill	150
Horizon Energy	150
Nelson Electricity	150
Network Tasman	150
Orion NZ	825
OtagoNet	150
The Lines Company	181
Top Energy	198
Unison Networks	520
Vector Lines	2,022
TOTAL	5,645

F4 The new recoverable cost is specified in clause 3.1.3 of the EDB IMs. The criteria are specified in the EDB DPP determination.

Contribution from the distributor

F5 The new recoverable cost requires an equal or greater contribution from the distributor, to be treated as capital or operating expenditure under our rules of regulation.

F6 The main reasons for the requirement of a contribution from distributors are that doing so will ensure that there are incentives in place for the distributor to minimise the cost of the project and ensure that customers are not exposed to all of the financial risks associated with such projects.

F7 We recognise that the contribution requirement may incentivise distributors to select projects that are more likely to be successful and benefit them financially, for example, projects where the full extent of potential benefits are uncertain but most likely to result in efficiency or quality improvements in future regulatory periods. However, on balance, we consider that maintaining an incentive to minimise costs is more important than this risk.

F8 If the innovative project involves capital expenditure, the expenditure treated as a recoverable cost would not be eligible to be placed in the regulated asset base because doing so would allow for over-recovery of the costs. The IMs have therefore been amended to specifically exclude any capital expenditure portion of the recoverable cost from the definitions of value of commissioned assets and forecast value of commissioned assets. [500]

F9 The contribution from the distributor is a minimum requirement, so greater contributions from the distributor or other parties are possible and encouraged.

F10 Distributors are also able to seek contributions from other sources such as innovation and science funds in addition to their contribution. We understand that some third-party funding sources require a contribution from the recipient, and the innovation mechanism will support this. Distributors may also use the funds for joint projects with other distributors or other businesses or organisations, which may result in greater innovation benefits for the sector.

F11 Unison has suggested that the innovation mechanism should be a pooled mechanism to allow for larger projects than individual distributors will be able to afford.[501] However, we consider that distributors are able to manage the arrangement of joint projects, as suggested by MEUG, without the mechanism forcing the pooling of the mechanism funds.[502]

Limit: calculated as the higher of 0.1% of revenue or $150,000

F12 The cumulative total of the recoverable cost is limited for each distributor to the amounts specified in Table F1, which was calculated as the greater of 0.1% of our forecast of net allowable revenue or $150,000 over the regulatory period. This equates to approximately $6m across the non-exempt distributors if fully used, excluding distributors that are currently on CPPs.[503]

F13 The limit applies cumulatively over the full regulatory period rather than on an annual basis to avoid distributors needing to spread the project(s) over the full regulatory period. It may be the case that distributors wish to undertake higher levels of investment in particular years given the nature of the projects funded through this incentive mechanism.

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[500] Commerce Commission *Electricity Distribution Services Input Methodologies Amendments Determination (No. 2)* [2019] NZCC 20 (26 November 2019), clause 2.2.11(1)(k).

[501] Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

[502] MEUG "Cross-submission on EDB DPP reset draft decisions paper" (12 August 2019).

[503] However, we note that the recoverable cost will not be available to distributors that are currently under a CPP until they enter a new DPP or CPP.

F14 We have used our judgement to calculate the limits at the higher of 0.1% or $150,000. Although we recognise that this limit is lower than some of the mechanisms in other countries and that there may be significant benefits from a larger scheme, we consider that this level is an appropriate starting point because it recognises that there are several risks and downsides of the new mechanism (as described in paragraphs 4.76 to 4.83), and so balances the benefits and risks. The moderate limit also means that we can set the approval and compliance requirements in a relatively simple and low-cost way.

F15 As detailed in Chapter 4, there was no consensus in submissions on our draft decision on the introduction and scale of the innovation mechanism. Submitters that supported an innovation mechanism submitted that the limit should be higher, while others submitted that it should not be introduced at all. This aligns with our view that there are a range of benefits and risks, reinforcing our decision to introduce the mechanism with a moderate limit.

F16 In its submission on our draft decision, MEUG also noted these uncertainties and suggested that there was insufficient evidence of lower than optimal levels of innovation to support such a mechanism. [504] We agree that it would be beneficial to regulation-setting to have more evidence on innovation in the sector. However, we do not consider that it is feasible to thoroughly research this without significant research costs, which may not be proportionate to the scale of the issue, and consistent with the relatively low-cost nature of the DPP. We consider that this is consistent with our decision to introduce the mechanism at the level of funding we have implemented.

F17 We have set the limit as a maximum of a percentage of revenue or an absolute value to ensure that the mechanism is relevant to the smaller distributors to support diversity of innovation, without creating an excessive price burden for consumers. This decision is in line with several submissions that we received on the draft decision (which only set the limit at 0.1% of revenue) that the amount would be too small to be of any use for smaller distributors, such as Centralines:[505]

> The Commission proposes an innovation allowance of 0.1% of revenues, subject to the EDB contributing an equal amount and having an engineer verify the innovation. For Centralines, the innovation allowance would amount to $10,000 per annum, which would be insufficient allowance to fund any innovation project, let alone make any contribution to an engineering report.

[504] MEUG "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

[505] Centralines “Submission on EDB DPP reset draft decisions paper” (18 July 2019), page 17.

F18 For the smallest distributor, Nelson Electricity, the $150,000 over the regulatory period equates to approximately 0.5% of forecast net allowable revenue. Several submissions argued for a larger increase in the limits, however, we do not think that this is appropriate at this time under the DPP framework. We also note the concerns of MEUG, which considers that distributors should be able to adequately fund innovation projects from existing funding and by partnering with third parties. [506]

F19 Circumstances where a distributor wishes to undertake substantial changes to the way it manages its network are beyond the scope of the innovation recoverable cost and are more appropriately considered as part of a CPP application. A CPP allows us the ability to apply greater scrutiny, and to vary the way the price-quality path functions to account for innovative approaches.

Ex-post approval by Commission and ex-ante confirmation by a suitable specialist

F20 Our ex-post approval requirements for the recoverable cost is that the Commission must be provided with a report by a registered engineer or other suitable specialist that the ex-ante criteria are met

F21 The IMs and DPP determination also require that:

F21.1 the amount would not make the cumulative innovation recoverable cost amount over the regulatory period greater than the specified limit;

F21.2 the distributor has made a contribution to the project of at least the same amount as the recoverable cost; and

F21.3 a report that covers the findings of the project is made public after the completion of the project.

F22 The inclusion of the requirement to publicly share project findings is a change from our draft decision, and is in response to several submissions that raised the importance of doing so in order to achieve the benefits of innovation across the sector.[507]

F23 Our ex-ante criteria for the recoverable cost, to be confirmed by an independent specialist to the best of their knowledge, are:

F23.1 The specialist making the report is independent of the distributor(s) and is registered as an engineer (New Zealand CPEng), or is a suitable specialist;

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[506] MEUG "Cross-submission on EDB DPP reset draft decisions paper" (12 August 2019).

[507] Such as ENA “Submission on EDB DPP reset draft decisions paper” (18 July 2019).

F23.2 the planned expenditure is solely aimed at either or both of:

F23.2.1 delivering the electricity distribution service at a lower cost; or

F23.2.2 delivering the electricity distribution service at a higher level of quality; and

F23.3 the planned expenditure is focused on the creation, development, or application of a new or improved technology, process, or approach in respect of the provision of electricity lines services in New Zealand; and

F23.4 the focus of the planned expenditure has a reasonable prospect of being scaled up within the distributor or to other distributors if it is successful, i.e. the benefits are of general application to that distributor or other distributors

F24 The requirement for the projects to be solely focused on the cost and quality of the electricity distribution services is to reduce any risk of distorting investment in adjacent markets. This requirement may be able to be altered in future regulatory periods if this risk is found to be minimal or is otherwise reduced.

F25 The requirement for ex-ante reporting by an independent engineer or other suitable specialist is for them to state that, in their opinion, the project planned by the distributor as evidenced by a published business case meets the Commission's criteria. We consider that this relatively low-cost and simple requirement is proportionate to the limit of the recoverable cost.

F26 The signed statement by the independent engineer or suitable specialist and the business case are required to be published and provided to the Commission. The business cases may be provided to the Commission on a confidential basis if required for reasons of commercial sensitivity, in which case we would require an explanation of the cost allocation approach if the commercial sensitivity relates to the distributor itself, or a statement of commercial sensitivity from a third-party provider if the sensitivity relates to the third-party provider

F27 We may be open to engaging with distributors on the kinds of projects they are seeking to put the allowance towards, and the suitability of proposed specialists. Any view provided ex-ante by the Commission would be non-binding, but we understand that such a view may be useful to distributors to provide an indication of the outcomes of the approvals process.

F28 We have tightened the definition of innovation in the criteria as we have accepted MEUG's submission that including the words "in that type of situation" would have made the definition too broad and may have covered projects that were not true innovation.[508] We note that Orion objected to this suggestion by MEUG, but we consider that the change makes the requirements more clear and reduces the risk of non-innovative projects being covered by the recoverable cost.[509]

F29 We have added "suitable specialist" to the people that could write a report confirming that the innovation project criteria have been met in response to the following submission by emhTrade, which we agree with:

> While subtle, the draft paper makes reference to an 'independent engineer'. If this mechanism for independent scrutiny is retained, we suggest this wording could better reflect that the innovations of tomorrow may not be those traditionally considered engineering solutions (whilst many will be). Part of encouraging more rapid uptake of innovation is changing cultures. The electricity distribution industry is going through a period of unprecedented change; 'independent technical expert' might better reflect that and promote wider thinking about potential solutions or efficiency measures.[510]

F30 A specialist should have the following attributes to be suitable and approved by the Commission, which can be evidenced to the Commission by provision of a curriculum vitae:[511]

F30.1 Specialist skills or knowledge in a relevant field (which could be a field outside of electrical engineering, such as robotics or computer science) based on training, study, or experience; and

F30.2 Independence from the distributor.

F31 In terms of the independence attribute, we would expect that the specialist is not employed by the distributor and would not directly benefit from the Commission's approval of the recoverable cost. However, we accept that the specialist may have previously worked for the distributor under contract given the relatively small size of the relevant fields in New Zealand.

[508] MEUG "Submission on EDB DPP reset draft decisions paper" (18 July 2019), paragraph 23.

[509] Orion "Cross submission on proposed amendments to input methodologies for electricity distributors and Transpower NZ Ltd" (18 July 2019).

[510] emhTrade "Submission on EDB DPP reset draft decisions paper" (18 July 2019), page 1.

[511] We note that the role of specialist could be undertaken by a group of people that collectively have the appropriate attributes.

F32 Some submissions on our draft decision suggested that the innovation mechanism should involve a greater level of scrutiny directly by the Commission or through a competitive tender process.[512] We recognise that this may produce better innovation projects, but administering such a scheme would not be proportionate to the scale and relatively low-cost nature of the DPP3 regime. We also note that, given the distributor bears half the cost of delivering the project, ordinary efficiency incentives will apply. As such, distributors may decide to deliver the project through a competitive tender if doing so would lead to a lower cost outcome.

F33 The approval requirements that we have set do not mitigate all the risks to consumers of the innovation recoverable cost. However, we consider that the level of approval and remaining risk is proportionate to the relatively low limit.

Balance of rules between IMs and DPPs

F34 We have defined the recoverable cost term in the IMs because all recoverable cost terms are defined under the specification of price in the IMs, which supports long-term certainty of the regulatory regime.

F35 However, the criteria, distributor contribution, and limits are defined in the section 52P DPP determination so that the limit and contribution can be increased or decreased in future DPP resets depending on the required strength of the incentive at the time and the success of the incentive during DPP3. If the limit is changed, then the approval criteria should also be reconsidered to maintain an approach that is proportionate to the size of the limit. The criteria may also need to be revised to take account of changing needs in the sector.

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[512] Such as ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019); and First Gas "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

Attachment G Reopeners for large unforeseen capex

Purpose of this attachment

G1 This attachment explains the details of our two new reopener mechanisms for major capex projects or programmes in respect of:

G1.1 large connections (including alterations to existing connections);

G1.2 large system growth;

G1.3 combination of large connections and system growth; and

G1.4 large asset relocation.

G2 Our reasoning for introducing this new mechanism is provided in Chapter 4, while the detail is provided in this attachment.

New reopeners for large new connections, system growth, and asset relocations

G3 We have introduced two new reopeners in the EDB IMs that apply to individual projects or programmes relating to large connections, system growth, and to asset relocation capex. The reopeners have been introduced for the following types of situations:

G3.1 Projects and programmes that were unforeseen at the time of publishing the expenditure forecasts that the Commission based its allowances on;

G3.2 Projects and programmes that were foreseen but resulted in the Commission setting allowances at less than the distributors' forecast because the project is a one-off large project meaning it is out of step with historic expenditure or household growth rates;

G3.3 Projects and programmes that were foreseen, but changes in circumstances mean that the cost is expected to be significantly greater than that forecast in the disclosures used by the Commission for setting allowances; or

G3.4 Projects and programmes that were foreseen for later regulatory periods, but changes in circumstances mean that the project or programme is brought forward into the current regulatory period.

G4 The more specific requirements of the reopeners are:

G4.1 The reopeners only apply to the portion of the additional expenditure that is not covered through the distributor's capital contributions policy (which must be reasonable) and there must be reasonable justification of the distributor's intended approach to allocating costs to consumers;

G4.2 The value of the reopeners in terms of additional expenditure allowance[513] must be at least 1% of forecast net allowable revenue for the regulatory period or two million dollars (whichever is less); however, the cumulative additional expenditure from all reopeners under this provision cannot exceed $30 million dollars in any disclosure year.

G4.3 The distributor must show a high level of confidence in the requirement for the expenditure, for example through a firm request and commitment from a new connecting party that this investment is required.

G5 The reopeners have a minimum threshold because we consider that distributors are able to manage small changes in expenditure requirements within the DPPs set for them. A minimum threshold is also required to avoid situations where the cost of administering the reopener is greater than the benefits to consumers. We have also put a cap in place because it is our view that larger projects and programmes that are out of step with historic expenditure or forecasts require a level of scrutiny that is not consistent with DPPs, so a CPP would be more appropriate, particularly in the case of system growth projects and programmes (which has been added to the reopeners following consultation).

G6 Some submitters have suggested that the issue could be solved by making these types of projects recoverable costs or making the IRIS retention rate zero for them.[514] We appreciate these suggestions and note that they would have the benefit of ensuring that consumers only pay for projects that are actually undertaken.

[513] The project or programme may include a combination of related system growth and connection expenditure. However, asset relocation expenditure cannot be combined with system growth or connection expenditure in one reopener application. However, a reopener application may also be for a project of system growth expenditure alone, which is not tied to a specific new connection.

[514] Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019); and Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

G7 However, we consider that it is more appropriate to introduce reopeners because this is more in line with our approach to DPPs and maintains incentives upon the distributor to minimise costs. It does this because the reopeners will, if appropriate, add additional allowable revenue to the distributor's price path through increased expenditure allowances. If the distributor makes efficiency gains and delivers the project or programme for a lower cost than forecast, then these efficiency benefits will be shared between the distributor and its consumers via the IRIS.

Unforeseen, under forecasted, or under-funded

G8 The reopeners apply to projects and programmes that are unforeseen, under-forecasted, or under-funded.

G9 We consider that it is appropriate to apply the reopeners to unforeseen projects and programmes because we acknowledge that these projects and programmes can arise without the ability for distributors to accurately forecast them. The scale and nature of these projects and programmes mean that a reopener would promote investment. This is more of a case for DPP3 than it has been for previous regulatory periods because the shift to revenue caps means that distributors cannot gain additional revenue from a higher than expected increase in demand. Unison explained this in their submission:[515]

> The reality for Unison is that once the customer capex allowance has been spent, there is not any financial incentive to undertake customer works because the NPV>0 test cannot be met. The major customer capex reopener addresses large works, but anything less would mean a loss to Unison, and would fail board approval processes.

G10 The issue that would arise without such a reopener may also be greater during DPP3 than in the past because of the potential changes in the electricity sector described in Chapter 4, with a greater focus on electrification of industry and transport to support the decarbonisation of the economy.

G11 We consider that unforeseen projects and programmes include incorrectly forecasted projects and programmes with unforeseen timing or extent. By this, we mean that the reopeners also cover projects and programmes that were broadly foreseeable but not expected until future regulatory periods or reasonably expected to be significantly less costly. That is because these situations have the same implications for distributors and consumers as projects and programmes that were entirely unforeseen.

[515] Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019); paragraph 53.

G12 For example, a distributor may have expected a new dairy plant to be constructed during the period, and so included the costs of a new connection in its forecasts. However, the new customer might decide after the forecasts were made that they would like the dairy plant to be double the original planned size, requiring a new connection with a much greater capacity.

G13 In a change between the draft decision and the final decision, we have expanded the reopeners to potentially apply to under-funded projects and programmes, ie, those that were included in a distributor's forecast but where we limited the expenditure allowance for that expenditure category. We consider that this is appropriate because our capital expenditure forecasting approach for consumer connections and system growth is focused on expected broad growth (eg, through the relationship with forecast household growth) and not scrutiny of individual large projects such as a new dairy plant.

G14 Our understanding is that access to new connections and increased capacity of connections is an important feature of quality to consumers and is investment that should be incentivised. So, we consider that this decision better promotes the purpose of Part 4 of the Commerce Act.

Not covered by the distributor's capital contributions policy

G15 The reopeners will not apply to the portion of a project or programme that is covered by the distributor's current capital contributions policy because these costs should not need to be recovered from consumers under the distributors' revenue cap.

G16 We expect distributors to take a reasonable approach to allocating the costs of the project or programme to customers through a reasonable capital contributions policy and future pricing, ideally in line with the pricing principles published by the Electricity Authority.

G17 MEUG proposed a further requirement on distributors when they seek these new reopeners. MEUG suggested that a distributor must also attest, in seeking the reopener that it is fully complying with the pricing principles published by the Electricity Authority, or has a development plan to move to compliance at a rate expected of a reasonable and prudent distributor.[516] Orion in its cross-submission on our draft decision disagreed and did not believe that it is appropriate to have a stand-alone requirement in this regard and it being codified in the IMs.[517]

[516] MEUG "Submission on IM amendments for DPP and IPP" (5 July 2019).

[517] Orion "Cross submission on proposed amendments to input methodologies for electricity distributors and Transpower NZ Ltd" (18 July 2019).

G18 We expect distributors to take a reasonable approach to allocating the costs of the project or programme to customers through a reasonable capital contributions policy and future pricing, ideally in line with the pricing principles published by the Electricity Authority. As such, we may consider a distributor's planned pricing in relation to the project or programme when considering whether a reopener should be granted. We consider that this addresses the points raised on this issue by MEUG and Orion.[518]

G19 We recognise that recovery of costs for connection and system growth projects and programmes under the revenue cap (rather than capital contributions) exposes other customers to the risk of disconnection of the major customer because the costs would be borne by existing consumers. However, on balance, we consider that this risk is outweighed by the benefits of these new reopeners.

Threshold of 1% of revenue or two million dollars

G20 We have set the threshold for the reopeners as at least 1% of forecast net allowable revenue over the regulatory period or two million dollars per project or programme—whichever is less for the distributor. We are also capping the reopeners at $30m of aggregate expenditure across all projects and programmes applied for in any one disclosure year. The threshold relates to the amount of additional expenditure (net of capital contributions) that the distributor includes in its reopener application (rather than the calculated effect on revenue).

G21 We have set the threshold to ensure that the benefits of the reopeners outweigh the administrative and compliance costs associated with distributors making the application and us assessing that application. The incentives of the DPP mean that consumers will still pay for the majority of any additional expenditure without a reopener.[519]

G22 We have set the threshold as a percentage and an absolute value—whichever is the lesser for a distributor—because, as several submitters raised, the percentage threshold may be unrealistic for the largest distributors to be able to meet on individual projects or programmes.

[518] MEUG "Submission on IM amendments for DPP and IPP" (5 July 2019); and Orion "Cross submission on proposed amendments to input methodologies for electricity distributors and Transpower NZ Ltd" (18 July 2019).

[519] This is because of the capex IRIS incentive rate shares most of the cost of any overspend with consumers. See Attachment E for a more detailed discussion of the IRIS mechanism.

G23 We have introduced a cap to the reopeners because we consider that, particularly with the addition of system growth and asset relocations, the reopeners could otherwise apply to situations for which a CPP is more appropriate. The limited level of scrutiny applied under these reopeners, in line with the relatively low-cost nature of DPPs, is not appropriate for larger projects and programmes that are out of step with original forecasts or historic expenditure. It is our view that 30 million dollars is the appropriate level to achieve this.

G24 To further ensure that the reopener is not used when a CPP would be the appropriate mechanism, we will not allow reopeners where the application relates to a project (or part thereof) that is better viewed as part of a larger project or programme, where that wider project or programme would not be under the cap. In those circumstances we consider that a CPP would be the more appropriate mechanism.

Sufficient certainty of the project or programme

G25 We are proposing a requirement for sufficient certainty of the project or programme. Where appropriate, this should be commitment from the connecting party or party requesting the asset relocation to reduce the risk that other consumers face paying for the project or programme without benefit if the other party decides to no longer connect to the network or require the relocation.

G26 Where the application is due to a range of factors—such as system growth projects resulting from growing demand and operational requirements leading to a likely exceedance of capacity in the near future—we would expect a thorough explanation of these factors and why they result in the need for the project, similar to what would typically be included in a business case. We will consider requesting independent verification for this aspect on a case-by-case basis.

G27 We note that this requirement affects the timeliness of the project or programme, and risks delaying large consumer projects like transport projects that require asset relocations by the distributor. However, we consider that the requirement is necessary to avoid other customers paying for a project or programme that is ultimately not required.

G28 We are open to working with distributors in providing an initial non-binding view on applications, particularly for the initial applications and particularly in regard to the certainty requirements. This will support the process if any distributors are uncertain of the criteria that we will apply in considering a reopener and the level of evidence required (which should be proportionate to the scale of the reopener).

Attachment H Revenue cap with wash-up

Purpose of this attachment

H1 This attachment sets out our decisions relating to the price setting and wash-up processes to be applied by distributors subject to DPP3.

Structure

H2 Implementing the revenue cap wash-up takes place through the price setting and wash-up processes discussed in this attachment. We set out below our decisions on the price setting and the wash-up processes under the following sections:

H2.1 Process sequence and timing: This section sets out the sequence and timing of the price setting and compliance assessment process and the wash-up calculations.

H2.2 Price setting process and assessing compliance: This section outlines the price setting process and how compliance for price setting will be assessed against the DPP3 determination. The flowcharts presented in Figure H1 and H2 at the end of this attachment also set out these processes.

H2.3 Limit on the percentage annual increase in forecast revenue from prices: This section outlines a regulatory control we have not previously used. We have adopted this control to limit price shocks to consumers arising from step increases in forecast revenue from prices. It also discusses submissions on this topic.

H2.4 Voluntary undercharging: This section outlines another regulatory control we have not previously used. We have adopted this control, again to limit price shocks to consumers.

H2.5 Wash-up calculation: This section outlines our approach for calculating the wash-up and the relevant inputs to the wash-up calculation. The flowchart presented in Figure H2 at the end of this attachment also sets out this process.

H2.6 Changes suggested in submissions on the draft decision: This section is outlined in more detail in the following paragraph.

H3 We discuss our response (other than those referred to at H2.3 above) to submissions in the section "Response to submissions on the draft default price path decision", starting at Paragraph H129 under the following headings:

H3.1 New investment contract charges

H3.2 Definition of other regulated income

H3.3 Compliance reporting date for the Annual Compliance Statement

H3.4 Changes in the schedules to the draft default price path determination relating to price and wash-up calculations

H3.5 Rate of change (X-factor) for Aurora

H3.6 Setting rates of change (X) for 5 years

H3.7 Applying a forecast of other regulated income when determining starting prices

H3.8 Submission of an annual compliance statement during 2020/21

H3.9 Protection of distributors against retailer bad debts

H3.10 Revenue foregone as a result of a major Transpower interruption

H3.11 The proportion of total electricity charges to consumers that are distributor charges.

Background

Purpose of the wash-up mechanism

H4 The IMs for distributors provide that the form of control must be a pure revenue cap with a wash-up of under- and over-recovery of revenue. The purpose of the wash-up is to ensure that revenue is not under- or over-recovered over time.

Summary of decisions

H5 Key decisions we have made as part of the DPP decision are:

H5.1 retained the draft decision to amend the IM to introduce a “limit on the percentage increase in forecast allowable revenue from prices” from one assessment period to the next, and setting the limit to 10%

H5.2 retained the draft decision to not specify the use of the IM control “annual maximum percentage increase in forecast allowable revenue as a function of demand” from one assessment period to the next

H5.3 retained the draft decision to set the limit on voluntary undercharging at 90%

H5.4 changed the draft decision to set an alternative X-factor for Aurora at -8.9% to not setting an alternative X-factor for Aurora, which results in the X-factor being the default value of 0%.

H5.5 introduced a limit on the percentage increase in "forecast revenue from prices" from one assessment period to the next.[520] This is discussed in paragraphs H28 to H62.

H5.6 implemented a voluntary undercharging regime which limits the cumulative amount a distributor may undercharge before it starts to permanently forego revenues.[521] This means if a distributor undercharges to the extent that the cumulative undercharge limit is exceeded, the distributor will not be able to fully recover its undercharging through the wash-up mechanism. This is discussed in paragraphs H69 to H98.

Process sequence and timing

H6 In this section we set out the sequence and timing of the price setting and compliance assessment process and the wash-up calculations by going through the process steps for what must occur in each of the five assessment periods of the next regulatory period. This approach is generally consistent with our approach used for the current DPP for gas transmission businesses[522].

H7 Figure H1 sets out the price setting and compliance setting process and Figure H2 sets out the wash-up calculations. These figures are near the end of this attachment after paragraph H178.

The process - first and second assessment periods of the regulatory period

H8 Only the price setting and compliance assessment process will be performed when setting prices for the first and second assessment periods of the next regulatory period. This is because, as outlined below for the third and subsequent assessment periods, setting prices and taking into account any amounts to be washed up requires two prior assessment periods.

[520] Electricity Distribution Services Input Methodologies Amendments Determination 2019 (November 2019).

[521] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.3(12)(b) and clause 3.1.3(13)(a).

[522] Gas Transmission Services Default Price-Quality Path Determination 2017 [2017], NZCC 14 (consolidated 18 December 2018).

The process - third and subsequent assessment periods of the regulatory period

H9 When setting prices for the each of the third, fourth, and fifth assessment periods of the regulatory period, the wash-up calculation of a prior assessment period will be taken into account. Three consecutive assessment periods will feature in each of these wash-up calculations. For this attachment we define names for each of these three assessment periods as follows:

H9.1 the ‘assessment period to be washed up’, will be the earliest of these three assessment periods;

H9.2 the ‘calculation assessment period’, will be the second of these three assessment periods; [523] and

H9.3 the ‘assessment period for which prices are to be set’, will be the last of these three assessment periods.

H10 The table below shows the three consecutive assessment periods. For the calculation assessment period it shows that this assessment period comprises four phases:

H10.1 waiting for data from the prior assessment period (such as quantities supplied) to become available;

H10.2 doing the wash-up calculation;

H10.3 setting prices for the subsequent assessment period once the results of the wash-up calculation are available; and

H10.4 the notice period for prices, which is from the time that finalised prices are published by the distributors to the time they take effect. This notice period includes the time required for retailers to set their prices and the notice period for retail prices.

[523] Prices are calculated, set, and notified by the distributor in advance of the assessment period in which those prices apply.

Table H1 Process timeline

Second and subsequent assessment periods of DPP3					
Assessment period to be washed up	**Calculation assessment period**				**Assessment period for which prices are to be set**
	Phase 1 Waiting for data from prior assessment period	**Phase 2** Wash-up of prior assessment period	**Phase 3** Price setting for forthcoming assessment period	**Phase 4** Notice period for prices	

H11 For example, for setting prices that apply in the third assessment period of the regulatory period (i.e., the assessment period ending March 2023), the assessment period to be washed up will be the first assessment period (i.e., the assessment period ending March 2021). The calculation assessment period will be the assessment period ending March 2022. The assessment period for which prices are to be set will be the assessment period ending March 2023.

H12 A few months into the calculation assessment period, the necessary information for the distributor to perform the wash-up calculation will be available. This information will relate to the assessment period to be washed up and would include:

H12.1 actual quantities of services provided in the assessment period to be washed up;

H12.2 prices;

H12.3 actual pass-through and recoverable costs;

H12.4 actual CPI values for the calculation of actual net allowable revenue;

H12.5 other regulated income;

H12.6 any voluntary undercharging amount foregone;

H12.7 any revenue foregone; and

H12.8 the revenue wash-up draw-down amount.

H13 The distributor can then undertake the wash-up for the assessment period to be washed up, which is discussed from Paragraph H100 onwards. This would then be followed by the price setting process for the assessment period for which prices are to be set, which is discussed below. This process comprises:

H13.1 forecasting quantities of services provided in the assessment period for which prices are to be set;

H13.2 forecasting pass-through and recoverable costs;

H13.3 calculating the forecast allowable revenue;

H13.4 setting individual prices so that the forecast revenue from these prices is not more than the forecast allowable revenue; and

H13.5 determining the ‘revenue account draw-down amount’. (See paragraph H102.)

Price setting process and assessing compliance

H14 In this section we outline the price setting process and the process for how compliance is assessed against the DPP3 determination.

Assessing compliance with the DPP Determination

H15 Compliance with the DPP3 determination requires “forecast allowable revenue” (including the recovery of forecast pass-through and recoverable costs) to be calculated, and a set of prices to be developed such that the “forecast revenue from prices” does not exceed the “forecast allowable revenue”.[524]

Price setting methodology

Forecast allowable revenue

H16 The forecast allowable revenue must be the sum of:[525]

H16.1 the “forecast net allowable revenue”;[526]

H16.2 the forecast pass-through and recoverable costs (excluding any revenue account draw-down amount);

H16.3 the opening balance of the wash-up account; and

H16.4 pass-through balance allowance.

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[524] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.1(1).

[525] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.1(4).

[526] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.1(6) or clause 3.1.1 (7).

H17 We have calculated values for the forecast net allowable revenue for each assessment period of the regulatory period in the financial model, so these values are now available.[527] Each of the five values is listed in Schedule 1.4 of the DPP3 determination. [528]

H18 The distributor will prepare a forecast of the pass-through and recoverable costs during each price setting process. These forecasts will exclude a revenue account draw-down amount (which will itself be a recoverable cost).

H19 There may be pass-through and recoverable costs from the regulatory period ending 31 March 2020 that will remain unrecovered at the end of that regulatory period.

H20 The Powerco CPP determination provided, at Schedule 1.6, for a specified amount of $264,000 as the estimated amount of the pass-through balance as at the start of the CPP period. We have implemented a similar provision for the pass-through balance as at 31 March 2020, except that the amount would not be quantified in the DPP3 determination but instead would be specified in the DPP3 determination as the amount reasonably estimated by the distributor.

Forecast revenue from prices

H21 The distributor will prepare a schedule of prices and forecast quantities. From these the distributor will calculate the forecast revenue from prices as the total of each price multiplied by its corresponding forecast quantity.[529] Distributors will need to take account of the two mechanisms discussed in the next two sections:

H21.1 Limit on the percentage annual increase in forecast revenue from prices; and

H21.2 Voluntary undercharging.

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[527] The methodology for calculating the forecast net allowable revenue for the second and subsequent assessment periods, given the first assessment period value, is set out in clause 3.1.1(7) of the EDB IM on a CPI-X basis. The financial model applies this methodology. Forecast net allowable revenues for each non-exempt distributor subject to DPP3 for the whole of the regulatory period are specified in Schedule 4 of the DPP3 determination. This can be done because the forecast CPI values and the forecast net allowable revenues are all set at the time the path is set.

[528] For clarification, we note that the forecast net allowable revenue is referred to in the draft financial model as the maximum allowable revenue before tax, or MAR.

[529] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.1(3).

Limit on the percentage annual increase in forecast revenue from prices

H22 We have amended the IMs to apply a limit on the percentage annual increase in forecast revenue (the limit) from prices during the regulatory period for DPP3.[530] This amount goes towards calculating the maximum revenues that may be recovered by a distributor for the purposes of section 53M(1)(a) of the Act. We apply this limit to respond to increases in the gross revenue distributors can earn, which is one of the causes of potential price volatility in DPP3.

H23 This is not the primary control on distributors' revenues. It applies as well as the primary control which is the determination Clause 8.3 requirement that "the forecast revenue from prices for each assessment period must not exceed the forecast allowable revenue for that assessment period."

H24 The EDB IMs also contain an optional mechanism to control the other major source of price volatility – changes in total demand on the network – which we refer to as the 'limit in price increase as a function of demand'. However, because of workability concerns, we have not made use of this mechanism in DPP3.

H25 As discussed further in paragraphs H39 to H47, new sources of price volatility are:

H25.1 The change in the form of control from a weighted average price cap to a revenue cap means that any reduction in quantities supplied will generally translate into price increases as a distributor seeks to restore its revenue to the allowable limit.

H25.2 Some recoverable costs of significant magnitude will apply for the first time, such as IRIS recoverable costs.[531]

H25.3 If a new Transmission Pricing Methodology is applied during DPP3, the Transpower New Zealand Limited (Transpower) transmission charge recoverable cost could cause a significant revenue increase for some distributors as a result of a reallocation of some portions of those charges.[532]

H25.4 Annual wash-up draw-down amounts could contribute to volatility.

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[530] Commerce Commission *Electricity Distribution Services Input Methodologies Amendments Determination (No. 2)* [2019] NZCC 20 (26 November 2019), clause 3.1.1(1)(b).

[531] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.3(1)(a).

[532] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.3(1)(b).

H26 The limit would mitigate the risks from several drivers of price volatility for consumers. Applying this limit should have a low compliance cost, as it is based on just two numbers which are calculated by distributors in any event.

H27 These two numbers are the 'forecast revenue from prices' for:

H27.1 the assessment period for which prices are being set; and

H27.2 the assessment period prior to that.

H28 To implement the limit, we have made an amendment to the EDB IMs allowing us to specify in a DPP or CPP a "limit or limits on the percentage annual increase in forecast revenue from prices". [533]

H29 We have implemented the limit for DPP3 by including a mechanism that limits, with one exception, every change in forecast revenue from prices from one assessment period to the next, including the increase to the first assessment period of a new regulatory period from the last assessment period of the prior regulatory period.

H30 The exception is that on transition to this new rule, the limit would not apply to the price setting by distributors for the assessment period ending 31 March 2021. We discuss this exception below at paragraph H33.

H31 We discuss the choice of 10% as the value of the default limit starting at Paragraph H53.

H32 We have specified a value of 10% for the default value of the limit in the DPP3 determination. This was the value proposed in the draft decision, and we did not receive any submission suggesting a different default value.

Managing price shocks in the first assessment period of a regulatory period

H33 The limit will not apply to the price setting by distributors for the first assessment period of DPP3 (the assessment period ending 31 March 2021). This is because applying the limit would require a forecast revenue from prices for the assessment period ending 31 March 2020, but that forecast will not exist as it was not required under the DPP2 form of control.

[533] Commerce Commission *Electricity Distribution Services Input Methodologies Amendments Determination (No. 2)* [2019] NZCC 20 (26 November 2019), clause 3.1.1(1)(b).

H34 To manage price shock risk for that first assessment period of DPP3, we considered using X values as levers to adjust the MARs for the first assessment period. We estimated increases in revenues between 2019/20 and 2020/21 and consider that none of the increases are large enough to warrant applying an alternative X value to manage price shock risk.

H35 While have not applied the limit to the first assessment period of DPP3, we consider that for future price-quality path resets, using the limit may be the most effective way of managing price shocks for the first assessment period of a regulatory period. Distributors will have the better information on any revenue wash-up draw-down amount and will have better forecasts of quantities, pass-through costs and recoverable costs when setting prices than we will have.

H36 A distributor will apply this better information when making its forecasts as part of its price setting process, and this will inform the application of the limit.

Alternative values of the limit

H37 In the draft decision reasons paper, we proposed specifying the default value of the limit as 10%, and also considered that that for the final decision we may specify alternative values for the limit for specified distributors.

H38 We have not set an alternative value of the limit for any specified distributor. We did not receive any submissions suggesting we should set an alternative limit for a specified distributor.

Volatility in allowable revenue

H39 Volatility of prices will be driven by a combination of volatility in allowable revenue and volatility of quantities. We discuss volatility in allowable revenue in this section and volatility in quantities in the next section.

H40 IRIS recoverable costs, particularly the 'opex incentive amount' component of the 'IRIS incentive adjustment',[534] could significantly increase from one assessment period to the next as distributors recover their incentive amounts through prices.

H41 We received submissions that we should apply a limit on Transpower similar to the limit on distributors. Wellington Electricity and Vector submitted concerns that they would carry the cash flow burden of smoothing prices for Transpower, rather than Transpower carrying that burden.

[534] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.3.1 and clause 3.3.2.

H42 Any issue as to whether Transpower should smooth its revenues is not a DPP issue. Transpower's RCP3 proposal includes price smoothing without annual updates to its MAR.[535] We consider that this should remove the necessity of having to apply a similar limit to Transpower, and therefore, make submitters' concerns moot.

H43 We consider that the limit will address these sources of volatility as well as volatility from wash-up draw-down amounts, and all pass-through and recoverable costs, including IRIS and quality incentive adjustment recoverable costs.

Volatility in forecast quantities

H44 The change in the form of control from a weighted average price cap to a revenue cap which was implemented in the 2016 IM review will tend to increase the volatility of allowable prices. The revenue cap means that any reduction in forecast quantities supplied will generally translate into price increases as a distributor seeks to restore its revenue to the allowable limit. The current weighted average price cap does not result in price increases arising from quantity reductions.

H45 Ideally, we would specify an "annual maximum percentage increase in forecast allowable revenue as a function of demand"[536] as that could effectively mitigate price volatility risk from quantities volatility as well as allowable revenue volatility. However, we consider that this mechanism is not workable to implement in DPP3 in the event of certain price restructurings.

H46 We have therefore not applied an "annual maximum percentage increase in forecast allowable revenue as a function of demand". We discuss the implementation workability in the next section.

H47 A catastrophic event could cause a significant reduction in quantities supplied, with a corresponding step increase in prices to restore revenues. We consider that the existing EDB IM provisions provide an appropriate mechanism for responding to a significant reduction in quantities caused by a catastrophic event. These mechanisms are:

- that we may reconsider a DPP if a catastrophic event has occurred
- the risk sharing provision in the cap on the wash-up amount.[537]

[535] Transpower "Regulatory Control Period 3 Proposal" (November 2018), p. 49.

[536] As allowed under Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.1(2).

[537] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clauses 3.1.3(13)(c), 4.5.1, 4.5.6(1)(a)(i), 4.5.6(2) and 4.5.7.

Workability of the implementation of the limit on forecast allowable revenue as a function of demand

H48 We have not been able to develop a workable mechanism for a limit on forecast allowable revenue as a function of demand for DPP3 in the event of a distributor carrying out certain types of price restructure.

H49 We consulted on an illustrative implementation of that mechanism in the draft decision for the 2017 reset of the gas transmission DPP.[538] That illustrative implementation avoids some of the problems that can arise from price restructurings, but it still relies on the continuity of several pricing metrics from one assessment period to the next.

H50 We decided not to apply it to the 2017 gas transmission DPP reset, given the proposed price restructuring that First Gas is contemplating in a new gas transmission access code. As noted in the reasons paper for the final gas transmission decision, we considered that the revenue class approach would not be workable in the context of the First Gas proposed access code.[539]

H51 We were concerned that similar challenges could emerge if we were to apply that illustrative implementation to distributors for DPP3. For example, a change from the grid exit point pricing (GXP) structures used by some distributors to the pricing structures used by most distributors (ICP pricing) could be particularly problematic.

H52 For such a price restructuring from GXP pricing to ICP pricing, we consider that very few pricing metrics (such as $/day, $/kWh, $/monthly maximum kVA demand) would have effective continuity through the pricing restructuring.[540]

The default 10% limit on the annual percentage increase in forecast revenue from prices

H53 Setting the limit was a judgement call. We have set a limit of 10% in nominal terms because we consider this a reasonable balance between what might be considered upper and lower bounds for our setting of this limit.

H54 If a distributor's pricing was at this 10% revenue limit but also reflected a reduction in quantities, then the pricing change could be higher than 10%.

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[538] The illustrative implementation was set out in Schedule 6 to the draft determination that formed part of the consultation papers for the draft decision. Commerce Commission, "Draft Gas Transmission Services Default Price-Quality Path Determination 2017" (10 February 2017), Schedule 6.

[539] Commerce Commission, "Default price-quality paths for gas pipeline businesses from 1 October 2017, Final Reasons Paper" (31 May 2017), paras F21 – F27.

[540] A $/kWh metric may not have effective continuity because distributed generation will be netted off consumption at a grid exit point, while ICP pricing would charge without the netting off effect. $/kVA of maximum demand may also not have continuity because of diversity of demand.

H55 We have in the past used both 5% and 10% as indicators of target maximum real price increases. For the assessment periods ending 31 March 2014 and 31 March 2015, we restricted price increases to 10% real.[541] For DPP2, we tried to restrict price increases to the first assessment period of the regulatory period (assessment period ending 31 March 2016) to 5% by applying a negative X value for some distributors, but in practice allowed for real price increases of up to 11% by setting X at -11% for one distributor.[542]

H56 We wish to see the limit on the annual percentage increase in forecast revenue from prices to bind only as an exception, which also implies a lower bound on the percentage increase. We consider this lower bound on the limit should be set high enough to allow for routine changes, such as the CPI change, the usual volatility of recoverable costs, and the usual volatility of quantities, to occur without triggering the limit on the annual percentage increase in forecast revenue from prices.

H57 In the draft decision, we suggested the lower bound be 8%, which left a range from 8% to 10% for the limit. The value of 10% for the limit on distribution charges translates into an increase in a consumer's total electricity charge in the order of 3%.

H58 We did not receive any submissions suggesting a value of other than 10%.

Smoothing price shocks into future assessment periods in a present value-neutral manner

H59 The discussion above on the limit on the percentage annual increase in forecast revenue from prices (from paragraph H22 to this paragraph) focuses on limiting allowable revenues in an assessment year in which a price shock might otherwise occur. We must also consider how these revenue reductions may be recovered by the distributor in subsequent years to achieve the objective that the mechanism is present value neutral.

H60 The EDB IM provisions for the wash-up of the revenue cap and the way in which this was implemented in the three determinations to date with a revenue cap have been implemented to provide for the recovery of the revenue reductions with little modification and low additional compliance costs.[543]

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[541] Commerce Commission "Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors" (30 November 2012), p. 49.

[542] Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main Policy Paper" (28 November 2014), pp. 73-75.

[543] The three determinations to date with a revenue cap are the gas transmission DPP and the CPPs for Powerco and Wellington Electricity Lines Limited (Wellington Electricity).

H61 When the limit binds, the distributor will earn less revenue in the applicable assessment period than it would without the limit. This reduced revenue will increase the wash-up amount for the assessment period, which will in turn allow for a higher revenue in a future assessment period.

H62 The consequential NPV neutral impact on the wash-up will be dealt with through the established methodology for the revenue cap with wash-up. A time value of money adjustment will be applied per the IMs at a discount rate of the post-tax WACC, so the mechanism as a whole will be NPV neutral.

Submissions on the limit on the percentage annual increase in forecast revenue from prices to exclude pass-through and recoverable costs

H63 We have not adopted Orion's, Wellington Electricity's and Vector's submissions that the limit on the percentage annual increase in forecast revenue from prices be applied to only the distributor's costs and not to the component of revenues related to the recovery of pass-through and recoverable costs.[544]

H64 The purpose of the limit is to mitigate the risk of price shocks to consumers. Excluding potential sources of such shocks would reduce the effectiveness of the limit and not be in consumers' interests.

H65 Wellington Electricity's concern relates particularly to the possibility of large changes in Transpower charges. We have considered two drivers of Transpower charge volatility:

H65.1 In the Electricity Authority's July 2019 paper "Transmission pricing methodology: 2019 issues paper", Table 12 lists the 2022 change in charges that would result from adopting a proposed transmission pricing methodology.[545] The increase for Horizon Energy, relative to the 2022 MAR, would be 11.9% of the MAR. This would be the largest such percentage. Network Tasman would have the second highest percentage at 9.0%.

H65.2 Transpower's RCP3 proposal includes price smoothing without annual updates to its MAR, and we expect this to limit changes in Transpower charges during DPP3.

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[544] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18; Orion "Cross submission on EDB DPP reset draft decisions paper" (12 August 2019); Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), para 257.

[545] Electricity Authority, Transmission pricing methodology: 2019 issues paper, 30 July 2019

H66 We consider that the level of potential volatility to be acceptable. If the limit binds, then the distributor's cash flows will be delayed, but any revenue reduction will be able to be recovered in future years along with a time value of money adjustment.

Limit on the percentage annual increase in forecast revenue from prices to be applied in constant-price terms

H67 Aurora submitted for the 'limit on the percentage annual increase in forecast revenue from prices' be applied in constant-price terms, rather than in nominal terms.[546]

H68 We have not adopted this approach because:

H68.1 the approach would not make a very material impact on the operation of the limit;

H68.2 the approach would add complexity to both the specification of the limit and to the calculations relating to the limit; and

H68.3 we expect that the limit will bind relatively infrequently.

Voluntary undercharging

Purpose of the voluntary undercharging mechanism

H69 The purpose of the voluntary undercharging mechanism for DPP3 is to mitigate the risk of price shocks that could arise from voluntary undercharging.

H70 Under the revenue cap with wash-up, distributors may carry forward under-recovered revenue in a wash-up account.[547] Absent a mechanism to limit accumulation of the wash-up balance, a distributor that prices below the revenue cap may accrue a large balance, which could then create price shocks when it is passed through to consumers.

H71 While the limit on the percentage annual increase in forecast revenue from prices could significantly mitigate this risk, an accumulation of a large credit balance in the wash-up could result in increases in forecast revenue from prices at the 10% limit value for multiple consecutive assessment periods. We consider this would be undesirable, and we therefore applied the voluntary undercharging mechanism to avoid the building up of a large credit balance in the first place.

[546] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), para 8.3.

[547] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.3(12)(b) and clause 3.1.3(13)(a).

IM requirement for calculating a "voluntary undercharging amount foregone"

H72 Under the current DPP, which applies a weighted average price cap with no wash-up, a distributor that charges below its price cap immediately and permanently foregoes that revenue. In the 2016 IM review, the form of control for distributors changed from a weighted average price cap to a revenue cap with wash-up.[548]

H73 To implement the revenue cap mechanism, we introduced an IM requirement for us to specify within a DPP a method for distributors to calculate and record any "voluntary undercharging amount foregone".

Implementing the voluntary undercharging mechanism

H74 Part of the process for the wash-up account is the calculation of a "closing wash-up balance". To calculate this amount, a distributor must, for each disclosure year, calculate and record any "voluntary undercharging amount foregone".[549]

H75 Under the revenue cap, when a distributor is undertaking its annual price setting exercise, it must calculate its "forecast revenue from prices" for the forthcoming assessment period. The primary revenue control of an EDB DPP will be that the "forecast revenue from prices" must be no higher than the "forecast allowable revenue".[550]

H76 The voluntary undercharging regime sets a more stringent control, but it is not a mandatory limit. It sets a value of "forecast revenue from prices" that is a threshold for triggering a permanent foregoing of revenue.

H77 If prices are set higher than this threshold but nevertheless result in an undercharge, then there will be a temporary foregoing of revenue in the assessment period to which the prices apply. The loss of revenue to this level of undercharging will be fully recovered, with financing costs, in later assessment periods through the wash-up mechanism.

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[548] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.1; Commerce Commission "Input methodologies review decisions: Report on the IM review" (20 December 2016), p. 78.

[549] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.3(12)(b).

[550] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.1(1).

H78 We must specify in our DPP3 determination how a voluntary undercharging amount foregone must be calculated.[551] The approach is set out below starting at paragraph H80.

H79 We have specified in our DPP3 determination how a "voluntary undercharging amount foregone" will be taken into account in the wash-up mechanism. This will be done through the calculation of the closing wash-up account balance.

Calculation of voluntary undercharging amount foregone in DPP3

H80 We have applied the following methodology for a distributor to calculate, when setting its prices, any voluntary undercharging amount foregone:[552]

H81 Defining "voluntary undercharging revenue floor" as the lesser of

H81.1 90% of forecast allowable revenue, and

H81.2 (1 +10%) × the previous assessment period's forecast revenue from prices.[553]

H82 If a distributor is to avoid any permanent foregoing of revenue from undercharging, it will choose to set its prices such that its "forecast revenue from prices" is greater than the "voluntary undercharging revenue floor".

H83 If a distributor sets its prices such that the "forecast revenue from prices" is less than the "voluntary undercharging revenue floor", then:

H83.1 "voluntary undercharging amount foregone" = "voluntary undercharging revenue floor" less "forecast revenue from prices".

H84 The floor is not a mandatory level below which a distributor must not charge. It is instead a threshold below which the distributor will permanently forego revenue because of its undercharging.

H85 A numerical example of the process is provided starting at Paragraph H179.

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[551] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.3(13)(a).

[552] Commerce Commission *Electricity Distribution Services Default Price-Quality Path Determination 2020* [2019] NZCC 21 (27 November 2019), clause 9.

[553] This amount of 110% of the previous assessment period's forecast revenue from prices is the limit imposed through the "limit on the percentage annual increase in forecast revenue from prices". The 90% and 10% values in Paragraph H80 are references to the proposed "voluntary undercharging amount foregone" and the "limit on the annual percentage increase in forecast revenue from prices" respectively.

Approach proposed in the draft decision

H86 The approach proposed in the draft decision was the same as the approach described in this attachment.

Response in submissions

H87 We received no submissions on voluntary undercharging in response to our discussion of this in our draft decision.

Relevant considerations

H88 The approach reflects the cumulative undercharge of revenues because "forecast allowable revenue" includes the "balance of the wash-up account available for draw-down",[554] and that balance includes the cumulative undercharging from previous assessment periods.[555]

H89 If a distributor consistently sets prices such that in each assessment period its actual revenue is less than that assessment period's costs, the distributor would have an ever-increasing wash-up balance which would eventually result in an amount of "voluntary undercharging amount foregone".

H90 The IM definition of "voluntary undercharging amount foregone" refers to undercharging being intentional and voluntary.[556] Each of the parameters used to calculate the voluntary undercharging amount foregone will be precisely known when prices are being set, so any undercharging would be intentional.

H91 Foregoing of revenue will be voluntary. The approach avoids a distributor being forced to set its forecast revenue from prices so low that it foregoes revenue, as discussed in the next section.

Avoiding a perverse outcome from the limit on increases in forecast revenue from prices

H92 The definition of "voluntary undercharging revenue floor" includes the sub-paragraph at H81.2 above which ensures that the floor will be no higher than the ceiling, the ceiling being the level of the limit on annual price increases.

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[554] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.1(4)(d).

[555] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), the definition of 'wash-up account' in clause 1.1.4(2) and clause 3.1.3(12)(b).

[556] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.3(13)(a) refers to situations where "the EDB has intentionally and voluntarily undercharged…".

H93 If we were to set the price floor definition without this restriction, it would be simply set at 90% of forecast allowable revenue. In unusual circumstances, a perverse outcome could arise in which the "voluntary undercharging amount foregone" would be incurred involuntarily.

H94 With this simplified definition, the limit on price increases could force a distributor to limit its forecast revenue from prices to a level so low that the distributor would incur a "voluntary undercharging amount foregone".

H95 The approach resolves this by keeping the limit on price increases intact and reducing the level of the "voluntary undercharging revenue floor".

H96 The "unusual circumstances" referred to above are when the forecast allowable revenue for the assessment period for which prices are being set is greater than 1.222 times the forecast revenue from prices from the previous assessment period's price setting.[557]

H97 This 1.222 ratio of revenues should be unusual. There are, however, several possible independent drivers of such a ratio, and if they happen to drive in the same direction, such a ratio might be possible. Those drivers include each forecast of a pass-through and recoverable cost, and quantity forecasting.

The 90% value of the voluntary undercharging threshold

H98 We have specified the voluntary undercharging threshold at 90% in our DPP3 determination. We consider that values significantly lower or higher than 90% could give rise to problems. We examine this through the following two examples:

H98.1 If a distributor were to set prices for a lower threshold of 85% rather than 90%, consumers could subsequently have at least a 17.6% average price increase from the distributor fully recovering this undercharge alone in a later assessment period.[558]

H98.2 If a distributor were to set prices for a higher threshold of 95% rather than 90%, then this would give the distributor only a narrow range (from 95% to 100%) in which to set its forecast revenue from prices. This might restrict the distributor's ability to manage the many sources of price volatility.

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[557] This value applies for the 10% value for the "limit on the annual percentage increase in forecast revenue from prices", and the 90% value for the voluntary undercharging threshold. For values other than the 10% and 90% proposals, the ratio is (1 + limit on annual increases in forecast allowable revenue) / forecast revenue from prices$_{t-1}$.

[558] The value of 17.6% is 1/85% -1. This represents the increase in revenue that could occur in the assessment period after undercharging from a distributor that could occur if we were to set the threshold at 85% and all other parameters remained constant. The change from setting prices such that forecast revenue from

H99 We proposed the value of 90% in our draft decision and did not receive any submissions suggesting a different value.

Wash-up calculation

H100 In this section we outline the approach for how the wash-up is calculated and how the relevant inputs to the calculation are determined.

Revenue wash-up draw-down amount

H101 If the distributor has built up a positive balance in its wash-up account, it may use some or all this balance when setting prices, such that the prices would be higher than if it did not use any of this balance. This is generally referred to as drawing down the account.

H102 If the wash-up account has a negative balance, then the balance will reduce the distributor's forecast allowable revenue.

H103 For calculating the actual allowable revenue and for calculating the closing wash-up account balance, we have set the revenue account draw-down amount to the opening balance of the wash-up account. This means that actual allowable revenue will be set each assessment period based on fully drawing down the wash-up balance.

H104 However, the requirement to set the draw-down amount equal to the opening balance of the wash-up account does not mean that the distributor must price up to its maximum limit.

H105 The distributor may price lower than it is allowed to. If it does, the undercharging will increase its wash-up amount for that assessment period. That increase will in turn increase (via the wash-up balance) the actual allowable revenue for the assessment period two assessment periods after prices had been set lower than allowed.

H106 Through this mechanism, the distributor will generally be able to recover previous undercharging two assessment periods after the undercharging, together with a time value of money adjustment. If, however the distributor has undercharged to the extent of incurring a voluntary undercharging amount foregone, then it will not fully recover its undercharging.

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prices is 85% of forecast allowable revenue to 100% of forecast allowable revenue will be the amount 1-1/85% referenced above. This ignores time value of money effects which would increase the revenue by more than this.

Wash-up amount

H107 The wash-up amount will be calculated as the actual allowable revenue, less actual revenue, less revenue foregone.[559]

H108 The difference between the actual allowable revenue and the actual revenue reflects to what extent a distributor has under or over-recovered. Whether the difference is added to, or subtracted from, the wash-up account depends on whether the difference is a positive or negative amount.

H109 An amount of 'revenue foregone' may be subtracted from the difference to be applied to the wash-up account if the cap on the wash-up amount (as specified in the EDB IM) binds.[560]

Actual net allowable revenue

H110 The value of actual net allowable revenue for the first assessment period of the regulatory period is provided in Schedule 1.4 of the DPP3 determination. For subsequent assessment periods, it is to be calculated on a CPI-X basis from the previous assessment period's value. The actual CPI increase will be required for this calculation. It will be able to be calculated from CPI values published by StatsNZ in time for the wash-up calculations to be done.

Actual pass-through and recoverable costs

H111 In a similar way, actual values of pass-through and recoverable costs will be available in time for the wash-up calculations during each calculation assessment period.

Actual allowable revenue

H112 The actual allowable revenue will be calculated as the sum of the actual net allowable revenue and the actual pass-through and recoverable costs. The recoverable costs in this instance include the draw-down amount applicable to the assessment period to be washed up.

H113 All the amounts discussed in this 'wash-up process' section up to this point relate to the assessment period to be washed up. We will now discuss maintaining the balance of the wash-up account.

[559] This method of calculating the wash-up amount is specified in EDB IM clause 3.1.3(13)(b). Note that the "revenue foregone" refers to the IM defined term and relates to the sharing of risk discussed below starting at paragraph H123. It does not relate to the voluntary undercharging amount foregone.

[560] Commerce Commission "Input methodologies review decisions: Report on the IM review" (20 December 2016).

Maintaining the wash-up account

H114 As discussed in paragraphs H9 to H11, the relevant assessment period for updating the wash-up account will be the assessment period for which prices are to be set. The opening balance of this account for the first and second assessment periods of the regulatory period will be nil, while the opening balance for the third and subsequent assessment periods will be the closing balance of the previous assessment period.

H115 The closing balance of the wash-up account for the second and subsequent assessment periods will be:

> (the wash-up amount for the previous assessment period - any voluntary undercharging amount foregone) × (1 + 67th percentile estimate of post-tax WACC)^2

H116 The time value of money adjustment relates to the two-year delay between the wash-up amount being incurred and the assessment period in which it will be able to be taken into account in future prices.

H117 The discount rate for the time value of money adjustments is the 67th percentile estimate of the post-tax WACC as at 1 September 2019. Its value is 4.23% and is set out in the DPP determination.

H118 A positive wash-up amount indicates that the actual revenue received (plus any amount of revenue foregone) has been less than the actual allowable revenue. That positive balance would lead to a positive balance in the wash-up account, which would be in favour of the supplier.

H119 For calculating the actual allowable revenue and for calculating the closing wash-up account balance, the revenue account draw-down amount has been set to the opening balance of the wash-up account.

H120 The calculation of the closing wash-up account balance in the flow chart below could alternatively be specified as:

H120.1 opening wash-up account balance

H120.2 less revenue wash-up account draw-down amount

H120.3 plus wash-up amount

H120.4 plus time value of money adjustment for wash-up amount

H121 The first two terms of this calculation cancel each other out, which has allowed the formula in the determination to be simplified by deleting these two terms. This simplified approach is also shown in the flow chart below.

H122 The actual allowable revenue for the first assessment period will include an additional term in the formula stated in the flow chart below. It shall account for any unrecovered pass-through and recoverable costs in the regulatory period ending 31 March 2020 that were not recovered in that regulatory period. The amount of the additional term shall be the amount not recovered plus a time value of money adjustment for one assessment period on that amount. The discount rate for time value of money adjustment shall be post-tax WACC.

Cap on the wash-up amount

H123 As set out in the IMs, there is a cap on the wash-up amount.[561] The aim of this cap is to provide a sharing of risk between the distributor and consumers when the quantities of services provided are significantly lower than forecast quantities. The implementation of this cap is through ‘revenue foregone’, which is the amount of permanent loss the distributor will incur if the cap binds.

H124 Calculating revenue foregone requires another parameter to be defined and determined: the ‘revenue reduction percentage’. This reflects the extent to which actual revenue from prices are less than forecast revenue from prices. It is, in turn, the average reduction in quantities between forecast and actual values, using the prices as weights in the weighted average calculation.

H125 The formula for revenue reduction percentage is:

Revenue reduction percentage = 1 - (actual revenue from prices ÷ forecast revenue from prices)

H126 The formula for revenue foregone is:

Revenue foregone = actual net allowable revenue × (revenue reduction percentage - 20%), subject to the revenue foregone being nil if revenue reduction percentage is not greater than 20%.

H127 In this formula, the actual net allowable revenue is the value for the assessment period being washed up.

[561] Commerce Commission “Input methodologies review – Topic paper 1” (20 December 2016), p. 34.

H128 This amount of revenue foregone will be subtracted from the amount that would otherwise be the wash-up amount. In other words, the wash-up amount will be actual allowable revenue less actual revenue less revenue foregone. This has the effect of capping the wash-up amount.

Response to submissions on the draft default price path decision

H129 We set out our response to topics raised in submissions on the draft decision below. There were two submissions on the 'limit on the percentage annual increase in forecast revenue from prices', and those submissions are discussed above in the section discussing that limit, starting at paragraph H63.

New investment contract charges

H130 We have clarified and extended the scope of the recoverable cost relating to charges for a 'new investment contract' (as defined in the Electricity Industry Participation Code). A distributor will be able to use a third-party financier to finance a new investment contract between the distributor and Transpower or an equivalent contract with another Transmission provider.[562]

H131 We have made an IM amendment very similar to one suggested by Transpower in its submission on our draft decision. Transpower submitted that:

> In our view, the Electricity Distribution IM should be amended to provide the costs of third party finance contracts with unrelated third parties to fund costs under investment contracts are a recoverable cost. We suggest drafting for clause 3.1.3(1)(c) as follows:
>
> A recoverable cost is…
>
> … (c) a charge payable:
>
> by an **EDB** to **Transpower** in respect of a new investment contract (as 'new investment contract' is defined in the Electricity Industry Participation Code) between those parties, or an equivalent type of contract; or
>
> by an **EDB** to a non-related party financer of the amounts payable to **Transpower** in respect of a new investment contract (as 'new investment contract' is defined in the Electricity Industry Participation Code) between an EDB and Transpower, or an equivalent type of contract …
>
> provided that in respect of a new investment contract an EDB may only treat as recoverable costs the charges in (i) or (ii); [563]

[562] Commerce Commission *Electricity Distribution Services Input Methodologies Amendments Determination (No. 2)* [2019] NZCC 20 (26 November 2019), clause 3.1.3(1)(c).

[563] Transpower "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 1.

H132 Network Tasman submitted that it expects to have a new GXP serving its growing demand during DPP3 and that the GXP would be built by Transpower using a new investment contract with Transpower.[564]

H133 Network Tasman would prefer to be able to spread its repayment of the GXP capital cost over a longer period than may be available from Transpower and has considered using a third-party financier to do this. However the IM recoverable cost provision before we extended its scope would have not allowed for this and still allow for the total cost to be recovered.

H134 Network Tasman submitted that the rate of return Transpower would require if it were to finance the GXP would be higher than Network Tasman's cost of debt.

H135 The IM amendment extends the scope of the recoverable cost to remove a barrier to distributors making necessary network enhancements and possibly to reduce the financing costs of enhancements. The barrier was that Transpower has generally only offered financing for up to 5 years, which could result in repayments that could be unsustainably high for the distributor.

Definition of other regulated income

H136 We have amended the EDB IM to clarify that the EDB IM definition of 'other regulated income' includes gains/(losses) on disposals.

H137 We received submissions from Orion and Powerco seeking this clarification. It has been both our intention and our practice to include gains/(losses) on disposal in other regulated income since 2014.[565]

Compliance reporting date for the Annual Compliance Statement

H138 We have extended the date by which the annual compliance statement from each distributor must be provided to us from the 50 working days proposed in the draft decision to 5 months after the end of each assessment period.

H139 We received submissions from Orion, Aurora, Powerco and ENA, each submitting that the 50 working day timing could be problematic.[566]

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[564] Network Tasman "Submission on EDB DPP reset draft decisions paper" (18 July 2019)

[565] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 20; Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

[566] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 18; Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 16; Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 22.

H140 We have adopted Orion’s suggestion that the date for publishing the compliance statement be amended to align with the publication date for Schedules 1 to 10 of the distributor’s disclosures.

H141 The change should allow distributors to more accurately report some parameters, and reduce compliance costs by aligning the audit timing of the annual compliance statement and ID. We consider these benefits outweigh any downside to the later reporting.

H142 The discussion in this attachment of the change in reporting date is in the context of reporting on the revenue wash-up. The annual compliance statement must also include information on quality standards and transactions.

H143 The information required to be provided on transactions in the annual compliance statement includes information on an adjustment to a distributor’s forecast allowable revenue and information on the wash-up calculation for a part-year ending on the date of the transaction. We consider the later reporting of this information to be acceptable.

Changes in the schedules to the draft default price path determination relating to price and wash-up calculations

H144 We have made changes to the draft determination schedules 1.3 to 1.7 to correct for mechanical errors in the price setting and wash-up mechanism and to make the drafting more intuitive and easier to apply.

H145 Orion submitted on the draft determination noting errors in allowing for the time value of money in taking account of the DPP2 residual pass-through balance. We agree with Orion and have addressed the issue it raised.[567] The issue was that the 2019/20 pass-through balance should be adjusted for one year's time value of money when applying it to the 2020/21 assessment period.

H146 We noted a further issue in the draft determination in the accounting for the pass-through balance. The draft determination did not recognise that a positive pass-through balance represents money owed by the distributor to consumers, whereas a positive wash-up account balance has the reverse sense, ie, a positive balance represents money owed by consumers to the distributor.

H147 As well as taking these issues into account, we have made some changes to make the determination more intuitive and easier to apply, as discussed in the next three paragraphs.

[567] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 19.

H148 We have changed the definition of "actual pass-through costs and recoverable costs" in Clause 4.2 to reflect the natural meaning of the defined phrase, ie, it no longer includes a cost that is neither a pass-through cost nor a recoverable cost.

H149 We have changed the opening wash-up account balance for first and second assessment periods to nil, because the third assessment period will be the first assessment period that will take a wash-up into account.

H150 We have amended Schedules 1.3 and 1.5 to directly apply the transitional issues that arise from the residual DPP2 pass-through balance.

H151 We tested the outcomes of the price setting and wash-up process in the final version of the DPP3 determination and found that it results in a present value of revenues that would be the same as if the distributor had had perfect foresight for all forecasts it must make in the price setting and wash-up process.

Rate of change (X-factor) for Aurora

H152 We have not set an alternative rate of change (X-factor) for Aurora, which is a change from our draft decision in which we set an alternative rate of change of -8.9%.

H153 Aurora submitted that the draft decision X value of -8.9% would likely lead to price reductions for consumers in 2020/21, once the forecast 2020/21 IRIS incentive adjustment is accounted for.[568] This would be potentially followed by substantial price increases in subsequent years.

H154 Aurora submitted that its increase in allowable revenue between 2020 and 2021 would be much closer to zero if we were to take the IRIS incentive adjustment into account, which could mean that no alternative X may be required.

H155 We agree with Aurora’s submission. Since the draft decision we have received information disclosures that have allowed us to calculate the IRIS incentive adjustment. We estimate the combined effect of the increase in the net allowable revenue and IRIS incentive adjustment would result in a revenue increase of 2.7% between 2019/20 and 2020/21.

H156 This increase is modest, and we have not set an alternative X. The default X of 0% will apply.

[568] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 14.

Setting rates of change (X) for 5 years

H157 Vector submitted that our mechanism for setting X values is simplistic and suggested we apply an X-factor to the revenue change from 2019/20 to 2020/21 as well as to the four revenue changes within DPP3.[569]

H158 We have not adopted this submission because:

H158.1 If we were to adopt a single X across all five revenue changes for each distributor, then each distributor would have a different X. This would breach section 53P(5) of the Act.

H158.2 Section 53P (5) requires us (with an exception in section 53P(8)) to "set only 1 rate of change per type of regulated goods or services (for example, if the rate of change (x) is 1% in a CPI−x path, 1% must be the rate for all goods or services of that type)."[570]

H158.3 Our approach in the DPP2 and DPP3 resets has been to consider section 53P(8) for particular suppliers, and in those cases we take account of the change in revenue between the last assessment period of one regulatory period to the first assessment period of the next regulatory period.

H158.4 When applying section 53P(8), we are not constrained to one methodology. For example, when setting the X value for Aurora in the DPP3 final decision, we took account of Aurora's 2020/21 IRIS incentive adjustment. Our methodology allows us the flexibility to avoid perverse outcomes.

Applying a forecast of other regulated income when determining starting prices

H159 Vector, Powerco, and ENA submitted for us to forecast other regulated income, and to take this into account in setting starting prices. The forecast would be washed up in the revenue cap wash-up.[571]

H160 We have not adopted this suggestion because:

H160.1 Our analysis of historical levels of other regulated income indicated that their magnitude was generally too small to cause significant levels of volatility.

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[569] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p68

[570] Commerce Act 1986, Paragraph 53P(5)

[571] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 70; Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 7.

H160.2 We do not have a forecasting method that can deal with outlier values in a particular historical assessment period. Using an average of historical values of other regulated income would not address this issue.

H160.3 We considered a forecasting approach based on the average of the 2016 to 2019 information disclosure values of other regulated income of the 15 distributors for which we are setting starting prices. To obtain a materiality indicator of other regulated income, we divided this average by the average disclosed line charge revenues.

H160.4 The largest materiality indicator was for Vector and was 1.05%. The second and third largest indicators were 0.68% and 0.33% for EA Networks and Electricity Invercargill respectively.

H160.5 These average values for EA Networks and Electricity Invercargill are largely driven by their 2016 values, which were -4.36% and -1.07% respectively. These values, relative to the averages for these distributors, indicate that other regulated income is highly volatile. A simple average of historical values is unlikely to be a reasonable forecast.

H160.6 The materiality is not significant for any of the distributors in the context of other more significant drivers of revenue volatility.

H160.7 We considered whether there are forecasting methods other than a simple average of nominal or real historical values of other regulated income. We do not have any such alternative methods that would fit with the low-cost DPP framework.

Applying a forecast of disposals or a forecast of other regulated income when setting the forecast net allowable revenue

H161 In its submission on the Updated Models Companion Paper, Vector submitted (in effect) that we should allow a distributor to take its forecast of disposals into account when determining its forecast allowable revenue.[572] Vector submitted that without such a forecast, the magnitude of wash-ups will be unnecessarily significant.

H162 We have not implemented Vector's submission because of the impact on distributors' price setting process during December 2019 and January 2020 and because of the low level of materiality anticipated.

[572] Vector "Submission on companion paper to updated models" (9 October 2019), p. 6.

H163 Distributors will need to have largely completed their draft price schedules by Christmas 2019, which gives them less than a month to do this from the publication of our DPP3 decision. We consider our decision should not include an unanticipated requirement to develop a forecast of loss on disposals or a forecast of other regulated income.

H164 We do not consider that the magnitude of wash-ups will be unnecessarily significant. We discuss the materiality of other regulated income in the previous section and note in that section that it is generally low for the 15 distributors for which we are setting starting prices.

Accounting for extraordinary values of historical disposals

H165 In Orion's submission on the draft decision, it submitted that when we forecast Orion's disposals, we should exclude $1.6m of its $3.055m disclosed 2016 disposals, as the $1.6m amount was extraordinary.[573]

H166 We have not excluded the extraordinary $1.6m as Orion suggested. The impact of excluding the extraordinary amount would have increased Orion's net allowable revenues by 0.042%, which would have been immaterial.

H167 Vector cross-submitted that it also had high one-off disposals and that we should ensure that "our forecasts for disposals reflect the anticipated level of disposals per annum for the DPP3 period".[574] Vector did not quantify the level of its one-off disposals or how one-off disposals should be distinguished from business as usual disposals. It did not propose an alternative forecasting methodology.

H168 We consider our forecasting method to be appropriate, given the generally low materiality of the impact of disposals on starting prices and given the low-cost nature of a default price path.

Submission of an annual compliance statement during 2020/21

H169 Orion submitted that it was not clear whether an "annual compliance statement" is required to be submitted during the 2020/21 assessment period.[575]

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[573] Orion "Submission on companion paper to updated models" (9 October 2019), p. 3.

[574] Vector "Cross-submission on companion paper to updated models" (16 October 2019), p.2.

[575] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 18.

H170 We clarify that an “annual compliance statement” is not required during the first assessment period of DPP3 (2020/21) from the compliance reporting requirements in the DPP3 determination. An “annual price setting compliance statement” that reports on 2020/21 is required to be submitted during 2019/20. This statement is to demonstrate ex-ante that the price path will be complied with. The DPP2 determination (published November 2014) does require an “annual compliance statement” in accordance with that determination to be submitted during 2020/21, and that statement would report on the 2019/20 assessment period.

Protection of distributors against retailer bad debts

H171 Orion submitted for a change in the IM definition of ‘revenue from prices’ to effectively exclude revenues not collected because of bad debts.[576]

H172 We have not adopted this submission because:

H172.1 doing so would remove the incentive for distributors to pursue bad debts

H172.2 we are not aware of significant historical retailer default events

H172.3 the Electricity Authority has developed processes for managing retailer default.

Revenue foregone as a result of a major Transpower interruption

H173 Wellington Electricity submitted against a ‘revenue foregone’ amount applying as a result of a major Transpower interruption.[577] It noted that the interruption would be outside a distributor’s control and the distributor may be still required to pay Transpower charges and Use of Network Agreement payment obligations to consumers.

H174 We have not adopted this submission because:

H174.1 The purpose of the revenue foregone provision (“cap on wash-up amount”) in the input methodologies was “… to ensure that suppliers bear some of the risk if a major demand event occurs (for example, a catastrophic event). We consider that a principle established in the Orion CPP decision should be applied; consumers and suppliers should share the risk of catastrophic events.”[578]

[576] Orion “Submission on companion paper to updated models” (9 October 2019), p. 19.

[577] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18.

[578] Commerce Commission, “Input methodologies review decisions Topic paper 1 Form of control and RAB indexation for EDBs GPBs and Transpower” (20 December 2016)

H174.2 A Transpower interruption would need to be unusually large to cause the “revenue reduction percentage” to exceed 20%, which is the threshold for a revenue foregone amount to apply. If a distributor’s entire supply of electricity were to be interrupted for a whole month, the revenue reduction percentage would not come close to 20%.[579]

The proportion of total electricity charges to consumers that are distributor charges

H175 Aurora submitted when we were setting Aurora’s draft decision X value, no consideration seems to have been given to the fact that the prices charged by distributors make up just a proportion of the total charges that consumers face for electricity.[580]

H176 When making our draft decision, we had been well aware that distributor charges are just a proportion that of the total charges. We quantified estimates of several measures of revenue and charges in our revenue change model and consumer bills impact model in our draft decision.

H177 The modelling includes consideration of the charges for distributor’s costs, Transpower’s costs and retailer charges. These models have been updated for the updated draft and final decisions.

Flow charts for the revenue cap with wash-up

H178 These flow charts (H1 and H2) do not show the transitional provisions to account for the residual pass-through balance from DPP2.

[579] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.1.3(13)(c) and 3.1.3(13)(j).

[580] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 14.

Figure H1 Setting prices and assessing compliance for assessment period-t

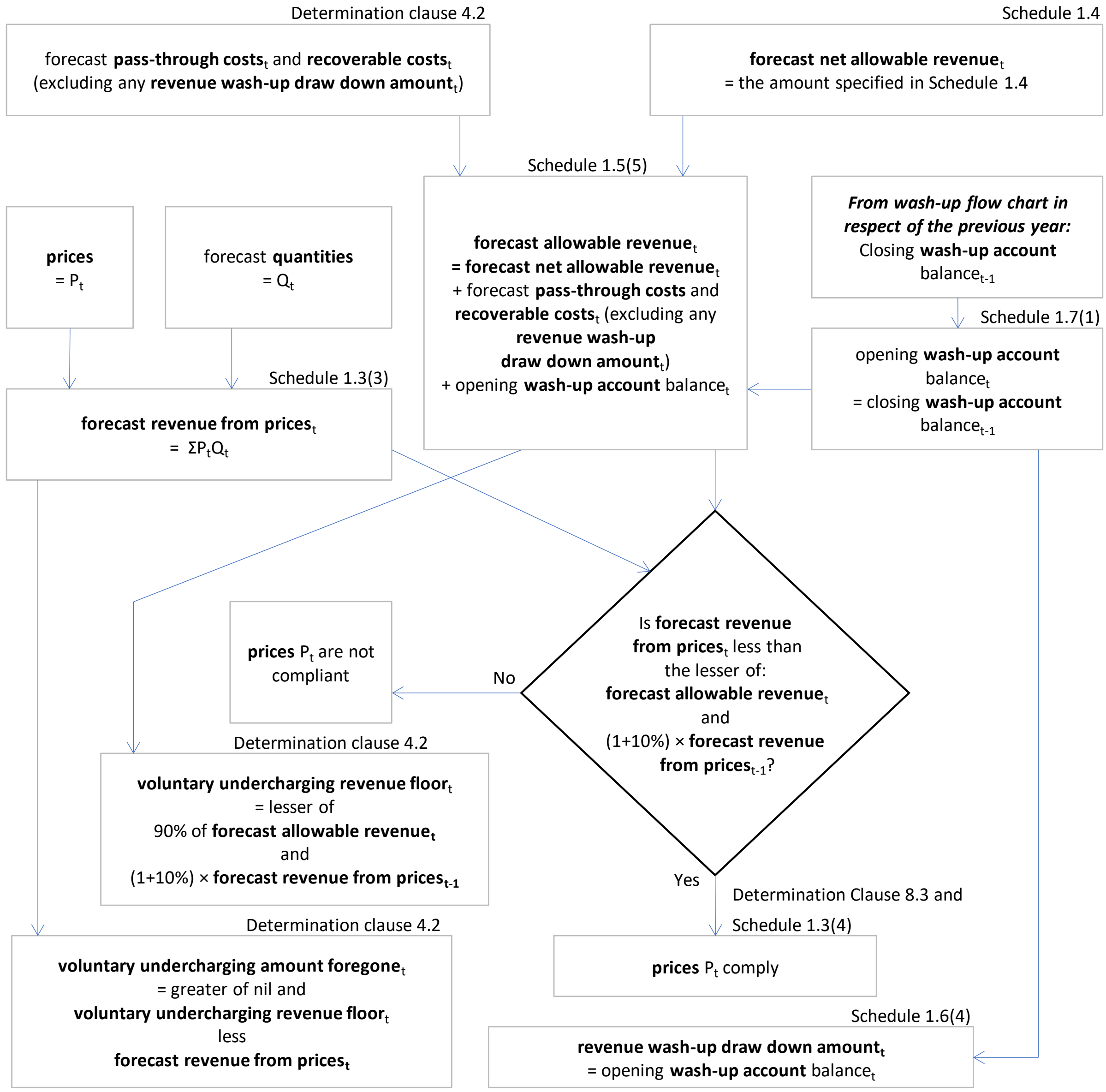
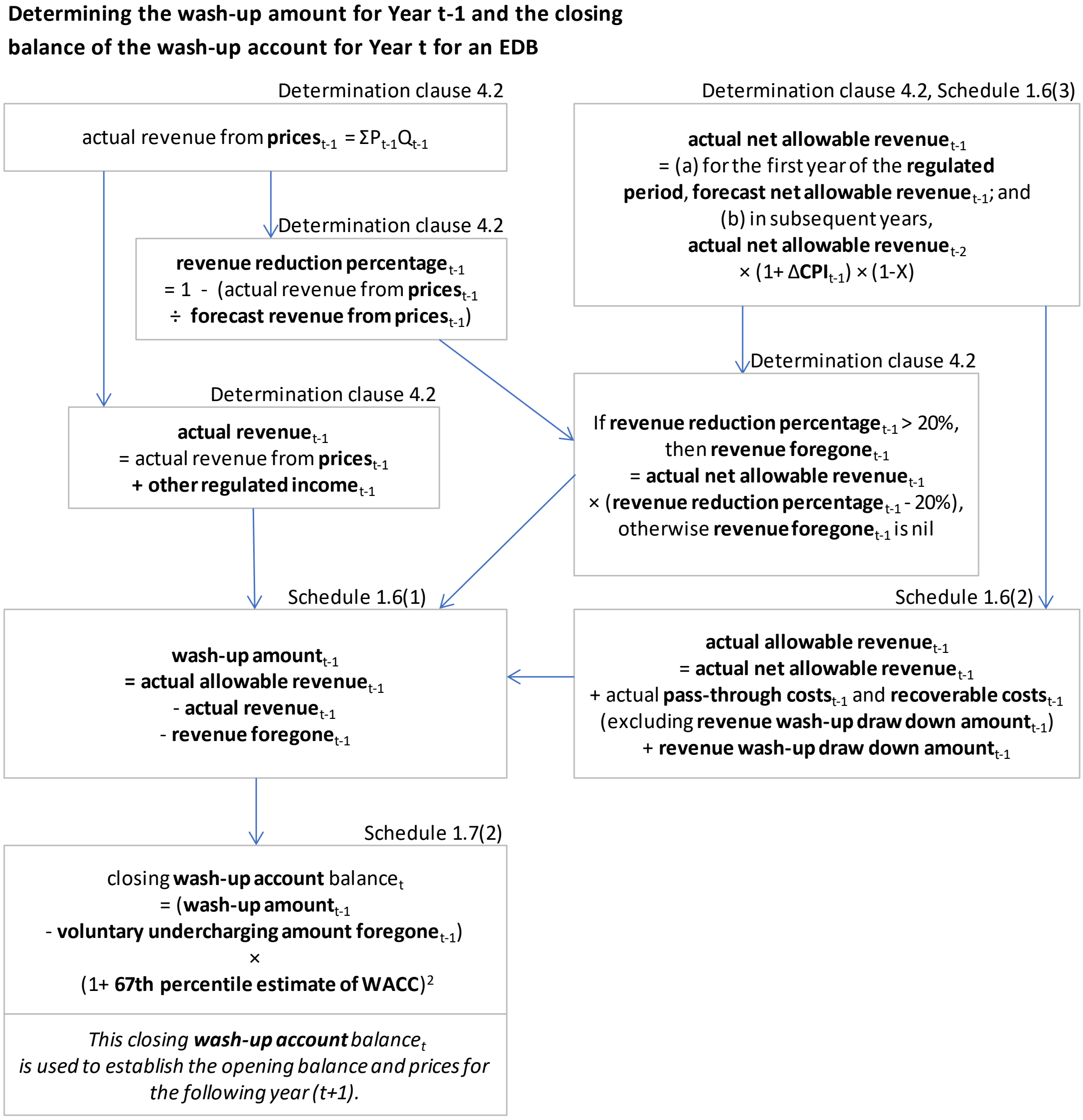


Figure H2 Determining the wash-up amount and the closing wash-up account balance



Numerical example of the revenue cap with wash-up

H179 Consider for example a distributor that sets prices for a disclosure year such that:

- Forecast revenue from prices = \$87m
- Forecast allowable revenue = \$100m
- Voluntary undercharging threshold = 90%
- Previous year's forecast revenue from prices = \$80m
- Limit on annual increases in forecast allowable revenue = 10%

H180 Note that the distributor is undercharging by only seeking a forecast revenue from prices of 87% of what it is allowed to charge.

H181 The methodology for calculating the voluntary undercharging revenue floor is to define a "voluntary undercharging revenue floor" as the lesser of:

- 90% of forecast allowable revenue, and
- (1 +10%) × the previous year's forecast revenue from prices

H182 The first of these bullet point amounts is 90% of $100m, i.e., $90m.

H183 The second of these bullet point amounts is 110% of $80m, i.e., $88m.

H184 The lesser of these two amounts is $88m, so that is the floor.

H185 If a distributor sets its prices such that the forecast revenue from prices is less than the voluntary undercharging revenue floor, it will permanently forego revenue ("voluntary undercharging amount foregone") to the extent the forecast revenue from prices is below the floor.

H186 The distributor has set its prices such that the forecast revenue from prices is $87m, which is $1m less than the floor of $88m. It will therefore incur a "voluntary undercharging amount foregone" of $1m. The wash-up amount will be reduced by this $1m, which will in turn mean that the distributor will not be able to recover the $1m.

H187 If the distributor had instead set its forecast revenue from prices at the floor value of $88m, it would have avoided the foregoing of revenue. The $88m is also the maximum amount under the "limit on annual increases in forecast allowable revenue" (being 110% of $80m). The distributor must therefore set its prices such that its forecast revenue from prices is at $88m, no more and no less, if it is to both avoid the foregoing of revenue under this mechanism and to be compliant with the 10% uplift, i.e., the 10% "limit on the annual percentage increase in forecast revenue from prices".

Perverse floor > ceiling issue

H188 As noted above, the "voluntary undercharging revenue floor" will be defined as the lesser of 90% of forecast allowable revenue, and (1 +10%) × the previous year's forecast revenue from prices.

H189 If we were not to have the second limb of this definition, and simply set the "voluntary undercharging revenue floor" as 90% of forecast allowable revenue, then the floor would be $90m. This was the regime we proposed in the issues paper.

H190 The distributor would however have a hard ceiling of $88m, being the maximum amount of forecast revenue from prices that would be allowed under the 10% limit on annual increases in forecast allowable revenue.

H191 We would then have a non-mandatory floor of $90m and a mandatory ceiling of $88m. This would be a perverse situation of the floor being higher than the ceiling. The highest the distributor may set its prices at is such that its forecast revenue from prices is $88m. This will mean that it will *involuntarily* incur a "voluntary undercharging revenue foregone" of $90m – $88m, or $2m.

Attachment I Interactions between the DPP and CPPs

Purpose of this attachment

I1 This attachment explains how we have treated Powerco and Wellington Electricity in the DPP3 reset, and the dates for any future CPP applications. After briefly summarising our decisions and explaining the reasons why we are addressing this issue, the attachment discusses:

I1.1 starting prices for Powerco;

I1.2 starting prices for Wellington Electricity;

I1.3 forecasts of opex and capex for IRIS purposes for Powerco and Wellington;

I1.4 quality standards and incentives for both Powerco and Wellington Electricity; and

I1.5 the dates by which distributors may apply for CPPs during DPP3.

High-level approach

Summary of our decisions

I2 We have:

I2.1 not set starting prices now for Powerco (but will do so in 2022);

I2.2 not set starting prices now for Wellington Electricity, but have provided guidance on how we will set the starting price in 2020, based on the same methodology applied to all other distributors;

I2.3 not determined opex and capex forecasts for Powerco or Wellington Electricity for the purposes of calculating IRIS incentives; and

I2.4 set quality standards for Powerco and Wellington Electricity using the same methodology applied to all other distributors; and

I2.5 determined a single final CPP application date in each year of the DPP3 period.

Statutory framework for considering CPP-DPP transitions

I3 What happens when a CPP ends is governed by section 53X of the Act. Section 53X(2) of the Act gives the Commission two options for determining starting prices for the CPP-DPP transition:

I3.1 rolling over the starting prices which applied at the end of the CPP period; or

I3.2 with at least four months' notice to the supplier prior to the end of the CPP period, determining different starting prices that will apply.

I4 Under this provision, we may determine starting prices for a distributor when they transition, but it does not give us the power to determine quality standards and incentives when a distributor transitions off a CPP.

Starting prices for Powerco

Problem definition

I5 If Powerco does not apply for a new CPP following its current CPP, it will return to the DPP, and we will need to determine what starting prices apply.[581] Powerco will transition off its current CPP on 31 March 2023.

Decision

I6 Consistent with the position we set out in the draft decision, we have not set starting prices for Powerco in the DPP3 reset, and instead will address the matter closer to the end of its CPP.

Alternatives considered

I7 As alternatives, we considered:

I7.1 setting binding starting prices in the DPP3 reset; or

I7.2 setting an indicative starting price, and then formalising it closer to the end of the CPP under section 53X of the Act.

Analysis

I8 The DPP reset occurs too far in advance of Powerco's transition for us to reliably forecast what its starting prices should be in the year starting 1 April 2023, and the availability of setting prices at a later date under section 53X makes this unnecessary.

[581] Commerce Act 1986, section 53X(1).

I9 Orion’s transition during the current DPP period gives us a useful precedent for how to manage the transition following Powerco’s current CPP. We anticipate engaging with Powerco later in the EDB DPP3 period in advance of deciding how we will set its prices from 1 April 2023.

Stakeholder views

I10 Powerco, in its submission on the draft decision, supported this approach.[582]

Starting prices for Wellington Electricity

Problem definition

I11 Wellington Electricity’s current CPP ends on 31 March 2021. Wellington Electricity is not on a ‘full’ CPP, but one which took the existing DPP revenue and expenditure allowances as a base and added an increment for additional resilience work. As such, the existing CPP is not a suitable base for future revenue allowances.

Decision

I12 We have not set starting prices for Wellington Electricity but have provided guidance on the starting price we will set in 2020, based on the same methodology applied to all other distributors. Indicative opex allowances for Wellington Electricity are discussed in Attachment A, and indicative capex allowances are discussed in Attachment B.

Analysis

I13 Unlike Powerco and Orion, Wellington Electricity’s CPP only overlaps the DPP by a single year. This means that forecasting its revenue requirements for the DPP3 period posed only limited additional difficulty over and above other distributors on the DPP.

I14 Furthermore, Wellington Electricity’s unique CPP circumstances – where the DPP2 revenue allowance was used as a base, with an increment for resilience investments – means that a roll-over is not an appropriate means of transitioning them off the CPP. We considered that a roll-over was not appropriate as this would effectively lock-in the revenue allowance first set in 2015 (and increased in 2018) until 2025.

I15 We intend to determine the starting price that applies from 1 April 2021, once more up-to-date information is available.

[582] Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 6.

Stakeholder views

I16 Wellington Electricity supported this approach in its submission on the draft decision, noting:

> An additional adjustment will be needed to ensure CPP operating costs are included in the DPP operating cost allowance (which are excluded from the current draft DPP operating allowance). WELL's current CPP determination includes on-going operating costs for the continued operation of its earthquake readiness programme. The CPP operating costs will not be fully captured in the base year used to forecast DPP – there are operating costs which fall in the last two years of the CPP programme and will fall after the selected base year.[583]

IRIS opex and capex forecasts for Powerco and Wellington Electricity

I17 We can determine opex and capex forecasts for the purposes of IRIS at the time when we determine starting prices under section 53X(2).

I18 Under clause 3.3.3(8)(a) of the EDB IMs, "forecast opex" for the purposes of calculating opex incentive amounts where we determine starting prices under section 53X (2) is "the amount of forecast operating expenditure specified by the Commission for the relevant disclosure year in the DPP determination.[584]

I19 Under clause 3.3.11(1)(b), "forecast aggregate value of commissioned assets" for the purposes of calculating the capex incentive amounts is the amount of capex determined by the Commission when setting starting prices.[585]

I20 The relevant capex and opex forecast values which will apply for each distributor for IRIS purposes are set out in Table I1

[583] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

[584] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clause 3.3.3(8)(a).

[585] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 (Consolidated as at 31 January 2019), clauses 3.3.11(1)(b) and 4.2.5

Table I1 Capex and opex forecasts for IRIS purposes

Year of the DPP3 period	Powerco	Wellington Electricity
2020/2021	2018 CPP forecasts	2018 CPP forecasts
2021/2022	2018 CPP forecasts	**2021 DPP forecasts**
2022/2023	2018 CPP forecasts	**2021 DPP forecasts**
2023/2024	**2023 DPP forecasts**	**2021 DPP forecasts**
2024/2025	**2023 DPP forecasts**	**2021 DPP forecasts**

I21 In both cases, the relevant time is when we determine starting prices. Under the proposal discussed above, for both Powerco and Wellington this will be when we determine starting prices under section 53X(2).

Quality standards for Powerco and Wellington Electricity

Problem definition

I22 Unlike starting prices, section 53X does not give us the power to determine quality standards when a distributor transitions off a CPP. For this reason, when setting the 2015 DPP, we set quality standards for Orion.[586]

Decision

I23 We have set quality standards and incentives for Powerco and Wellington Electricity on the same basis as all other distributors.

Alternatives considered

I24 We also considered:

I24.1 determining a binding formula at the outset of DPP3 that Powerco and Wellington Electricity would then apply for the years after they transition back to the DPP to determine their quality standards and incentives; or

I24.2 rolling over CPP standards.

Analysis

I25 Given we have made several changes to the way we determine quality standards (for example, to reference periods, normalisation, and the treatment of planned interruptions), it is not appropriate to roll over CPP quality standards prepared based on an older methodology.[587]

[586] Orion's reliability standards for the 2019/20 year were set equal to its standards in the final year of the CPP, and the quality incentive mechanism was not applied to Orion.

[587] These issues are discussed in Chapter 7, and in detail in Attachments J to M.

I26 Given the intricate suite of calculations required to set reliability targets and limits, including normalisation, we do not consider specifying a formula to determine quality standards and incentives closer to the transition time desirable. We note that if the quality standards we set prove to be inappropriate by the time either distributor transitions, they have the option of proposing a quality standard variation.

I27 We have not made additional adjustments to Powerco's standards, as contemplated in our draft decision, as we consider that our reliability methodology does not produce an outcome inconsistent with the goals of Powerco's CPP.[588]

Stakeholder views

I28 Powerco and Wellington Electricity supported this approach (while also identifying concerns with the overall approach to quality standards).[589]

CPP application dates

Problem definition

I29 Where a distributor considers that the DPP does not meet their particular circumstances, they may apply for a CPP. The Act requires us to specify in the DPP determination the date or dates by which a distributor may submit its CPP application.

Decision

I30 We have set a final application date 190 working days prior to the start of the next pricing year for the first four years of the DPP period (prior to the 31 March year-end).[590] In the final year of the DPP period, we have set a final application date of 29 March, as there is a statutory prohibition on CPP applications in the final year of the DPP period (1 April 2024 – 31 March 2025).[591] The dates that result from this approach are set out in Table 6.1 below.

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[588] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft reasons paper" (29 May 2019), para I22

[589] Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

[590] For consistency, we rounded each date to the preceding Friday.

[591] Commerce Act 1986, section 53Q(3).

Table I2 CPP application deadlines

CPP beginning	Final date for application
1 April 2021	Fri 12 Jun 20
1 April 2022	Fri 11 Jun 21
1 April 2023	Fri 10 Jun 22
1 April 2024	Fri 9 Jun 23
1 April 2025	Fri 29 Mar 24

I31 These deadlines apply to all CPP applications, including those triggered by catastrophic events.

I32 We note that where a distributor wishes to know its final CPP starting prices early enough to give notice of price changes to retailers, the CPP application would need to be made sooner than the final date above. Based on a 190 working day timeline, our estimates of the date by which a distributor would need to apply for a CPP with a four-month notice period (like that used for a DPP) are set out in Table I3 below.

Table I3 CPP application with four-month notice period[592]

CPP beginning	CPP decision date	Approximate application date
1 April 2021	Fri 27 Nov 20	Fri 28 Feb 20
1 April 2022	Fri 26 Nov 21	Fri 26 Feb 21
1 April 2023	Fri 25 Nov 22	Fri 25 Feb 22
1 April 2024	Fri 24 Nov 23	Fri 24 Feb 23
1 April 2025	Fri 22 Nov 24	Fri 23 Feb 24

Stakeholder views

I33 Submissions on this approach were supportive, with Aurora Energy noting the additional flexibility it provides.[593]

Changes since the draft decision

I34 This is a slight change from the approach we set out in the draft decision. The timeframes for the draft were based around a 180 working day timeframe and applied an incorrect definition of 'working day'.

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[592] These dates assume a 190 working-day consideration period, and are for guidance only, and are not part of the DPP determination.

[593] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 15; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 39; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 5.

Preliminary assessment of CPP proposals

I35 The 180-working day lead time was based on the CPP assessment timeframes set out in the Act:

I35.1 the Commission has 150-working days to assess a CPP and determine starting prices and quality standards;[594]

I35.2 and by agreement with the distributor, may apply a 30-working day extension.[595]

I36 However, this did not account for the process of preliminary assessment of a CPP proposal, as contemplated by section 53S of the Act. This provision allows the Commission 40 working days to assess whether a CPP proposal complies with the relevant IMs.

I37 To account for this, we have extended the timeframe to 190 working days.

Correction to dates for application

I38 In working out the application date based on the lead time above, our draft decision applied an incorrect definition of working days. This error has been corrected in our final decision.

[594] Commerce Act 1986, section 53T(2).

[595] Commerce Act 1986, section 53U. This option to extend remains available, however may result in a final decision date after 1 April the following year.

Attachment J Approach to setting the quality path

Purpose of this attachment

J1 This attachment sets out our final decisions on our high-level approach to setting the quality path for EDB DPP3. Attachments K to N provides more detail on setting the components of the quality standards and incentives.

Summary of our final decision

J2 The quality path for distributors for DPP3 consists of three quality standards and a quality incentive mechanism as summarised below:

J2.1 unplanned and planned interruptions will be assessed separately for the purposes of quality standards and revenue-linked incentives (unchanged from draft);

J2.2 a reference period from 1 April 2009 to 31 March 2019 is used as a baseline against which material deterioration is measured, and the baseline for distributors making quality trade-offs (updated one year from draft);

J2.3 the movement in unplanned SAIDI and SAIFI targets between regulatory period is limited to 5% (unchanged from draft);

J2.4 unplanned major interruptions, assessed on a rolling 24-hour period, are largely normalised out and reported on, which is discussed further in Attachment K;

J2.5 three quality standards which are discussed further in Attachment L, these are:

J2.5.1 an annual reliability standard for unplanned interruptions based on SAIDI and SAIFI (modified from draft);

J2.5.2 a regulatory period reliability standard for planned interruptions based on SAIDI and SAIFI (unchanged from draft); and

J2.5.3 an extreme event standard set at 120 SAIDI minutes or 6,000,000 customer minutes for interruptions predominantly caused by specified external factors (changed from draft);

J2.6 SAIDI and SAIFI will be recorded on the same basis as that disclosed in the distributor’s audited interruption data in response its section 53ZD request, namely its treatment of successive interruptions;

J2.7 introduce automatic reporting requirements following a contravention of any quality standard, which is discussed further in Attachment L (modified from draft);

J2.8 revenue-linked quality incentives will be applied to SAIDI, with an additional incentive to meet minimum notification requirements for planned interruptions, which is discussed further in Attachment M (modified from draft); and

J2.9 no new quality metrics are introduced as part of the quality standard or revenue-linked quality incentive scheme, which is discussed further in Attachment N (unchanged from draft).

High-level approach

J3 Section 53M(1)(b) of the Act requires us to determine the quality standards that must be met by regulated suppliers. Additionally, section 53M(2) permits us to include incentives for suppliers to maintain or improve quality of supply.

J4 Our overall approach to setting quality standards and incentives that relate to the duration and frequency of interruptions (SAIDI and SAIFI) experienced by customers begins with a principle of "no material deterioration" in network performance.

J5 This approach is consistent with our low-cost DPP forecasting principles, in that future revenues and quality are set with reference to historical levels of performance. At the same time, our incentive arrangements (discussed in Attachment M) do allow for distributors to – within certain limits – target a lower level of reliability at a lower cost to consumers.

J6 To apply this, we need a period of historical data against which distributors' future performance is assessed. Given changes in distributors' operating environment, network performance, and maintenance practices, the choice of reference period can have a significant impact on the standards we set.

J7 The extreme event standard is the exception to the use of historic baseline data because these events are too rare to be able to reliably set a limit based on historic data. Applying the DPP3 extreme event standards to the past ten years would have resulted in just two instances over all of the non-exempt distributors.

J8 Effective reliability standards and incentives are necessary in the first instance to encourage distributors to supply electricity distribution services at a level that reflects consumer demands. However, the standards and incentives also work to mitigate the risk that distributors – facing a revenue constraint – under-invest in their networks in order to maximise profitability.

Quality standards and revenue-linked incentives

J9 Quality standards, with the potential for prosecution of contraventions, up to a point provide an incentive for distributors to not let quality degrade. However, the incentives relating to reliability standards are strongest as the risk of contravention increases, which may vary during the year depending on performance. Performance can also analysis shine a light on degrading quality, providing an incentive to avoid it.

J10 The revenue-linked incentive scheme for reliability is designed to provide distributors with incentives to consider cost-quality trade-offs in their decision-making. In the absence of adequate incentives, distributors may be incentivised to reduce expenditure, at the expense of quality, to increase profitability.

J11 As noted by Castalia when critiquing the Commission's setting of the IMs in 2012, on behalf of Vector:[596]

> …the evidence from overseas suggests a well-designed regulatory system of penalties and rewards is needed to translate customer expectations into reality. Regulation should provide incentives to achieve true efficiency…

Revenue-linked incentives vs. quality standards incentives

J12 We consider that the quality standards associated with reliability do not provide sufficient incentives to move towards a price-quality trade-off that better reflects both consumer willingness to pay and distributor cost to serve. The incentives of the standards largely depend on the risk of contravening and the consequences of contravening. Specifically:

J12.1 as the risk of contravening the quality standard grows the incentives to improve reliability grows, most likely in a non-linear manner which is not reflective of the consumers' willingness to pay; and conversely

J12.2 if there is little to no risk of contravening, especially as the assessment period nears its end, there is minimal financial incentive to maintain reliability.

J13 This means that with quality standards alone, distributors are not exposed to a consistent cost-quality trade-off in the decisions they make regarding reliability throughout the year and over the long term. Distributors are likely to focus more on the expenditure impact in addressing reliability when contravention risk is low.

[596] Castalia Strategic Advisors "Evidence on the Impacts of Regulatory Incentives to Improve Efficiency and Service Quality – Report to Vector Limited" (April 2012), pp. 18 to 19.

J14 Furthermore, these standards have a buffer above historical performance built in to reduce false-positives. This means that to the extent these standards incentivise reliability, it may be to a lower level of performance than experienced during the reference period.

J15 However, a quality standard can help capture a concerning level of deterioration beyond which we might accept under a revenue-linked incentive scheme. Where a distributor believes quality delivered below this level is in the long-term benefit of its consumers, we consider a quality standard variation reopener or a CPP, and the greater scrutiny we can apply to them, is the better response.

J16 We consider that revenue-linked incentives on reliability provide useful incentives to manage the price-quality relationship, as long as the incentives are not too strong. With conservative revenue-linked incentive settings profit maximising distributors will be:

J16.1 encouraged to find inexpensive solutions to improve reliability as marginal benefits will outweigh the marginal costs for both distributors and consumers;

J16.2 encouraged to find solutions up to the point where marginal benefits equal marginal costs for both distributors and consumers, assuming incentives are reflective of the consumers value of quality; and

J16.3 discouraged to find expensive solutions to improve reliability such that marginal costs exceed the marginal benefits for distributors, and therefore consumers.[597]

J17 However, if the revenue-linked incentives are too strong, then distributors may be encouraged to find solutions where the costs to consumers can exceed the benefit to consumers—that is marginal benefits could exceed marginal costs for distributors but not for consumers.

J18 Conversely, if the revenue-linked incentives are too weak, or zero, then distributors will not be encouraged to find all solutions that would optimise marginal costs and benefits for both distributors and consumers.

[597] Marginal benefit (MB) for EDBs is the revenue-linked incentive payment and for consumers is the value of improved reliability. Marginal cost (MC) for EDBs is the increased expenditure (net of IRIS paybacks) and for consumers is the incentive payments (including IRIS).

J19 As discussed in Attachment M, we use VoLL as a proxy for consumers cost-quality preferences. On balance, we consider the revenue-linked incentive scheme for reliability that we have recommended is conservative.[598] However, we consider that this is more appropriate than providing no incentive or too high an incentive.

Are the revenue-linked incentives working?

J20 Our analysis suggests that the revenue-linked incentives may be working.

J21 As discussed further in Attachment M, a consequence of setting revenue-linked incentives based on setting the revenue at risk (0.5% each for SAIDI and SAIFI) and setting the incentive range (caps and collars) is that incentive rates varied substantially between distributors. This resulted in distributors with a relatively narrow cap and collar band having much stronger incentives via the implied incentive rate.

J22 Nelson Electricity and Electricity Invercargill, which were exposed to greater incentives relative to other distributors, made among the best improvements in SAIDI and SAIFI. A third, Wellington Electricity, also submitted that the incentive scheme does impact distributors' decisions.[599]

J23 Also, we have noted that for most distributors SAIFI has performed much better than SAIDI. We consider that reducing SAIFI may have been more cost-efficient for the distributor, for example, through the installation of reclosers.

J24 Ultimately, as a regulator, our role is to ensure distributors face incentives that align its interests with the long-term interests of consumers. Whether a distributor prioritises responding to those incentives is a decision for each distributor and it is for investors to make, relative to other priorities they may have.

Consideration of an asymmetric incentive scheme

J25 Our decision is to retain a symmetric incentive scheme where the incentive rate is constant below the quality standard we have set.

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[598] This is due to the greater long-term risk of EDBs over investing in quality beyond what consumers want, the availability of a CPP for situations where EDBs want to significantly improve quality (and provide evidence that doing so meets consumers' demand), and existing measures to account for the probability of underinvestment (for example, the WACC uplift).

[599] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 15.

J26 Consumers may have more aversion to a deterioration in reliability than they have a desire for improvements in reliability. In other words, consumers are willing to accept (WTA) a higher level of payment for lower reliability than they are willing to pay (WTP) for higher reliability. For example, London Economics, in advising Ofgem, considered that:[600]

> … When consumers are used to enjoying a service that they pay for, they typically want greater payment in order to bear a loss of that service than they are willing to pay to retain it. This is because individuals feel a sense of ownership (property rights) for something they already have (in this case a secure electricity service). Psychologically, the loss from giving something up feels greater than the gain from keeping it and avoiding the loss.

J27 PricewaterhouseCooper (PwC) undertook a consumer survey to assess how consumers value lost electricity. The results suggested that the value consumers place on supply when asked to accept an interruption (WTA) is significantly higher than the value they place on it when asked about paying for avoiding an interruption (WTP), typically two to five times as much (although this varies depending on several factors).[601]

J28 Furthermore, we have heard from distributors that their 'consumers do not accept deteriorating reliability and are not prepared to pay for improved reliability', implying that consumers always want the status quo. However, we note that the 'status quo' reliability experienced by consumers does change over time.

J29 This assumption in some ways informs our overall approach to the DPP – a status quo-based approach, with low-cost optimisations (to efficiency and quality) at the margins, and with a CPP available either where the distributor wishes to change the status quo or is unable to maintain current quality at something approaching current cost.

J30 To the extent it is true that this asymmetry extends to overall reliability, this would lend itself to an asymmetric (or even one with negative incentives only) incentive scheme. We generally accept the notion the consumers may be more willing to accept payment to have an interruption than to pay to avoid an interruption. However, it is unclear how this translates into a deterioration or improvement in overall reliability.

[600] London Economics "The Value of Lost Load (VoLL) for Electricity in Great Britain – Final report for Ofgem and DECC" (July 2013), p. xii.

[601] PwC "Estimating the Value of Lost Load in New Zealand" (March 2018).

J31 There are some other drawbacks of applying an asymmetric incentive scheme:

J31.1 it may erode the expectation of a normal return unless other parameters are adjusted, for example, the reliability 'target' or the revenue allowance;[602]

J31.2 it requires us to make a further assumption about where the inflection point from 'material' deterioration is;

J31.3 cost-quality trade-off complications for a distributor, in that a distributor may not know the marginal incentive of any reliability decision during the year or effects in the long-term;

J31.4 setting the separate incentive rates, revenue at risk, and/or caps and collars; and

J31.5 consumer quality preferences are likely to change over time as better or worse reliability is experienced.

Consideration of a consumer compensation scheme

J32 Consumer compensation is something we are specifically empowered to implement by section 53M of the Act.

J33 A consumer compensation scheme is similar to a negative incentive-only incentive scheme, the principal difference is that each consumer is compensated directly for interruptions they experience, rather than the losses being pooled and distributed less directly. One appealing feature of a compensation scheme is that there can be a more direct relationship between the price a consumer pays and the reliability they experience.

J34 However, like an asymmetric or negative incentive-only incentive scheme, or like the quality standards, it may erode the expectation of a normal return unless revenue is adjusted upwards.

J35 As discussed in Attachment N, we are not introducing a consumer compensation scheme for DPP3, but it may be something that we revisit for DPP4. To determine the appropriate settings for a consumer compensation scheme would require significant analysis and further information, and we may ask for that additional information during DPP3.

[602] Where we, and the distributor, expect as a matter of ordinary volatility, that the distributor has half its assessment periods above the mean and half below, the greater losses for underperformance will outweigh the rewards for overperformance, thus not creating the ex-ante expectation of a normal return, even when quality standards are met.

J36 In particular, given the interposition of retailers between distribution businesses and consumers, we decided that it was likely not possible to develop the mechanisms that allow payments to reach affected consumers in time for this DPP3 reset.

Why should consumers pay for reliability beyond the historical norm?

J37 We recognise that the nature of the SAIDI and SAIFI metrics we use are aggregate in nature. This can result in individual consumers receiving a service level higher or lower than they desire relative to the cost of lines services. This is true for both financial incentives and quality standards.

J38 However, we also note that in the DPP:

J38.1 the revenue allowance (net of all financial incentives) is pooled, which a distributor can recover from consumers as it sees fit;

J38.2 expenditure allowances are pooled, which a distributor can spend on consumers as it sees fit; and

J38.3 reliability targets and limits are pooled, which will be distributed among consumers.

J39 In any case, it would likely be difficult for a distributor to tailor different reliability outcomes for the preferences of each individual consumer on shared infrastructure.

J40 For DPP3, we are setting incentives at a conservative level tailored to each distributor. In our view, the incentives that we are implementing do not exceed the value consumers place on lost load, at an aggregate level. This is consistent with all other substantial DPP settings.

J41 We also consider it is important that distributors are not disincentivised to provide improved reliability for those consumers who want it. Without an incentive scheme, and with the move to a revenue cap, there is little financial incentive for a distributor to make even the lowest cost improvement to reliability even if desired by consumers because:

J41.1 the distributor will not receive additional revenue, as it is capped;

J41.2 there is a cost, which the distributor must bear a portion of; and

J41.3 as a result, the distributor's profitability would be reduced.

J42 The opposite is also true — distributors may be incentivised to allow deterioration in reliability, within the bounds of any quality standard as:

J42.1 distributors may have an expectation that we would re-align their quality target in DPP4 to account for their poor performance in DPP3 by including DPP3 in the reference period;

J42.2 they will not lose revenue as distributors can still recover up to the cap;[603]

J42.3 they can reduce costs, of which they will keep a portion of; and therefore

J42.4 it will increase its profitability.

J43 Our decision is not aimed at setting the price-quality optimum for each consumer (or group of consumers). However, given the aggregate nature of the settings in the DPP, it is important to ensure that distributors face improved price-quality trade-offs. In order to do this, between the standards and incentive scheme, we have attempted to set reasonable limits on quality, within which it is up to each distributor to decide what best meets their consumers' needs and expectations.

J44 To the extent we wish to set the parameters of prices and quality at a more disaggregated level, enhanced ID requirements and performance analysis is likely to be required.

Setting quality standards without revenue-linked incentives?

J45 We have considered whether setting standards and incentives that are reflective of consumers' current demands and also in the long-term interest of consumers would still require the need for a revenue-linked incentive scheme.

J46 There are several barriers to setting 'optimal' standards that make it not feasible, for example:

J46.1 distributors have different network characteristics that will require different price-quality settings;

J46.2 each consumer (or consumer group) will implicitly have different views of what the optimal price and optimal quality is, and furthermore, there may also be a temporal dimension where future consumers have different preferences;

[603] This is exacerbated under a revenue cap with a wash-up, as distributors will be able to recover the revenue for quantities not delivered on a two-year lag.

J46.3 even with normalisation, there is inherent volatility within any reliability metric we use to assess standards, and unless all events beyond the distributors’ reasonable control that cause the volatility can be filtered out, this makes an assessment against an 'optimal' standard unrealistic—although even where the event is outside of the distributors’ control, it will have at least control over the extent of interruptions arising from it;

J46.4 distributors cannot have precise control over interruptions so as to precisely meet such a given standard consistently; and

J46.5 a restriction on benchmarking for setting quality standards in a DPP prevent adequately accounting for network and consumer characteristics.

J47 There are also issues with setting 'optimal' penalties for contravening the standards, for example:

J47.1 by law, we are limited to financial penalties of $5m for each standard contravened, and this may not be enough to deter some contraventions;

J47.2 specifying the 'optimal' penalty for contravening each standard for each distributor, recognising that they will be different;

J47.3 the cost (to the Commission) of administering the enforcement standards needs to be taken into account; and

J47.4 penalties do not get distributed back to consumers.

J48 As previously noted, we consider that revenue-linked incentives on quality will better facilitate the movement towards a price-quality balance that consumers prefer at an aggregate level.

Setting the baseline planned and unplanned SAIDI and SAIFI

J49 To set reliability parameters for the DPP3 period, we require a baseline that informs those parameters. Previously, we have considered the distributors’ historical performance to provide that baseline. Without reliable external evidence about customers’ preferred level of quality and without the ability to use benchmarking to identify a more ‘optimal’ level of reliability we take the same approach for DPP3.

J50 Our decision is to set quality standards and financial incentives separately for planned and unplanned interruptions. As such, we considered the two reference periods separately (although ultimately, we use the same reference period for both).

J51 The specific decisions we have implemented are:

J51.1 SAIDI and SAIFI are measured consistently with how the distributor measured them as at 31 March 2019 within its audited section 53ZD response;[604]

J51.2 an unplanned reference period from 1 April 2009 to 31 March 2019;

J51.3 a cap of 5% on the inter-regulatory period movement in unplanned quality parameters; and

J51.4 a planned reference period from 1 April 2009 to 31 March 2019.

Measuring SAIDI and SAIFI

J52 SAIDI and SAIFI are the reliability measures that form the basis of the quality standards and incentives. By definition:

J52.1 SAIDI is the sum of the minutes customers are not supplied with electricity due to an interruption divided by the number of customers on the network; and

J52.2 SAIFI is the sum of the number of interruptions experienced by customers divided by the number of customers on the network.

J53 Only interruptions to customers caused by a failure of the distributor's assets (excluding LV lines) is assessed for the purpose of the quality standards and incentives.[605]

J54 Normally, we would expect that a unique interruption, for the purposes of measuring SAIDI and SAIFI, will be triggered every time supply is interrupted to any customer. For example, where a customer is interrupted twice as part of the same "event":

J54.1 no SAIDI would be accumulated between the end of the first interruption and the beginning of the second interruption; and

J54.2 two interruptions would occur for the purpose of calculating SAIFI, rather than one.

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[604] Commerce Commission "Notice to supply information for 2020 DPP reset under section 53ZD" (28 June 2019).

[605] These are sometimes referred to as Class B (planned interruptions on the network) and Class C (unplanned interruptions on the network) interruptions.

J55 However, we were made aware that many distributors were not applying a consistent definition of interruption, and subsequently SAIDI and SAIFI, consistent with this. For example, some distributors were defining an interruption on an "event" basis where multiple interruptions as part of the same event would be treated as one continuous interruption.

J56 Due to data problems, distributors may face substantial costs realigning their SAIDI and SAIFI historical values in order to be consistent, we therefore require for DPP3 that SAIDI and SAIFI is measured consistently with the approach applied in the audited interruption dataset each distributor provided to the Commission.[606] We plan to consult with stakeholders after the DPP3 reset to ensure that in the future the definition of an interruption is applied consistently by distributors, firstly as part of ID.

J57 Submitters to our SAIFI consultation paper generally accepted our proposed approach requiring distributors to use the same methodology for calculating SAIFI during DPP3 as that applied on 31 March 2019.[607] However, Aurora Energy submitted that it had restated its historic SAIFI data to be better aligned with the definition of an interruption after 31 March 2019.[608] We agree with Aurora that this is appropriate and for this reason we have also tied the SAIFI definition to the methodology applied within its audited section 53ZD response.

J58 For consistency we will require that SAIDI is also measured consistently with the approach that applied in each distributor's audited section 53ZD interruption data.

Unplanned interruptions

J59 We use the 10 years from 1 April 2009 to 31 March 2019 as the reference period to set unplanned reliability parameters for the final decision.

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[606] See Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Recording of successive interruptions for SAIFI: Consultation paper" (7 October 2019) for more information on this issue and the options we considered for setting quality standards and incentives in lieu of inconsistent interruption data across distributors.

[607] ENA "Comments on SAIFI successive interruptions consultation" (18 October 2019), p. 2; Orion "Submission on EDB DPP3 Recording of Successive Interruptions for SAIFI" (18 October 2019), para 5-6; Vector "EDB DPP3 reset - SAIFI consultation" (18 October 2019), para 11; The Lines Company submission on the SAIFI consultation paper (16 October 2019), p. 2; Wellington Electricity "EDB DPP3 reset-SAIFI consultation" (18 October 2019), p. 1.

[608] Aurora Energy "Submission to Commerce Commission: Recording of successive interruptions for SAIFI" (18 October 2018), p. 1.

J60 Consistent with our DPP2 decision, we consider that a minimum reference period of 10 years best reflects the current underlying level of reliability performance, given the availability of reliable and consistent data. ENA, Eastland Network, and Orion supported using the latest 10 years.[609] For example, ENA submitted that for unplanned interruptions this is "… appropriate because it helps mitigate year-on-year variation due to circumstances outside distributor control, and the longer duration captures the longer-term weather cycles."

J61 We also consider that rolling over to the most recent 10-years is better aligned with expenditure incentives, in that the distributor will, within limits, keep any improvements or deterioration in reliability performance for at least five years. For example, if a distributor were to spend money to improve reliability, with expenditure incentives it would retain that additional spend for five years before being passed on to consumers. In principle, we consider that any associated reliability improvement should also be retained for five years.

J62 We considered an IRIS-like[610] approach to setting reliability parameters, where distributors would need to adjust SAIDI and SAIFI parameters each year to reflect the latest years performance, would add a level of complexity for little added value given the volatile nature of SAIDI and SAIFI. For this reason, we considered that fixing reliability parameters for the regulatory period using data from the most recent 10-years to be a simpler approach, while still approximating the expenditure incentives.

J63 Submissions from distributors generally agreed with using the latest ten years as the reference period for setting SAIDI and SAIFI standards and targets going forward.[611] For example Orion stated that ten years "reflects the recent operating environment of distributors, and includes the frequency and variability of longer weather cycles over a reasonable time period."[612]

[609] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 8; Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 4; Orion "Submission on EDB DDP3 Reset " (20 December 2018), p. 10.

[610] Refer to Attachment E for discussion on expenditure incentives.

[611] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 10; Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Horizon "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 24; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 28. We note that Wellington Electricity had a preference for five years in the context of a non-separate planned and unplanned standard, refer to Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

[612] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 10.

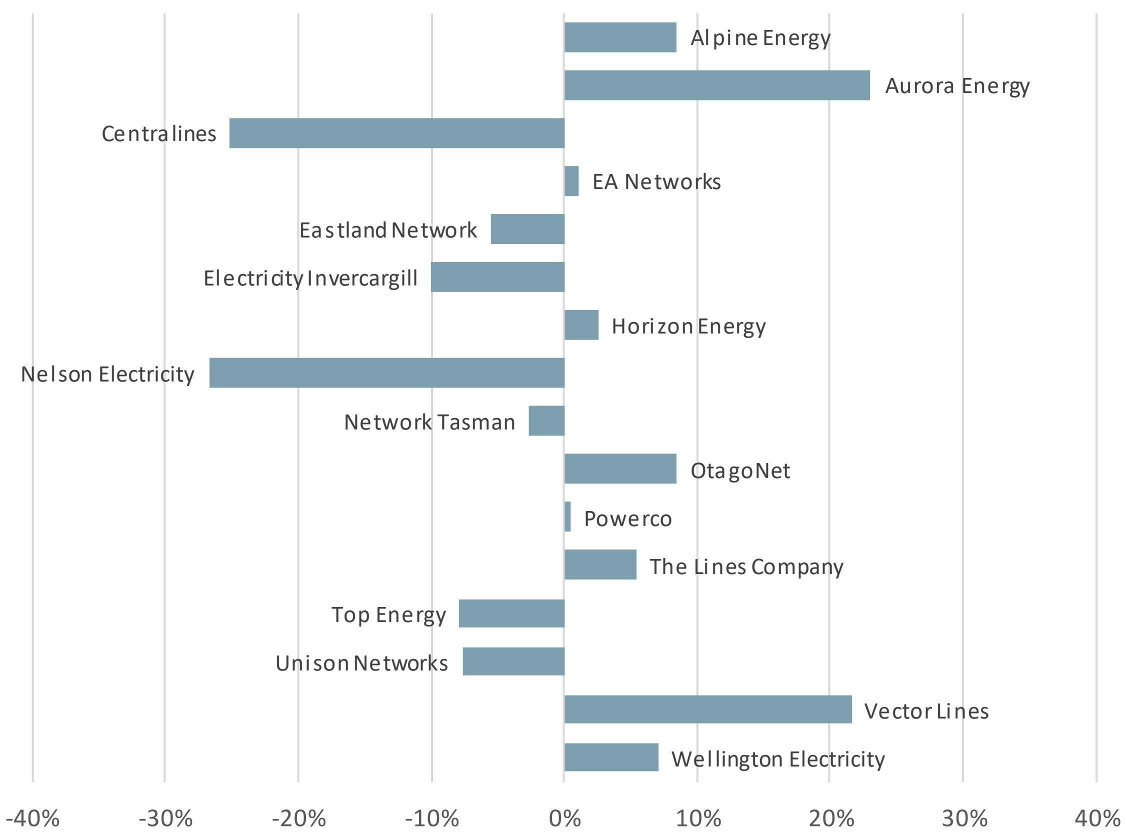
Capping the inter-regulatory period change for unplanned reliability

J64 We have limited the change in unplanned reliability targets between DPP2 and DPP3 at ±5%.

J65 Given the aggregated and blunt nature of our quality scheme, we do not consider it appropriate to embed significant deterioration or improvements in the reliability parameters without further scrutiny of whether it is in consumers' best interests. Similarly, we do not consider it appropriate that deteriorating performance should be rewarded with more relaxed standards and improved performance penalised through stricter standards.

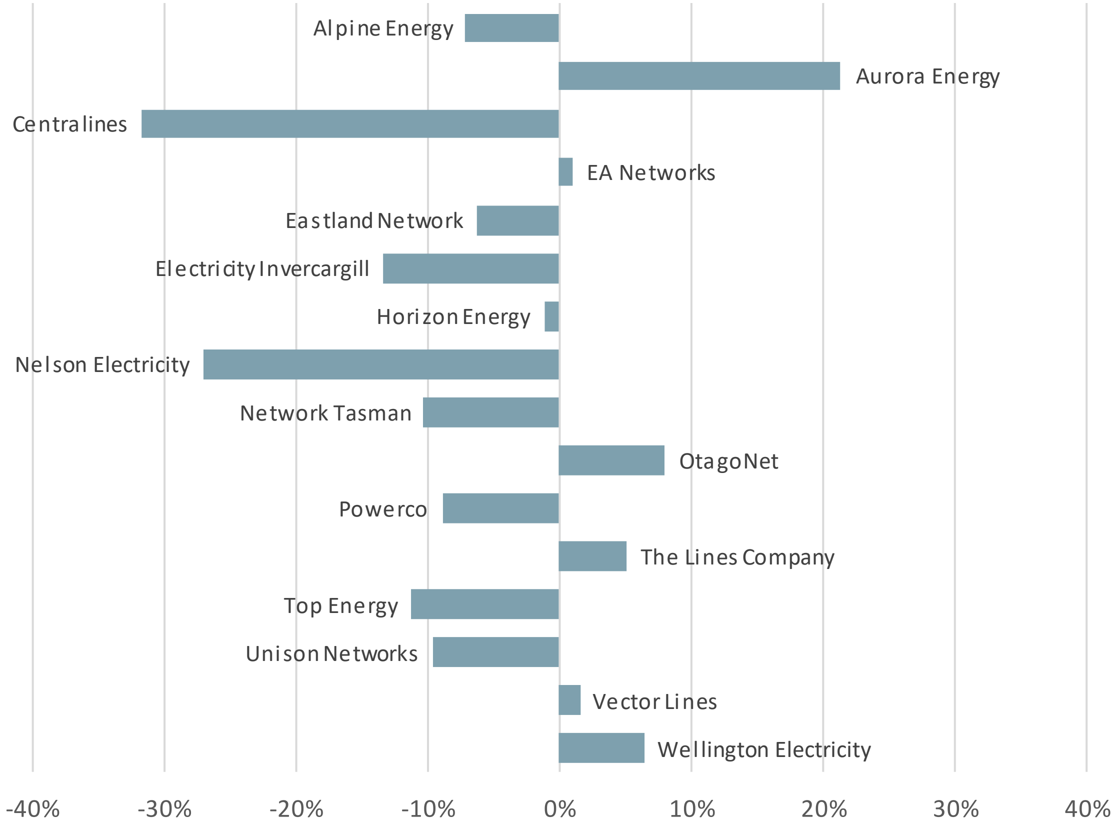
J66 Figure J1 and J2 below show the change in SAIDI and SAIFI targets from DPP2 to DPP3.[613]

Figure J1 Difference between DPP2 and uncapped DPP3 SAIDI targets



[613] DPP2 and DPP3 targets have been assessed on a consistent basis closest to the proposed methodology, where the targets are the annual SAIDI and SAIFI averages after normalisation of the relevant reference periods for each regulatory period. Recognising that we do not have timings of interruptions for earlier years of DPP2, the normalisation of this analysis is done using calendar days for both regulatory periods.

Figure J2 Difference between DPP2 and uncapped DPP3 SAIFI targets



J67 In order to apply the 5% inter-period cap for unplanned interruptions we limit the DPP3 target to a 5% change relative to DPP2. However due to changes in how unplanned interruptions are normalised, as discussed in Attachment K, we applied normalisation consistently across the DPP2 and DPP3 reference periods to assess the difference in targets between the two regulatory periods. The DPP3 SAIDI and SAIFI targets are then amended to ensure the change between regulatory periods does not exceed 5%.

J68 We also note that as five years (1 April 2009 to 31 March 2014) are common to both DPP2 and DPP3 reference periods, we have effectively allowed a maximum change of around 10% over 10 years (2004-2009 v 2014-2019).

J69 Table J1 shows how distributors will be impacted by this 5% inter-period cap, and the adjustment that would be made to the final unplanned SAIDI and SAIFI targets (relative to an uncapped target).

Table J1 Adjustments to DPP3 targets based on 5% cap

Distributor	SAIDI Adjustment	SAIFI Adjustment
Alpine Energy	-3.19%	2.25%
Aurora Energy	-14.66%	-13.51%
Centralines	26.84%	39.16%
EA Networks	0.00%	0.00%
Eastland Network	0.54%	1.32%
Electricity Invercargill	5.57%	9.68%
Horizon Energy	0.00%	0.00%
Nelson Electricity	29.68%	30.23%
Network Tasman	0.00%	5.88%
Orion NZ	0.00%	0.00%
OtagoNet	-3.17%	-2.81%
Powerco	0.00%	4.20%
The Lines Company	-0.42%	-0.17%
Top Energy	3.11%	6.96%
Unison Networks	2.88%	5.12%
Vector Lines	-13.65%	0.00%
Wellington Electricity	-1.94%	-1.37%

Stakeholder views

J70 Most distributors that submitted agreed that some limit on the degree to which standards could increase or decrease between regulatory period was appropriate. However, they had divergent views as to what the limit should be that was largely determined by the impact such a cap would have on them. These submissions can be summarised as:

J70.1 Centralines, Horizon Energy, Powerco, and Unison agreed with the 5% limit;[614]

[614] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18; Horizon "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3; Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3; and Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 22-23.

J70.2 Alpine Energy (10%), Aurora Energy (15%), and Wellington Electricity (1 standard deviation) suggested the limit should be increased;[615] and

J70.3 Vector disagreed with having any limit.[616]

J71 We note that distributors appeared to be more receptive to this symmetric limit on inter-regulatory period movement in reliability standards and incentives than our issues paper approach of removing the most extreme years from the reference period.

J72 Wellington Electricity submitted that 5% represents a small absolute movement for more reliable networks and suggests the caps and collars (one standard deviation above and below the historical average) as an acceptable range of movement. It also considers that a 5% limit reduces “predictability and certainty expected from a low-cost price-quality regime.”[617]

J73 We disagree with Wellington Electricity on both fronts. Firstly, we consider that consistently averaging one standard deviation above or below the normalised historical average for five years represents significant deterioration or improvement. This would rarely impact distributors except in extreme cases.[618] Secondly, we consider that reduced inter-period volatility in reliability standards would provide more certainty to distributors and consumers as to the degree in which deterioration or improvements will be captured over time.

J74 Aurora Energy submitted that the 5% limit “exposes EDBs to too much risk of quality standards with which they cannot reasonably comply” and “it would be inappropriate to set limits that essentially entailed a future breach of the price-quality path.”[619]

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[615] Alpine Energy “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 12; Aurora “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 3; and Wellington Electricity “Submission on EDB DPP reset draft decisions paper” (18 July 2019), pp. 22-23.

[616] Vector “Submission on EDB DPP reset draft decisions paper” (18 July 2019), pp. 42,54.

[617] Wellington Electricity “Submission on EDB DPP reset draft decisions paper” (18 July 2019), pp. 22-23.

[618] Our analysis suggests that using one standard deviation as the inter-period cap will only impact three distributors for SAIDI (Aurora, Centralines, and Vector) and SAIFI (Aurora, Centralines, and Powerco).

[619] Aurora “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 3.

J75 We emphasise that the 5% limit is relative to a performance standard that was historically achieved, namely between 2004 and 2014. Furthermore, as noted in Attachment L, unplanned standards have a further 2.0 standard deviation buffer before a contravention is triggered. To the extent that inadequate asset management has led to a deterioration such that a distributor is unlikely to comply given this, we consider that it is appropriate that the distributor should improve its performance. An option to apply for a quality standard variation is available to distributors. We can assess whether a less stringent quality path is in the long-term interests of consumers.

J76 Alpine Energy submitted that the limit should increase to 10% citing that it would better reflect the natural variability of reliability.[620] In response, we consider that the 10-year reference periods that are used, along with normalisation, absorbs a significant portion of the random variability in SAIDI and SAIFI metrics, and as such, we consider 5% represents an appropriate balance of accepting some variability in reliability over time and not rewarding or penalising deteriorating or improving network performance.

Planned interruptions

J77 We also use the 10 years from 1 April 2009 to 31 March 2019 as the reference period to set planned reliability parameters. However, we do not apply any inter-period limit as we do not consider planned interruptions are as closely tied to the deterioration of network assets.

J78 ENA, in response in the issues paper, submitted specifically on a reference period for planned interruptions, proposing the latest five years.[621] This was widely supported by distributors at the quality workshop held 28 February.[622] ENA submitted that:

> An alternative to the forecast approach for setting the standard for planned outages described above, is to use a five-year historical reference dataset for setting planned outage targets. A shorter, more recent dataset than for unplanned outages will better reflect current operating environments and the benchmark expenditure levels which influence DPP revenue paths. This may also be a default option available for EDBs who have insufficient certainty over future planned outages at the time the 2020 DPP is reset.

[620] Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 12.

[621] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 8.

[622] Commerce Commission "Notes on EDB DPP3 Workshop on quality and consumer outcomes" (27 February 2019).

J79 We undertook analysis to assess the changes in planned interruptions over time. We note that there is substantial volatility, both up and down. For example, four distributors more than tripled their planned SAIDI and SAIFI in the last five years relative to the five years before. Conversely, there was one distributor which significantly reduced its planned SAIDI over the same period. On balance, we consider using the same reference period as for unplanned reliability is most appropriate. To the extent distributors have recently made operational changes this will be partially captured in the reference period.[623]

Stakeholder views

J80 Several distributors disagreed with a 10-year reference period for planned interruption with many citing a misalignment with current work practices (such as increased de-energised works).[624] Distributors suggest that if there is no explicit adjustment in planned SAIDI and SAIFI for reductions in live lines work then the planned reference period should be shorter, for example four or five years.

J81 We considered operating practices relating to live lines work as a potential step change in the draft decision and our views are outlined in more detail below. In summary, we do not support an explicit step change nor an implicit step change through shortening the reference period to reflect only recent operating practices.

J82 As discussed in Attachment L, our decision is to set the compliance standard for planned interruptions at triple the historical average. As a result, the decision about which reference period to use is less material for the purposes of assessing compliance.

[623] As noted in Attachment L, we consider the separation of planned and unplanned interruptions and the wide planned standard we have adopted accommodate distributors who have changed their operating practices with sufficient flexibility.

[624] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 25-26; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 10; Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10; Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 20; The Lines Company "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

J83 Furthermore, as discussed in Attachment M, with adequate notification to consumers the weighting of planned interruptions for assessment purposes can be halved relative to those interruption not adequately notified. We consider this asymmetric incentive that is to distributors' benefit will allow them to adequately manage their planned interruptions without being unduly penalised.

J84 We consider that operating practices that are not binding may be reversed by the distributor at its discretion. Furthermore, a distributor may consider alternative ways of mitigating the reliability impact of planned work, for example, by meshing, back-feed, or generation.

Step changes

J85 The scope to include step changes for setting the reliability parameters applicable to standards and incentives may capture operational or situational changes outside the control of the distributor.

J86 We considered the step change criteria for operating expenditure was a useful starting point for assessing step changes for reliability, namely that any changes:

J86.1 be significant;

J86.2 be robustly verifiable;

J86.3 be largely outside the control of the distributor;

J86.4 in principle, affect the reliability of most, if not all, distributors; and

J86.5 not be captured in the other components of our reliability parameters (reference period, normalisation methodology).

J87 Submitters to the issues paper raised a few potential step changes that may be considered, for example:

J87.1 decreased live lines work resulting from harsher Health and Safety Work Act (HSWA) penalties;[625]

J87.2 increased incidence of weather events, potentially arising from climate change;[626]

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625 Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018), p. 4.

626 Orion "Submission on EDB DDP3 Reset " (20 December 2018), para 51.

J87.3 increased third-party interruptions, for example third-party vehicle damage incidents;[627] and

J87.4 increased asset investment plans.[628]

J88 Of these requested step changes, we had identified that only the HSWA/live lines issue was supported by extensive evidence demonstrating their existence and effect. While the other potential changes may be serious (climate change, third-party interruptions, investment) given the lack of evidence about their effect on quality, they do not meet the verifiable criterion.

J89 Further, changes due to increased investment on the network are likely to be distributor-specific, and more properly the subject of either a quality standard variation reopener or – where the investment increase itself is significant – a CPP proposal.

J90 In response to our draft decision, Unison submitted that we should:

> consider a further adjustment to align planned SAIDI targets with the capex allowances, by indexing the allowance to the increase in capex on replacement expenditure. There seems little point in providing EDBs with increased capex allowances, but at the same time penalising them for undertaking the approved additional replacement work with no additional minutes to undertake the work.

J91 We acknowledge that increased replacement and renewal expenditure will likely require increased planned interruptions However, we do not consider it feasible at this stage, in the context of a low-cost DPP, to estimate a direct link between these. For example:

J91.1 the volatility of planned works due to factors outside of asset replacement and renewal distorts this relationship; and

J91.2 the nature of those assets to be replaced or renewed are likely to have different expenditure and interruption impacts.

J92 Nonetheless, we consider it is appropriate that consumers are compensated, via the incentive scheme, for an increased level of planned interruption due to increased allowed replacement and renewal expenditure (which consumers are also paying for).

[627] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), paras 129 to 130.

[628] Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018), p. 4; and Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 24.

Approach to changes in live line practices

J93 As noted above, planned SAIDI and SAIFI have increased significantly for some businesses in recent years, and this may be in part due to policies that reduce live lines works.

J94 We offered distributors an opportunity to voluntarily provide further data on the impact of reducing live line works as part of their section 53ZD responses in December 2018.[629] Eight distributors submitted responses on this and the results for planned interruptions up to 31 March 2018 are summarised in Table J2.

Table J2 Estimated planned SAIDI impact of health and safety practices

Distributor	Date started (first impact)	SAIDI impact of HSWA	Other SAIDI since start	Percent of planned SAIDI
Centralines	5-Sep-17	1.73	24.30	7%
EA Networks	18-Apr-17	50.43	109.24	32%
Electricity Invercargill	26-Feb-18	0.60	0.00	*
OtagoNet	8-May-15	181.16	227.38	44%
Top Energy	22-Jul-16	35.28	209.83	14%
Unison Networks	5-Apr-16	18.95	97.48	16%
Vector Lines	3-Aug-15	104.88	80.90	56%
Wellington Electricity	1-Apr-16	8.13	14.20	36%

** Electricity Invercargill sample is only one month, with only one planned interruption*

J95 We discuss the potential live lines step change with regard to each step change criterion below.

Significance

J96 From the table above, for the distributors that disclosed the impact of reducing live line works, the impact is significant for planned interruptions. We note that only Vector disclosed any material impact on unplanned interruptions of 18.1 SAIDI minutes over 32 months.

Verifiability

J97 As the data supporting this decision has come via a 53ZD request, we consider the numerical evidence sufficiently robust. However, for the reasons discussed in more detail below, we do not consider that we can robustly link the change in practices to the impact it had on interruption metrics.

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[629] We accepted responses to our initial information request until February 2019.

Control

J98 While all distributors must comply with relevant health and safety laws, the safety management system or policies they apply, the practices they undertake as a result, and the reliability mitigations they put in place to limit the impact on consumers are all within the control of the distributor.[630] In this regard, we note the different interpretations of and approaches to the Health and Safety at Work Act different distributors have taken.[631]

Affects most or all distributors

J99 There is widespread disagreement as to what extent health and safety laws require reduced live lines work (and whether they do at all).[632] Accordingly, distributors have altered their health and safety policies to differing extents, and we have been advised that some distributors have increased the extent to which they work on live lines during recent years.

J100 Accordingly, neither the option of applying a step change consistently across all distributors or applying a step change selectively to different distributors depending on the extent of their live lines work is attractive, for the following reasons:

J100.1 Applying a step change consistently to all distributors would mean those who have not reduced their live lines work would receive an easier planned SAIDI target and reliability standard. Accordingly, by continuing their practices (which include live lines work), all else being equal, these distributors could receive financial rewards by outperforming their target without improving the quality of service to consumers and be less likely to contravene their compliance limit;

[630] This issue was discussed in our response to Vector's health and safety reconsideration request and in the legal advice we received in considering Vector's request. Letter from Sue Begg (Commerce Commission) to Richard Sharp (Vector Lines) responding to Vector's request that the DPP be re-opened (5 September 2018).

[631] As an example, Wellington Electricity cite that they have spent $600,000 per year on mobile generation to limit the impact of interruptions from planned interruptions. Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 14.

[632] It is not a binary decision to do live lines work or not, instead, EDBs differ in the circumstances they will do live lines work based on their different views as to what is safe.

J100.2 Applying a step change to only those distributors who have decreased their live lines practices (with the size of the step change differing depending on the distributors self-reporting of the impact of their changes) would create difficulties in the likely event that live lines policies continue to evolve. Distributors who have received a step change allowance may reverse their live lines reductions (as they are a matter of distributor policy, not regulatory directive), resulting in easier targets and standards referred to in the previous paragraph (with the added inequity that distributors who never reduced their live lines work in the first place would not receive the step change). In addition, some of the distributors who have not reduced their live lines work may decide to do so in the future, but would do so under the constraint of a different planned SAIDI target than those who have already made that decision.

J101 We also consider that it is not the Commission's place to dictate whether live line work is appropriate or not. Choosing either of these paths would effectively mean that the Commission is endorsing live lines work.[633]

J102 Not making a step change does not mean we are endorsing the view that health and safety law does not require reduced live lines work. Rather we are allowing each distributor to determine what live lines policy is required by law and is appropriate for it. We are doing this by allowing the effects of live lines practices to filter into the historical average over time,[634] and by structuring quality standards such that live lines practices are unlikely to lead to a contravention.

Capture by other components

J103 Operational changes that distributors have made to reflect their health and safety policies will be captured within our reference period, although those changes will be diluted by the inclusion of earlier years before such changes were implemented. Accordingly, to some extent the effects of distributors live lines practices has been incorporated into distributor's SAIDI and SAIFI targets.

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[633] Worksafe do not have a publicly stated position on live-lines, instead they will assess whether an incident when working on live lines was contrary to the law after the fact.

[634] If we take the same approach to having a ten-year reference period in DPP4, companies' planned SAIDI target will largely incorporate their live lines approach.

J104 In addition, our changes to the structure of the quality standards mean that an increase in SAIDI or SAIFI due to live lines practices will unlikely cause a contravention of the quality standards, all else being equal. Planned interruptions are treated as a separate quality standard, and the threshold for that standard is set three times the distributor's historical average. Vector reported the highest proportion of planned SAIDI due to live lines practices at 56%, but this on its own would not cause it to contravene the planned SAIDI limit under our approach, which is 200% higher than its historical average.

J105 Our approach (as discussed in Attachment L) greatly reduces distributors' exposure to quality standard contraventions for planned interruptions, even in circumstances where strict live lines policies are implemented. Accordingly, we consider that our approach will address distributors' concerns about exposure to quality standard contravention due to live lines policies.

J106 We consider that the planned reliability standard is sufficient to accommodate changes to live lines practices. We acknowledge that the incentive scheme will continue to apply to interruptions related to live lines practices, although to some extent this is offset by them being captured in the historical reference period. Furthermore, the incentives for planned interruptions have been set at a conservative level and can be further reduced if distributors meet the notification criteria (as discussed in Attachment M). Our view is that this approach will allow distributors flexibility in making cost-quality trade-offs, including to account for their live lines policies.

Stakeholder views

J107 ENA proposed in its Working Group report, and reiterated in its submissions that adjustments are made:

> … to address the impact of changes in operational environments which have occurred during the current regulatory period and which have impacted the reference periods for SAIDI and SAIFI target setting … the ENA proposes that the adjustments are EDB-specific, limited to a value that can be supported by quantified evidence provided by the EDB and approved by the Commission … [they] caution against the Commission making judgements about operational risk for EDBs.[635]

[635] Electricity Networks Assoc. "ENA Working Group on quality of service regulation – Interim report to the Commerce Commission" (1 October 2018), p. 14.

J108 They also noted that:

> … there is precedent for EDB-specific adjustments being incorporated into the DPP (for example for spur asset purchases) and therefore do not consider the fact that some EDBs are more affected by the legislative change than others should prevent this matter being addressed in the DPP reset.[636]

J109 Furthermore, ENA rejected that a DPP reopener is an appropriate option to resolve distributor-specific circumstances stating that it does:

> … not consider that it is consistent with the legislative intent to rely on a DPP reopener to address circumstances which are well understood and a consequence of legislative change, at the time a DPP is set.[637]

J110 Wellington Electricity and Vector endorse the views of ENA.[638] For example, Vector submitted on the reasons and impacts of minimising live lines work and other operating issues impacting reliability, for example:

> … by suggesting EDBs are taking a "more risk-averse approach" the Commission is taking an active role in articulating the appropriate safety precautions to execute tasks on or near energised assets. We believe EDBs are the best judge as to when different hazard prevention approaches should be adopted. Accordingly, the regulatory framework should not limit the judgement of EDBs to make safety related decisions for their staff, contractors and public safety. This includes financial [incentives] such as the Service Quality Incentive mechanisms encouraging safety precautions to be lowered. [639]

J111 Mercury Energy submitted that no adjustment should be made to recompense distributors for more risk-averse operating practices.[640] Furthermore, they consider an application process to adjust the reference dataset would create a risk of asymmetric information bias, as described in the ENA's working group paper. However, to the extent that there is a material and unavoidable change in the operating environment, they consider the quality standards may be reset.

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[636] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 9.

[637] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 9.

[638] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 14; Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), pp. 22 to 29.

[639] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), pp. 22 to 29.

[640] Mercury "Default Price-Quality Paths for Electricity Distribution Businesses from 1 April 2020" (20 December 2018), pp. 5 to 6.

Enhanced reliability

J112 We recognise the aggregate and limited nature of SAIDI and SAIFI as reliability metrics. As such, the issues paper proposed further reliability metrics and disaggregation of current metrics as future ID requirements, which could be considered for DPP4.

J113 The issues paper proposed several reliability metrics that may provide a fuller picture of reliability experienced by consumers including:

J113.1 reliability on the LV network;

J113.2 momentary average interruption frequency – MAIFI;

J113.3 SAIDI and SAIFI by customer type (residential, commercial, industrial);

J113.4 SAIDI and SAIFI by network type (urban, rural, remote);

J113.5 SAIDI and SAIFI by location;

J113.6 worst served customers; and

J113.7 electricity not served from interruptions.

J114 Looking forward, we consider that most, if not all, of these metrics will better facilitate setting reliability standards and incentives in the future. However, whether these benefits in terms of the purpose of ID regulation outweigh the additional costs to suppliers in collecting the information needs to be carefully considered.[641] As with the other measures of quality discussed in Attachment N, given time and resource required by distributors and the Commission, and the impact on exempt distributors, we consider updating ID at a later date appropriate.

[641] Commerce Act 1986, section 53A. "The purpose of information disclosure regulation is to ensure that sufficient information is readily available to interested persons to assess whether the purpose of this Part is being met."

Attachment K Identification and treatment of major events

Purpose of this attachment

K1 This attachment explains our approach to identifying and normalising major interruption events to deal with volatility in the reliability measures we use to assess quality.

Purpose of normalisation

K2 Reliability and the metrics we use to measure it (SAIDI and SAIFI) are inherently volatile. Year-on-year volatility in total SAIDI or SAIFI may be the result of major events, rather than the result of underlying declines or improvements in network performance. Specifically, the size and number of major events a distributor experiences in a given year can have a material impact on its total SAIDI or SAIFI performance.

K3 The purpose of normalisation is to limit the impact of these major events, so that the unplanned standards we impose, and the incentives distributors face are not merely reflecting unpredictable events, such as severe weather events. This attachment sets out our detailed final decisions on normalising out unplanned major events for EDB DPP3.

Summary of our final decision

K4 Our final decisions on identifying major events for EDB DPP3 are summarised below:

K4.1 major events are only attributable to unplanned interruptions (unchanged from draft);

K4.2 the major event boundary value has been identified as the 1104th highest half-hourly rolled 24-hour period for SAIDI and SAIFI over the 10-year reference period—which is approximately in line with 2.3 major event days per year used in DPP2 (modified from draft);

K4.3 the number of expected major events for the smallest distributors is reduced (unchanged from draft);

K4.4 a major event may extend for as long as the 24-hour rolled period exceeds the boundary value (unchanged from draft); and

K4.5 SAIDI and SAIFI major events are triggered independently (unchanged from draft).

K5 Our final decisions for treating an unplanned major event when identified are summarised below:

K5.1 replace any half-hour within an identified major event that is greater than 1/48th of the boundary value with 1/48th of the boundary value (changed from draft); and

K5.2 distributors must provide additional reporting for each unplanned major event in its compliance statement relative to DPP2 (unchanged from draft).

K6 We note that regardless of which methodology we use to determine the major event threshold (boundary value), the resulting values are applied consistently to the reference dataset that determines the reliability parameters we set for the standards and financial incentives, as well as the distributor's assessment of reliability going forward.

Approach raised in the Draft Reasons Paper

K7 Our draft decision for DPP3 was to identify a major event on a rolled three-hour basis and, in principle, the 'boundary value' was the 25th highest unplanned SAIDI or the 25th highest unplanned SAIFI three-hour period over a 10-year historical dataset. This was a substantial change from DPP2 where major events were assessed on a calendar day basis. We considered this appropriate to counter the arbitrary nature of a fixed calendar day, for example, major events extending both sides of midnight.

K8 Once a major event was triggered, these would then be normalised down to a pro-rated 'boundary value', reducing the impact of major events on assessed SAIDI and SAIFI for compliance and incentive purposes. This was largely consistent with our approach in DPP2, however, major events were replaced with a fraction of the boundary value, rather than the entire boundary value. We considered this appropriate as to reduce the volatility of SAIDI and SAIFI caused by the frequency of major events.

Response in submissions

K9 In general, submissions were supportive of the concept of a rolling approach,[642] although Eastland Network and ENA raised concerns that the extra complexity would require investment in outage recording systems.[643]

[642] See for example: Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 18-19; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 32.

[643] Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 9; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23.

K10 Many distributors also supported reducing the impact the frequency of major events has on compliance and financial incentive outcomes, although some suggested it did not go far enough.[644]

K11 Distributors submitted concern in shortening the length of a major event from 24 hours (or a calendar day) to three hours. It was noted that even though major events may often not last longer than three hours, their effects can continue for a longer period.[645] Furthermore, they also expressed concern that our draft decision deviated from the IEEE methodology in a way that would change the expected frequency of major events and create a risk of unforeseen outcomes.[646]

Updated approach

K12 In response to submissions on the draft decision and the targeted quality of service workshop, we outlined an alternative methodology for identifying and normalising major events in our updated draft models' companion paper.[647] Our final decision on normalisation is largely consistent with that proposed in that companion paper.

K13 Submissions to the draft and updated decisions, and our responses, are outlined in more detail under the relevant decision below.

Major events are initiated by unplanned interruptions only

K14 Distributors are occasionally exposed to major and unpredictable events. These major events can be caused by extreme weather, and defective equipment, among other things. Consequently, major events, due to their large impact on measuring network reliability, can disproportionately skew SAIDI and SAIFI metrics.

K15 Consistent with DPP2 and our draft DPP3 decision, the final decision is that major events are initiated by unplanned interruptions only. We consider this is appropriate as unforeseen major events that severely disrupt the network cannot be planned for.

K16 Across the industry we identified that of the largest periods of interruptions, around 93% of SAIDI and 95% of SAIFI are attributable to unplanned interruptions. Figure K1 and Figure K2 shows the proportion SAIDI and SAIFI attributable to unplanned interruptions during identified major events for each distributor.

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[644] See for example: ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 32-33.

[645] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 18-19; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23.

[646] See for example: ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 31.

[647] Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Updated draft models – Companion Paper" (25 September 2019), Chapter 5.

Figure K1 Proportion of unplanned SAIDI during a major event day, 2009/10 to 2018/19

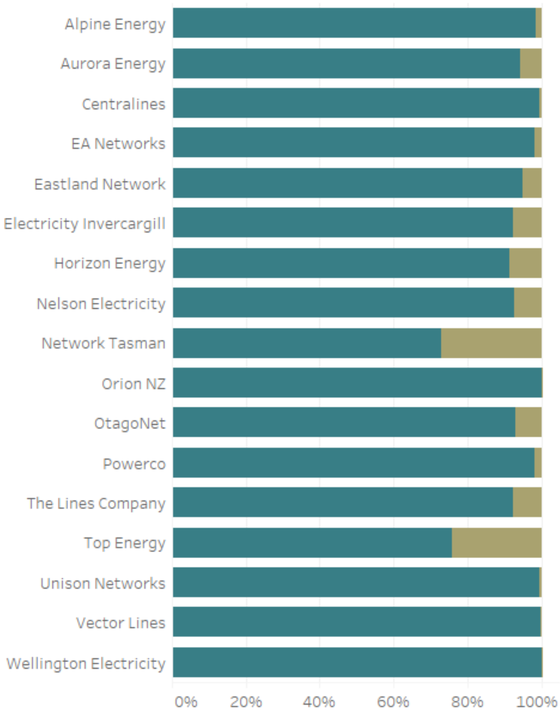
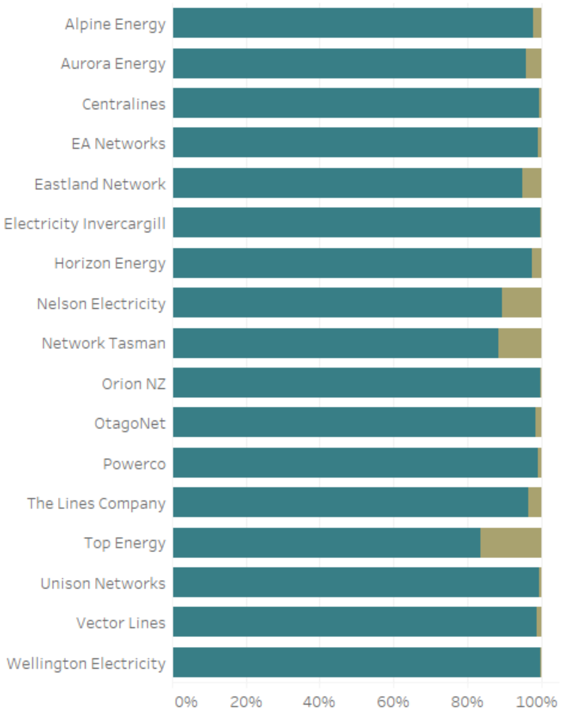


Figure K2 Proportion of unplanned SAIFI during a major event day, 2009/10 to 2018/19



K17 Submissions to the draft decision did not raise any objection to confining major event identification to unplanned interruptions only.

Major events are identified on a 24-hour rolling basis

K18 For DPP3, a SAIDI major event will be classified as any 24-hour period where the SAIDI exceeds the unplanned SAIDI boundary value. Likewise, a SAIFI major event will be classified as any 24-hour period where the SAIFI exceeds the unplanned SAIFI boundary value.

K19 In DPP2, major events were identified on a calendar day basis. However, given that distributors were able to provide us with times and dates for each interruption on its network, we did not feel constrained to limiting major events to one calendar day or 24-hour period.

K20 For the draft DPP3 decision, we adopted a three-hour rolling approach. We considered that the use of a fixed calendar day is somewhat arbitrary and means that significant events that span two calendar days may not be captured adequately, as discussed from paragraph K26. In shortening the length of a major event, we considered that major events typically occurred within a much shorter timeframe than 24 hours.[648] In changing from using a calendar day to a rolling three-hour approach for identifying major events, we noted that:

K20.1 some interruptions that previously would have been classified as a major event day will no longer be classified as a major event;

K20.2 some major events would not have previously triggered a major event day;

K20.3 it is possible that calendar days can have multiple distinct major events within that day; and

K20.4 some major events can last longer than three hours.

Assessing major events on a 24-hour basis

K21 Submitters questioned whether the move to a three-hour window risked creating false-positives and false negatives, highlighting that certain events that were major events under the calendar day DPP2 methodology were not captured under the draft methodology and vice versa.[649] In discussions at the quality of service workshop, attendees highlighted that we should consider not only how many major events are triggered in a given period, but the properties of those major events.[650]

K22 Over the reference period across all distributors, around 15% of major events captured by the DPP2 methodology were not captured by the draft methodology, and around 15% of the major events not captured by the DPP2 methodology were captured. While we acknowledge that the different methodologies do change the profile of what is considered a major event, we consider a longer window is more likely to trigger 'false positive' major events that are driven by the accumulation of coincidental smaller events, we did not consider this difference was reason to revert to a 24-hour approach.

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[648] In the draft, we observed that of the major, or near major, event days across 17 distributors, over 80% of the total SAIDI impact occurred within a three-hour period, and similarly for SAIFI. Refer Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft reasons paper" (29 May 2019), paras K20 and K21.

[649] Horizon "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 4-6; and ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 32.

[650] Commerce Commission "EDB DPP3 – Targeted Workshop on Quality of Service" (16 August 2019).

K23 Many submitters also noted that even though major events may often not last longer than three hours, their effects can continue for a longer period.[651] For example, a major storm causing widespread damage can continue to impair efforts to restore any subsequent interruptions after the storm is over – as crews cannot react to a 'normal level' of interruptions as they normally would.

K24 Further, submitters also noted that there is a potential perverse incentive where distributors could prioritise restoration work after a major event rather than on what best meets customer needs (reducing total interruption duration) to optimise financial incentives and compliance performance.[652]

K25 We agree with these two concerns and have reverted to a major event assessment length to a 24-hour period, but on a rolling basis.

Assessing major events on a rolling basis

K26 For the final decision, major events will be identified on a rolling basis. However, to reduce complexity we consider that the 24-hour periods are rolled half-hourly, rather than on a continuous basis.

K27 Major events do not necessarily fit neatly within calendar days. However, using a rolling major event length does add complexity in identifying major events both during the reference period and for future assessment.

K28 Consistent with the DPP3 issues paper and Draft Reasons Paper, we consider that a major event should not be arbitrarily constrained to a fixed period, such as a calendar day. For example, if an extreme storm hits a distributor at 11:00pm and results in several interruptions stretching into the following day, it would be reasonable to treat the same as a storm hitting at 12:00am. The move to a rolling window means that all interruptions are treated equally regardless of the time of day they occurred.

[651] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 18-19; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 31; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), pp. 16-17.

[652] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 18-19; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23.

K29 In general, submissions from distributors were supportive of the concept of a rolling approach. ENA, Wellington Electricity, Vector, Eastland Network, Powerco, and The Lines Company all expressed support for a rolling 24-hour basis for identifying a major event.[653] For example, in its submission to the issues paper, ENA stated:[654]

> This will address situations when an event stretches over two calendar days, with a total impact in a 24-hour period qualifying for MED treatment, but where the impact on either of the calendar days is not sufficient to qualify. This would also improve alignment with international practice and result in a more accurate identification of real MEDs, avoiding the current, somewhat arbitrary, measure that results in some MEDs not being identified.

K30 We acknowledge that the rolling methodology does introduce additional complexity relative to using fixed calendar days. However, we disagree with Eastland Network and ENA that this complexity would require changes to outage reporting systems given the required data should already be recorded.[655] Aurora Energy also expressed concern that the systems required to identify a major event on a rolling basis would be overly complex relative to any benefit.[656] At least one distributor, having attempted to apply a rolling methodology, also considered it a complex process.[657] We will publish a model to assist distributors to comply with the normalisation approach we have adopted before DPP3 begins.

K31 In deciding how the rolling periods should be applied, we initially considered rolling on a continuous basis would best meet the policy intent of this decision. However, we acknowledge the complexity of applying this to the reference period, and the complexity for distributors to apply during the regulatory period.[658]

K32 We tested the feasibility of assessing three-hour rolling periods in 15, 30, and 60-minute increments. In our view, a 30-minute increment strikes a reasonable balance between workability while still being reflective of the policy intent. A major event resolution of 30-minutes did not materially deviate from a continuous method.

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[653] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 14; Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 14; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019) , pp. 18-19.

[654] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 14.

[655] Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 9; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23.

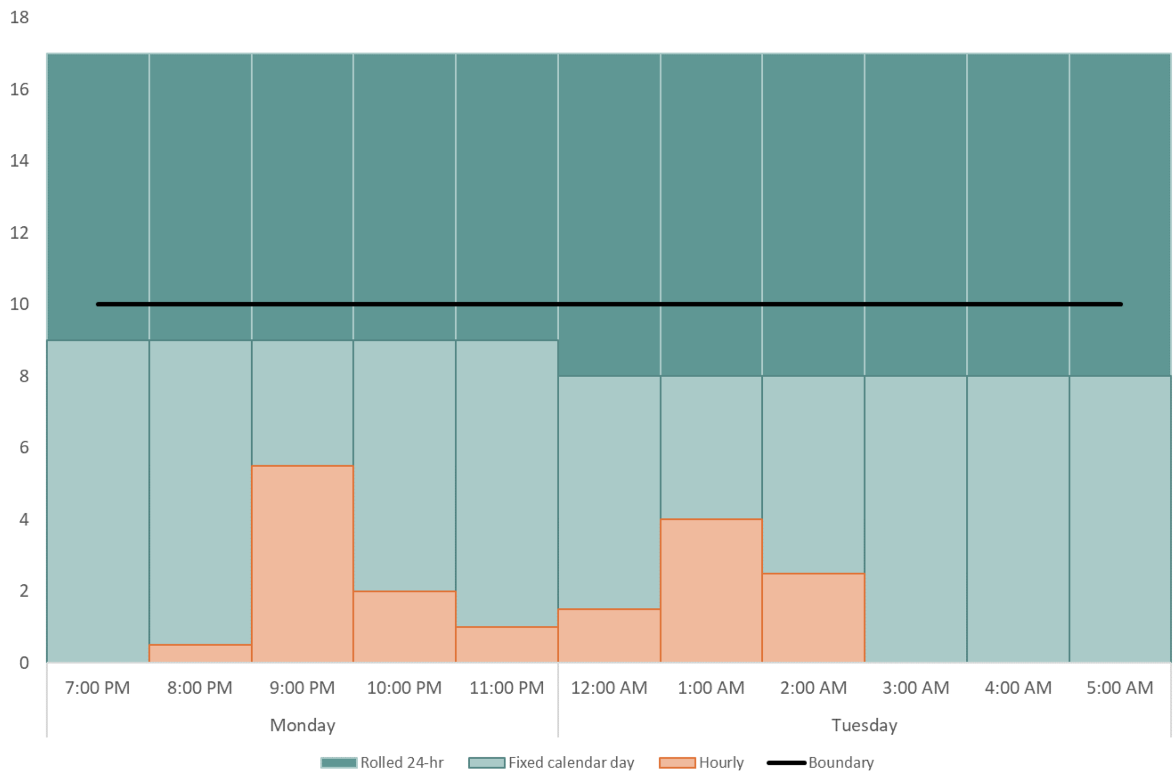
[656] Aurora Energy "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018), p. 8

[657] Commerce Commission "Notes on EDB DPP3 Workshop on quality and consumer outcomes" (27 February 2019).

[658] We note that our modelling is done in Stata and uses coding to implement our policy recommendations. We would envisage the degree of accuracy and complexity of implementing a continuous rolling sum of SAIDI and SAIFI would be compromised in spreadsheet type applications.

K33 Figure K3 below shows an illustrative example of where the timing of the raw SAIDI or SAIFI (orange bars) means that no major event is triggered using calendar days, as neither calendar day aggregates (light green bars) the applicable raw SAIDI or SAIFI to be more than the boundary value (black line). Conversely, the same interruptions will trigger a major event on a rolling 24-hour basis (dark green bars).

Figure K3 Illustrative example of rolled 24-hour vs. calendar day



K34 Orion queried in its submission whether the rolling was intended to be backward- or forward-looking.[659] The draft decision was intended to capture any three-hour period that exceeded the major event boundary value, and therefore, was essentially both backwards- and forward-looking in recognition that major events can have interruption profiles. However, as noted in the update draft models companion paper, the degree to which a major event is normalised depended on the profile of the major event. For example, a major event that was triggered in a single half-hour is normalised for 5.5 hours rather than 3.0 hours. So even though both events in Figure K4 and Figure K5 below had the same raw SAIDI, one was normalised to 1/8th of the boundary value with the other almost double that.

[659] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 17.

Figure K4 DPP3 draft normalisation (1)

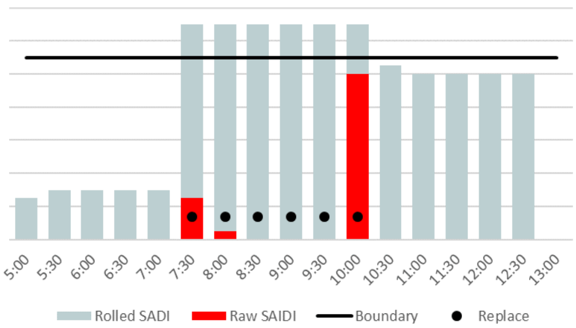
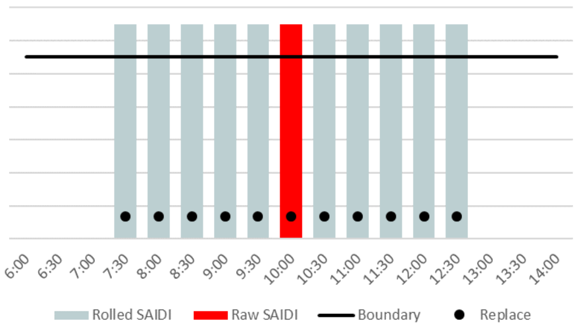


Figure K5 DPP3 draft normalisation (2)



K35 The rolling methodology for the final decision is done on the same basis albeit for a longer period. Consequently, it is possible that if one half-hour period of interruptions exceeds the full boundary value the major event will last 47.5 hours, as the 23.5 hours before and after will also be part of a 24-hour period that exceeds the boundary value. This means that it is possible for half-hours to be normalised which are by definition part of the major event but some time from the initial cause of the major event. While we consider that this is not ideal, we have implemented this for practical reasons, namely, to capture major events of different profiles without adding increased complexity. However, as noted below, only those half-hours that exceed 1/48th of the boundary value are normalised down.

K36 Submissions from distributors generally agreed with extending the time frame of a major event to 24 hours.[660] However, ENA questioned the half-hour granularity of assessing major events.[661] Aurora submitted the approach was still unnecessarily complicated and preferred reverting back to the calendar day approach.[662]

K37 The method has been applied to the reference period and will be used during the assessment period.

[660] ENA "DPP for EDBs from 1 April 2020 Updated draft models – companion paper: Submission to the Commerce Commission" (9 October 2019), pp. 8-9; Orion "Submission on EDB DPP3 Updated Draft Models" (9 October 2019), p. 3; Wellington Electricity "Submission on Default price-quality paths for electricity distribution businesses from 1 April 2020 - Draft Decision Update" (9 October 2019), p. 5; Powerco "Powerco submission on the updated DPP3 Draft Decision" (9 October 2019), p. 2; Unison "Submission on Default Price-Quality Paths – Updated Draft Models" (9 October 2019), p. 2; and Centralines "Submission on Default Price-Quality Paths – Updated Draft Models" (9 October 2019), p. 3.

[661] ENA "DPP for EDBs from 1 April 2020 Updated draft models – companion paper: Submission to the Commerce Commission" (9 October 2019), p. 8.

[662] Aurora "Submission to Commerce Commission: Default price-quality paths for electricity distribution businesses from 1 April 2020 – Updated draft models: Companion Paper" (9 October 2019), p. 8.

Statistical expectation of a major event

K38 In DPP1 and DPP2, it was considered that 2.3 major event days per year was an appropriate benchmark, based on the IEEE expectation of a major event day.[663] We still consider this a reasonable benchmark for a calendar day or 24-hour assessment of a major event.

K39 In summary, to determine the boundary value we:

K39.1 use the IEEE expectation of 2.3 major event days per year as a base;

K39.2 multiply by 48 (half-hours per day) to reflect our move to a rolling half-hourly assessment—110.4 'half-hours' per year; and

K39.3 multiply by ten (years) to the length of the reference period—1104th highest half-hourly rolled 24-hour SAIDI and SAIFI over the reference period.

K40 Given that we now assess major events half-hourly, and there being 48 half-hours within each day, we consider the 1104th highest assessed SAIDI or SAIFI half-hour, based off the rolling 24-hour sum, over the 10-year reference period as a broadly similar outcome to the 23rd highest major event calendar day.

Stakeholder views

K41 ENA, Eastland Network, and Meridian Energy were supportive of using the historical dataset to identify the highest values. For example, using the 23rd highest SAIDI and SAIFI values for a 10-year reference period to define the boundary value for major event days.[664] ENA noted that this approach aligns with the intent of the IEEE's method which is to allow for 2.3 major event days (MEDs) per year on average.[665]

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[663] Institute of Electrical and Electronics Engineers "IEEE 1366 Guide for Electric Power Distribution Reliability Indices" 2012. The IEEE methodology is premised on the assumption that daily reliability follows a log-normal distribution whereby major event days are identified as those days more than 2.5 standard deviations above the average day (as considered appropriate by a Distribution Design Working Group). This translates to an expectation of the top 0.63 percentile days, or 2.3 days per year, being major event days.

[664] Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 5; ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 13; Meridian Energy "2020-2025 Distribution default price-quality path – Issues paper" (20 December 2018), p. 4.

[665] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 13.

K42 Orion has submitted that due to climate change, there is more exposure to major events, citing NIWA climate projections suggesting a slow increase in extreme wind events and wet days over the next century.[666] Similarly, Wellington Electricity cited an Insurance Council report indicating that storms are becoming more frequent.[667] We noted in the draft decision that NIWA climate projections suggesting increases in extreme wind events for some parts of the country are on a 90-year horizon, rather than five years.

K43 Aurora Energy had submitted reverting back to the modified IEEE methodology as proposed in the 2014 draft decision.[668] They state that this may provide more realistic boundary values than the current methodology which saw them with more MEDs than anticipated. We note that Aurora Energy was an outlier and do not consider reverting to the IEEE methodology appropriate on this basis. We also note that the IEEE methodology does not facilitate our approach for normalisation.

Reduced frequency of major events for small networks

K44 Smaller networks, all else being equal, can expect to have fewer interruptions relative to larger networks. This is because there is less equipment than can fail at any given time, and consequently less equipment at risk of truly experiencing a major event.

K45 Electricity Invercargill and Nelson Electricity have significantly less interruptions than any other price-quality regulated distributor. This is largely because they are much smaller networks, rather than because they are reliable networks. Consequently, without modification, a high proportion of the interruptions that take place would be considered a major event.

K46 Our final decision reduces the expected frequency of major events if a distributor has less than 1,000 kilometres of circuit length. As outlined in Table K1 this impacts only the two distributors above, Electricity Invercargill (658 km) and Nelson Electricity (298 km), with the next smallest price-quality regulated distributor being Centralines (1,807 km).

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[666] Orion "Submission on EDB DDP3 Reset " (20 December 2018), pp. 11 to 12

[667] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 17.

[668] Aurora Energy "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018), p. 8

Table K1 Reduced frequency of major events

Distributor	2019 Circuit length (km)	Major events (compared to 23)	'Major half-hours' (compared to 1104)
Electricity Invercargill	658	15.1	726
Nelson Electricity	298	6.8	328

K47 As an extreme example, if a small distributor experiences less interruptions than the frequency of major events we allow, this will result in a major event threshold of zero for SAIDI and SAIFI, that is every interruption would be considered a major event. We do not consider that this would meet the intention of major event normalisation, and therefore would be inappropriate. This is further exaggerated given our decision to reduce major events to a pro-rated value for assessment purposes.

K48 While no distributor falls within this extreme scenario, Nelson Electricity comes very close. Nelson Electricity had only around 60 unplanned interruptions over the 10-year reference period. Without modification, around 40% of its unplanned interruptions and 95% of its unplanned SAIDI would be normalised. Furthermore, most of Nelson Electricity's interruptions did not relate to adverse weather or environmental factors.

K49 We did not receive any submissions opposing this adjustment.

SAIDI and SAIFI major events are triggered independently

K50 For the final decision SAIDI or SAIFI major events will be triggered independently, consistent with the current DPP.

K51 Over the previous two resets we have considered three different approaches for determining whether SAIDI or SAIFI major events should be prerequisites for triggering any major event, or whether they should be triggered independently.

K52 For the final DPP1 decision the SAIDI boundary value needed to be exceeded to trigger any major event. We said:[669]

> The Commission notes that the IEEE Standard specifies the use of SAIDI (and not SAIFI) when identifying MEDs, as SAIDI better reflects the total cost of reliability events including utility repair costs and customer losses. In keeping with the IEEE Standard, the Commission retains its view that SAIDI data should be used to identify MEDs.

[669] Commerce Commission "Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses: Decisions Paper" (30 November 2009), para 6.31.

K53 For the draft DPP2 decision we favoured using SAIFI as the trigger for a major event. We said:[670]

> Using SAIFI to trigger a major event day is appropriate as extreme events are most likely to affect a large number of customers, which distributors have no control over … Distributors do have some control over the duration time of any outage resulting from a major event. We therefore consider that it may be inappropriate to use SAIDI as a trigger, given that there would be no incentive within this scheme to minimise the duration of an event once the boundary has exceeded.

K54 In our final DPP2 decision SAIDI and SAIFI were independently used to trigger major events. We consider that our reasons for assessing major events independently for SAIDI and SAIFI remains valid and is supported by distributors.[671] For the final DPP2 decision we said:[672]

> [Major events] may affect a large number of customers in an urban area for a relatively short period of time and therefore triggering SAIFI but not SAIDI; or … a relatively small number of customers may be affected for a significant length of time and therefore triggering SAIDI but not SAIFI, for example a severe storm in a remote area.

Replacing SAIDI and SAIFI values during a major event

K55 Consistent with our draft decision, major events that are identified will be replaced with a pro-rated boundary value, however, only those half-hour SAIDI or SAIFI raw values that exceed 1/48th of the respective boundary value will be replaced. In principle, this approach is broadly consistent with that currently applied in DPP2 where a major event day is replaced with the boundary value. However, with the decision to identify major events on a 24-hour basis and replacing major events with a pro-rated boundary value, the impact of major events will generally be much lower than replacing with the full boundary value.

K56 Normalisation of major events is intended to limit the impact of the most substantial interruptions on underlying reliability data. We considered that replacing the entire major event with the full boundary value may create too big a driver for standards and incentives. However, we do not consider removing the impact completely would be appropriate. Therefore, our final decision replaces major events with something between the boundary value and the half-hourly average.

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[670] Commerce Commission "Proposed Quality Targets and Incentives for Default Price-Quality Paths From 1 April 2015" (18 July 2014), paras 3.20 to 3.21.

[671] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 31.

[672] Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020 : Quality standards, targets, and incentives" (28 November 2014), para 5.23.

K57 With replacing only those half-hours within a major event that exceed 1/48th of the boundary value with 1/48th of the boundary value, the impact of a major event will be capped. However, given that a pro-rated boundary value is still relatively large compared to a normal half-hour, distributors would still face some exposure to the frequency of major events.

K58 Distributors disagreed with our DPP2 approach of replacing MEDs with a boundary value.[673] They note that the frequency of major events was a large driver of volatility in SAIDI and SAIFI, and therefore contribute largely to compliance contraventions and incentive scheme gains and losses. For example, Wellington Electricity submitted to the issues paper that a more than average number of MEDs almost guarantees that the reliability limits will be exceeded and would likely require uneconomic investment to avoid.

K59 In the context of MEDs, many distributors suggest that they should be replaced with either the daily average or zero. The ENA suggested that increased reporting requirements of major events can provide extra transparency to the extent the Commission has concerns with any potential perverse incentives. Distributors were generally supportive of reducing the impact of major events on compliance and financial incentive outcomes in our draft approach, although some suggested it did not go far enough.[674]

K60 While some major events (such as those caused by extreme weather) are somewhat beyond the control of distributors, the degree of controllability is not always clear. The underlying performance of the network does have some effect on how well networks respond to significant events. For example, the engineering advice we have received with respect to many recent contraventions suggests that there were operational decisions distributors could have made to minimise the impact of external events.

K61 However, we recognise that to some extent the effects of extreme external events may be beyond the control of distributors, and this can cause some variability in reliability performance which distributors will not be able to eliminate. We agree with distributors that replacing major events with the full boundary value may make the frequency of major events too large a driver of underlying reliability performance.

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[673] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 13; Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018), p. 4; Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), p. 34; Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 18.

[674] See for example: ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 32-33.

K62 For the final decision, any 24-hour rolling period that is identified as a major event will be replaced with a pro-rated boundary value for only those half-hours that exceed 1/48th of the boundary value. However, a major event can last longer than 24 hours, so a pro-rated approach will account for those 'longer' major events and will bear a bigger impact.

K63 On balance, we considered that a change to replace identified major events with a reduced replacement value is appropriate, given that:

K63.1 enhanced major event reporting requirements, as discussed from paragraph K79, will provide more transparency and incentives around the main cause of events.

K63.2 reducing a large source of volatility may provide a clearer indication of the underlying reliability of the network;

K63.3 the introduction of an extreme event standard, as discussed in Attachment L, will place further onus on distributors to take practicable steps to minimise the likelihood of high impact, low probability events that are within its control as well as mitigating the extent of them; and

K63.4 there are other incentives at play which may mitigate some of the above risks, such as customer complaints and reputational risk.

K64 However, we still do not consider it appropriate to completely remove the major event impact for assessment purposes, or replace it with a daily (or half-hourly) average, as this would completely remove variation caused by major events, regardless of the extent to which the event was outside the distributor's control, and potentially create assessed values which ignore an aspect underlying reliability.

K65 We note that Unison Networks submitted that it rejects the inference from the 2014 draft decision that distributors may be incentivised to trigger a major event day if they were removed. They state that:[675]

> EDBs take clear pride in restoring power as quickly as possible following outages – the concept of network controllers being directed to delay restorations to obtain regulatory benefits would run against the strong public service ethic in EDBs and their recognised role as essential service providers.

[675] Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018), p. 4.

K66 While we agree that other non-financial incentives mitigate this risk and accept that distributors may choose to act appropriately even when that is contrary to our incentives, we do not consider it appropriate to provide any regulatory incentive for taking fewer steps to prevent or reduce the extent of interruptions which they perceive may potentially trigger a major event. This potential incentive arises because once an interruption tips over the boundary value and becomes a major event, the impact of that event on their assessed SAIDI and/or SAIFI figures reduces significantly.[676]

K67 The average impact of alternative normalisation methodologies for SAIDI and SAIFI during the reference period are outlined in Figure K6 and Figure K7 respectively. These figures represent the simple annual average of normalised SAIDI and SAIFI across distributors over the 1 April 2009 to 31 March 2019 reference period under alternative normalisation methodologies we have considered.

Figure K6 SAIDI normalisation impact

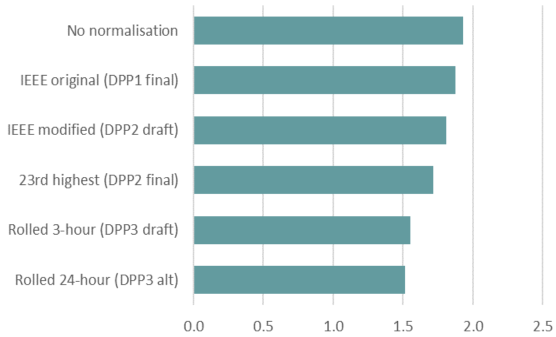
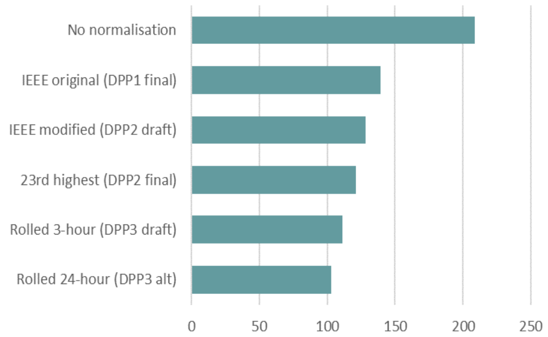


Figure K7 SAIFI normalisation impact



K68 Submissions to this alternative proposal as presented in the update draft model companion paper generally acknowledged that this method of replacing major events will remove more of the volatility associated with major events.[677] Although Unison and Centralines still expressed concern that major event were not completely removed.[678]

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[676] We also note that submissions from distributors citing a commercial incentive to "divert resources" away from a major event, even if not in the best interests of the consumer, to those events that are not normalised.

[677] ENA "DPP for EDBs from 1 April 2020 Updated draft models – companion paper: Submission to the Commerce Commission" (9 October 2019), pp. 8-9; Orion "Submission on EDB DPP3 Updated Draft Models" (9 October 2019), p. 3; Wellington Electricity "Submission on Default price-quality paths for electricity distribution businesses from 1 April 2020 - Draft Decision Update" (9 October 2019), p. 5; Powerco "Powerco submission on the updated DPP3 Draft Decision" (9 October 2019), p. 2.

[678] Unison "Submission on Default Price-Quality Paths – Updated Draft Models" (9 October 2019), p. 2; and Centralines "Submission on Default Price-Quality Paths – Updated Draft Models" (9 October 2019), p. 3.

Extended major events and follow-up interruptions

K69 Major events can last longer than the specified length of a major event. For the final DPP3 decision, major events can last longer than 24 hours as long as the major event criteria is met.

K70 In the issues paper we also considered whether when a distributor acts to restore an unplanned interruption quickly but is then followed by a planned interruption to complete the fix, that follow-up interruption should also be normalised.

Extended major events

K71 As noted above, for the final decision, any half-hour which falls within any 24-hour period that exceeds the applicable boundary value will be considered as part of a major event. This approach naturally ensures that events can last for as long as the major event criterion is met.

K72 In the issues paper we acknowledged that extreme weather events or natural disasters, for example, can last multiple days and, in principle, we considered whether it is appropriate for such events to be normalised as one event. Our final decision to allow major events to last longer than 24 hours is based on the same logic. We consider it reasonable that a major event can last for as long as the 24-hour rolling SAIDI or SAIFI exceeds the major event boundary value.

K73 Distributors were supportive of further consideration of allowing aggregation of major events lasting longer than one day.[679]

K74 Mercury Energy submitted that aggregating multi-day events would create inconsistency as to whether interruptions are part of the initial major event.[680] We consider that the approach, which assesses events half-hourly, will somewhat alleviate this concern.

Follow-up planned interruptions

K75 We noted in the issues paper that not allowing normalisation of follow-up planned interruption may discourage distributors from quickly restoring major interruptions if subject to further losses for follow-up interruptions.

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679 Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 5; ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 14; The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), p. 9; Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), p. 33; Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 18.

680 Mercury "Default Price-Quality Paths for Electricity Distribution Businesses from 1 April 2020" (20 December 2018), p. 5

K76 Eastland Network and Wellington Electricity were supportive of considering normalisation of follow-up planned interruptions resulting from a prior major event.[681] For example, Eastland Network cited an example where they temporarily restored power following a plane crash disrupting supply on a high voltage circuit in 2016. This was followed-up with planned works to fully repair the circuit and was not subject to any normalisation.

K77 For the final decision, follow-up interruptions will not be subject to normalisation. This is purely from a practical perspective, namely we:

K77.1 do not have enough information to apply on a backwards-looking basis; and

K77.2 have concerns that this would be difficult to implement and manage on a forward-looking basis.

K78 However, with the other decisions relating to assessing reliability, we consider that any potential perverse incentive is somewhat mitigated with:

K78.1 unplanned follow-up interruptions able to be replaced with a pro-rated boundary value if a new major event is triggered;

K78.2 less risk of contravening the quality standard due to a planned interruption, as discussed in Attachment L; and

K78.3 adequately notified follow-up interruptions weighted one-quarter of an unplanned interruption for revenue-linked incentive purposes, as discussed in Attachment M.

Major event reporting

K79 We consider that when a major event is identified, there should be full transparency as to when and why the major event happened, and the impact of normalising the major event. This is important given our final decision to replace major events with a pro-rated boundary value, rather than the full boundary value.

K80 The final decision requires that in addition to reporting the cause of each major event, as required in DPP2, a distributor must report for each major event in its annual compliance statement:

K80.1 the start date and time;

K80.2 the end date and time;

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[681] Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 5; Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 18.

K80.3 the raw SAIDI and SAIFI values;

K80.4 the normalised SAIDI and SAIFI values;

K80.5 the location and equipment involved;

K80.6 the event cause and response to the event; and

K80.7 any mitigating factors that may have prevented or minimised the major event.

K81 As per clause 11.5(f) of the 2015-2020 EDB DPP Determination, the only current requirement with respect to major event reporting is that "the cause of each major event day within the assessment period" is included in the annual compliance statement. Without transparency, we are unable to assess when the major events occur, the magnitude and causes of these major events, and whether there were any preventative measures that could have minimised the major event.

K82 However, despite the lack of requirements, many distributors have voluntarily provided additional information within their compliance statements. Therefore, we do not consider that there would be significant regulatory burden to increase the requirements for those distributors that do not.

K83 We consider that increased transparency of major events is essential to mitigate against any risk that distributor may be encouraged to trigger a major event given our decision to replace major events that are identified with a lower SAIDI and/or SAIFI value. Furthermore, increased reporting will allow us to cross-check the causes of any extreme event, as discussed in Attachment L.

K84 The ENA, Wellington Electricity, and Orion were generally receptive of enhanced reporting on major events, as a compromise for removing major events from assessment.[682] For example, Wellington Electricity submits that "substituting major event days with the average SAIDI and SAIFI will require more transparent information".

[682] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 13; Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 18; and Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 17.

Overview of methodology for identifying and replacing major events

K85 We recognise that our final decisions for identifying and replacing a major event represents a major change from the DPP2 methodology. The purpose of this section is to provide:

K85.1 clarity on how we practically derive the boundary values; and

K85.2 guidance for distributors to identify and replace major events for unplanned reliability assessment purposes.

K86 We intend to publish an Excel template before 1 April 2020 to assist distributors with normalising its annual interruptions for the purpose of assessing compliance and financial incentives.

Deriving the boundary values for SAIDI and SAIFI

K87 To identify the trigger for what is considered a major event, or the major event boundary value, for the reference period for unplanned interruptions only, we:

K87.1 aggregate the raw SAIDI and SAIFI values from each unplanned interruption in to half-hour blocks (rounding each interruption down to the nearest half-hour);

K87.2 sum the raw SAIDI and SAIFI values of each half-hour block with the respective SAIDI and SAIFI values of the following 47 half-hour blocks (to create a rolled 24-hour value for SAIDI and SAIFI); and

K87.3 separately identify the 1104th highest rolled half-hour values for SAIDI and SAIFI to determine the respective SAIDI and SAIFI boundary values for all distributors except for the following small networks:

K87.3.1 Electricity Invercargill where the 726th highest rolled 24-hour SAIDI and SAIFI values are used; and

K87.3.2 Nelson Electricity where the 328th highest rolled 24-hour SAIDI and SAIFI values are used.

K88 Table K2 shows the boundary values for unplanned SAIDI and SAIFI for each price-quality regulated distributor for DPP3.

Table K2 Unplanned boundary values

Distributor	SAIDI boundary	SAIFI boundary
Alpine Energy	9.17	0.0671
Aurora Energy	5.69	0.0737
Centralines	6.79	0.1442
EA Networks	6.25	0.0729
Eastland Network	13.10	0.1765
Electricity Invercargill	4.13	0.0804
Horizon Energy	14.69	0.1170
Nelson Electricity	8.68	0.1430
Network Tasman	7.22	0.0688
Orion NZ	7.60	0.0668
OtagoNet	11.81	0.1776
Powerco	9.82	0.0628
The Lines Company	11.17	0.1596
Top Energy	27.92	0.2284
Unison Networks	4.48	0.0735
Vector Lines	4.83	0.0371
Wellington Electricity	2.16	0.0313

Identifying and replacing major events for SAIDI and SAIFI

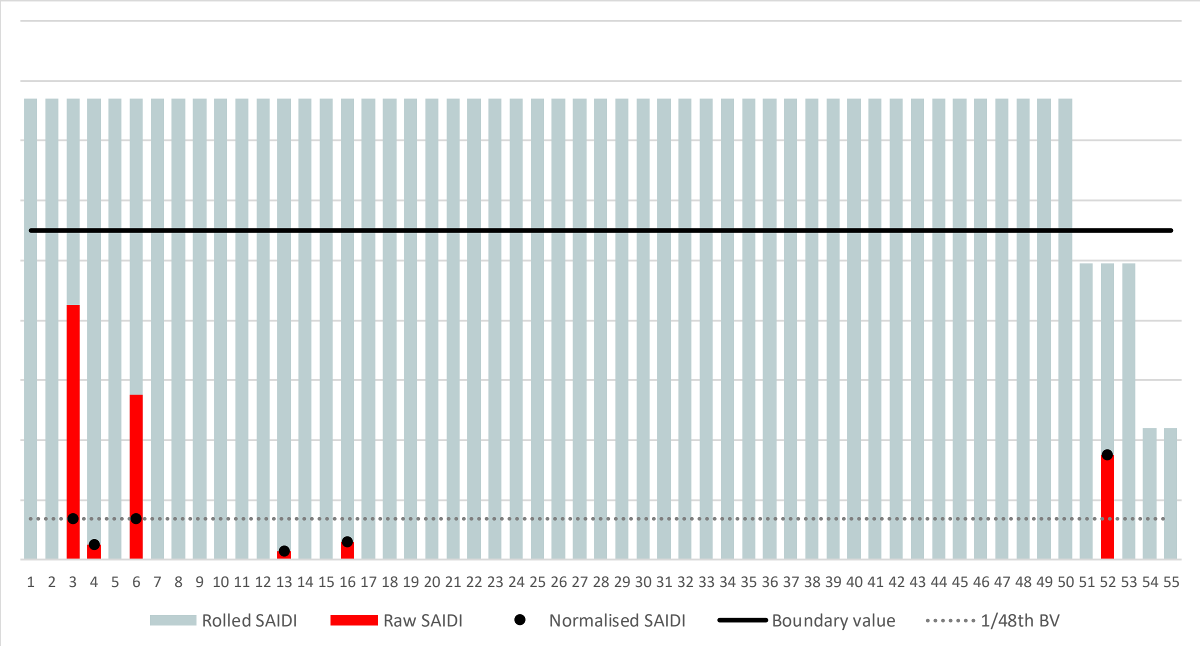
K89 To normalise the dataset over the reference period, and for each assessment period, for unplanned interruptions only, we replace each half-hour with 1/48th of the boundary value if:

K89.1 that half-hour is part of any 24-hour rolled period that exceeds the applicable SAIDI or SAIFI major event boundary value; and

K89.2 that half-hour exceeds 1/48th of the applicable SAIDI or SAIFI boundary value.

K90 Figure K8 illustrates the identification and normalisation of major events, where the raw half-hourly SAIDI (red bars) is normalised to 1/48th of the boundary value (dotted line) if it is part of any 24-hour period (green bars) that exceeds the boundary value (black line).

Figure K8 Identifying and normalising major events [683]



683 Not to scale for illustrative purposes.

Attachment L Quality standards

Purpose of this attachment

L1 This attachment sets out our detailed decisions on setting the quality standards for EDB DPP3 and responds to the submissions on our draft decisions for quality standards.

Purpose of quality standards

L2 Section 53M of the Commerce Act 1986 requires that every DPP must specify "the quality standards that must be met by the regulated supplier."

L3 However, the description of quality standards in the Act is broad, leaving the Commission with significant discretion for setting quality standards. In setting quality standards, we should have regard to the purpose of Part 4. This includes promoting outcomes such that suppliers have incentives to provide services at a quality that reflects consumer demands and to invest. This should be weighed against the other performance areas that we are required to promote under section 52A of the Act. The Act explains quality standards as follows:

> Quality standards may be prescribed in any way the Commission considers appropriate (such as targets, bands, or formulae) and may include (without limitation)—
>
> (a) responsiveness to consumers; and
>
> (b) in relation to electricity lines services, reliability of supply, reduction in energy losses, and voltage stability or other technical requirements.[684]

Summary of our decision

L4 Our decisions on setting the quality standards for EDB DPP3 are summarised below:

L4.1 quality standards will be based on SAIDI, SAIFI, and customer interruption minutes;

L4.2 unplanned and planned interruptions will be assessed separately;

L4.3 unplanned SAIDI and SAIFI standards are set 2.0 standard deviations above the normalised reference period average and are assessed annually;

L4.4 planned SAIDI and SAIFI standards are set at three times the reference period average and are assessed for the regulatory period;

[684] Commerce Act 1986, section 53M(3).

L4.5 there is a new extreme event standard, to be set at 120 SAIDI minutes or six million customer interruption minutes, excluding specified events that we consider are predominantly caused by external factors; and

L4.6 there are new automatic reporting requirements that are triggered by a contravention of any quality standard.

L5 Quality standards and the quality incentive scheme have been an area of particular focus for the Commission in this reset of the DPPs, partially in response to feedback from stakeholders. This has resulted in a relatively large number of changes from the DPP2 settings.

Changes from draft decision

L6 Our final decisions on quality standards include the following changes from the draft decision:

L6.1 The limit for the extreme event standard is 120 SAIDI minutes or six million customer interruption minutes, in comparison to the draft limit which was three times the normalisation boundary value;

L6.2 The unplanned SAIDI and SAIFI standards have been set at the historic average plus a buffer of 2.0 standard deviations, an increase from the draft decision of 1.5 standard deviations.

Overview of quality standards

L7 Our overall approach to the quality path, which includes quality standards and a quality incentive scheme, and is underpinned by the normalisation methodology and selection of a historic reference period, is described in Attachment J. In particular, Attachment J explains that, given the aggregate nature of the SAIDI and SAIFI metrics used to assess reliability, setting an unplanned standard at a level that perfectly reflects consumer preferences is not possible at this stage. In the absence of better information, we consider that the unplanned standard should identify instances of material deterioration in overall reliability performance.

L8 This section provides an overview of the quality standards that form part of the overall package of the quality paths for distributors.

L9 The quality standards are a key aspect of the DPPs that we set. They promote outcomes consistent with competitive markets in terms of providing the level of quality demanded by consumers.

L10 Quality standards are required to counter any incentive to under-invest created by the price path that incentivises distributors to minimise expenditure. If there was no counter-measure like quality standards, then distributors may be incentivised to reduce expenditure such that the quality level expected by customers is not being met, to pursue excessive profits.

L11 For DPP3, we have set three standards, focused on the reliability of supply. They are:

L11.1 a standard for unplanned interruptions to avoid material deterioration of network performance, similar to the DPP2 quality standards;

L11.2 a standard for planned interruptions that is set over the regulatory period to eliminate any perverse incentives for distributors to avoid network investment or maintenance (which could occur with a combined planned and unplanned standard), and give distributors greater flexibility on the timing of work requiring planned interruptions; and

L11.3 a new extreme event standard to incentivise distributors to minimise the likelihood of high impact and low probability events as well as to mitigate the scale of them, as these have a large impact on consumers experience of reliability but are not adequately covered by the unplanned interruption standard.

L12 We have set these standards in the way and level that we think best supports the long terms interests of consumers, balancing a number of considerations. We have sought to balance the costs of compliance against the benefits of the standards, and have considered how the standards fit within the whole quality path (as described in Attachment J).

L13 Along with the other parts of the quality path described in Attachment J, we have made a number of simultaneous changes to the quality standards compared to DPP2. We recognise that this may make it more difficult for stakeholders to understand the implications of the whole package of standards and incentives, as suggested by Centralines.[685] Wellington Electricity also suggested in its submission that the scale of change in this area undermines the certainty in the DPP regime.[686]

L14 However, we consider that the changes are a significant improvement, better promoting the purpose of Part 4 of the Act and are justified as a focus area of this DPP reset.

[685] Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18.

[686] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018).

SAIDI and SAIFI as quality standards

L15 We consider that SAIDI and SAIFI cover the main aspects of reliability for consumers. Network reliability is considered as being one of the most important dimensions of quality for consumers of electricity distribution services. SAIDI and SAIFI remain important metrics for quality standards for distributors in that they are:

L15.1 standard and internationally recognised measures;

L15.2 measures that the distributors already collect and monitor;

L15.3 measures for which we have significant historical data for each distributor to aid setting the limits;[687]

L15.4 measures that cover the main impact of unreliability across all consumers of the network; and

L15.5 closely tied to the physical condition of the network (albeit on a 'lagged' basis).

L16 While SAIDI and SAIFI are not perfect measures of the reliability delivered to consumers, we are not aware of any better measures, especially when considering the importance of the availability of data. To the extent we wish to add additional reliability metrics to the quality standards in the future, we consider it appropriate to acquire the necessary data through either ID or a section 53ZD notice (if appropriate to use section 53ZD) first as to set a baseline. Submissions generally agreed that additional metrics should be added to ID requirements first. The topic of other potential measures of reliability and quality more generally is covered in Attachment N.

L17 One of the limits for the extreme event standard is measured in terms of customer interruption minutes rather than SAIDI or SAIFI. However, we note that this is a similar measure to SAIDI and can easily be converted to SAIDI for each distributor based on the number of customers connected to the network.

L18 Our reliance on SAIDI and SAIFI measures for the quality standards is consistent with the previous two regulatory periods.

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[687] However, as noted in Attachment J, there has been some inconsistency in approaches to recording SAIFI.

Separation of planned and unplanned interruption standards

L19 For DPP3 we are separating planned and unplanned interruption standards, with a larger buffer above the reference period average for planned interruptions. Likewise, as discussed in Attachment M, revenue-linked incentives for planned and unplanned interruptions will be assessed separately. This is in contrast to the DPP2 quality standards, for which planned and unplanned interruptions are combined into one assessed SAIDI value and one assessed SAIFI value, although the planned interruptions are de-weighted by 50% to reduce their impact on the quality standard results.

L20 We are separating them for DPP3 because we consider that the integration of planned and unplanned interruptions into a single standard have the potential to create incentives to unnecessarily defer asset maintenance or other work on the network where a distributor is nearing a potential compliance contravention (and to bring work forward if a contravention is unlikely). This situation could cause inefficiency or deter investment, which goes directly against the purpose of Part 4 of the Act.

L21 Planned interruptions are also less inconvenient for consumers because, as long as they are notified of planned work, they can plan accordingly, and planned interruptions are also generally required by the distributor to perform maintenance and investment that benefits consumers in the long run. These different factors mean that separation is beneficial so that we can set the parameters of the standards differently (such as the annual limits for unplanned SAIDI and SAIFI in comparison to the five-year limit for planned SAIDI and SAIFI).

L22 There was no consensus in submissions on our draft decision whether to separate the planned interruption standard from the unplanned interruption standard.

L23 Some distributors supported the separation. For example, Powerco supports separating the standards for planned and unplanned interruptions because “It supports delivery of maintenance and investment programmes that benefits consumers in the long run” and “It removes perverse incentives to reduce planned construction and maintenance to manage unplanned interruptions”.[688]

[688] Powerco “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 2.

L24 Wellington Electricity did not consider separation appropriate, because it says it works hard to minimise the number and impact of planned interruptions for its consumers.[689] However, the ENA supported separating them to remove the current incentive to reduce planned interruptions in years with a high number of unplanned interruptions.[690] The ENA reiterated its support for the separation of quality standards for planned and unplanned interruptions in its submission on our draft decision.[691]

L25 In adopting the separation of planned and unplanned interruptions, we considered that this will eliminate the ability of distributors to avoid contravening the quality standard by deferring planned work when it forecasts that it is otherwise likely to contravene. We are aware that this may be happening under the current settings. This may mask deteriorating unplanned quality performance and is unlikely to be in the long-term interests of consumers. Also, separating the planned and unplanned interruptions means that a contravention due to a high level of planned interruptions can be investigated as such, with a suitably narrow investigation.

L26 We note that this less stringent standard for planned interruptions compared to DPP2 does mean that there will be less incentive on distributors to minimise the frequency and duration of planned interruptions while still undertaking the necessary maintenance and investment work. For example, the planned standard provides less incentive for distributors to use mobile generators to avoid planned interruptions.

L27 However, we consider that there are limitations with quality standards, and so quality incentive schemes are retained to supplement the standards. This is especially true for planned interruptions, for which the buffer over the historic average is higher. The collar for the quality incentive scheme for planned interruptions will be zero, so the incentive will apply to most interruptions, which we consider is a more appropriate way to disincentivise inefficient planned interruptions.

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689 Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 14; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 20.

690 ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 6.

691 ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 25.

L28 We previously considered whether to further separate SAIDI and SAIFI interruptions into separate standards for unplanned and/or planned interruptions. Given there is some crossover between the SAIDI and SAIFI metrics as every interruption contributes to both measures, we consider that combining into a single standard for unplanned interruptions and a single standard for planned interruptions is appropriate.

Setting the unplanned interruption standard

L29 There was general support for the 'no material deterioration' standard, but diverging views on implementation (for example, reference periods, data adjustments, and normalisation). For example, the ENA submitted that “customer feedback to date strongly suggests that declining reliability standards are not generally acceptable”.[692] This is consistent with our recommendation to base the quality standards on the historical average, with a buffer added to reduce the risks from random year-to-year volatility of the SAIDI and SAIFI metrics.

L30 With our decision to separate planned and unplanned interruptions for setting quality standards, an unplanned interruption standard is required to be specified for SAIDI and SAIFI. In summary, for DPP3 the unplanned interruption standard is:

L30.1 assessed annually (based on the reliability performance for that one year) for unplanned SAIDI and SAIFI standards, removing the current two-out-of-three-year test; and

L30.2 set with limits for unplanned SAIDI and SAIFI of 2.0 standard deviations above the reference period average, an increase from 1.0 standard deviation under the current DPPs.

Annual unplanned standard

L31 We have replaced the current two-out-of-three-year rule of DPP2 with a simpler annual limit for unplanned SAIDI and SAIFI. We consider that the other quality standard settings—namely, reducing the impact of major events and the buffer above the historical mean—are more effective means of reducing the risk of false-positives.

L32 We have made this change because it simplifies the standard while still achieving its purpose. This simplification will allow for more timely compliance investigations and enforcement action. We consider that the simplicity and more prompt response will be better for consumers engaging with the regulation of their local distributor.

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[692] ENA “DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)” (20 December 2018), p. 6.

L33 The two-out-of-three-year rule required distributors to exceed SAIDI or SAIFI limits in any two-out-of-three years to contravene the quality standard, and it was put in place to reduce the number of 'false-positives' where contraventions were caused by random volatility. However, this meant that significantly high levels of unreliability over a single year were not considered to be contravention on their own.

L34 A change to an annual standard on its own would make this quality standard more stringent on distributors. However, we consider that the difference is offset by our decision to increase the buffer between the historical mean and the limit.

L35 We recognise the volatility issue, and have only removed the two-out-of-three-year rule because we have simultaneously made other changes that will reduce volatility and the chance of 'false-positives'. However, we do not consider that unplanned interruptions triggered by external events beyond the immediate control of distributors as a satisfactory reason for keeping the two-out-of-three-year rule. While external events may be outside of a distributors' control, how well a network mitigates or responds to those events is often within the distributors' control.

L36 The improvements that we have made to the normalisation methodology will also reduce the volatility of SAIDI and SAIFI. An increase to the buffer—in terms of the standard deviation multiplier—is still required because the reduction in volatility is reflected in a lowered standard deviation.

L37 In theory, the change from a two-out-of-three-year-test to an annual test could see contraventions from distributors with a single year of poor performance, which would not have contravened under the DPP2 quality standards. At the same time distributors with mildly decreased reliability performance for multiple years may not contravene when they would have under the DPP2 quality standards because of the larger buffers. In practice, however, we consider that this effect is relatively small and in general the same distributors will contravene the quality standards under either an annual or two-out-of-three-year approach (so long as the buffer is suitably increased for the annual standard).

L38 Most distributors submitted that one year of poor performance does not represent deterioration because it is not a long-term trend and so we should retain the two-out-of-three-year rule.[693] Wellington Electricity for example submitted that it may take three or four years for asset deterioration to properly reveal itself in reliability trends. Horizon also suggested extending the standard to a three-out-of-five-year standard to ensure it is focused on longer-term trends of deterioration.[694] However, we consider that consumers experiencing poor performance for a year is a significant enough deterioration in performance to warrant investigation and potential compliance action.

L39 Horizon submitted that the reporting requirements mean that an unplanned interruption standard that is assessed once at the end of a regulatory period is appropriate despite the potential time lag between poor performance and enforcement response.[695] However, we disagree with Horizon—the new automatic reporting requirements are triggered by contraventions so would also not occur until after the end of the regulatory period and so would not offset the time lag caused by only assessing contraventions at the end of the regulatory period.

Unplanned standard set 2.0 standard deviations above historical annual average

L40 We consider that using the historical mean with an additional buffer is working well in capturing material deterioration in reliability. The Commission has investigated and publicly commented on three distributors who have contravened the DPP2 quality standards and in each case it has found that the contraventions were, at least in part, caused by failure of those distributors to act consistently with good industry practice. [696] Conversely, we have not found contraventions of the quality standard so far in the current regulatory period to be caused by random volatility alone.

L41 Our decision to increase the buffer above the historical average to 2.0 standard deviations is to provide a suitable level of protection against random volatility. This increase from DPP2 is required to offset the decision to move to an annual standard. We consider that a 2.0 standard deviation buffer, when combined with our other recommendations, will result in a similar expectation of contravention as the current settings. That is, the increased buffer helps offset the removal of the two-out-of-three-year rule.

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693 Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019); Alpine Energy "Submission on EDB DPP reset draft decisions paper" (18 July 2019); and Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

694 Horizon "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

695 Horizon "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

696 Other EDBs have contravened the DPP2 quality standards, but the Commission's investigation into them is not yet complete, and some also contravened prior to DPP2.

L42 Several distributors submitted that the change from the two-out-of-three-year rule to an annual test with a buffer of 1.5 standard deviations would result in too many contraventions.[697] Specifically, it was submitted that there would be more contraventions than under the DPP2 quality standards. Some submitters also noted the significant expense involved for the distributors and the Commission in investigating any contraventions.[698]

L43 While most distributors' preferred position is to retain the two-out-of-three-year rule of DPP2, we have instead responded to these submissions by raising the buffer to 2.0 standard deviations. This is in line with the submission by PowerNet, which suggested that we increase the buffer if retaining the annual standard that we proposed in the draft decision.[699]

L44 We compared the outcomes of annual standards (with a 2.0 standard deviation buffer) and two-out-of-three-year standards (using a 1.0 standard deviation buffer). For this analysis, we applied the normalisation approach set for DPP3 and the DPP3 SAIDI and SAIFI limits to the 2012 to 2018 interruptions experienced on the 17 non-exempt distributors. We found that there were 16 hypothetical contraventions of the annual quality standard (from ten unique distributors) compared to 18 under the two-out-of-three-year standard (from 11 unique distributors).

L45 This analysis suggests that the DPP3 quality standards provide a similar likelihood of contravention (all else being equal) as a two-out-of-three-year quality standard with a 1.0 standard deviation buffer. However, we note that there are several assumptions required for this analysis, such as applying the updated normalisation approach and removing planned interruptions.

L46 Nine of the ten distributors that hypothetically contravened under the annual standard (with a buffer of two times the standard deviation) also hypothetically contravened under the two-out-of-three-year standard (with a buffer of one-times the standard deviation), while just one did not.

[697] See for example: Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019); and Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

[698] See for example: Horizon "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

[699] PowerNet "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 4.

L47 In its submission on our draft decision the ENA said that we should retain the two-out-of-three-year rule from DPP2 and apply the higher buffer from the draft decision of 1.5 standard deviations. However, we disagree and consider that such an approach would result in a loosening of the quality standards. We consider that would not be in the long-term interests of consumers because it would risk the standards missing poor performance that should be addressed. As noted in paragraph L40, contraventions that we have so far investigated and published findings on have all found the distributor to be at least partially responsible for failing to meet good electrical industry practice.

Deriving the standard deviation

L48 For DPP3 we have calculated the historic standard deviations of SAIDI and SAIFI by annualising daily data. This is the same method that was used to set the previous two regulatory periods.

L49 We used half-hourly data to calculate the standard deviations in our updated draft (published September 2019) because we had calculated the half-hourly data for normalisation. However, Powerco requested in its submission on our updated draft that we keep the methodology the same as for previous regulatory periods.[700]

L50 We have decided to return to the use of daily data as suggested by Powerco because it has sufficient data points for statistical robustness and there is a risk that half-hourly data will produce errant results because they may not be independent (eg, during storm events that last several hours).

L51 Table L1 shows the standard for unplanned SAIDI and SAIFI for each price-quality regulated distributor for DPP3.

[700] Powerco “Powerco submission on the updated DPP3 Draft Decision” (9 October 2019), p. 2.

Table L1 Annual unplanned reliability standards

Distributor	Unplanned SAIDI	Unplanned SAIFI
Alpine Energy	124.71	1.1970
Aurora Energy	81.89	1.4687
Centralines	83.61	3.1616
EA Networks	91.98	1.2826
Eastland Network	219.46	3.1525
Electricity Invercargill	25.86	0.6956
Horizon Energy	194.53	2.3904
Nelson Electricity	19.60	0.4277
Network Tasman	101.03	1.1956
Orion NZ	84.71	1.0336
OtagoNet	160.35	2.4172
Powerco	180.25	2.2684
The Lines Company	181.48	3.2715
Top Energy	380.24	5.0732
Unison Networks	82.34	1.8152
Vector Lines	104.83	1.3366
Wellington Electricity	39.81	0.6135

Setting the planned interruption standard

L52 With the decision to separate planned and unplanned interruptions for setting quality standards, a planned interruption standard is required to be specified for SAIDI and SAIFI. In summary, the planned interruption standard is:

L52.1 assessed once for the regulatory period for planned SAIDI and SAIFI standards, i.e., assessment is against a five-year total; and

L52.2 a regulatory period limit for planned SAIDI and SAIFI set at three times the reference period performance (or 15 times the reference period annual average).[701]

[701] As discussed in Attachment M, we have halved the revenue-linked incentive impact of planned interruptions that meet a notification criterion. This flows through to the assessment of planned interruption for the quality standard, effectively meaning EDBs have more flex within the planned interruption standard if it provides the required notification.

Regulatory period planned interruption standard

L53 Our decision to set the planned quality standard over the full regulatory period will allow distributors to schedule planned works in the way that works best for their business and consumers, rather than for regulatory settings.[702] For example, the current settings may incentivise distributors to defer or bring forward work that would be less efficient for consumers. This contrasts with the current two-out-of-three-year rule or the annual assessment for unplanned SAIDI and SAIFI.

L54 We note that this creates the potential of a significant lag between the time that a distributor begins excessive levels of planned interruptions and the time that compliance and enforcement action can be taken. It also reduces the maximum pecuniary penalty that a distributor that continues high levels of interruptions over several years will face. However, the distributor will continue to face the incentives of the quality incentive scheme each year, and continual years of high interruption frequency or duration will be taken into account in our enforcement response, and presumably in any Court decision on pecuniary penalties.

L55 We also think that only assessing compliance at the end of the regulatory period is justified given that planned interruptions:

L55.1 are generally less harmful for consumers, as long as they are notified of planned work, as they can plan ahead for them and make alternative arrangements if required;

L55.2 are required for beneficial network maintenance and investment;

L55.3 are not an indicator of current under expenditure (although may be required for historical under expenditure);

L55.4 can be driven by operating policies, such as live lines practices; and

L55.5 are exposed to our revenue-linked incentives.

[702] For distributors that are on a CPP for part of the regulatory period, the planned interruption standard will be pro-rated to reflect the number of years the distributor is subject to the DPP either prior to or following a CPP, and assessed on this basis.

Planned interruption standard set 200% above historical average

L56 We have implemented a large buffer for setting the planned interruption standard. We have decided to apply a buffer of 200%, or triple the historical average, which is less stringent than in DPP2, because of the long-term benefits to consumers of the network investment and maintenance that is associated with planned interruptions. It will also allow for some flexibility in work practices that may impact the level of SAIDI or SAIFI, such as changes implemented by some distributors to reduce the amount of live lines works it undertakes.

L57 We consider that the revenue-linked incentive scheme is a better mechanism than quality standards to ensure that planned interruptions are managed appropriately because it allows for flexibility so long as they are within a reasonable range, as discussed in Attachment M. This approach of a relatively high-quality standard limit combined with an incentive scheme will provide distributors with improved flexibility to increase their level of planned interruptions for network maintenance and investment, without affecting the requirements for unplanned interruptions. The high limit for the planned interruption standard is complemented with a high cap associated with the revenue-linked incentive scheme. The incentive scheme also includes incentives to improve the notification of planned interruptions.

L58 Some distributors have submitted that the 200% buffer for planned interruptions is not sufficient and that we should have more regard for each distributors' planned level of investment.[703] Wellington Electricity also noted that if a distributor expects to contravene the standard, then there are no marginal incentives from the quality incentive scheme.[704]

L59 We do not consider that it is appropriate to set individual planned interruption quality standards based on a full assessment of planned investment for the regulatory period and operational approaches to planned interruptions within the context of a low-cost DPP, particularly when a large buffer is already given. However, distributors could apply for a quality standard variation or a CPP if they consider that their particular circumstances, such as a high level of investment, requires it and we would consider such an application under the appropriate rules and processes.

L60 Table L2 shows the standard for unplanned SAIDI and SAIFI for each price-quality regulated distributor for DPP3.

[703] Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

[704] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019).

Table L2 Regulatory period planned reliability standards (5-year total)

Distributor	Planned SAIDI	Planned SAIFI
Alpine Energy	824.87	3.4930
Aurora Energy	979.80	5.5385
Centralines	1064.46	5.8573
EA Networks	1376.08	4.8939
Eastland Network	1290.68	7.4745
Electricity Invercargill	114.49	0.5183
Horizon Energy	858.63	5.4415
Nelson Electricity	180.11	2.3663
Network Tasman	1129.14	4.9021
Orion NZ	198.40	0.7481
OtagoNet	2114.43	9.6212
Powerco	772.50	3.5113
The Lines Company	1331.68	8.7527
Top Energy	1905.36	7.7526
Unison Networks	625.79	4.4649
Vector Lines	585.38	2.8783
Wellington Electricity	69.70	0.5536

Introducing and setting an extreme event standard

L61 We have introduced the new extreme event standard for distributors, which will be contravened if—for any 24-hour period—a distributor's SAIDI is greater than 120 minutes or if its count of customer interruption minutes is greater than six million. We have decided that a contravention will only occur if the interruptions are not the result of a major external factor. However, we note that all major events can be cross-checked against the enhanced major event reporting requirements, as discussed in Attachment K.

L62 The introduction of an extreme event standard is intended to incentivise distributors to take practicable steps to minimise the likelihood of high impact, low probability events that are within its control as well as mitigating the extent of them. Currently under the quality standards used in DPP2, there may be little incentive from our regulatory settings to appropriately guard against such events as most of the impact on reliability will be removed through normalisation. Our approach to normalisation is described in Attachment K.

L63 Normalisation of major event interruptions means that particularly large interruptions will unlikely contribute to a contravention unless the assessed unplanned SAIDI or SAIFI is high enough for other reasons. As major events are assessed on a statistical basis, rather than based on cause, the unplanned interruption standard may miss large interruption events that are caused by not applying good electricity industry practice or under-spending on network maintenance and investment. So, we consider that it is in the long-term interests of consumers to set a quality standard relating to extreme events.

L64 Centralines' submission on our draft decision suggested that one reason an extreme event standard is not required is because distributors are exposed to incentives for such events through the quality incentive scheme. However, for the same reason cited above, the exposure of major event interruptions to revenue-linked incentives is very low.

L65 Several submissions claimed that it is not appropriate to introduce an extreme event standard because it is not consistent with a principle of maintaining no material deterioration.[705] We acknowledge that the standard is not based on deviation from historic outcomes. However, we consider that it is not possible to set a limit based on the reference period for an expectation of no material deterioration because of the infrequency of such events. This is not reason enough to avoid introducing an extreme event standard, although it has influenced us in introducing it with conservatively high limits.

L66 Several submissions on our draft decision suggested that we should introduce the extreme event standard as an ID requirement for DPP3 before considering it as a quality standard in future regulatory periods. However, we do not consider that this is necessary as we have sufficient historic information already, including from the information requirements in annual compliance statements for MEDs.

Extreme event standard excludes events largely triggered by external forces

L67 We have opted for the standard to only be contravened by interruptions that were not triggered by external factors like a severe wind storm. To be clear, we mean that at least 120 SAIDI minutes or six million customer interruption minutes must be attributed to causes other than major external factors for a contravention to occur.

L68 We consider it would likely not be in the long-term interests of consumers for distributors to upgrade their networks to a level of resilience against major external factors such that they would never exceed the extreme event threshold, because of the expense in doing so.

[705] Such as Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10.

L69 We note that there may well be instances of consumer harm from large interruption events triggered by external factors like a severe storm, but which could have been significantly mitigated had the distributor applied good industry practice resulting in more resilience. However, we do not consider that it is possible at this stage to create a quality standard that differentiates based on the practices of the distributor without a level of compliance burden that is not in the long-term interests of consumers.

L70 In the draft decision, the exclusions to the extreme event standard related to the cause categories used in ID. However, we have decided to apply separate criteria because further analysis has shown inconsistency in the application of cause categories in ID in the past. For example, the majority of historic interruption events that would have exceeded the limit and not been excluded due to its cause category under ID, were actually events that we would have intended to be excluded, particularly due to storms.

L71 Powerco submitted that an extreme event standard is unsuitable because including unknown causes may incorrectly capture events unrelated to asset management because these interruptions can be triggered by uncontrollable events. This concern should be partially assuaged by our new definition of extreme event, which no longer refers to the ID categories of cause. However, there is still a chance that some events with a truly unknown cause may be included. We consider that situations like this are appropriate to be considered in more detail under a compliance investigation.

Extreme event standard set at 120 SAIDI minutes, or 6 million customer interruption minutes

L72 We have set the extreme event standard at 120 SAIDI minutes or six million customer interruption minutes because we consider that a stricter threshold could result in too many contraventions, when the purpose of this standard is to focus on the events that have the largest impact on customers and because it is the first regulatory period in which we have introduced this standard. Applying this limit to the past ten years would have resulted in two clear contraventions. They are:

L72.1 a substation fire on Vector's network in 2014 (SAIDI of 217 and customer interruption minutes of 117 million); and

L72.2 a substation fire on Alpine's network in 2009 (SAIDI of 169 and customer interruption minutes of five million).[706]

[706] There was also an interruption event in 2012 on what is now the Eastland network but was at the time part of the Transpower network, which may have been over the limit and not caused by external factors.

L73 We have used SAIDI and customer interruption minutes to set the standard because they better represent the objective of the standard—capturing extremely large interruption events. We do not consider that it would be appropriate to use SAIDI alone because the SAIDI result of extreme events in large distributors, especially those with multiple networks, are diluted by the large number of ICPs on the network.

L74 Using a multiplier of the major event boundary, as proposed in our draft decision, unnecessarily references the limit to the past level and volatility of each distributors' reliability.

L75 Wellington Electricity submitted that a simple comparison of VoLL of the minimum size of an extreme event (as proposed in the draft decision) against the court-imposed penalty was out of balance with the VoLL being much smaller. In our final decision, the limits of the extreme event standard are generally much higher than those proposed in our draft decision.

L76 We consider that these higher targets will better target the interruption events with the largest impact on consumers, while reducing the risk of incentivising the over-investment that several submissions noted concern about.

L77 This risk of over-investment will also be reduced by our publication of enforcement response guidelines next year and we note that this was referred to in some submissions.[707] The case register of our past decisions, available on our website, should also aid distributors understanding of our enforcement response.[708]

L78 However, we note that this does leave a 'gap' where some major interruption events are normalised for the unplanned interruption standard, but too small to be covered by the extreme event standard.

L79 As explained in our draft decision reasons paper, we also considered setting the extreme event standard based on the frequency or SAIDI attributable to major events across each whole assessment year. However, we consider that basing the standard on individual events best reflects the purpose of this standard, which is to identify the interruptions will have the most impact on consumers and largely within the distributors' control.

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[707] Such as Centralines "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 19.

[708] https://comcom.govt.nz/case-register

Specification of the three quality standards

L80 We have set three distinct quality standards relating to network reliability which are summarised as:

L80.1 A non-exempt distributor must, in respect of each assessment period:

L80.1.1 have an assessed unplanned SAIDI below the limit; and

L80.1.2 have an assessed unplanned SAIFI below the limit.

L80.2 A non-exempt distributor must, in respect of the DPP3 regulatory period:

L80.2.1 have a total assessed planned SAIDI below the limit; and

L80.2.2 have a total assessed planned SAIFI below the limit.

L80.3 A non-exempt distributor must not have an extreme event, unless it was the result of one or more of the major external factors set out below having occurred, where an extreme event is one in which exceeds the following over a 24-hour period:

L80.3.1 120 SAIDI minutes; or

L80.3.2 Six million customer interruption minutes.

L81 For the purposes of the extreme event standard, major external factors means:

L81.1 natural disaster;

L81.2 third-party interference;

L81.3 a fire that does not originate on the non-exempt distributor’s network; or

L81.4 wildlife.

Automatic reporting requirements for quality contraventions

L82 In DPP2, when a distributor contravenes the quality standard we typically require information from the distributor to inform our enforcement response to the contravention. However, due to the time lag between the distributor contravening, the Commission being informed of the contravention and issuing an information request, and the distributor responding to the request, it may take some time to receive the information required to aid our investigation of the nature and circumstances of the contravention.

L83 To speed up this process and allow interested parties to better understand the contravention, we have introduced additional reporting requirements for any distributor that contravenes a quality standard. The required information is in line with the initial information requests made in 2018 for the distributors that contravened their 2018 quality standards, which is summarised in Table L3 below. We note that this is not as fulsome as the information requests including full engineering reports that were required for quality standard contraventions.[709]

L84 As requested by Vector in its submission, the information provided would likely be considered in the Commission's investigation of the contravention.[710] Further information may be required depending on the nature of the contravention, but it would be additional information rather than a repeat of the information already provided by the distributor under the automatic reporting requirements.

L85 Submissions on the draft decision that addressed the automatic reporting requirements were generally supportive of their introduction.[711] However, we have made the information requirements following contraventions of the extreme event standard more targeted in response to the ENA's submission on our draft decision:

> If information is to be provided about extreme events associated with these selected causes, the information requirements must be more targeted than those included in the Draft Determination.[712]

L86 The changes from the draft decision to the final in making the requirements more targeted include limiting the timeframes in particular, so that only recent information is required to be published.

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[709] Such as our recent investigation of Alpine for contravening its quality standard, see: https://comcom.govt.nz/case-register/case-register-entries/alpine-energy-limited.

[710] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 59.

[711] Such as Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 17.

[712] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), para 155.

Table L3 Information requirements following a contravention

Unplanned interruption standard
• Data of the unplanned interruptions. • Any independent reviews of the state of the network or operational practices conducted in the three years prior to the contravention. • Any investigations into significant individual interruptions (that occurred during the contravening period) or causes of the contravention. • Any analysis of trends in asset condition conducted in the three years prior to the contravention. • Any analysis of interruption causes conducted in the three years prior to the contravention. • Any analysis, conducted in the three years prior to the contravention, of the sufficiency of asset replacement and renewal. • Any analysis, conducted in the three years prior to the contravention, of the sufficiency of vegetation management. • Outline of any relevant analysis or investigation that would meet the categories above and is planned but not yet completed.
Extreme event standard
• A description of the causes of the interruption event. • Data on the interruptions during the major interruption event. • Any existing independent reviews of the state of the network or operational practices completed in the two years preceding the interruption event. • Any analysis of trends in asset condition for assets relating to the interruption event. • Any investigation, analysis, or post-event review of the major interruption event. • Any analysis of the sufficiency of asset replacement and renewal for assets relating to the interruption event. • Outline of any relevant analysis or investigation that would meet the categories above and is planned but not yet completed.
Planned interruption standard
• Data of the planned interruptions during the contravening regulatory period and the prior regulatory period. • Any strategy for managing planned interruptions that was in place during the regulatory period. • Any analysis or investigation of planned interruptions that was undertaken during the regulatory period. • Outline of any relevant analysis or investigation that would meet the categories above and is planned but not yet completed.

L87 To ensure a timely production of this information, we are introducing this as a standing reporting requirement with respect to any quality contravention over the regulatory period. This approach will ensure:

L87.1 timely production of information, without requiring additional resources and processes for the Commission;

L87.2 consistency in the information required from distributors;

L87.3 signal to distributors of the types of activities and analysis we expect; and

L87.4 the information will be public, unless considered commercially sensitive or confidential.

L88 The information will be required to be provided in the same timeframe as the annual compliance statement.

L89 The cost to distributors of this standing request for additional information is negligible given it is information that we would usually request anyway.

L90 There was general support in submissions from distributors for our proposal to introduce automatic reporting requirements for distributors that contravene their quality standards. For example, Orion said the following:

> When EDBs contravene limits we think it appropriate and helpful to EDBs and the Commission's investigation process for a quality report with predetermined requirements as described in the Issues Paper.[713]

L91 The proposal also received support from electricity retailers, such as Meridian, who "strongly support additional reporting requirements".[714]

[713] Orion "Submission on EDB DDP3 Reset " (20 December 2018), para 54.

[714] Meridian Energy "2020-2025 Distribution default price-quality path – Issues paper" (20 December 2018), p. 4.

Attachment M Reliability incentives

Purpose of this attachment

M1 As discussed in Attachment J, the revenue-linked incentive scheme for reliability is designed to provide distributors with incentives to consider cost-quality trade-offs in their decision making. In the absence of other adequate incentives, distributors may be incentivised to reduce expenditure, at the expense of quality, to increase profitability.

M2 This attachment sets out our detailed decisions on setting the revenue-linked quality incentives for EDB DPP3 and responds to submissions regarding incentives we received in response to our issues paper and Draft Decisions.

Summary of our final decision

M3 Our decisions on setting the revenue-linked quality incentives for EDB DPP3 are summarised below:

M3.1 revenue-linked incentives to apply to unplanned and planned SAIDI only, SAIFI is excluded (unchanged from draft decision);

M3.2 unplanned incentive rates are informed by the value of lost load (VoLL), discounted by 76.5% to reflect expenditure incentives, and a further 10% to reflect quality standard incentives (updated from draft decision);

M3.3 planned incentive rates are reduced by 50% relative to the unplanned incentive rate to reflect less inconvenience to consumers (unchanged from draft decision);

M3.4 incentives are introduced to encourage additional notification of planned ("notified") interruptions by further discounting the planned incentive rates by 50% (modified from draft decision);

M3.5 incentives are revenue-neutral at the average of the reference period, also known as the target (unchanged from draft decision);

M3.6 the SAIDI caps (maximum losses) are set equal to the SAIDI limit, namely:

M3.6.1 2.0 standards deviations above the normalised reference period annual average for unplanned SAIDI (updated from draft decision); and

M3.6.2 triple the reference period annual average for planned SAIDI (unchanged from draft decision);

M3.7 the SAIDI collars (maximum gains) are set at zero for unplanned and planned SAIDI (unchanged from draft decision); and

M3.8 revenue at risk is set endogenously based on the above decisions, but subject to a cap of 2% of the allowed net revenue for the assessment year over planned and unplanned SAIDI (unchanged from draft decision).

M4 Illustrative examples of our decisions for the reliability revenue-linked incentive scheme are shown in Figure M1 for unplanned SAIDI and Figure M2 for planned SAIDI.

Figure M1 Unplanned SAIDI incentive

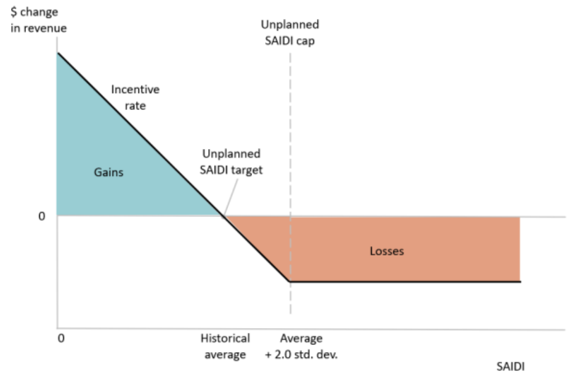
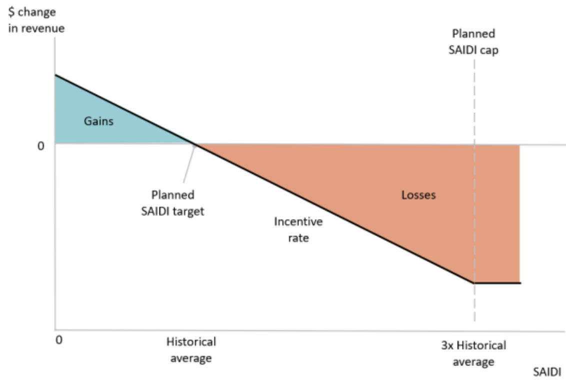


Figure M2 Planned SAIDI incentive



Revenue-linked incentives apply to planned and unplanned SAIDI

M5 Our final decision is that revenue-linked quality incentives will apply only to unplanned and planned SAIDI. The removal of SAIFI from the incentive scheme is informed by:

M5.1 SAIFI and CAIDI, both important reliability metrics, are implicitly captured in the SAIDI incentives;

M5.2 SAIFI is also subject to a quality standard which will ensure distributors appropriately manage the frequency of interruptions; and

M5.3 SAIFI incentives may place undue priority on short-term mitigations rather than preventing long-term deterioration.

Consideration of SAIDI and SAIFI

M6 We are concerned that retaining equal weighting on SAIDI and SAIFI has been duplicating the impact of the frequency of interruptions. This is because interruption duration (SAIDI) is a function of interruption frequency (SAIFI) and interruption length (CAIDI).[715] We therefore consider that reducing or removing SAIFI from incentives is appropriate.[716]

M7 We noted in our Draft Reason Paper that in 2018, the Australian Energy Regulator (AER) increased the weighting of SAIDI to 60% and decreased the weighting of SAIFI to 40% from previously distributing the incentives equally.[717] The AER considered that an equal weighting of SAIDI and SAIFI was not well balanced and considered that:

M7.1 distributors were reacting to SAIFI incentives much more than the SAIDI incentives, resulting in a longer average duration of interruptions (also known as CAIDI); and

M7.2 customers furthest from the feeders may be more disadvantaged by an incentive scheme that excessively rewards reducing short interruptions (via SAIFI) due to the time it takes for staff to respond.

M8 Ofgem also had a lower effective weighting of 27% for SAIFI, with 73% for SAIDI.[718] S&C Electric, submitting on the service target performance incentive scheme in Australia, noted that Ofgem's incentive balance has still seen improvements in both frequency and duration of interruptions.[719]

M9 Our analysis suggests that New Zealand is consistent with the experience of Australian electricity distributors. As shown in Figure M3, most distributors performed significantly better relative to the targets for SAIFI than for SAIDI.

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[715] Specifically, SAIDI is the product of SAIFI and CAIDI.

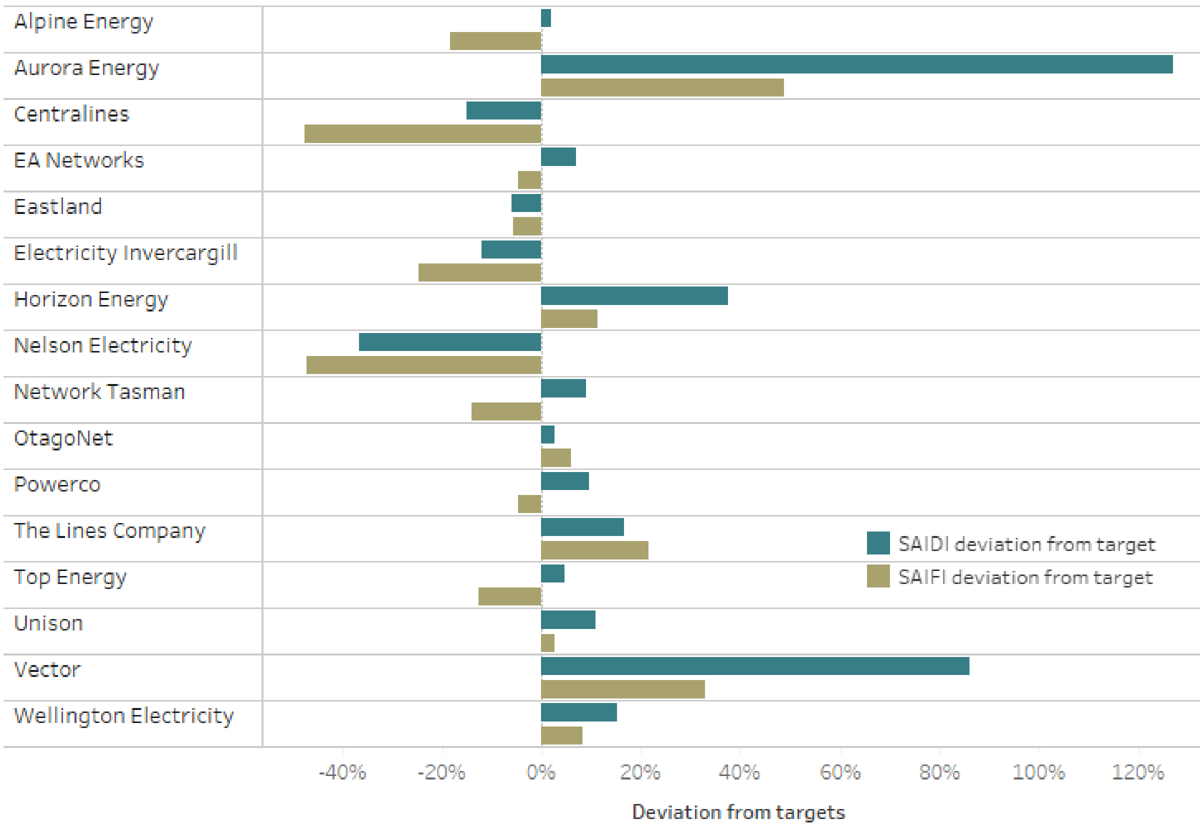
[716] We note that the VoLL also includes an element of the VoAO.

[717] Australian Energy Regulator "Amendment to the Service Target Performance Incentive Scheme (STPIS): Final decision" (November 2018), p. 9.

[718] Ofgem allocated 37 return of regulatory equity (RORE) basis points for the number of customers interrupted per 100 customers (CI) and 102 RORE basis points for the number of customer minutes lost (CML). We note these frequency and duration metrics are functionally the same as the SAIFI and SAIDI metrics we use. Ofgem "Electricity Distribution Price Control Review Final Proposals - Incentives and Obligations" (7 December 2009), p. 85.

[719] Australian Energy Regulator "Amendment to the Service Target Performance Incentive Scheme (STPIS): Final decision" (November 2018), p. 38.

Figure M3 Average deviation from reliability targets, 2015/16 to 2018/19



M10 Orion, Unison, and Aurora expressed support for excluding SAIFI from the incentive scheme. However, Aurora suggested that the removal of SAIFI should be extended to quality standards noting that:

> Increased SAIFI is frequently the price that is paid for actions taken to mitigate SAIDI. The key issue with SAIFI as a compliance measure, is that it drives a poor outcome for consumers, as distributors try to find an almost unachievable balance between interruption duration and frequency.[720]

M11 While acknowledging the overlap of SAIDI and SAIFI, Vector disagree with the removal of SAIFI altogether and consider a de-weighting would be more appropriate. Vector reiterated its issues paper submission that:

> … SAIFI – is a more direct measure of asset performance and material deterioration than SAIDI, which focuses on duration and is conflated by response times and outage frequency. Failing assets lead to interruptions. Slower responses lead to greater duration.[721]

M12 Further Vector state that:

[720] Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 18.

[721] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 62.

> … by narrowing the scope of the quality incentive the Commission – in the unique way proposed – is implicitly signalling that other service outcomes do not matter, or at least should not be a focus for EDBs.[722]

M13 We reiterate that we consider performance of SAIFI is important to consumers, and as such remains a part of the quality standard.[723] However, to the extent a distributor reduces the frequency of interruption events to its consumers this will generally reduce SAIDI. We also agree with Aurora that, assuming SAIFI is appropriately recorded for each interruption, incentives on SAIFI may inadvertently discourage distributors to partake in staged restorations which would likely not be in consumers interest.

Consideration of CAIDI

M14 To the extent that longer interruptions are less desirable from a consumer perspective, we considered whether a CAIDI incentive could be introduced. This would incentivise distributors to reduce the average length of interruptions experienced by consumers. However, we consider that there may be perverse outcomes of the CAIDI incentive. For example:

M14.1 a deterioration in both SAIDI and SAIFI can lead to an “improvement” in CAIDI if SAIFI deteriorates more than SAIDI; and conversely

M14.2 an improvement in both SAIDI and SAIFI can lead to an “deterioration” in CAIDI if SAIFI improves more than SAIDI.

M15 At worst, the introduction of a CAIDI incentive may give distributors scope for increasing the number of short interruptions to improve observed CAIDI. At best, it may disincentivise reducing the number of short interruptions.

M16 CAIDI incentives may be considered in conjunction with SAIDI and/or SAIFI incentives. However, we consider this adds greater complexity than it is worth at this stage. As noted above, SAIDI incentives naturally incentivise reductions in the number (SAIFI) and length (CAIDI) of interruptions.

M17 CAIDI remains useful as an analytical metric to assess performance, as it can act as an ‘early warning’ indicator of distributors with underlying declines in performance, as it points to lower levels of network performance, even where temporary measures (like reclosers) are masking this decline in the short-term.

[722] Vector “Submission on EDB DPP reset draft decisions paper” (18 July 2019), p. 63.

[723] As discussed in Attachment L.

Setting the incentive rates

M18 The incentive rates determine the level of financial exposure of distributors to a marginal change in reliability. For DPP2 this was set endogenously based on the revenue at risk and the applicable caps and collars. However, for our DPP3 decision we have explicitly set the incentive rates.

M19 For the final decision, we have set SAIDI incentive rates that are informed by a VoLL of $25,000 per megawatt hour (MWh) and discounted to reflect expenditure incentives and quality standard incentives.

Reason for change from DPP2

M20 We have made a change from DPP2, where revenue at risk was set explicitly and incentive rates were derived from that, to one where the incentive rates are based on VoLL. We have implemented relatively conservative incentives compared to those set in Australia and UK distributors (see paragraph M31 below).

M21 Setting conservative incentives will avoid the possibility that we are over-incentivising quality improvements beyond what consumers are willing to pay for reliability, especially with quality standards providing some security against under-investment. By setting a conservative incentive scheme we intend to encourage distributors to pick off the 'low hanging quality fruit' (low-cost, high impact solutions that they might otherwise not be incentivised to implement), without incentivising less cost-effective solutions which consumers may not demand.

M22 In the revenue-linked incentive scheme under DPP2, the revenue at risk and caps and collars were set explicitly, and the incentive rates were derived from this. We considered this approach appropriate, as the revenue-linked quality incentive scheme was being introduced for the first time in DPP2. However, that approach led to very different incentive rates for each distributor, with no link to consumer preferences.

M23 While we tested that SAIDI incentive rates did not exceed VoLL (by too much), we note that the incentive scheme also included SAIFI and did not account for expenditure incentives.

M24 Consequently, for more reliable distributors, the narrower bands between caps and collars may have created incentives beyond that which consumers value. Conversely, less reliable distributors with wider bands had much weaker incentives.[724] Figure M4 shows an illustrative example of how variable the incentive rate can be (as indicated by the slope of the diagonal line).

Figure M4 Illustration of incentive rate variance

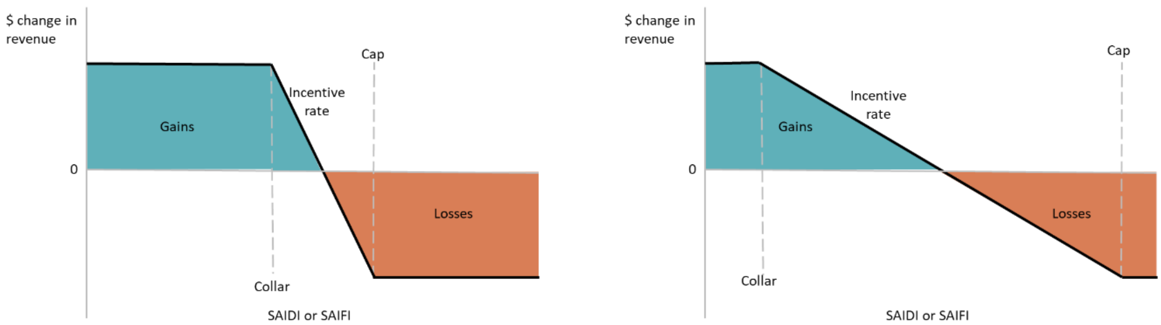


Table M1 DPP2 SAIDI incentive rates

Distributor	Incentive rate ($/SAIDI)	Incentive rate per customer	Implied VoLL ($/MWh)
Alpine Energy	7,134	0.22	4,788
Aurora Energy	31,741	0.36	12,758
Centralines	2,462	0.29	12,158
EA Networks	9,080	0.47	8,901
Eastland Network	3,560	0.14	6,730
Electricity Invercargill	9,620	0.55	19,991
Horizon Energy	4,285	0.17	4,198
Nelson Electricity	5,664	0.61	21,127
Network Tasman	8,100	0.20	6,842
Orion NZ	-	-	-
OtagoNet	4,084	0.25	4,977
Powerco	57,526	0.17	6,349
The Lines Company	6,830	0.29	9,436
Top Energy	2,107	0.07	3,394
Unison Networks	45,378	0.40	14,824
Vector Lines	242,885	0.44	15,195
Wellington Electricity	95,091	0.57	21,658

[724] This is because more reliable distributors typically have less volatility in their SAIDI and SAIFI metrics, meaning a smaller and 'cap' and 'collar' range due to a lower standard deviation. Likewise, less reliable distributors typically have more volatility in its SAIDI and SAIFI metrics, meaning a bigger and 'cap' and 'collar' range due to a higher standard deviation.

M25 Table M1 shows the incentive rates for SAIDI for each distributor in DPP2 and the implied VoLL. For example, Nelson Electricity and Wellington Electricity were exposed to five times more incentive per customer than Top Energy and Horizon Energy. We consider that higher incentive rates for the most reliable distributors is counterintuitive and we did not consider this is appropriate to carry forward into DPP3.

Using VoLL to set incentive rates

M26 The decision to base SAIDI incentives rates is informed by a VoLL of $25,000 per megawatt hour (MWh).[725] However, as discussed below, we discount this by:

M26.1 76.5% to reflect the 23.5% retention factor for expenditure incentives under IRIS; and a further

M26.2 10% to reflect incentives associated with the quality standard giving an adjusted VoLL of $5,288 for each distributor.

M27 To derive the SAIDI incentive rate for each distributor, we have multiplied the adjusted VoLL by the typical electricity consumption per minute on the network over the last three years.

M28 The average strength of the SAIDI incentives across affected distributors, as compared between Table M1 above and Table M2 below, has decreased from $0.33 per customer per SAIDI minute in DPP2 to $0.17 per customer per SAIDI minute for DPP3. The range of SAIDI incentive rates has also narrowed, with the difference attributable to differences in average electricity consumption per customer, rather than the cap and collar settings.

[725] VoLL is an estimate of the economic value, in dollars per MWh, that a consumer places on electricity they plan to consume but do not receive because of an interruption. PwC, on behalf of Transpower, has estimated VoLL to be centred at around $25,000. For more information, see Transpower's VoLL study, available at: https://www.transpower.co.nz/sites/default/files/publications/resources/Value%20of%20Lost%20Load%20%28VoLL%29%20Study%20-%20June%202018.pdf.

Table M2 DPP3 SAIDI incentive rates

Distributor	Incentive rate ($/SAIDI)	Incentive rate per customer	Implied VoLL ($/MWh)
Alpine Energy	7,879	0.24	5,288
Aurora Energy	13,155	0.15	5,288
Centralines	1,071	0.13	5,288
EA Networks	5,394	0.28	5,288
Eastland Network	2,797	0.11	5,288
Electricity Invercargill	2,544	0.15	5,288
Horizon Energy	5,397	0.22	5,288
Nelson Electricity	1,417	0.15	5,288
Network Tasman	6,260	0.16	5,288
Orion NZ	31,686	0.16	5,288
OtagoNet	4,339	0.27	5,288
Powerco	47,908	0.14	5,288
The Lines Company	3,827	0.16	5,288
Top Energy	3,283	0.10	5,288
Unison Networks	16,185	0.14	5,288
Vector Lines	84,519	0.15	5,288
Wellington Electricity	23,215	0.14	5,288

M29 Furthermore, consumers were also exposed to SAIFI incentives which effectively doubled the incentives available to distributors, and consumers are also exposed to any overspends via the expenditure incentives under the IRIS incentive mechanism. To illustrate this point further, with an expenditure incentive rate of 23.5%:

M29.1 Nelson Electricity could spend $10,000 opex to improve reliability, and only be exposed to $2,350 of that spend via expenditure incentives. For a one-minute improvement in SAIDI Nelson Electricity would receive $5,664 in quality incentive payments.

M29.2 However, for its consumers, they would bear $7,650 of the increased cost net of the expenditure incentive *plus* $5,664 in quality incentives. They would pay a total of $13,314 for a one-minute improvement in SAIDI, or $1.45 per customer. Assuming a VoLL of $25,000, the consumer would only value that SAIDI minute at $0.75, a loss for them.

M30 For DPP3 we have explicitly set incentive rates that are better aligned with consumer preferences using VoLL. Given the aggregate nature of SAIDI, and the aggregate nature of the revenue cap, we consider an aggregated VoLL an appropriate starting point for capturing consumer preferences within the incentive rate.

M31 We note that a starting VoLL of $25,000 per MWh is conservative relative to the measures used by the AER and Ofgem:

M31.1 The AER uses a value of customer reliability of $37,000 (~NZ$40,000);[726] and

M31.2 Ofgem uses a rate of around £16,000 (~NZ$32,000).[727]

M32 To ensure that consumers are not overpaying for quality driven expenditure, we factor in the expenditure incentives that consumers are also sharing. Taking account of expenditure incentives, we scale back the VoLL, or incentives rates, to (1 – the retention factor) or 23.5% of VoLL for DPP3.[728] Put another way, under the IRIS, distributors keep the value of improvements in efficiency for five years before sharing them with consumers. Under our recommended approach, distributors will keep the value of quality improvements or declines (VoLL) at least until the end of the regulatory period.

M33 We also include a further reduction of 10% to the incentive rate to recognise that there are natural incentives associated with meeting the quality standard (a change from 20% in the draft). We consider this further de-weighting is appropriate as to mitigate the risk of over-incentivising investment to improve reliability beyond that which consumers demand.

M34 These reductions result in an implied VoLL of $5,288 per megawatt hour which is used as a basis for setting incentive rates, as outlined in Table M2, which reproduces Table M1 for DPP3.[729] We note the variability in the SAIDI incentive rates per customer is due to the differences in observed annual consumption per customer between distributors.

M35 The option of explicitly setting the incentive rates and setting either the revenue at risk or the caps and collars endogenously was first raised in the issues paper. Submitters to the issues paper had mixed views on this approach, however some changed their stance after viewing our draft decision.

[726] Australian Energy Regulator "Amendment to the Service Target Performance Incentive Scheme (STPIS): Final decision" (November 2018), p. 9.

[727] Ofgem "Strategy consultation for the RIIO-ED1 electricity distribution price control: Reliability and Safety" (28 September 2012), para 4.12.

[728] Attachment E discusses the IRIS incentive rates.

[729] The implied VoLL for implementing the incentive rate is $25,000 x 23.5% x (1 - 10%) = $5,288 per MWh.

M36 NZIER, on behalf of MEUG, noted that for DPP2:[730]

> … the wide difference in historical performance of EDB leads to a wide variation in quality standards and the range over which the incentive for individual EDB. Accordingly, the implied average cost to customers of achieving improved reliability varies widely across EDB … there is a potential mis-match between the cost to customers of incentive driven changes in reliability and the value customers attach to the change in reliability.

M37 NZIER went on to express conditional support for using VoLL as an input in setting the incentive rate, stating that:[731]

> … subject to consultation on how VoLL would be estimated … an incentive based on the VoLL is more likely to ensure the incentive reflects the benefit of improved reliability to consumers than a uniform percentage of maximum allowable revenue.

M38 The Lines Company agree in principle "that linking the incentive rate to VoLL provides a more transparent methodology", subject to further detail.[732] Unison and Aurora also agreed with explicitly setting the incentive rates for consistency of incentives between distributor, although noting the VoLL is a highly averaged measure.[733]

M39 Wellington Electricity supported using incentive rates that reflect consumer preferences in its submission to the issues paper. However, it expressed reservations as to whether using a national aggregate VoLL was appropriate given the different customer bases of distributors.[734] It considered the incentive rate derived from the draft methodology for Wellington Electricity too low to incentivise improved quality. Consequently, it recommended reverting to the DPP2 method whereby the revenue exposure is explicitly set.[735]

M40 We refer Wellington Electricity to its issues paper submission which we agree with stating that:

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[730] Major Electricity Users' Group "NZIER on behalf of MEUG EDB DPP reset issues paper" (21 December 2018), p. 7.

[731] Major Electricity Users' Group "NZIER on behalf of MEUG EDB DPP reset issues paper" (21 December 2018), p. 10.

[732] The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), p. 8.

[733] Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13; and Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 19.

[734] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 17.

[735] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23.

> … it [is] more appropriate to set the incentive rate at a level which encourages a reasonable level of investment to support the level of quality that customers want. The incentive rate should not be too high to encourage overinvestment, or too low so that under-investment results in asset deterioration.[736]

M41 As discussed above, we consider that the incentive rates, in combination with expenditure incentives, resulted in the potential for Wellington Electricity to spend on quality improvements far in excess of that which consumers would be willing to pay.

M42 Given the information available, we consider that consistent incentive rates based on VoLL and discounted for IRIS are sound. Furthermore, we consider that recognition of incentives associated with not contravening the quality standard should be factored in. We also note we have reduced the discount for quality standards from 20% to 10% given we have increased the buffer for unplanned interruptions from 1.5 standard deviations to 2.0 standard deviations, thereby weakening the probability of a contravention.[737] However, this is largely offset by the decrease in the IRIS retention factor to 23.5%.[738]

De-weighted incentives for planned interruptions

M43 Consistent with DPP2, we have de-weighted all planned interruptions by 50% relative to unplanned interruptions. We consider de-weighting planned interruptions are appropriate as they are less inconvenient for consumers because, as long as customers are notified, they can plan accordingly. As noted in Attachment L, planned interruptions are also generally required by the distributor to perform maintenance and investment that benefits consumers in the long run.

M44 Vector suggested planned interruptions should be excluded from any revenue-linked incentive scheme noting that:

> … the Australian Energy Regulator (AER) for its Service Target Performance Incentive Scheme (STPIS). Under STPIS, only unplanned interruptions are taken into account for the reliability of supply component.[739]

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[736] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 17.

[737] See Attachment L

[738] See Attachment E

[739] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), p. 35.

M45 We do not consider removing planned interruptions appropriate. While it is less inconvenient for consumers, it is not without inconvenience. We consider it is important that distributors are incentivised to undertake its planned interruptions efficiently and consumers are compensated accordingly. Furthermore, our decision to relax the standards associated with planned interruptions is on the assumption that revenue-linked incentives are the appropriate avenue to encourage distributors to manage its planned interruptions appropriately.

M46 This 50% reduction in weighting for planned interruptions was broadly supported by distributors.[740] For example, ENA stated that:

> A further 50% discount is applied to the incentive rates for planned interruptions to reflect the lower levels of disruption for customers from planned outages.

Incentives for notification of planned interruptions

M47 As noted above, planned interruptions are generally less inconvenient for consumers. However, the current definition of a planned interruption only requires 24-hours' notice to be provided to consumers.

M48 To incentivise better notification to consumers of planned interruptions, we have strengthened distributors' incentives to give greater notification of planned interruptions. This is achieved by reducing the revenue impact of the planned SAIDI incentive by a further 50%.

M49 To qualify for the more beneficial incentive rate the planned interruption must:

M49.1 be opted in by specifying in the notice that the planned interruption is a 'notified interruption' and be recorded as a 'notified interruption' in the distributors' internal systems;

M49.2 be notified to relevant parties within a certain time period in advance of the interruption, specifically:

M49.2.1 all consumers directly impacted by the interruption must be notified at least four working days in advance of a planned interruption (unchanged from draft); or

M49.2.2 retailers must be notified at least ten working days in advance of a planned interruption (modified from draft); and

[740] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 36; and Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 19-20.

M49.2.3 any consumer directly billed by the distributor and impacted by the planned interruption must be notified at least ten working days' in advance of a planned interruption (modified from draft);

M49.3 specify the expected start time, the expected completion time, the reason for the planned interruption, and any alternate day if applicable (added since draft); and

M49.4 be accessible on the distributor's website or via other online means, along with instructions on the notification for accessing updates to the interruption (changed from draft).

M50 Once a distributor has opted in a planned interruption as a 'notified interruption':

M50.1 only the portion of the notified interruption that occurs within the specified notification window can qualify for the reduced incentive rate (modified from draft);

M50.2 the notified interruption is still counted for the purposes of assessing incentives even if that interruption does not eventuate unless it is:

M50.2.1 deferred to an alternate day as specified in the notification provide the update is made accessible on its website in advance of the notification window commencing; or

M50.2.2 cancelled provided affected consumers are informed at least 24 hours prior to the expected start time, (modified from draft); and

M50.3 the notified interruption is recorded as the length of the actual interruption or the length of the notification window less two hours, whichever is greatest.

M51 As noted in Attachment N, communication with consumers of planned interruptions was identified as being important in the Powerco application for a CPP. According to the consumer survey for Powerco, undertaken by PwC and Colmar Brunton, more than 90% of respondents reported that communication about planned power cuts was important.

M52 There was general support in submissions to our issues paper for considering additional dimensions of quality beyond reliability, including notification of planned interruptions. However, as Attachment N states, the lack of reliable data and robust information on the new measures would increase the risk of setting parameters for an incentive scheme (and standards) at an inappropriate level.

M53 Like other potential quality metrics, we consider the inclusion of an explicit standard or incentive for notification of planned interruptions may be considered for future DPPs once sufficient information is available to set a baseline. However, we acknowledge that notification of planned interruptions is important to mitigate the impact of the interruption and that our current definition of a planned interruption does not adequately reflect this. Currently, a planned interruption is any interruption where at least 24 hours' notice has been provided.

M54 For this reason, we have specified minimum notification requirements to qualify for a further lowering of the implied negative incentive for the interruption. This would be on top of the 50% deduction for planned interruptions relative to unplanned interruptions already in place.

M55 As noted above, we have a lack of information to inform the baseline. We consider using the planned dataset, without adjustment, to incentivise distributors to meet these requirements is appropriate. This does mean to the extent a distributor is already meeting the criteria it could be rewarded without changing its practices.

Nominating a notified interruption

M56 Many distributors, via submissions to the draft decision and the targeted quality workshop, queried whether they could opt in or out of the notification requirement.[741] Initially, we envisaged that the notification incentive would apply to every distributor subject to DPP3. However, in acknowledgement of the potential difficulty of recording and auditing all planned interruptions to ascertain whether it meets the notification criteria, we have allowed a process for distributors to explicitly opt in or out of the notification incentive for each planned interruption.

M57 To qualify for the notification incentive, it must state on the notice of planned interruption to retailers or consumers that the specified interruption is a 'notified interruption' and is recorded as such in its internal systems.

M58 Given that this is a new concept for DPP3, we consider it appropriate to provide some discretion to distributors as to whether it wishes to partake in this incentive, and the level to which they do so. Due to the asymmetric nature of the notification incentive in the distributors favour, and the adjustments made since the draft decision, we would expect distributors to trial it where it is economic to do so.

[741] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 9; Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019) , p. 11; Commerce Commission "Notes on EDB DPP3 Workshop on Quality of service held 16 August 2019" (25 September 2019).

Notice requirements

M59 We have extended the notice required to retailers and directly billed consumers to ten working days. Alternatively, distributors may advise all customers not directly billed with at least four working days' notice rather than the retailer.[742]

M60 In response to submissions, we are allowing distributors to specify one alternate day in which the notified interruption can occur, with the expectation it would only be used when adverse conditions prevent planned works happening on the specified day.

M61 In response to submissions, we will allow distributors to cancel or amend the notified interruption provided customers are given at least 24 hours' notice and a reason is provided. Any change in date must also meet notice period outlined above in M49. For example, Orion noted that the draft:

> … notification prescriptive requirements reduce EDB flexibility around notifications that may meet customer needs. This is important because we often alter interruption days and timeframes to work in with customer feedback. While this might not align with the definition provided, appropriate notification has been provided, it suits the customer and meets their expectations.[743]

M62 All notified interruptions must be easily accessible via the distributor's website or via other online means, for example, phone applications, or social media. As standard practice, we expect that the notification will advise affected consumers where up-to-date information on the notified interruption can be located online (for example, cancellations or changes).

Notification window

M63 In the draft decision we had specified four hours as the maximum length of a notification. Many distributors submitted that this was not sufficient suggesting that only around half of planned interruptions are completed within four hours.[744] Analysis of planned interruptions during the reference period confirms that around half of all planned interruptions extend beyond four hours.

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[742] This is in line with the service interruption communication requirements outlined in Schedule 5 of the Draft Default Distribution Agreement. Refer to Electricity Authority "Default Distribution Agreement Template – Version: 22 August 2018" (14 January 2019), pp. 63-64.

[743] Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 9.

[744] Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 10-11; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 26; Orion "Submission on EDB DPP reset draft decisions paper" (17 July 2019), p. 15; Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10; Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 22; Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 27; and Commerce Commission "Notes on EDB DPP3 Workshop on Quality of service held 16 August 2019" (25 September 2019).

M64 We consider that providing consumers with an excessively wide window in which to undertake planned works is not particularly helpful to consumers, for example, a one-week window to replace an insulator or crossarm. However, we recognise that the scale of planned works can vary considerably and therefore we have not specified a maximum length.

M65 We will allow distributors as long as they consider necessary to complete the planned works. However, to mitigate against excessively long windows we use the window length as a criterion for assessing the incentive, as discussed in more detail below.

M66 If an interruption extends beyond the specified window then the distributor may still consider the SAIDI of the interruption duration within the window as a notified interruption, with the associated incentive. This will ensure that the distributor is not unduly penalised for not completing the planned works within the allocated window.

Counting notified interruptions that do not occur

M67 We also consider that interruptions that have been notified but do not eventuate can also be an inconvenience to consumers, especially for vulnerable consumers who may need to make alternative accommodation arrangements, or for commercial consumers who may need to arrange for alternative supply or to close.

M68 To that end we consider it appropriate to penalise distributors to some extent if a notified interruption does not proceed and adequate cancellation notice is not provided to consumers. This should also mitigate any risk of 'over-notification' of interruptions.

M69 Distributors disagreed with counting SAIDI for those interruptions which were adequately notified but did not eventuate. Powerco directly addressed our concern that distributors may be incentivised to notify excessively stating that it considers "distributors already have natural incentives to mitigate this risk e.g. limiting consumer complaints and maintaining consumer trust" and that an ID first approach would be more appropriate.[745]

[745] Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 13.

M70 Distributors have provided several examples of where a notified interruption may need to be cancelled or deferred.[746] For example:

M70.1 responding to or preparing for unplanned interruptions;

M70.2 finding a better way to deal with the issue;

M70.3 health and safety considerations;

M70.4 adverse weather or environment;

M70.5 customer requests to defer interruptions; and

M70.6 staff shortages due to illness.

M71 ENA and Unison noted that planned interruptions that do not eventuate are not included in the reference period dataset that is used as a base to set the planned SAIDI incentive target.[747] Consequently, they considered that distributors would bear penalties to the extent that notified interruptions do not occur.

M72 We consider that this is outweighed by the half weighting of notified interruptions relative to planned interruptions without notification which is also excluded from the reference data. Furthermore, we have allowed distributors to specify alternate days and an avenue to cancel notified interruptions with at least 24-hours' notice.

Recording the 'notified' SAIDI

M73 While the notified incentive is largely a financial benefit for distributors that opt in, it is important that this is intended to be a consumer-facing incentive. For this reason, we consider it important that distributors can gain from this incentive to the extent it has meaningful benefits for consumers.

M74 For the purposes of measuring SAIDI for the incentive scheme, the length of a notified interruption that meets the criteria outlined above will be measured as the greater of the:

M74.1 actual length of the interruption within the notified window; and

M74.2 the length of the notification window less two hours.

[746] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 64-65; ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p.27; and Aurora "Submission on EDB DPP reset draft decisions paper" (18 July 2019), pp. 20-21.

[747] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 27.

M75 For example, if a notified interruption is specified as lasting eight hours but only lasts two hours, the length will be counted as six hours. For the avoidance of doubt, if a notified interruption does not occur the actual length is counted as zero hours.

M76 We consider that using the notification window, with some flexibility, as a criterion for measuring SAIDI will provide the distributor with an incentive to optimise the length of the window given the planned works to be undertaken. This should ensure that consumers are provided meaningful windows in which to plan to.

M77 For any planned interruption that does not meet the notification criteria, or partially falls outside of the notification window, it will be wholly or partially treated at the regular planned incentive rate, as specified in Table M4.

Setting the targets (revenue-neutral point)

M78 The reliability targets are the points at which no financial gains or losses are applicable to the revenue-linked incentive scheme. Our final decision sets incentives that are revenue-neutral at the average of the reference period (the target) for both planned and unplanned interruptions.[748]

M79 We consider an average of normalised SAIDI over the reference period an appropriate starting point for setting the revenue-neutral base. This is the point at which there is no observed deterioration or improvement in reliability relative to reference period.

M80 However, as discussed in Attachment J, we have limited the inter-regulatory period movement of targets between DPP2 and DPP3 to 5% for unplanned interruptions. We consider this necessary to ensure that recent performance, both good and bad, is not unduly captured.

M81 In the future we could consider setting a dynamic target above or below the historical average based on more informed views of consumer expectations. For example, we could set an improvement path over the regulatory period if that is what consumers want and are willing to pay for.

M82 We did not receive any submissions suggesting an alternative method for setting the targets. However, we note some distributors suggested a step change to reflect a change in operating policy relating to live line works, among others.[749]

M83 The unplanned and planned SAIDI targets are outlined in Table M3 and Table M4 respectively at the end of this chapter.

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[748] This approach is consistent with the 'ex ante expectation of a normal return, *provided quality standards are met'* economic principle discussed in Chapter 3.

[749] Discussed in Attachment J.

Setting the caps (maximum losses)

M84 The reliability caps are the points at which no further losses are applicable to the revenue-linked incentive scheme. Our final decision sets planned and unplanned SAIDI caps equal to the applicable limit for compliance standards, subject to maximum revenue exposure of 2%. These are set:

M84.1 2.0 standards deviations above the target for unplanned interruptions; and

M84.2 triple the target for planned interruptions.

M85 Once the upper bound of unplanned SAIDI (or the lower bound of reliability) applicable to the incentive scheme has been exceeded a compliance contravention will kick in.

M86 We consider that a cost-quality trade-off should always be in place up to the applicable reliability standard. We therefore do not consider a cap below the quality standard, or a 'dead-band', is necessary. To the extent that there is a lot of volatility in the metrics used to assess reliability this may be appropriate. However, with our recommended 'normalisation' methodology, more volatility has been removed from the assessment of SAIDI.

M87 We also did not consider setting incentives beyond the quality standards would be appropriate.

M88 Alpine Energy, Aurora Energy, and The Lines Company had submitted general support for widening the band between cap and target to two standard deviations.[750] It was noted this could complement an increase to the revenue at risk to 2% of allowable revenue each year.

M89 Eastland Network, Orion, and ENA expressed reservations for raising the cap beyond one standard deviation, considering that it:

M89.1 would increase price volatility;

M89.2 may allow material deterioration, assuming the quality standard is also increased beyond one standard deviation; and

[750] Alpine Energy "Submission on EDB DPP3 Issues paper" (20 December 2018), pp. 3-4; Aurora Energy "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018), p. 7; The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), p. 8.

M89.3 is inappropriate to widen the caps and collars to accommodate significant volatility within the metrics.[751]

M90 The unplanned and planned SAIDI caps are outlined in Table M3 and Table M4 respectively at the end of this chapter.

Setting the collars (maximum reward)

M91 The reliability collars are the points at which no further rewards are applicable to the revenue-linked incentive scheme. Our final decision sets planned and unplanned SAIDI collars at zero, subject to maximum revenue exposure of 2%. In other words, we have dropped the collars. This means that financial incentives for reliability will always apply below the SAIDI standards.

M92 As noted above, we consider the cost-quality trade-off should always be in place up to the applicable reliability standard as long as the incentive rate ensures that the benefit consumers get from incremental improvements in reliability are greater than the costs they are exposed to.

M93 We also note that as reliability improves we expect the marginal cost of further improvements will increase. Rational distributors will look for the least-cost improvements in reliability, and once exhausted opt for more expensive improvements until the cost-benefit trade-off is neutralised.

M94 We acknowledge that our recommended settings for caps and collars does create some asymmetry, as illustrated in Figure M1 and Figure M2 at the start of this Attachment. Specifically:

M94.1 for unplanned interruptions distributors generally have a wider range for gains than for losses, however, this asymmetry is somewhat countered by the potential penalties associated with contravening the unplanned SAIDI standard; and

M94.2 for planned interruptions distributors generally have three times the range for losses than for gains, however, this is the compromise made to allow distributors more flexibility to do more planned interruptions without contravening the standard.

[751] Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 4 Orion "Submission on EDB DDP3 Reset " (20 December 2018), p. 13; ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), pp. 16-17.

M95 Much of the asymmetry between the caps and collars of the incentive scheme are more theoretical than realistic—for example, at the extreme, zero unplanned interruptions or three times the average planned SAIDI are not outcomes that would typically be expected.

M96 We note that there were no objections from submitters to the draft decision in setting the collar at zero SAIDI minutes.

Limiting the revenue exposure

M97 Given our decision to explicitly set SAIDI incentive rates and the SAIDI bounds for which incentives apply, the revenue exposure to the revenue-linked incentive scheme is set endogenously. Consequently, the resulting revenue at risk for some distributors may be considered excessive. We consider that a cap on the total revenue exposure appropriate to limit price volatility for consumers.

M98 For the final decision the revenue exposure is set endogenously based on the incentive rates, caps, and collars, but subject to a cap of 2%.

M99 In DPP2 the revenue exposure was explicitly set at 1% (0.5% each for SAIDI and SAIFI) which was considered a conservative starting point for implementing a revenue-linked incentive scheme.

M100 However, as noted previously, a consequence of fixing the revenue at risk along with the caps and collar was significant variability in the relative incentives among distributors. More reliable distributors generally had much higher derived incentive rates than less reliable distributors which seems counter-productive. If anything, we would consider consumers experiencing worse reliability would be more willing to pay for improved reliability.

M101 For this reason, we have explicitly set the incentive rates rather than the revenue at risk. Consequently, the revenue exposure will vary between distributors. Less reliable distributors will generally be exposed to a higher revenue at risk than more reliable distributors.[752] However, we consider it appropriate the least reliable distributors are subject to more revenue exposure than the most reliable distributors.

[752] Strictly speaking, it is the absolute range between caps and collars that determine the revenue exposure. However, this is closely correlated with the observed level of reliability.

M102 Notwithstanding that, to protect consumers and distributors against potential large inter-year revenue volatility, we consider a cap on the total revenue at risk of ±2% of allowable revenue in any given year appropriate.[753]

M103 Some submitters expressed concern that increasing the revenue at risk to 2% would create price volatility.[754] We note that this 2% cap can come into effect for only some distributors and serves as guard against large price shocks. It is not expected to be a frequent occurrence. Furthermore, distributors may voluntarily 'bank' revenue, up to 10%, to manage price shocks on consumers.[755]

M104 Table M5 shows the maximum gains or losses each distributor would face as a percentage of its (estimated) allowable revenue. While some values appear high, it is important to note that:

M104.1 the realisation of the maximum unplanned reward would require the distributor to not have any interruptions during the assessment year; and

M104.2 the realisation of the maximum planned penalty would require the distributor to triple its historic planned SAIDI during the assessment year.

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753 Without a limit on the revenue at risk, we estimate the highest possible revenue impact would be 3.84% of allowed revenue.

754 ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 36; Eastland Network "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 10; and Unison "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 28.

755 The mechanics of the revenue cap, including distributor's ability to bank revenue and our reasons for limiting this ability are discussed in Attachment H.

Table M3 Unplanned incentive parameters

Distributor	Unplanned SAIDI collar	Unplanned SAIDI target	Unplanned SAIDI cap	Incentive rate per SAIDI
Alpine Energy	0.00	91.88	124.71	7,879
Aurora Energy	0.00	63.44	81.89	13,155
Centralines	0.00	62.83	83.61	1,071
EA Networks	0.00	71.65	91.98	5,394
Eastland Network	0.00	173.85	219.46	2,797
Electricity Invercargill	0.00	15.39	25.86	2,544
Horizon Energy	0.00	144.35	194.53	5,397
Nelson Electricity	0.00	9.53	19.60	1,417
Network Tasman	0.00	74.49	101.03	6,260
Orion NZ	0.00	66.47	84.71	31,686
OtagoNet	0.00	120.02	160.35	4,339
Powerco	0.00	151.96	180.25	47,908
The Lines Company	0.00	143.04	181.48	3,827
Top Energy	0.00	302.16	380.24	3,283
Unison Networks	0.00	67.81	82.34	16,185
Vector Lines	0.00	89.28	104.83	84,519
Wellington Electricity	0.00	31.20	39.81	23,215

Table M4 Planned incentive parameters

Distributor	Planned SAIDI collar	Planned SAIDI target	Planned SAIDI cap	Incentive rate per SAIDI
Alpine Energy	0.00	54.99	164.97	3,940
Aurora Energy	0.00	65.32	195.96	6,578
Centralines	0.00	70.96	212.89	535
EA Networks	0.00	91.74	275.22	2,697
Eastland Network	0.00	86.05	258.14	1,399
Electricity Invercargill	0.00	7.63	22.90	1,272
Horizon Energy	0.00	57.24	171.73	2,698
Nelson Electricity	0.00	12.01	36.02	709
Network Tasman	0.00	75.28	225.83	3,130
Orion NZ	0.00	13.23	39.68	15,843
OtagoNet	0.00	140.96	422.89	2,169
Powerco	0.00	51.50	154.50	23,954
The Lines Company	0.00	88.78	266.34	1,914
Top Energy	0.00	127.02	381.07	1,641
Unison Networks	0.00	41.72	125.16	8,093
Vector Lines	0.00	39.03	117.08	42,260
Wellington Electricity	0.00	4.65	13.94	11,607

Table M5 Implied maximum revenue at risk

Distributor	Maximum penalty			Maximum reward		
	Unplanned	Planned	Total	Unplanned	Planned	Total
Alpine Energy	0.58%	0.98%	1.56%	1.63%	0.49%	2.00%
Aurora Energy	0.27%	0.95%	1.21%	0.92%	0.47%	1.39%
Centralines	0.23%	0.78%	1.01%	0.69%	0.39%	1.08%
EA Networks	0.32%	1.43%	1.75%	1.12%	0.71%	1.83%
Eastland Network	0.51%	0.96%	1.47%	1.94%	0.48%	2.00%
Electricity Invercargill	0.21%	0.15%	0.36%	0.31%	0.08%	0.38%
Horizon Energy	1.09%	1.24%	2.00%	3.13%	0.62%	2.00%
Nelson Electricity	0.25%	0.30%	0.55%	0.24%	0.15%	0.38%
Network Tasman	0.60%	1.71%	2.00%	1.69%	0.86%	2.00%
Orion NZ	0.35%	0.25%	0.60%	1.28%	0.13%	1.40%
OtagoNet	0.65%	2.28%	2.00%	1.94%	1.14%	2.00%
Powerco	0.46%	0.83%	1.29%	2.45%	0.42%	2.00%
The Lines Company	0.41%	0.94%	1.35%	1.52%	0.47%	1.99%
Top Energy	0.65%	1.05%	1.70%	2.51%	0.53%	2.00%
Unison Networks	0.23%	0.65%	0.87%	1.05%	0.32%	1.38%
Vector Lines	0.32%	0.82%	1.14%	1.87%	0.41%	2.00%
Wellington Electricity	0.21%	0.11%	0.32%	0.76%	0.06%	0.82%

Attachment N Other measures of quality of service

Purpose of this attachment

N1 This attachment sets out our decisions on not expanding the scope of the quality standard and quality incentive scheme for EDB DPP3 to include dimensions of quality other than reliability.

Summary of our decision

N2 Our decisions on new measures of quality for EDB DPP3 are:

N2.1 not to introduce any new measures as part of the quality standard applying in EDB DPP3 beyond SAIDI and SAIFI;

N2.2 not to introduce any new measures as part of the revenue-linked quality incentive scheme in EDB DPP3.

N3 In 2020, we intend to consider changes to our ID requirements for distributors to ensure that distributors are required to report data that may be required for the future setting of additional quality standards, building on the work undertaken by the ENA Quality of Service Working Group. This will be as part of a targeted review of certain ID requirements.

N4 Over the DPP3 period we also intend to consider how we can better support consumer voice and accountability of distributors, particularly regarding investment delivery. Investment delivery or output measures could also be considered for future quality standards.

N5 We note that for DPP3, we have implemented a new incentive for the notification of planned interruptions. This is a refinement to the existing incentive scheme that applies to planned interruptions and is discussed further in Attachment M.

Why have we considered other quality dimensions?

N6 Section 53M(1)(b) of the Commerce Act requires that a DPP specifies the quality standards that must be complied with by regulated suppliers.

N7 The Commerce Act does not prescribe what should be included in a quality standard. The approach we have taken in previous DPPs is to set quality standards for distributors based on what is most important to consumers, and what we have the most reliable historic data on.

N8 This is consistent with section 53M(3) of the Commerce Act:

> Quality standards may be prescribed in any way the Commission considers appropriate (such as targets, bands, or formulae) and may include (without limitation) –
>
> (a) responsiveness to consumers; and
>
> (b) in relation to electricity line services, reliability of supply, reduction in energy losses and voltage stability or other technical requirements.

N9 Quality standards are an important part of determining a price-quality path. Quality standards ensure that any efficiency gains sought by the regulated suppliers do not come at the expense of meeting a minimum level of quality.

N10 The quality standards under the current DPP2 are based on measures of network reliability (specifically, the duration and frequency of interruptions, as measured by SAIDI and SAIFI respectively), as this was considered to be the most important aspect of quality for consumers.[756]

N11 However, the quality of electricity distribution services has a number of dimensions in addition to reliability. Quality dimensions can relate to the following:[757]

N11.1 ordering and provisioning of a new connection;

N11.2 management and restoration of faults (including the number and duration of faults);

N11.3 service performance, reflecting technical characteristics of the service such as voltage stability; and

N11.4 customer service (such as the time taken to respond to customer complaints or enquiries).

N12 While reliability remains an important dimension of the quality of electricity distribution services, we have considered whether further dimensions of quality should be included in DPP3.

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[756] Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main Policy Paper" (28 November 2014), para 6.2.

[757] We referred to a number of these dimensions in our decision for DPP2. See Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main Policy Paper" (28 November 2014), para 6.58.

Our reasons for not adopting new quality measures in DPP3

N13 We have three principal reasons for not introducing new measures or quality:

N13.1 a need to gather more information about current levels of performance;

N13.2 the need to engage with consumers on what measures of quality are most meaningful to them; and

N13.3 the availability of options outside DPP regulation.

Gathering more information about quality performance

N14 Our view, as expressed in the draft decision, was that the lack of information on any new measures would increase the risk of setting parameters for an incentive scheme at an inappropriate level. The concerns the ENA expressed around setting a quality standard for the new measures are also likely to arise in attempting to set appropriate parameters for an incentive scheme.

N15 Without a robust information base, the targets and other parameters that would apply under an incentive scheme could either be too tough (resulting in unwarranted revenue losses for the distributors) or too lax (resulting in unwarranted revenue gains).

N16 Additionally, the definitions used as part of any new quality measure needs to be specified in a way that can be consistently applied across all distributors to an auditable standard. We consider testing the workability of new measures under our information gathering and disclosure powers prior to attaching a quality standard or incentive. This will help reduce future compliance costs and the mitigate the risk of perverse incentives.

N17 Our view is that the information required should first be collated, with a view to establishing quality standards and potentially a financial incentive scheme for future DPP resets.

Engaging with consumers on quality

N18 As noted by the Electricity Price Review in its final report, there is a need for greater consumer engagement by electricity regulators. We consider that is especially true when it comes to understanding consumers' perspectives on the aspects of quality that are most meaningful to them.

N19 As part of a review of ID requirements and future work on quality measures we will look to engage with consumer groups to shape this process, whether through the Consumer Advocacy Council, through direct efforts on our own part, or via work with electricity distributors.

Options outside the DPP framework

N20 Finally, we note that both the Commission and distributors have options outside the DPP for addressing a wider suite of quality measures:

N20.1 information gathering and disclosure;

N20.2 alternate approaches to quality as part of a CPP; and

N20.3 action by distributors beyond the regulatory framework.

N21 Wellington Electricity and Powerco's CPPs either feature quality measures that go beyond quality and were based on the particular circumstances of those CPPs or were accompanied by information gathering requirements that were focused on what the CPP was intended to deliver. We would consider this as part of any future CPP applications.

N22 In Powerco's case, we acknowledge the work that has been done in producing its Annual Delivery Report as part of the information gathering request that accompanied its CPP. We are interested in working with Powerco and other distributors to develop this further to ensure such a report provides full transparency of how a distributor is performing.

N23 Finally, many distributors have taken steps to measure the quality and performance of their networks and to communicate with their consumers outside of the formal regulatory requirements. We consider that these developments, without prescriptive direction from the Commission are useful, and hope to seem the continue.

Summary of stakeholder views on draft decision

N24 Some submissions were disappointed with our draft decision not to implement customer-facing quality measures in DPP3. Powerco stated:[758]

> Powerco is disappointed the proposed quality standards do not include any new customer service measures that reflect customers' preferences. We believe the Commission is missing an opportunity to act on behalf of customers.

[758] Powerco "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 3.

N25 The ENA also continued to support the introduction of the suite of customer-facing quality measures in DPP3:[759]

> The ENA supports broader measures of service quality from a consumer point of view and we are disappointed that our suggested package of measures was not included in this reset. We understand that data availability is an issue for setting new customer service measures and therefore we support plans to expand Information Disclosures to include customer service measures. Our earlier research, including consultation with customers and other stakeholders, indicated that the following services were valued by customers, and were typically measured by EDBs: The average time taken for an EDB to quote new connection applications, and the proportion of planned outages notified in advance."

N26 We acknowledge the disappointment expressed by some submitters at our decision not to implement new quality standards. However, we consider that the data issues we outlined in the draft still mean it is not in consumers interests to introduce new standards immediately.

N27 Vector submitted specifically in support of introducing a guaranteed service level (GSL) incentive scheme, noting the benefits they have had elsewhere. Vector said:[760]

> A GSL scheme, for instance, arguably provides a much better price-quality nexus for individual consumers than the draft DPP3 does.
>
> Such schemes are also much more akin to service commitments offered for other infrastructure services, such as telecommunications where service outcomes are measured for the individual consumer. Measuring and incentivising service outcomes only as an average across all consumers – as the draft DPP3 decision proposes – misses the key point that consumers individually face price and quality outcomes not as a collective.

N28 While we accept the possible benefits Vector outlines, we note that our current approach to quality standards and revenue allowances is consistent. Both the allowable revenue used to set prices and the SAIDI and SAIFI used to set quality standards and incentives are specified at a network aggregate level, rather than at a customer class or individual customer level.

N29 Vector also expressed its interest in developing a trial GSL scheme for Vector specifically.[761] As noted below, other distributors are currently operating GSL scheme's independent of the Part 4 regime, and we do not consider that our regulation prevent this. Consistent with our low-cost DPP principles outlined in Chapter 3, we do not consider business-specific quality standards appropriate for a DPP that must be applicable to all distributors.

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[759] ENA "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 37.

[760] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 66.

[761] Vector "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 66.

N30 We also note that we can only introduce new quality incentives where there is a corresponding quality standard.

N31 On the other hand, Wellington Electricity supported the decision not to introduce any new standards or incentives:[762]

> WELL supports the Draft Decision to not include any new quality measures and to explore new customer metrics in the DPP period. WELL also supports the proposal to consider changing information Disclosures to ensure data is collected to support any new standard.
>
> This will also allow the industry to ensure that any new measure reflects the quality that customers find important.

Background

What we said in the issues paper

N32 In the issues paper, we noted that the quality standards that apply under the current EDB DPP are based on network reliability as measured by SAIDI and SAIFI (representing duration and frequency of interruptions respectively). We said these measures are likely to broadly remain appropriate.

N33 However, we sought views on whether the quality standards to apply during DPP3 should be expanded to include additional standards of quality that are important to consumers. We referred to our 2017 open letter on our priorities for the EDB DPP reset ("2017 open letter"), in which we noted that it may be appropriate to consider other dimensions of quality, beyond the current standards of SAIDI and SAIFI.[763]

N34 We also sought views on the recommendations submitted to us by the ENA Quality of Service (QoS) Working Group, as well as other potential measures of quality of service. We asked whether new measures should be included in the quality regime to apply under RDB DPP3, or through the ID regime that applies to distributors.

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[762] Wellington Electricity "Submission on EDB DPP reset draft decisions paper" (18 July 2019), p. 23.

[763] Commerce Commission "Our priorities for the electricity distribution sector for 2017/18 and beyond" (Attachment: Proposed focus areas for the 2020 reset of the default price-quality path) (9 November 2017), para 6.1.

ENA Quality of Service Working Group

N35 We acknowledged the work that the ENA had done during 2018 in establishing a QoS Working Group to consider potential refinements to the current DPP quality regime.[764] The ENA QoS Working Group had been considering current and potential new quality standards and measures through surveying distributors on their experiences under the quality regime and on the information that distributors collect,[765] and reviewing international practice.

N36 The ENA QoS Working Group submitted an interim report to the Commission on 1 October 2018, outlining recommendations for the quality regime to apply during EDB DPP3. This included recommendations for two new customer service measures to be included in the quality incentive scheme, but not in the quality standard used for compliance purposes. The two new customer service measures proposed by the ENA QoS Working Group relate to the time for distributors to provide a quote in response to applications for new connections, and the notification of planned interruptions.

N37 The ENA QoS Working Group also proposed that the use of GSL schemes be considered, where customers who receive a service below a minimum level would be entitled to a service level payment. Although the ENA QoS Working Group noted that a considerable amount of work would be required on designing such a scheme, a GSL scheme funded through the regulatory cost base would "allow appropriate transparent trade-offs to be made for improving service for customers experiencing service at levels below that specified by the GSL framework."[766]

Our preliminary views in the issues paper

N38 In the issues paper, we said there is merit in considering a wider range of measures of quality of service for inclusion in the quality regime for EDB DPP3, including but not limited to those proposed by the ENA QoS Working Group.

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[764] Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020: Proposed process" (14 June 2018), para 18.

[765] The Working Group undertook a survey of EDBs, using an updated survey from that used by the ENA Working Group in 2014. The survey gathered information on the type and granularity of data collected by the distributors relating to quality measures, and EDB use of customer surveys.

[766] Electricity Networks Assoc. "ENA Working Group on quality of service regulation – Interim report to the Commerce Commission" (1 October 2018), page 19.

N39 We agreed with the ENA QoS Working Group that the value to consumers of being notified of a planned interruption is likely to depend on the timeliness, accuracy, and reliability of the notification given of the interruption. However, we questioned the ENA QoS Working Group recommendation to include the notification of planned interruptions only as part of the revenue-linked quality incentive scheme but not as part of the quality standard for compliance purposes.

N40 We also noted that the ENA QoS Working Group recommendation regarding new connections is based on the time taken to provide a quote for new connections rather than the time to physically provision the new connection, and that the latter is likely to be particularly important to consumers.

N41 We also sought views on whether power quality should be considered, either as part of the quality standard or as new disclosure requirements or both. We noted that monitoring and transparency of power quality, including over the LV network, could assist distributors in identifying issues, allowing them to better target expenditure. Greater visibility for third parties would also allow them to offer solutions to the distributor which may be more economic.

N42 We asked for views on the potential use of a GSL scheme. In particular, whether a GSL scheme that allowed for consumers to be automatically compensated for poor service levels should be considered, including:

N42.1 how such a scheme would sit within a framework that already includes a quality incentive scheme; and

N42.2 how such a scheme and its funding as part of the regulatory cost base would affect incentives for distributors to offer a quality of service that reflects what consumers want.

N43 We were also interested in views on the use of 'leading' indicators of distributor network reliability performance. The existing measures of network reliability (SAIDI and SAIFI) are 'after-the-fact' measures in that they measure deterioration in reliability once an interruption has occurred. However, as we acknowledged in our 2017 Open Letter, leading indicators may be challenging to identify and implement.

N44 We noted that the ID framework has an important role in revealing the underlying condition of distribution networks and highlighting to distributors and to us any areas which may warrant further attention. In this regard, we may identify additional quality measures that we want distributors to report their performance against, but that may not necessarily result in additional quality standards for the DPP3 reset. For example, this may lead to changes to the ID regulations to require distributors to disclose this information and that will fall outside of the DPP workstream.

N45 In submissions on the issues paper, there was general support for considering additional dimensions of quality beyond reliability, although there were divergent views on how any new quality measures should be dealt with in EDB DPP3.

N46 Broadly speaking, the range of views on whether and if so, how, to accommodate new quality measures within EDB DPP3 were as follows:

N46.1 include new quality measures as part of the compliance quality standard that would apply under EDB DPP3 (Fonterra and Meridian[767]);

N46.2 include new quality measures as part of the quality incentive scheme that would apply under DPP3, but not as part of the compliance quality standard (ENA,[768] supported by Alpine,[769] Centralines,[770] Network Tasman,[771] Powerco,[772] and Unison[773]);

N46.3 exclude new quality measures from DPP3, but further develop the definition, measurement, and information requirements to consider introducing new standards as part of a future DPP (Aurora,[774] The Lines Company[775] and Orion[776]). These parties were open to considering new quality standards, but argued that inclusion in DPP3 would be premature.

N47 Eastland raised concerns around the involvement of third parties (and distributor control over the new measures).[777]

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767 Fonterra "Consultation Paper EDB DPP3 Issue Paper" (20 December 2018), pp. 3 to 4; Meridian Energy "2020-2025 Distribution default price-quality path – Issues paper" (20 December 2018), p. 5.

768 ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 18.

769 Alpine Energy "Submission on EDB DPP3 Issues paper" (20 December 2018), para 4.

770 Centralines "Submission on DPP Reset Issues Paper" (21 December 2018), p. 1.

771 Network Tasman "Submission on the Commerce Commission's Issue Paper - Default price-quality paths for electricity distribution businesses from 1 April 2020" (20 December 2018).

772 Powerco "Submission on DDP reset issues paper" (21 December 2018), p. 3.

773 Unison "Submission on default price-quality paths for electricity distribution businesses from 1 April 2020 Issues paper" (21 December 2018), para 1.

774 Aurora Energy "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018), p. 1.

775 The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), pp. 8 to 10.

776 Orion "Submission on EDB DDP3 Reset " (20 December 2018), p. 14.

777 Eastland Network "2020 DDPP Reset Issues Paper" (20 December 2018), p. 6.

N48 Vector submitted that any new quality standards must not increase the risk of non-compliance, and that any innovations to the quality framework should be within the current financial parameters of the service quality incentive scheme.[778]

N49 A number of submissions responded to the issues paper on the question of power quality. Several distributors noted that power quality is currently subject to technical regulations.[779] The ENA also submitted that collecting exhaustive information about voltage fluctuations, particularly on the LV network, would involve significant investment in monitoring, information systems and communications.[780]

N50 Orion agreed that it is increasingly important to understand power quality measures as networks become platforms for two-way flows, although did not support inclusion of a voltage stability disclosure in EDB DPP3.[781]

N51 Mercury supported the inclusion of power quality as part of the quality standard which would require distributors to disclose performance at the LV level.[782]

N52 Several parties supported introducing new measures as part of the disclosure regime rather than as part of the quality regime for DPP3.[783]

Guaranteed service level scheme

N53 In its submission on the issues paper, the ENA noted that GSL schemes, where customers who receive a service below minimum acceptable levels will be entitled to a service level payment, are common in other countries. According to the ENA,[784]

> A predetermined amount of revenue set aside for the scheme, funded through the regulatory cost base will allow a GSL scheme to operate in a manner consistent with price-quality trade-offs for investment and works programmes. A funded GSL scheme will allow appropriate transparent trade-offs to be made for improving service for customers experiencing service at levels below that specified by the GSL framework.

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[778] Vector “Submission to Commerce Commission Default Price Quality Path Issues Paper” (21 December 2018), para 189.

[779] Wellington Electricity “Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper” (21 December 2018), p. 20; The Lines Company “Default price-quality paths for electricity distribution businesses from 1 April 2020” (21 December 2018), p. 9.

[780] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 19.

[781] Orion "Submission on EDB DDP3 Reset " (20 December 2018), para 77.

[782] Mercury “Default Price-Quality Paths for Electricity Distribution Businesses from 1 April 2020” (20 December 2018).

[783] See for example: The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), p. 8; Orion "Submission on EDB DDP3 Reset " (20 December 2018), para 63; Aurora Energy "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018), paras 7.1-7.2.

[784] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 19.

N54 A number of other submissions also commented on the introduction of a GSL scheme.[785] There was generally support for looking into a GSL scheme, although most parties acknowledged that the development of such a scheme would require considerable time and effort.

Our views on specific new measures of quality

N55 We have considered whether the scope of the quality standard and quality incentive scheme for DPP3 should be expanded to include dimensions of quality other than reliability. In doing so, we have looked at whether there are other quality dimensions that meet the following:

N55.1 the dimensions are valued by customers;

N55.2 the dimensions can be clearly defined and measured;

N55.3 the dimensions are within the control of the distributors; and

N55.4 there is robust information available to implement the measures as part of DPP3.

N56 We have also considered whether a GSL scheme should be introduced as part of DPP3.

New quality measures

N57 In this section, we discuss the wider range of quality measures that we raised in the issues paper. These relate to the notification of planned interruptions, new connections, and power quality.

N58 We also discuss our consideration of alternative means of influencing output measures and delivery of planned investment.

Notification of planned interruptions

N59 According to the ENA, communication of planned interruptions is a top priority identified by distributors' customers. "Timely, accurate and reliable notification of planned interruptions reduces the impact of an interruption and leads to a better customer experience."[786] The ENA recommended a measure of the proportion of planned interruptions notified in advance of the interruption.

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[785] Orion "Submission on EDB DDP3 Reset " (20 December 2018), p.16; Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 20.

[786] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 18.

N60 Communication with consumers in relation to planned interruptions was also identified as being important in the Powerco application for a CPP. According to the consumer survey undertaken by PwC and Colmar Brunton on behalf of Powerco, more than 90% of respondents reported that communication about planned power cuts was important.[787]

N61 In its submission on the issues paper, Fonterra emphasised the importance of adequate and accurate notification of planned interruptions. Fonterra recommended that distributors be measured in terms of compliance with a 10-day notice period for planned interruptions.[788]

N62 Any new quality measures will need to be clearly defined and measured. In the case of notification of planned interruptions, the value to consumers of being notified of a planned power cut is likely to depend on the timeliness, accuracy, and reliability of the notification. In particular, as we noted in the issues paper:

N62.1 the period of advanced notice should be adequate to allow consumers (including business consumers) sufficient time to prepare for the power interruption;

N62.2 the notification should be accurate and reliable, so that the specified period of the interruption is reasonable; and

N62.3 the work undertaken on the distribution network actually takes place within the specified period (unless there are factors beyond the control of the distributor which prevents the work from being done).

N63 A quality measure for the notification of planned interruptions might therefore be defined by requiring a proportion of planned interruptions to meet criteria which reflect the dimensions listed above.

N64 According to the ENA, the information base required to set compliance standards for the ENA's proposed new measures (notification of planned interruptions, and time to quote for new connections) is yet to be developed, and as a result, the new measures should only be included in the quality incentive scheme for EDB DPP3.[789]

N65 We note that section 53M(2) of the Commerce Act, which allows us to include incentives for quality in a DPP, refers back to the supplier meeting or failing to meet or exceeding the required quality standards. This indicates that any incentive scheme must be accompanied by an enforceable quality standard.

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[787] Powerco CPP "Consultation report" (12 June 2017), p. 35 (PwC, "Full results from consumer survey").

[788] Fonterra "Consultation Paper EDB DPP3 Issue Paper" (20 December 2018), pp. 3 to 4.

[789] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 18.

N66 Although we are not proposing to introduce a new quality standard relating to the notification of planned interruptions for DPP3, we are proposing to introduce a new incentive for notification of planned interruptions. A planned interruption is currently defined as an interruption where 24 hours' notice has been provided. As discussed in Attachment M, we are proposing to encourage distributors to provide greater notification of planned interruptions. We propose to do this by reducing the revenue impact of the planned SAIDI incentive where adequate notification is provided by the distributor. To achieve the more beneficial incentive rate, the distributor must provide at least five working days' notice of a planned interruption, and the planned interruption must actually take place within a reasonable window.[790]

N67 In our view, the above mechanism is appropriate for DPP3, and we may consider introducing further measures, including a separate compliance standard and potentially a financial incentive scheme, for planned interruptions as part of future DPP resets.

New connections

N68 The ENA QoS Working Group has submitted that the average time to quote for a new connection is important to consumers:[791]

> Average time taken to quote new connections was identified as being of notable customer value. This was specifically identified by the ENA Customer working group during the review of customer values identified from existing individual EDB research, as well as through the ENA Customer Reference Panel, and through review of overseas regimes.

N69 For new connections, a quality measure could be defined in relation to the time the distributor takes to provide a quote for a new connection (as proposed by the ENA QoS Working Group), or the time to physically provision the new connection. A number of submissions noted that a well-defined measure for new connections would need to take account of variations in the size and complexity of customer connections, as well as the involvement of third parties in installation.[792] We note that other regulators have recognised these differences when setting requirements relating to new connections.

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[790] See Attachment M for further discussion.

[791] ENA "ENA Working Group on Quality of Service Regulation: Interim Report to the Commerce Commission" (1 October 2018), p. 20-21.

[792] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), para 199.

N70 For example, Ofgem note that:[793]

> The type of services a customer requires may depend on the type (or size) of connection they seek and this in turn may affect how performance should be measured and incentivised. For connections at the lower voltages (minor connections) the connections process can be reasonably straightforward. For connections at higher voltages and generation/unmetered connections (major connections) their requirements are often more complex.

N71 As discussed above in relation to the notification of planned interruptions, the ENA has submitted that the information required to set compliance standards for new connections is yet to be developed. The ENA proposed that any new measure relating to new connections should only be included in the quality incentive scheme for EDB DPP3, and not as part of the compliance regime.

N72 For the reasons given above, we disagree with the ENA's proposal to introduce a new connections measures as part of the quality incentive scheme but not as an enforceable quality standard. Our view is that the information required should first be collated, with a view to establishing compliance standards and potentially a financial incentive scheme for future DPP resets.

Power quality

N73 A number of submissions responded to the issues paper on the question of power quality. Orion agreed that it is increasingly important to understand power quality measures as networks become platforms for two-way flows. Orion said that basic visibility of the LV system is a prerequisite to reporting accurately and dynamically on power quality measures, and that targeted investment by distributors in the LV system will facilitate provision of accurate system performance data to inform real-time and future asset management decision making. As this capability build is in its early stages, Orion did not support inclusion of a voltage stability disclosure in DPP3.[794]

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[793] Ofgem "Guide to the RIIO-ED1 electricity distribution price control" (18 January 2017), para 9.2.

[794] Orion "Submission on EDB DDP3 Reset " (20 December 2018), para 77.

N74 Several distributors noted that power quality is currently subject to technical regulations,[795] although these regulations needed to be updated to reflect technical challenges that new technology will impose on voltage quality.[796] According to the ENA, the current technical regulations do not reflect the increasing tolerance of most modern electric devices to wider voltage ranges. The ENA also submitted that collecting exhaustive information about voltage fluctuations, particularly on the LV network, would involve significant investment in monitoring, information systems and communications.[797]

N75 Mercury did support the inclusion of power quality as part of the quality standard which would require distributors to disclose performance at the LV level. Mercury said that failing to maintain voltage within safe ranges can seriously impair the performance of electrical equipment.

N76 Having considered submissions on the issues paper, we remain of the view that greater transparency of power quality, including on the LV networks, is increasingly important.

N77 This is also consistent with draft views expressed by IPAG, that distributors should have greater visibility of the performance of their LV networks, "so they are better able to manage reliability with greater penetration of distributed energy resources, and specify needs which could be obtained from a third-party to support network management."[798]

N78 We are proposing to include a new recoverable cost for expenditure on innovation.[799] As discussed at the DPP3 workshop on 8 March 2019, this could include LV network monitoring. An ID requirement could increase transparency around LV network performance and accountability.

[795] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 20; The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), p. 9.

[796] Vector "Submission to Commerce Commission Default Price Quality Path Issues Paper" (21 December 2018), para 203.

[797] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 19.

[798] IPAG "Advice on creating equal access to electricity networks (draft for discussion)" (6 December 2018), slide 6.

[799] See Attachment F.

Investment delivery

N79 In some of our recent price path determinations, such as the Wellington Electricity CPP, we have introduced output or investment delivery measures into the quality standards or quality incentive schemes. We are not proposing to do this for DPP3 because we currently consider that these are more appropriate for price paths like CPPs and IPPs that have a higher level of scrutiny of particular expenditure and are not in the long-term interests of consumers for DPPs.

N80 However, we are considering options outside of the DPP determination that will support consumer voice and accountability of distributors in regard to investment delivery. We consider that increased focus on the delivery of network investment and maintenance would be helpful in improving the performance of electricity distributors and in making them more accountable to their customers.

N81 This is consistent with our open letter on priorities for the electricity sector, which highlighted our planned focus on asset management and investment sufficiency, among other things.

N82 While this issue is best addressed through our ID rules and analysis of the disclosed information, we consider that the DPP3 reset is an appropriate time to signal our intentions. There is an expectation that if the DPP3 reset allows distributors to charge consumers at a certain level to cover the costs of investing in and maintaining the network, then we expect them to complete that investment and maintenance unless the difference is due to an efficiency gain or an optimal deferral.

N83 Additional performance analysis of distributors may lead to us considering additional quality standards at future DPP resets, or changes to the ID requirements.

N84 However, we received several submissions on other quality standard measures, suggesting to us that it is best to start with ID of any new measures, which can then be considered for quality standards at the next reset. This is relevant to the topic of accountability because stronger requirements on accountability could be ID or quality standards, for example on output measures or asset health measures. Our proposed approach is consistent with these submissions.

N85 Mercury said that they "support more transparency, scrutiny, and accountability of distribution investment and operation decisions".[800] Our proposed approach is consistent with this.

[800] Mercury "Default Price-Quality Paths for Electricity Distribution Businesses from 1 April 2020" (20 December 2018).

N86 Orion submitted that an expenditure delivery report to provide accountability would be "beyond the requirements of a DPP and an unnecessary cost". Orion noted that many distributors already publish similar information voluntarily.[801] In somewhat of a contrast to Orion, The Lines Company submitted that "We believe a review by distributors of their capital expenditure at the end of a DPP period against what was proposed at the commencement could provide a means of assessing capital expenditure delivery."[802] The Lines Company also explain that it is important to note that there are a range of reasons why planned work may be deferred, brought forward, or not required.

Guaranteed service level scheme

N87 The current approach to the quality standard and quality incentive scheme applying to non-exempt distributors under the DPP are based on network reliability measured at the network level. A more granular approach, such as through an appropriately-designed GSL scheme, may enhance the incentives facing distributors to recognise and respond to poor service levels.

N88 In its submission on the issues paper, the ENA noted that GSL schemes, where customers who receive a service below minimum acceptable levels will be entitled to a service level payment, are common in other countries. According to the ENA:[803]

> A predetermined amount of revenue set aside for the scheme, funded through the regulatory cost base will allow a GSL scheme to operate in a manner consistent with price-quality trade-offs for investment and works programmes. A funded GSL scheme will allow appropriate transparent trade-offs to be made for improving service for customers experiencing service at levels below that specified by the GSL framework.

N89 A number of other submissions also commented on the introduction of a GSL scheme. There was generally support for looking into a GSL scheme, although most parties acknowledged that the development of such a scheme would require considerable time and effort.

N90 For example, Orion did not support the introduction of a GSL scheme for DPP3 but submitted that further consideration should be given to a GSL scheme for EDB DPP4. According to Orion, "contemplating development of a GSL so close to the final decision date for DPP3 risks compromising the quality of the scheme. We support

[801] Orion "Submission on EDB DDP3 Reset " (20 December 2018), para 24.

[802] The Lines Company "Default price-quality paths for electricity distribution businesses from 1 April 2020" (21 December 2018), p. 6.

[803] ENA "DPP3 April 2020 Commission Issues paper (Part Two, Regulating Quality)" (20 December 2018), p. 19.

further consideration of the construct for a GSL over the next period in conjunction with the Commission for further consultation at DPP4."[804]

N91 Mercury supported the concept of a GSL scheme, subject to appropriate design and funding.[805] Wellington Electricity supported the introduction of a GSL scheme as proposed by the ENA, although recognised that such a scheme would require considerable resources and investment to implement.[806]

N92 Aurora noted that it had operated a GSL scheme for many years, and so was not concerned about the introduction of such a scheme under the DPP. The key issue for Aurora related to how such a scheme would be funded.[807]

N93 In its cross-submission, MEUG said it was unclear what a GSL scheme might look like, and how such a scheme would be funded. "Neither do we understand if current or any proposed compensation schemes for loss of or poor service delivery leads directly to lower returns to distributor shareholders', or those costs are simply recovered by an uplift in the revenue path across all other customers. The incentive effect of the former relative to the latter and comparison with how non-performing businesses are affected in workably competitive markets should be an important consideration."[808]

N94 We consider that a well-designed and effective GSL scheme could enhance the incentives facing distributors to recognise and respond to poor service levels. GSL schemes can improve visibility of the actual level of service experienced by customers and incentivise distributors to take targeted steps to improve that experience. Such schemes provide a more direct link between the actual level of service and customer compensation, compared to quality standards and quality incentive schemes that are directed at the network level.

N95 A number of parties, including the ENA, have recognised that considerable work would be required to develop and design an effective GSL scheme. The ENA QoS Working Group noted some of the practical issues relating to a GSL scheme, including whether such a scheme should apply service level targets on a national or a network-specific level, and any exemptions from such a scheme (such as major events, planned interruptions, and third-party events).

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[804] Orion "Submission on EDB DDP3 Reset " (20 December 2018), para 75-76.

[805] Mercury "Default Price-Quality Paths for Electricity Distribution Businesses from 1 April 2020" (20 December 2018), p. 6.

[806] Wellington Electricity "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (21 December 2018), p. 20.

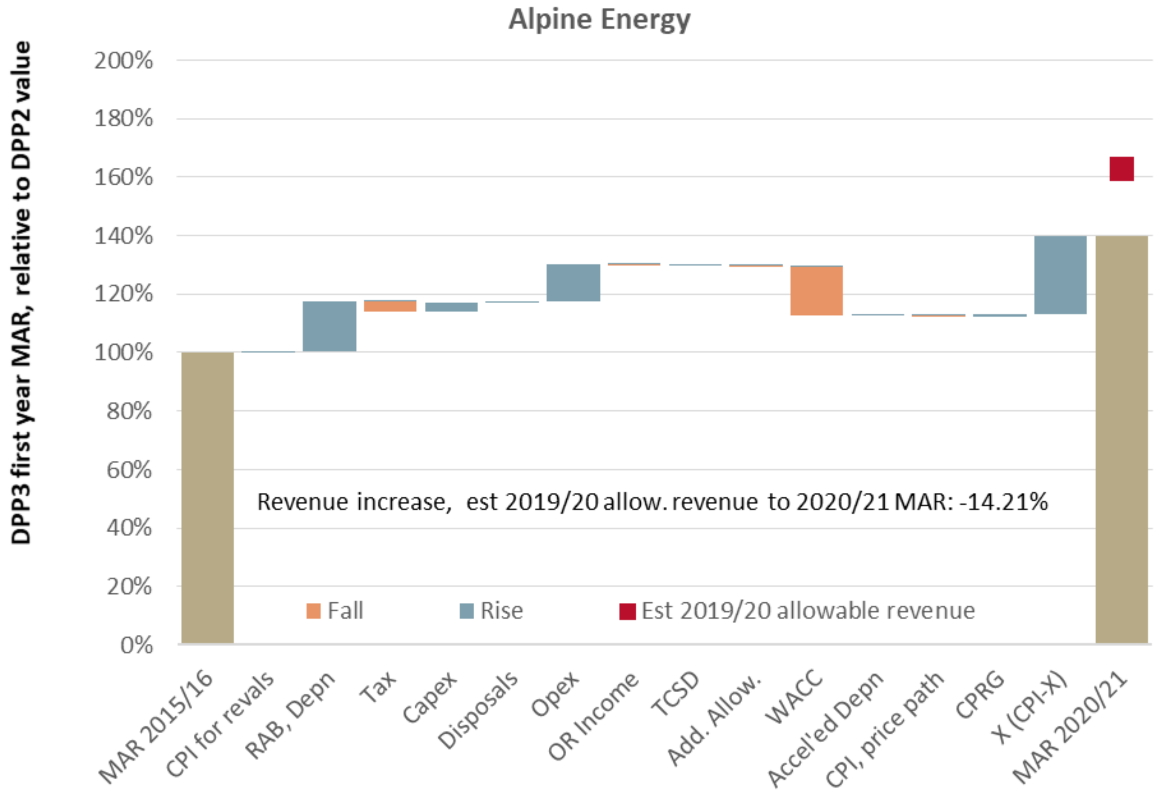
[807] Aurora Energy "Default price-quality paths for electricity distribution businesses from 1 April 2020 Issues Paper" (20 December 2018), para 7.2(c).

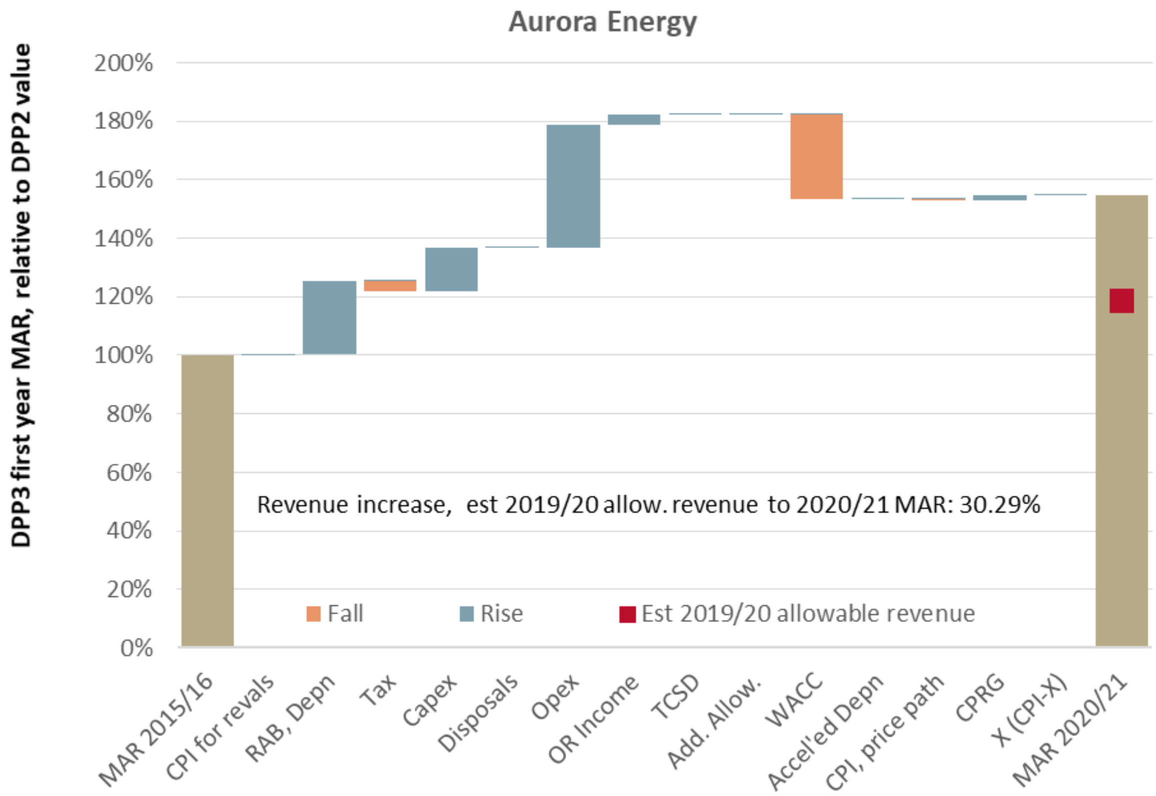
[808] MEUG "Cross submission on EDB DPP3 reset issues paper" (31 January 2019), para 4.

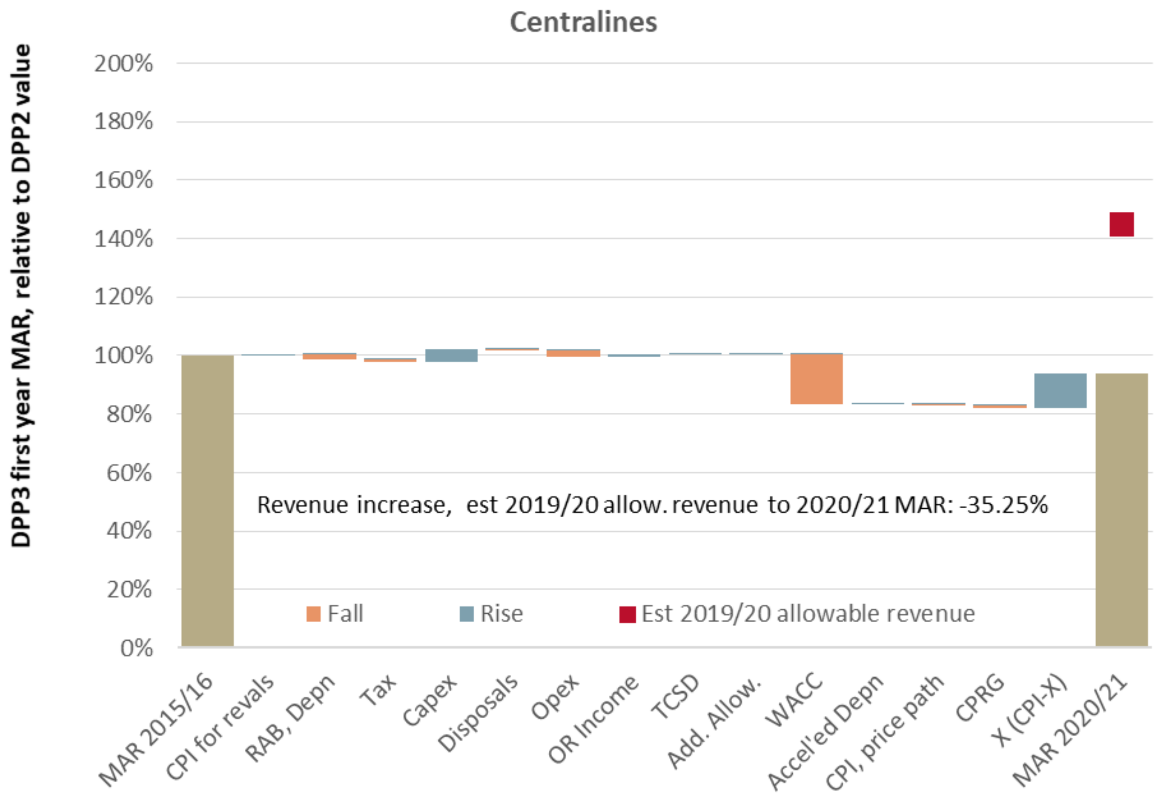
N96 Another essential part of a GSL scheme relates to the payment amounts of the scheme, and how such a scheme is funded. The strength of the incentive on the distributors to respond to poor service levels will depend on the proportion of funding that is sourced from customers (for example by funding the scheme through the regulatory cost base).

N97 Given the above, we agree with Orion that the development of a GSL scheme for the distributors should be considered during the DPP3 period, with a view to potential implementation for DPP4.

Attachment O Revenue and expenditure changes for individual distributors






Centralines
DPP3 first year MAR, relative to DPP2 value
200%
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160%
140%
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20%
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Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -35.25%
Fall
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Est 2019/20 allowable revenue
MAR 2015/16
CPI for revals
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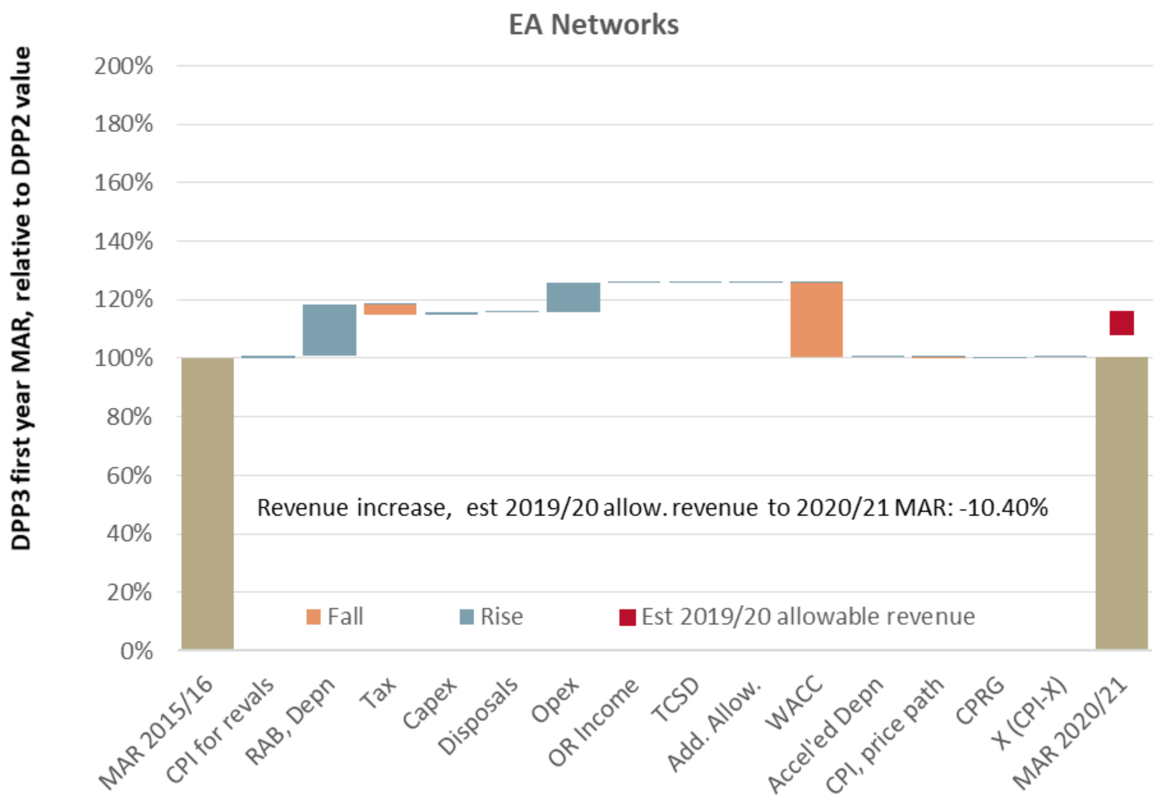
X (CPI-X)
MAR 2020/21


EA Networks
DPP3 first year MAR, relative to DPP2 value
200%
180%
160%
140%
120%
100%
80%
60%
40%
20%
0%
Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -10.40%
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Rise
Est 2019/20 allowable revenue
MAR 2015/16
CPI for revals
RAB, Depn
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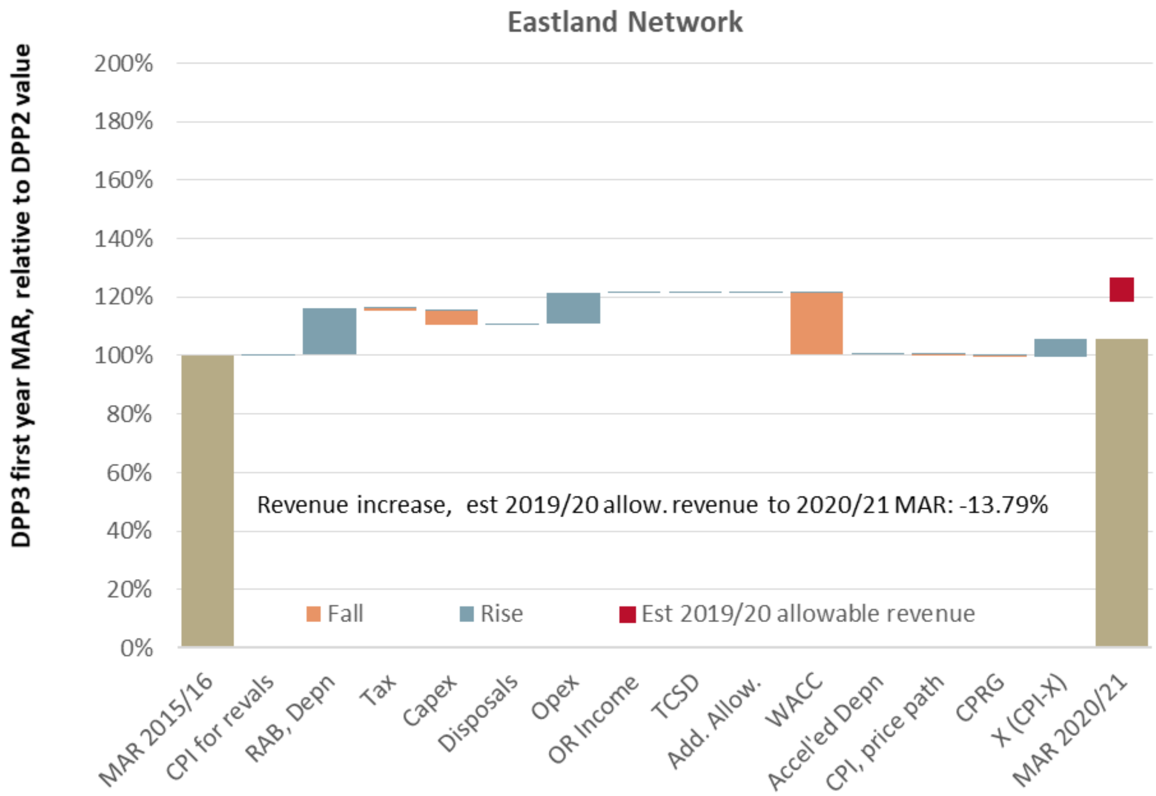
CPRG
X (CPI-X)
MAR 2020/21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DPP3 first year MAR, relative to DPP2 value
200%
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20%
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Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -13.79%
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Est 2019/20 allowable revenue
MAR 2015/16
CPI for revals
RAB, Depn
Tax
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Disposals
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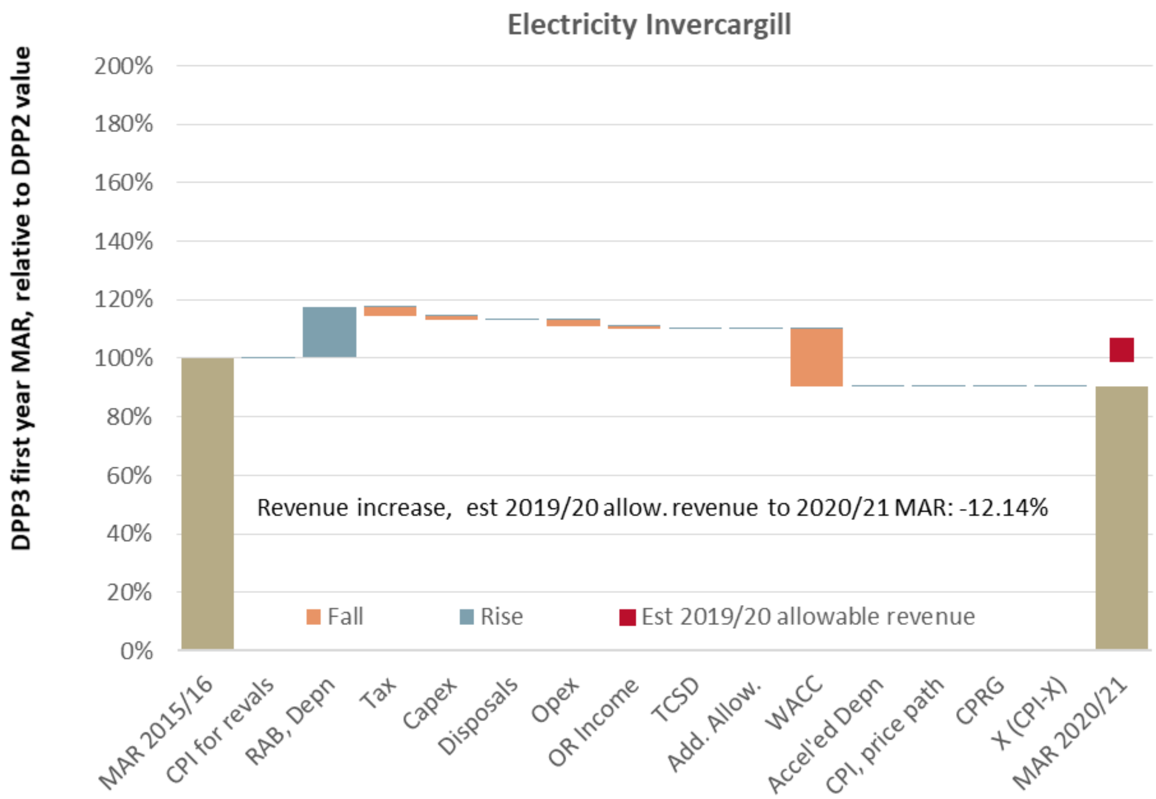
MAR 2020/21


Electricity Invercargill
DPP3 first year MAR, relative to DPP2 value
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40%
20%
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Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -12.14%
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Est 2019/20 allowable revenue
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Accel'ed Depn
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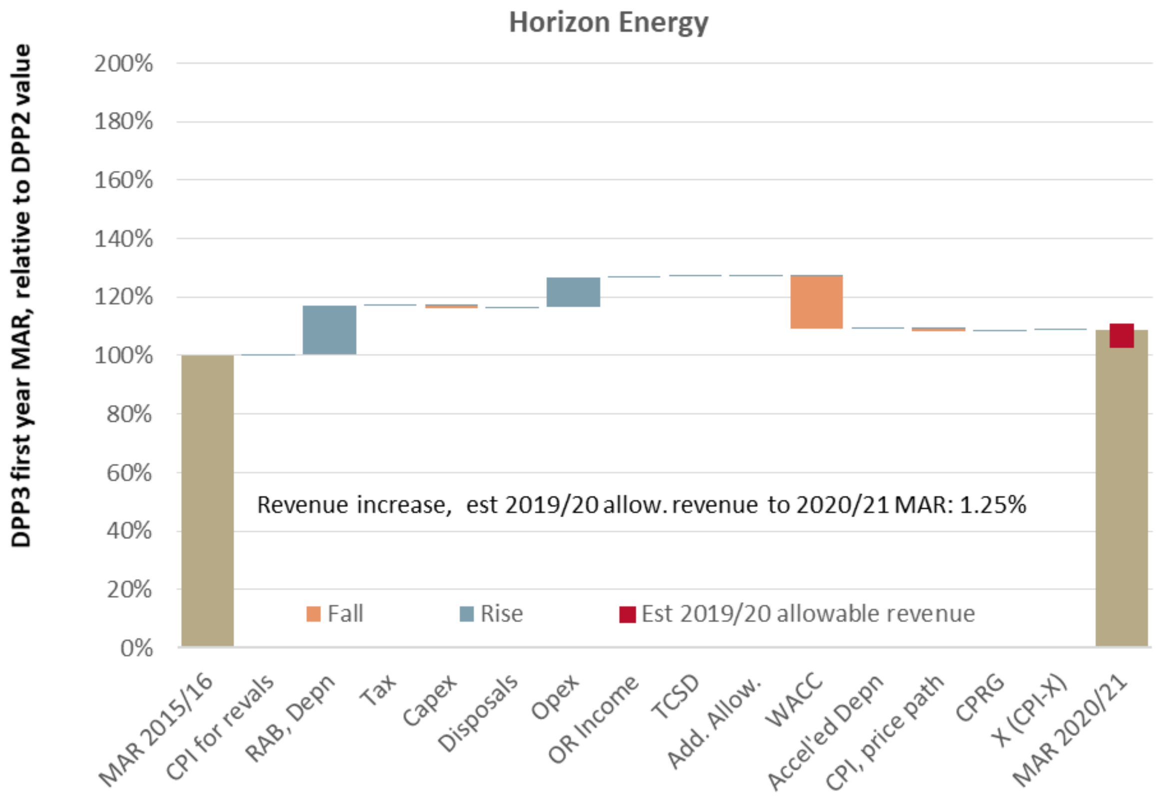
CPRG
X (CPI-X)
MAR 2020/21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DPP3 first year MAR, relative to DPP2 value
200%
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Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: 1.25%
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Est 2019/20 allowable revenue
MAR 2015/16
CPI for revals
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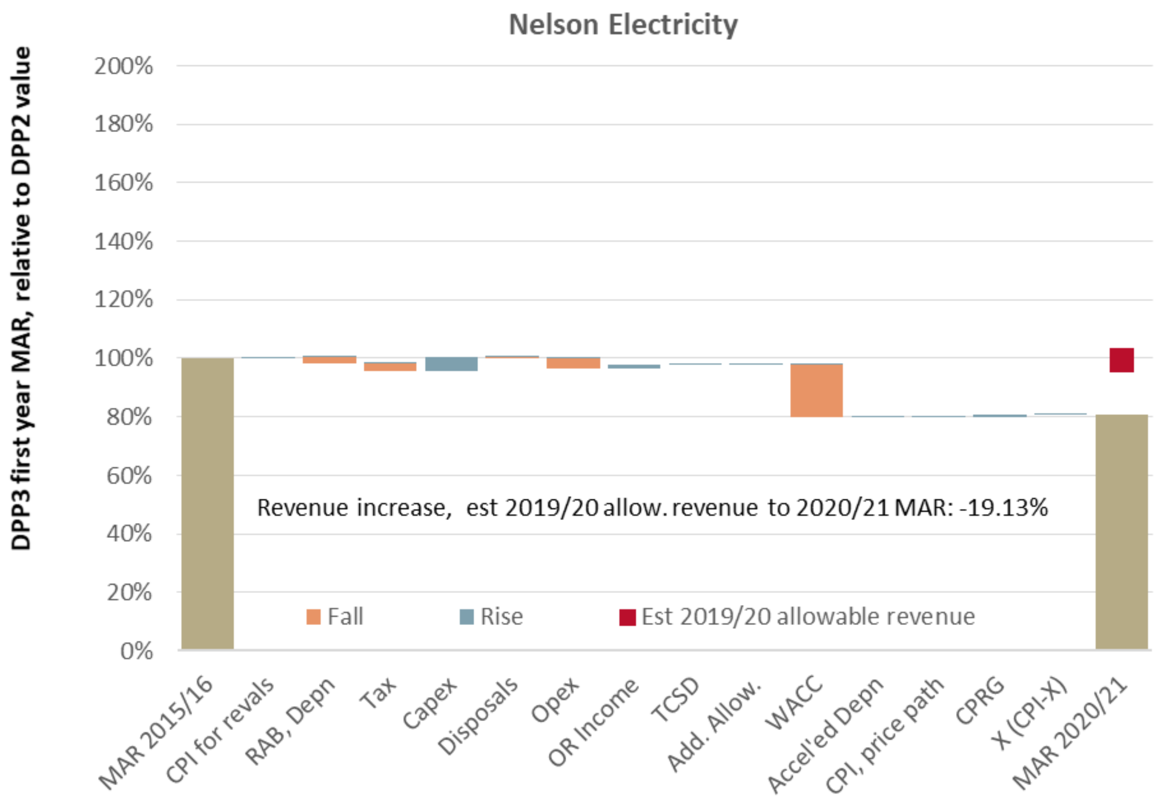
MAR 2020/21


Nelson Electricity
DPP3 first year MAR, relative to DPP2 value
200%
180%
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20%
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Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -19.13%
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Est 2019/20 allowable revenue
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CPI for revals
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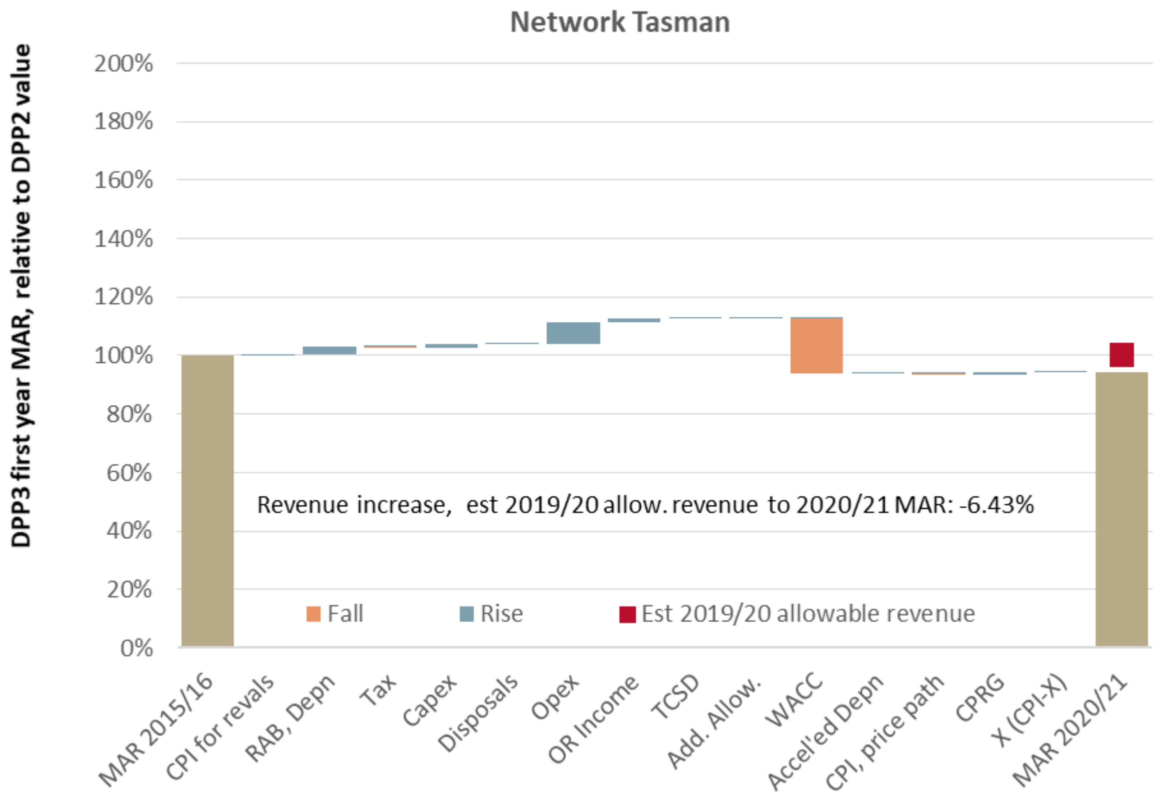
MAR 2020/21


Network Tasman
DPP3 first year MAR, relative to DPP2 value
200%
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140%
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Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -6.43%
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Est 2019/20 allowable revenue
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Accel'ed Depn
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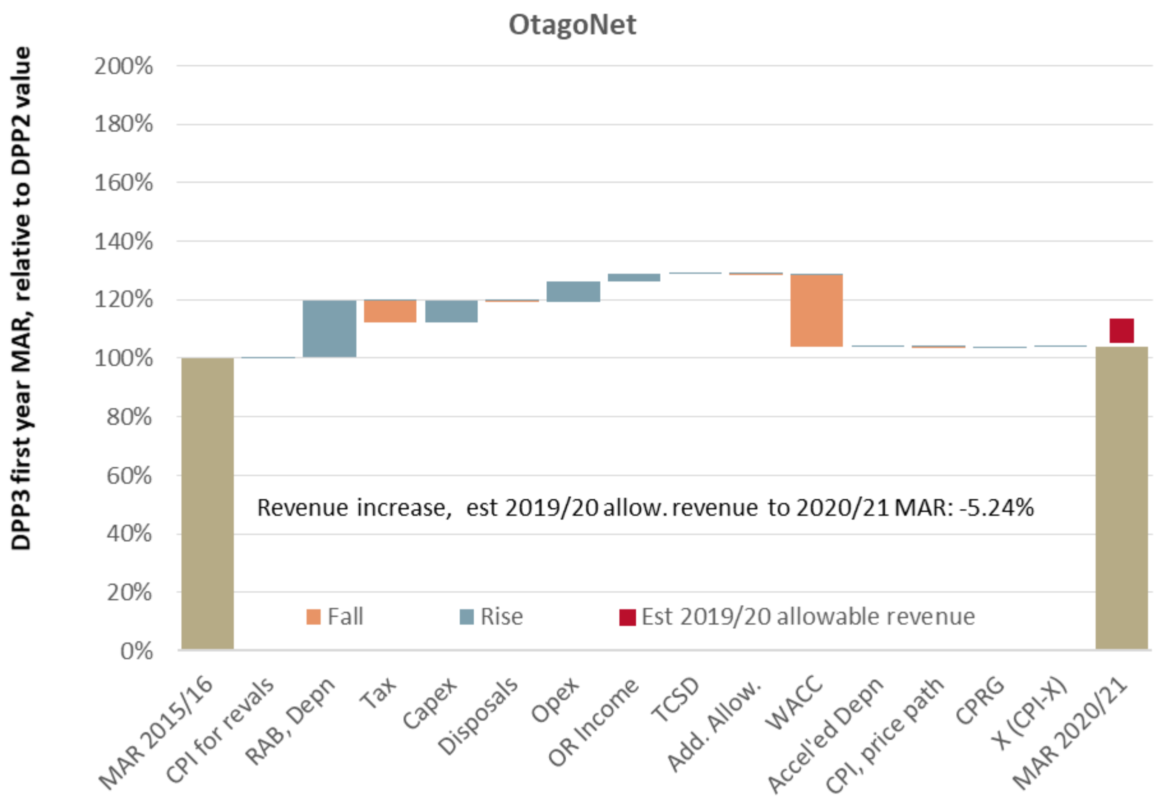
MAR 2020/21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DPP3 first year MAR, relative to DPP2 value
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Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -5.24%
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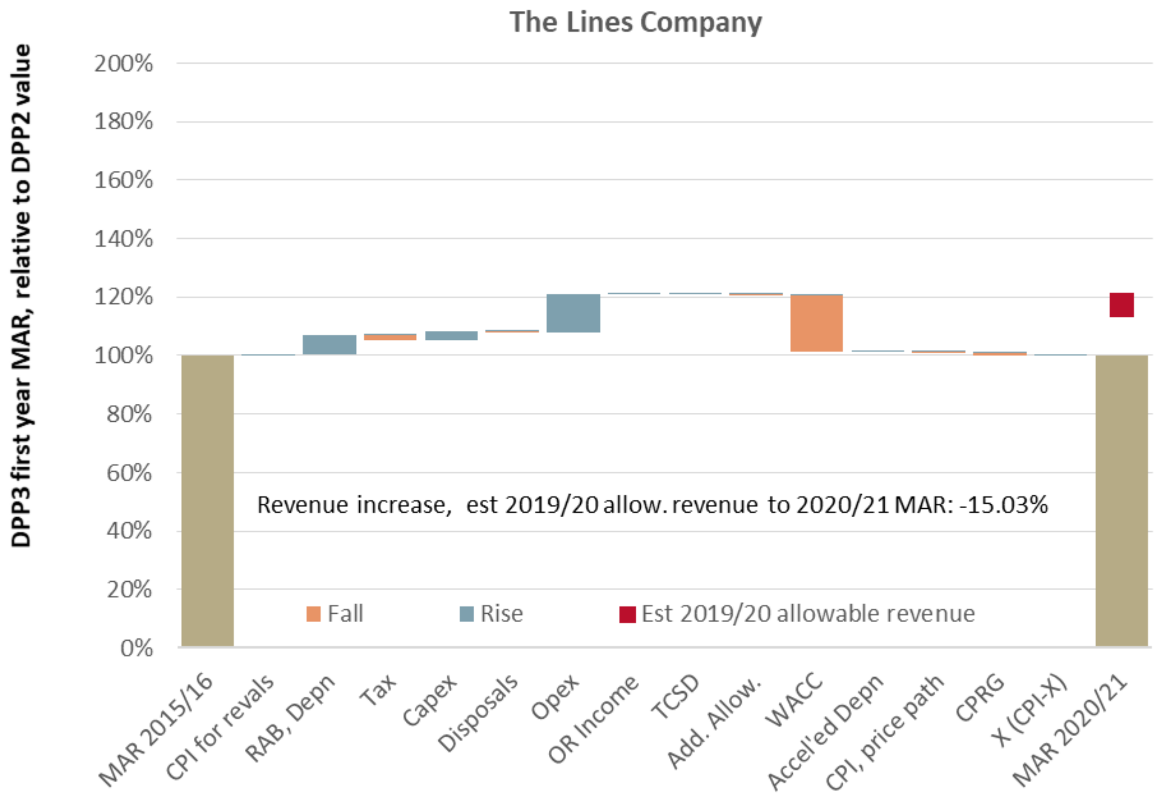
The Lines Company
DPP3 first year MAR, relative to DPP2 value
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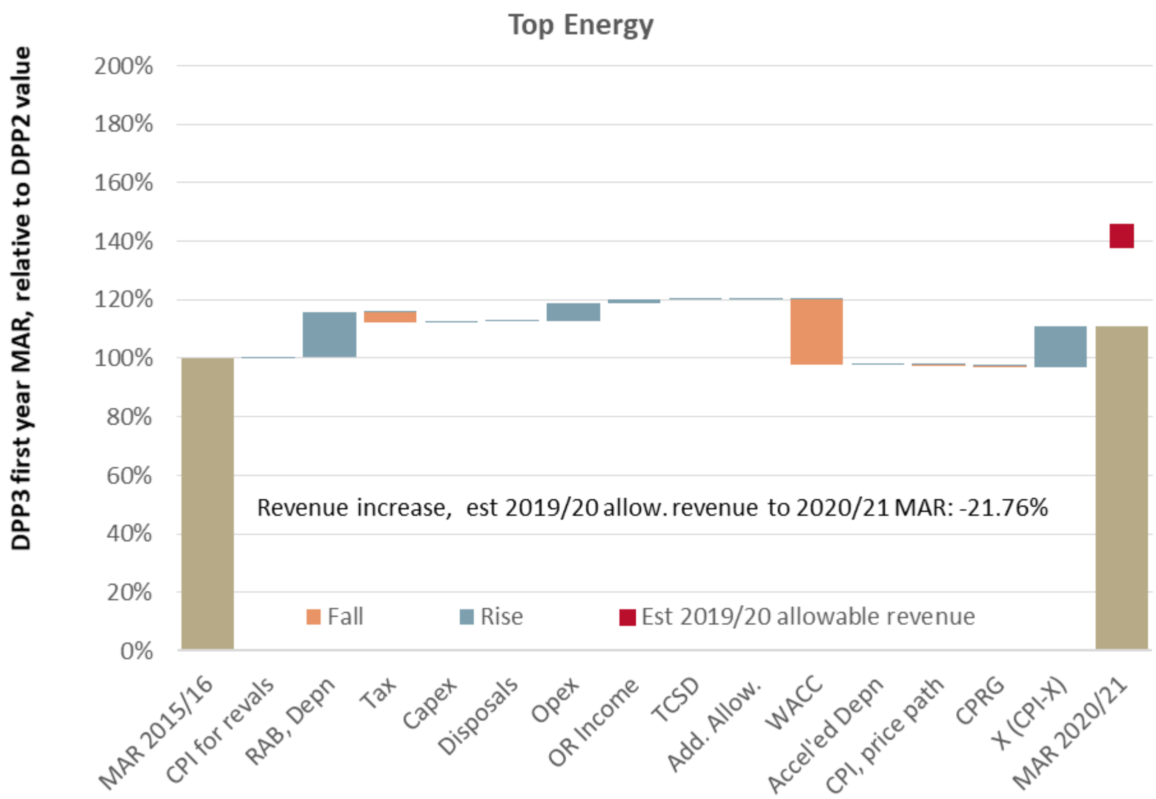
MAR 2020/21


Top Energy
DPP3 first year MAR, relative to DPP2 value
200%
180%
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Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -21.76%
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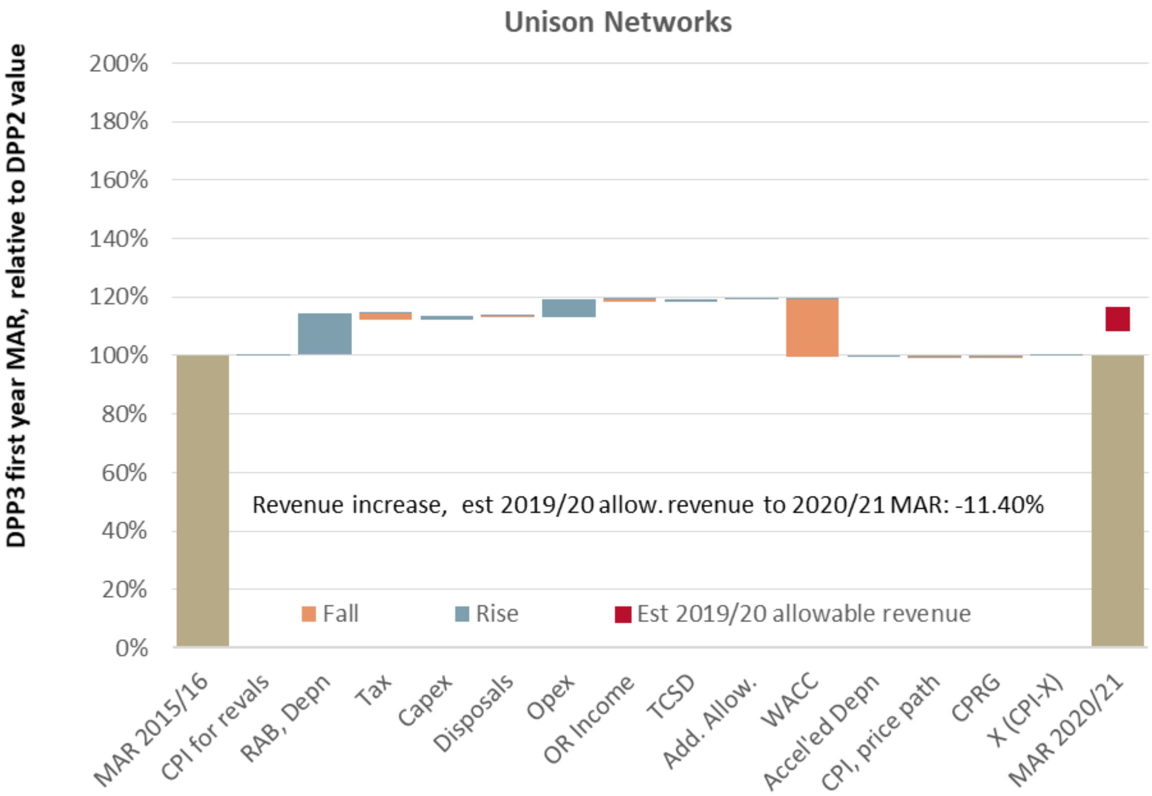
MAR 2020/21


Unison Networks
DPP3 first year MAR, relative to DPP2 value
200%
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Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -11.40%
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Est 2019/20 allowable revenue
MAR 2015/16
CPI for revals
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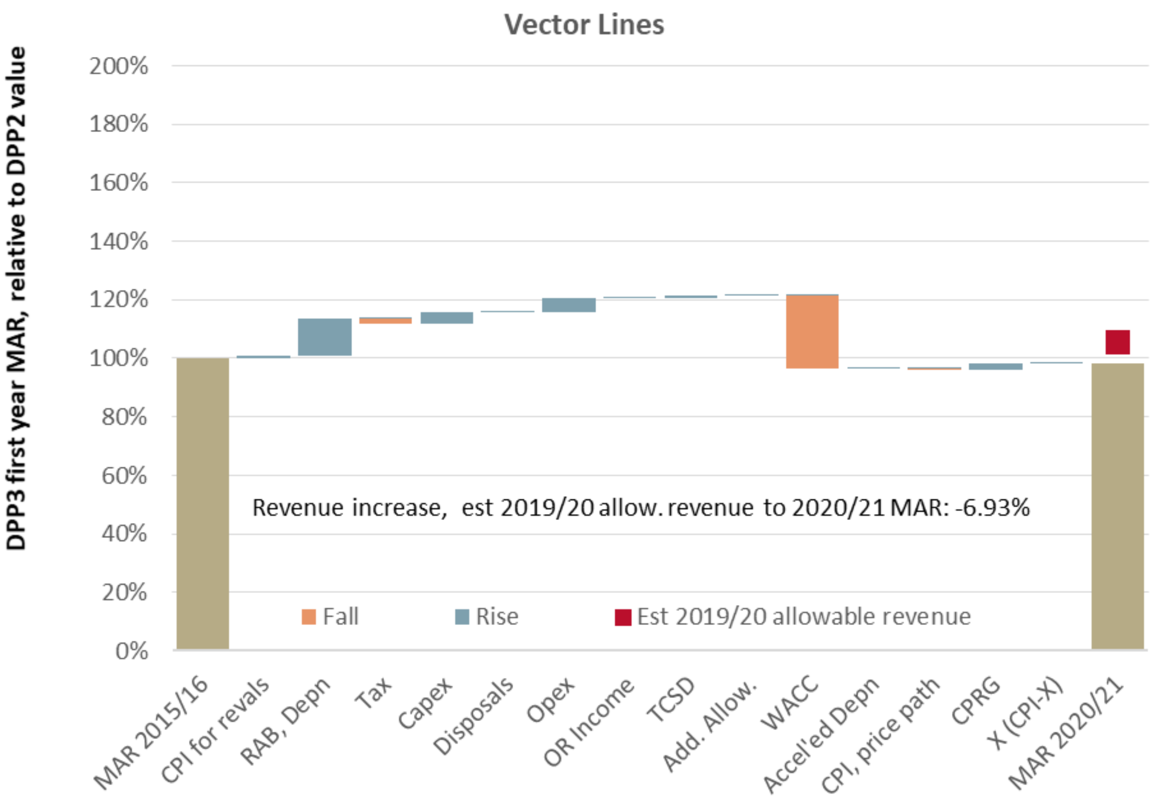
X (CPI-X)
MAR 2020/21


Vector Lines
DPP3 first year MAR, relative to DPP2 value
200%
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20%
0%
Revenue increase, est 2019/20 allow. revenue to 2020/21 MAR: -6.93%
Fall
Rise
Est 2019/20 allowable revenue
MAR 2015/16
CPI for revals
RAB, Depn
Tax
Capex
Disposals
Opex
OR Income
TCSD
Add. Allow.
WACC
Accel'ed Depn
CPI, price path
CPRG
X (CPI-X)
MAR 2020/21