



ISBN 978-1-869454-15-9
14.07/14118

Public version

Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020

Low cost forecasting approaches

Date of publication: 28 November 2014

Associated documents

Publication date	Reference	Title
28 November 2014	ISSN 1178-2560	Electricity Distribution Services Default Price-Quality Path Determination 2015 [2015] NZCC 33
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	ISBN 978-1-869454-13-5	Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Quality standards, targets, and incentives
28 November 2014	ISBN 978-1-869454-14-2	Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Compliance requirements
20 October 2014	ISSN 1178-2560	Electricity Distribution Services Default Price-Quality Path Draft Determination 2015
18 July 2014	ISSN 1178-2560	Electricity Distribution Services Default Price-Quality Path Draft Determination 2015
4 July 2014	ISBN 978-1-869453-80-0	Low Cost Forecasting Approaches For Default Price-Quality Paths

Regulation Branch, Commerce Commission
Wellington, NEW ZEALAND

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1. Introduction

Purpose of paper

- 1.1 This paper outlines and explains the low cost forecasting approaches that were used to set default price-quality paths for electricity distributors for the regulatory period 1 April 2015 to 31 March 2020.¹

Profitability-based adjustments to price limits

- 1.2 As part of the periodic reset of default price-quality paths, we have adjusted the price limits based on profitability of each distributor. In particular, we set starting prices based on the current and projected profitability of each distributor. The alternative available to us under the Act was to 'roll over' the price limit that previously applied.
- 1.3 The reasons for our decision to make profitability-based adjustments to the price limits can be found in our 'Main Policy Paper'.² The purpose of that paper is to outline and explain the main components of the default price-quality paths that will apply to electricity distributors from 1 April 2015 to 31 March 2020.
- 1.4 To adjust price limits based on the current and projected profitability of each distributor, we first forecast each distributor's costs on a 'building block' basis, and then set prices that reflect the outlook for future demand. The key building block cost components are the return on and of capital, operating expenditure, and tax.

¹ This paper should be read in conjunction with the 'Main Policy Paper' that outlines and explains the main components of the default price-quality paths. Refer: Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main policy paper" (28 November 2014).

² Refer: *ibid.*

Consultation on low cost forecasting approaches

- 1.5 In July 2014, we published a paper on the low cost forecasting approaches that we proposed to rely on to adjust the price limits based on the profitability of each distributor.³ The 'Proposed Approaches to Low Cost Forecasting' paper sought views on inputs that included:
- 1.5.1 Forecasts of operating expenditure;
 - 1.5.2 Forecasts of capital expenditure;
 - 1.5.3 Forecasts of other line items, such as asset disposals; and
 - 1.5.4 Forecasts of revenue growth.
- 1.6 As explained in our Main Policy Paper, we rely on a combination of low cost techniques to determine each of these inputs.⁴ Therefore, in July 2014, we proposed a combination of low cost techniques, eg, reliance on suppliers' own forecasts, independent forecasts, and simplifying assumptions.
- 1.7 The approaches we proposed in July 2014 were very similar to the approaches we relied on when adjusting the price limits in November 2012. We noted that there would be little reason to depart from our existing analytical approaches, unless new issues had become apparent, or new information was available.

Feedback received from a variety of stakeholders

- 1.8 In response to our July 2014 consultation material, we received feedback from a variety of stakeholders. Those submissions raised a number of issues with our existing approaches, and provided suggestions for how our approaches could be improved.

³ Commerce Commission "Low-cost forecasting approaches for default price-quality paths" (4 July 2014).

⁴ Refer: s 53K of the Act.

Incremental improvements to the approaches relied on in November 2012

- 1.9 As a result of the submissions received, we have been able to make incremental improvements to the approaches we relied on in November 2012. The most material changes since our draft decision have been:
- 1.9.1 For operating expenditure, the initial level of operating expenditure has been based on an average of 2013 and 2014 data, rather than relying solely on 2013 data;
 - 1.9.2 For capital expenditure, the limit applied to network capital expenditure is 20% for all distributors, rather than applying a lower limit to distributors based on past forecasting reliability; and
 - 1.9.3 For revenue growth, we have updated our assumption about future changes in electricity use per residential users, and our assumption about the elasticity of revenue from industrial and commercial users to GDP.
- 1.10 We are grateful to submitters for helping us to improve our existing approaches.

2. Summary of main inputs

Purpose of this chapter

- 2.1 This chapter summarises the main inputs used in our approach to set starting prices for each electricity distributor.⁵ The main inputs, which are summarised in turn, are:
- 2.1.1 Forecasts of operating expenditure;
 - 2.1.2 Forecasts of capital expenditure;
 - 2.1.3 Forecasts of revenue growth;
 - 2.1.4 Forecasts of asset disposals and other regulatory income; and
 - 2.1.5 The weighted average cost of capital and forecast rate of inflation for predicting asset revaluations.
- 2.2 We explain the approach to setting each of these inputs in the chapters that follow.

Forecasts of operating expenditure

- 2.3 As discussed in Chapter 3, we forecast each distributor's operating expenditure by setting an initial amount based on information disclosed by suppliers, and projecting that forward on the basis of expected changes in the three main drivers. The three main drivers are:
- 2.3.1 Network scale (the scale of the network may affect operating expenditure because the volume of service provided will change);⁶
 - 2.3.2 Operating partial productivity (changes in operating efficiency will affect the amount of operating expenditure needed to provide a given level of service); and
 - 2.3.3 Input prices (changes in input prices will affect the cost of providing a given level of service over time).

⁵ All figures shown in this chapter must be treated with caution. They have been developed for regulatory purposes only and the Commission does not warrant the use of the figures for other purposes.

⁶ For example, every additional kilometre of electricity line constructed may require maintenance, thereby increasing the required operating expenditure.

- 2.4 Table 2.1 shows the amount of operating expenditure we have included in our modelling for each distributor in each year, expressed in current prices. In Table 2.1, and throughout this paper, the values correspond to the disclosure years that distributors refer to when providing information, ie, 1 April to 31 March.

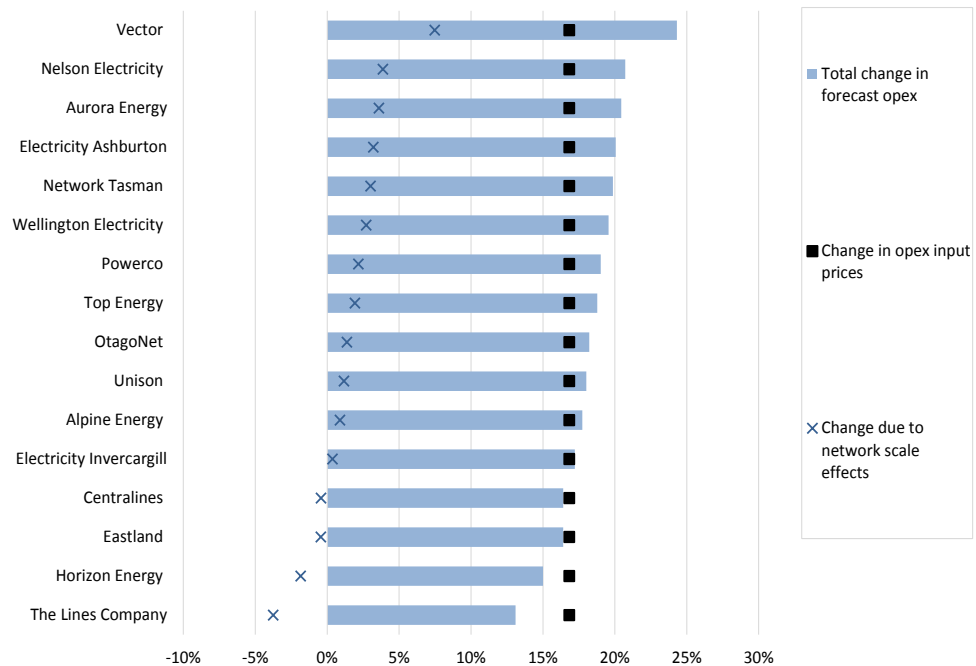
Table 2.1: Nominal operating expenditure forecasts 2016 to 2020 (\$m)

Distributor	2016	2017	2018	2019	2020
Alpine Energy	14.7	15.2	15.6	16.0	16.4
Aurora Energy	22.1	22.8	23.6	24.3	25.0
Centralines	4.5	4.6	4.7	4.9	5.0
Eastland	8.1	8.3	8.6	8.8	9.0
Electricity Ashburton	8.6	8.9	9.1	9.4	9.7
Electricity Invercargill	5.4	5.6	5.8	5.9	6.0
Horizon Energy	7.8	8.0	8.2	8.4	8.5
Nelson Electricity	2.5	2.6	2.6	2.7	2.8
Network Tasman	9.1	9.5	9.7	10.0	10.3
OtagoNet	7.5	7.7	7.9	8.1	8.3
Powerco	70.9	73.3	75.5	77.7	79.7
The Lines Company	10.7	11.0	11.2	11.4	11.6
Top Energy	13.6	14.0	14.5	14.9	15.3
Unison	35.9	37.0	38.0	39.1	40.0
Vector	108.6	113.0	117.2	121.6	125.6
Wellington Electricity	30.9	31.9	32.9	33.9	34.8
Total	360.8	373.5	385.2	397.2	408.0

Main drivers of operating expenditure for each distributor

- 2.5 Figure 2.1 shows the cumulative growth forecast from the 2013/2014 base year to 2019/2020 in each distributor's operating expenditure that is attributable to the three factors outlined above. The impact of changes in input prices and scale effects are also shown separately.
- 2.6 Partial productivity growth is assumed to be -0.25%, ie, we have assumed there will be a reduction in operating partial productivity relative to the rest of the economy. The base year value is calculated as the average of distributors' disclosed actual operating expenditure in 2012/2013 and 2013/2014 (in constant prices).

Figure 2.1: Cumulative growth in operating expenditure from 2014 to 2020



- 2.7 Cumulative growth in distributors' forecast operating expenditure over the 6 year period from 2013/2014 to 2019/2020 ranges from 13.1% for The Lines Company to 24.3% for Vector.
- 2.8 Negative changes due to network scale effects can be observed for The Lines Company, Horizon Energy, Eastland and Centralines. This analysis uses population growth projections from Statistics New Zealand as a proxy for changes in number of connections. The negative changes are a result of an expectation that the network areas that these distributors serve will experience population declines from 2013 to 2020.
- 2.9 In contrast, a relatively significant positive change due to network scale effects can be observed for Vector, Aurora and Electricity Ashburton. For these distributors, this is due in large part to projections that population will increase in their network areas between 2013 and 2020.
- 2.10 Figure 2.1 also shows a relatively significant positive change due to network scale effects for Nelson Electricity. This change is due to a projected increase in its network length between 2013 and 2020.

Comparison with distributor forecasts

- 2.11 Table 2.2 compares the allowances for operating expenditure to each distributor's forecast. It compares these forecasts on a cumulative basis over the years ending 2016 to 2020. The values are expressed in 2013 constant prices.

Table 2.2: Operating expenditure allowances compared to distributor forecasts (\$m)

Distributor	Distributor forecast	Our allowance	Difference (\$m)	Difference (%)
Centralines	14.5	21.5	7.0	32.5%
Electricity Invercargill	23.2	26.2	3.0	11.4%
Network Tasman	39.6	44.3	4.7	10.5%
OtagoNet	34.9	36.0	1.1	3.0%
Aurora Energy	103.9	107.1	3.2	3.0%
The Lines Company	50.3	50.9	0.6	1.2%
Top Energy	65.3	65.7	0.4	0.6%
Nelson Electricity	12.0	12.0	- 0.0	0.0%
Unison	175.6	172.9	- 2.8	- 1.6%
Vector	553.8	533.0	- 20.9	- 3.9%
Alpine Energy	73.7	70.9	- 2.8	- 3.9%
Powerco	361.9	343.2	- 18.7	- 5.5%
Horizon Energy	39.5	37.2	- 2.3	- 6.2%
Electricity Ashburton	45.6	41.5	- 4.1	- 9.8%
Wellington Electricity	166.6	149.6	- 17.0	- 11.4%
Eastland	53.5	38.9	- 14.6	- 37.5%
Total	1,814.0	1,750.8	- 63.1	- 3.6%

Note: Total for 2016 to 2020 in 2013 constant prices

- 2.12 We are allowing higher operating expenditure compared to distributor forecasts for seven distributors (Centralines, Electricity Invercargill, Network Tasman, OtagoNet, Aurora Energy, The Lines Company and Top Energy). For some distributors however, our allowances are significantly lower than the operating expenditure they have forecast, eg, Eastland Network and Wellington Electricity.⁷

⁷ Distributor forecasts of operating expenditure do not include expected expenditure on assets purchased from Transpower.

- 2.13 Our reasons for applying operating expenditure allowances that are different from distributor forecasts are discussed in Chapter 3.

Forecasts of capital expenditure

- 2.14 As explained in Chapter 4, our forecasts of capital expenditure are based on forecasts of network, and non-network capital expenditure.
- 2.14.1 Network capital expenditure is expenditure on assets that form part of the distribution network.
- 2.14.2 Non-network capital expenditure is expenditure on assets that do not form part of the distribution network.
- 2.15 Table 2.3 shows the combined amount of capital expenditure that we have forecast for each distributor in each year, expressed in current prices.

Table 2.3: Nominal capital expenditure forecasts 2016 to 2020 (\$m)

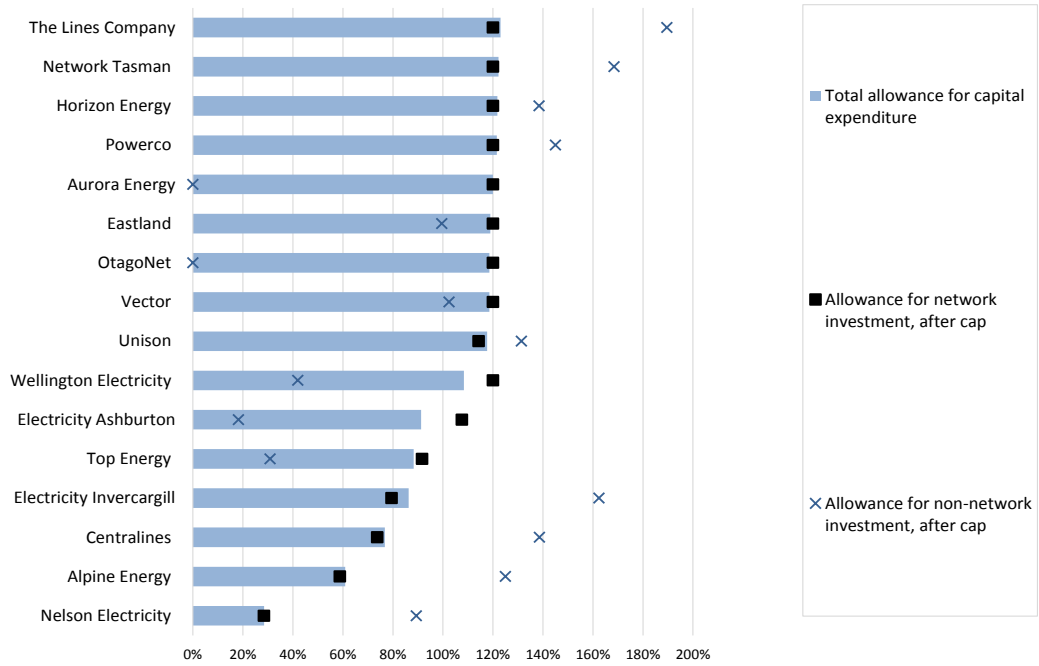
Distributor	2016	2017	2018	2019	2020
Alpine Energy	9.6	9.4	10.8	8.0	8.9
Aurora Energy	26.3	17.0	15.9	17.3	13.1
Centralines	3.4	3.0	3.2	3.0	2.8
Eastland	9.9	14.6	8.2	6.7	7.1
Electricity Ashburton	16.0	23.4	18.9	18.3	13.1
Electricity Invercargill	5.5	3.3	2.9	2.1	3.1
Horizon Energy	8.2	7.4	7.0	6.5	6.7
Nelson Electricity	0.8	1.0	1.5	1.6	2.0
Network Tasman	6.8	8.5	10.7	7.4	6.7
OtagoNet	11.2	9.7	10.6	10.7	10.5
Powerco	94.6	100.4	115.0	114.4	121.8
The Lines Company	14.4	10.0	10.1	9.6	11.3
Top Energy	17.2	20.6	17.8	16.3	18.4
Unison	47.7	38.5	37.4	37.4	34.3
Vector	151.0	156.7	160.7	166.7	162.5
Wellington Electricity	27.3	28.4	34.9	31.2	31.2
Total	449.8	451.9	465.6	457.3	453.6

- 2.16 Our forecasts of nominal capital expenditure provide for investment by distributors of around \$450 million in each year of the regulatory period (and almost \$2.3 billion for the entire regulatory period in today's prices).

Forecast relative to historic levels of investment

2.17 Table 2.4 shows the forecast of capital expenditure relative to each distributor’s historic levels of investment.

Table 2.4: Allowances for total capital expenditure relative to historic expenditure



2.18 Table 2.4 shows that our allowances for total capital expenditure relative to historic capital expenditure range from almost 28% for Nelson Electricity to 120% for The Lines Company. Allowances below 120%, relative to historic capital expenditure, are equivalent to the distributor’s own forecasts.

Comparison with distributor forecasts

2.19 Table 2.5 compares the allowances for capital expenditure to each distributor's own forecasts of capital expenditure for 2016 to 2020.

Table 2.5: Capital expenditure allowance compared to distributor forecasts (\$m)

Distributor	Distributor forecast	Our allowance	Difference (\$m)	Difference (%)
Alpine Energy	42.9	42.9	-	0.0%
Centralines	14.2	14.2	-	0.0%
Electricity Ashburton	82.5	82.5	-	0.0%
Nelson Electricity	6.3	6.3	-	0.0%
Top Energy	75.1	75.1	-	0.0%
Unison	180.0	179.8	- 0.2	- 0.1%
Electricity Invercargill	15.9	15.7	- 0.3	- 1.6%
Aurora Energy	84.9	82.7	- 2.2	- 2.6%
Vector	790.1	731.4	- 58.7	- 7.4%
OtagoNet	54.8	47.8	- 7.0	- 12.8%
The Lines Company	60.2	51.0	- 9.3	- 15.4%
Powerco	612.3	499.4	- 112.8	- 18.4%
Wellington Electricity	172.5	140.1	- 32.4	- 18.8%
Horizon Energy	44.0	32.9	- 11.0	- 25.1%
Eastland	38.7	28.3	- 10.4	- 26.9%
Network Tasman	58.5	33.5	- 25.0	- 42.8%
Total	2,332.9	2,063.6	- 269.4	- 11.5%

Note: Total for 2016 to 2020 in 2013 constant prices

2.20 Table 2.5 shows that our capital expenditure allowances are the same as the forecasts of five distributors (Alpine Energy, Centralines, Electricity Ashburton, Nelson Electricity, and Top Energy). Our allowances are within 20% of forecasts for another eight distributors, and are up to 42.8% less than forecasts for the remaining three distributors.

2.21 Our reasons for limiting some distributors' forecasts are explained in Chapter 4.

Forecasts of revenue growth

2.22 This section shows the forecasts that we have made of each distributor's revenue over the regulatory period. First, we set out the forecasts of inflation we have used in predicting changes in revenue. Then we set out the forecasts we have made of revenue growth in constant prices.

Forecast of inflation used when predicting changes in revenue

2.23 Each distributor's revenue is affected by changes in inflation. The CPI-X% constraint affects the average price that each distributor is allowed to charge before pass-through costs and recoverable costs are taken into account.

2.24 The inflation forecasts that we relied on for our final decision are shown in Table 2.6.

Table 2.6: Forecast of inflation for predicting changes in revenue

Year ending	All distributors
2016	1.53%
2017	1.51%
2018	1.77%
2019	2.11%
2020	2.15%

2.25 The figures shown in Table 2.6 are different to the inflation figures shown in Table 2.11 because they are calculated on a slightly different basis. In particular, the values shown in Table 2.6 are calculated consistent with the way the price or revenue path will be updated during the regulatory period.⁸ However, the values in Table 2.11 are calculated consistent with the input methodology for rolling forward asset values during the regulatory period.⁹

⁸ The price path is updated for CPI during the period using a measure of the CPI that is lagged by 18 months. In addition, changes in the index are calculated by comparing the four quarter average for one year with the four quarter average for the previous year.

⁹ Asset values will be rolled forward during the regulatory period by applying a measure of the CPI that is not lagged. In addition, changes in the CPI are measured by comparing the value of the index in one quarter with the value of the index a year prior.

Forecasts of revenue growth in constant prices

- 2.26 Constant price revenue growth is the revenue growth that occurs as a result of changes in quantities billed. It is calculated separately for residential users and industrial and commercial users. Constant price revenue from residential users is modelled as a function of the number of residential users and energy use per residential user. Constant price revenue from industrial and commercial users is modelled as a function of GDP.
- 2.27 The forecast of each distributor's revenue growth in constant prices is shown in Table 2.7. This table shows the revenue growth that is forecast to occur as a result of changes in the quantities billed by each distributor.¹⁰

Table 2.7: Constant price revenue growth forecasts (%)

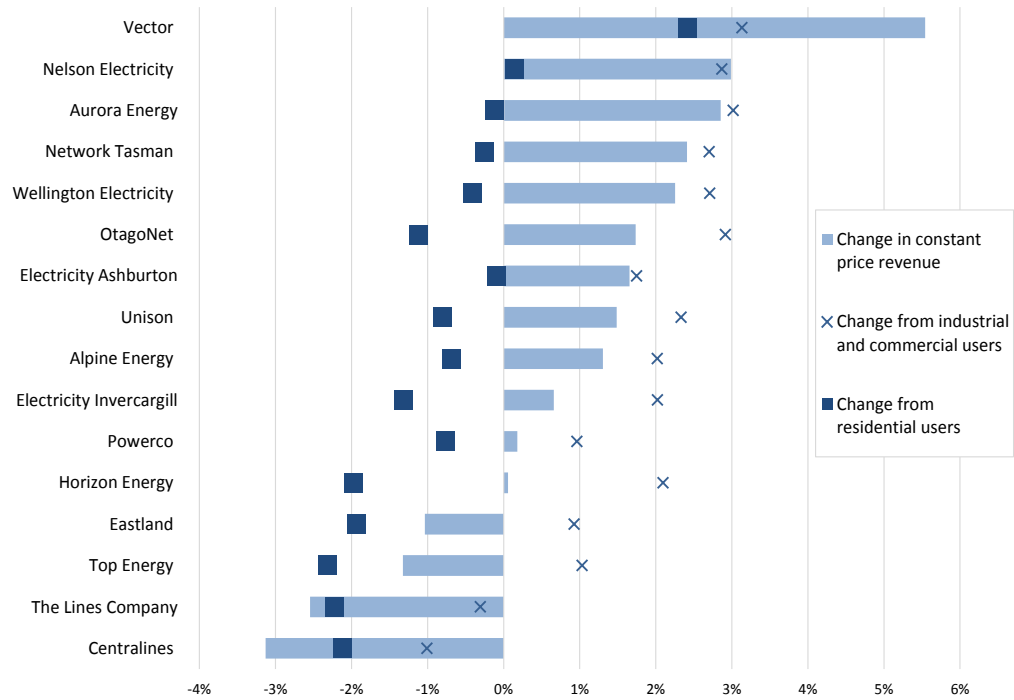
Distributor	2016	2017	2018	2019	2020
Alpine Energy	0.27	0.26	0.26	0.26	0.26
Aurora Energy	0.55	0.57	0.57	0.57	0.57
Centralines	-0.63	-0.63	-0.63	-0.63	-0.63
Eastland	-0.26	-0.19	-0.19	-0.19	-0.19
Electricity Ashburton	0.34	0.32	0.32	0.32	0.32
Electricity Invercargill	0.17	0.12	0.12	0.12	0.12
Horizon Energy	-0.02	0.02	0.02	0.02	0.02
Nelson Electricity	0.61	0.58	0.58	0.58	0.58
Network Tasman	0.50	0.47	0.47	0.47	0.47
OtagoNet	0.37	0.34	0.34	0.34	0.34
Powerco	-0.05	0.06	0.06	0.06	0.06
The Lines Company	-0.58	-0.50	-0.50	-0.50	-0.50
Top Energy	-0.36	-0.24	-0.24	-0.24	-0.24
Unison	0.28	0.30	0.30	0.30	0.30
Vector	1.03	1.10	1.10	1.10	1.10
Wellington Electricity	0.45	0.45	0.45	0.45	0.45

¹⁰ The forecast average change in the number of residential users, and forecast real GDP are constant over the period 2016-2020.

Main drivers of revenue growth in constant prices

2.28 Figure 2.2 presents the forecast cumulative change in constant price revenue for electricity distributors, broken down by user type. Our approach to forecasting revenue growth is discussed in more detail in Chapter 5.

Figure 2.2: Constant price revenue growth forecasts



2.29 Figure 2.2 shows that the main driver of revenue growth in constant prices for Vector is a forecast increase from residential users. This reflects Statistics New Zealand projections, which indicate that Auckland’s population is expected to grow faster than other regions in New Zealand between 2016 and 2020.

2.30 Figure 2.2 also shows a forecast decrease from residential users for several distributors, including Centralines and The Lines Company. This reflects projected declines in population for the network areas that these distributors serve.

Forecasts of asset disposals and other regulatory income

2.31 In this section we set out the values used for the other line items in our modelling, specifically:

2.31.1 Asset disposals; and

2.31.2 Other regulatory income.

2.32 These factors are further explained in Chapter 6.

Asset disposals

2.33 The value of disposals is the average of constant price historic disposals from 2010 to 2013 forecast forward using CPI as a price inflator. Table 2.8 shows the value of asset disposals that we have forecast for distributors from 2016 to 2020.

Table 2.8: Nominal asset disposal forecasts 2016 to 2020 (\$m)

Distributor	2016	2017	2018	2019	2020
Alpine Energy	0.3	0.3	0.3	0.4	0.4
Aurora Energy	0.2	0.2	0.2	0.3	0.3
Centralines	-	-	-	-	-
Eastland	0.4	0.4	0.4	0.4	0.4
Electricity Ashburton	1.4	1.4	1.4	1.5	1.5
Electricity Invercargill	0.3	0.3	0.3	0.3	0.3
Horizon Energy	0.3	0.3	0.4	0.4	0.4
Nelson Electricity	-	-	-	-	-
Network Tasman	0.4	0.4	0.4	0.4	0.4
OtagoNet	0.1	0.1	0.1	0.1	0.1
Powerco	8.3	8.5	8.7	8.9	9.1
The Lines Company	0.0	0.0	0.0	0.0	0.0
Top Energy	0.0	0.0	0.0	0.0	0.0
Unison	1.7	1.7	1.8	1.8	1.8
Vector	9.5	9.7	9.9	10.1	10.3
Wellington Electricity	0.1	0.1	0.1	0.1	0.1
Total	21.6	22.1	22.5	23.0	23.5

2.34 Disposals reduce the revenue allowance to suppliers on the basis that sale proceeds from an acquirer will provide a return of residual capital so this does not need to be recovered from electricity consumers.

Other regulated income

- 2.35 Other regulated income is income from the provision of regulated services that are not recovered through line charges (eg, rental income from regulated assets, and gains or losses on disposals). Other regulated income reduces the revenue allowance to suppliers. In calculating the value of other regulated income, we use the average of constant price historic disposals from 2010 to 2013 forecast forward using CPI as a price inflator.
- 2.36 Table 2.9 shows our forecasts of distributors' other regulated income from 2016 to 2020.

Table 2.9: Nominal other regulated income forecasts 2016 to 2020 (\$m)

Distributor	2016	2017	2018	2019	2020
Alpine Energy	- 0.3	- 0.3	- 0.3	- 0.3	- 0.3
Aurora Energy	2.0	2.0	2.1	2.1	2.2
Centralines	0.1	0.1	0.1	0.1	0.1
Eastland	- 0.1	- 0.1	- 0.1	- 0.1	- 0.1
Electricity Ashburton	- 0.1	- 0.1	- 0.1	- 0.1	- 0.1
Electricity Invercargill	- 0.1	- 0.1	- 0.1	- 0.1	- 0.1
Horizon Energy	0.1	0.1	0.1	0.1	0.1
Nelson Electricity	0.1	0.1	0.1	0.1	0.1
Network Tasman	0.4	0.4	0.4	0.5	0.5
OtagoNet	0.6	0.6	0.6	0.6	0.6
Powerco	- 8.0	- 8.2	- 8.4	- 8.5	- 8.7
The Lines Company	0.0	0.0	0.0	0.0	0.0
Top Energy	0.4	0.4	0.4	0.4	0.4
Unison	- 0.5	- 0.5	- 0.5	- 0.6	- 0.6
Vector	- 0.8	- 0.8	- 0.8	- 0.9	- 0.9
Wellington Electricity	0.4	0.4	0.5	0.5	0.5
Total	- 5.8	- 5.9	- 6.0	- 6.1	- 6.3

Weighted average cost of capital and forecast rate of inflation for asset revaluations

2.37 This section sets out our assumptions about the:

2.37.1 Weighted average cost of capital; and

2.37.2 Forecast rate of inflation for predicting asset revaluations.

Weighted average cost of capital — 7.19% used for final decision

2.38 The weighted average cost of capital (WACC) that we have used in reaching our final decision was 7.19%, which was our estimate of the WACC as at 1 September 2014. We published this estimate of the WACC on 31 October 2014.¹¹

2.39 Table 2.10 sets out the key parameters from the WACC determination.

Table 2.10: Main components of the Vanilla WACC

Parameter	Value	Parameter	Value
Risk free rate (5 years)	4.09%	Debt premium (5 years)	1.65%
Equity beta	0.61	Tax adjusted market risk premium	7.0%
Average corporate tax rate	28%	Average investor tax rate	28%
Debt issuance costs (5 years)	0.35%	Leverage	44%
Standard error of debt premium	0.0015	Standard error of WACC	0.011
Cost of debt (5 years; pre-corporate tax)	6.09%	Cost of equity (5 years)	7.21%
Vanilla WACC (5 years, midpoint)			6.72%
Vanilla WACC (5 years, 67th percentile estimate)			7.19%

2.40 The WACC that we have relied on is the 67th percentile Vanilla WACC. The corresponding midpoint estimate is 6.72%.

¹¹ *Cost of capital determination for electricity distribution businesses' default price-quality paths and Transpower's individual price-quality path* [2014] NZCC 28.

Forecast rate of inflation for predicting asset revaluations

2.41 Consistent with the input methodologies for asset valuation, we used a mix of actual and forecast data to predict inflation-indexed changes in asset values. In particular:

2.41.1 The actual data on the CPI was the latest available as at the time of our final decision, ie, the SE9A series published by Statistics New Zealand in June 2014; and

2.41.2 The forecast data was sourced from the Monetary Policy Statement from 12 June 2014, and applies from the June 2014 quarter to the March 2017 quarter.

2.42 The CPI data that we used to predict changes in asset values are shown in Table 2.11.

Table 2.11: Inflation adjustment for revaluations

Year ending	Forecast change in CPI
2013	0.86%
2014	1.53%
2015	1.43%
2016	1.74%
2017	2.11%
2018	2.17%
2019	2.11%
2020	2.06%

2.43 The series in Table 2.11 converges towards the target rate of inflation for the Reserve Bank of New Zealand. At present, the target rate is 2% within a symmetric range of 1% to 3%.

2.44 Our response to an issue previously raised by Vector that, if actual inflation is different to forecast inflation, then Financial Capital Maintenance may not be achieved on an ex post basis, is provided in Attachment F.

3. Operating expenditure

Purpose of chapter

- 3.1 This chapter outlines and explains our approach for forecasting operating expenditure.

Overview of approach

- 3.2 Consistent with our November 2012 approach, we have forecast operating expenditure for each distributor by projecting forward an initial level based on changes in three main expenditure drivers.¹² This general approach continues to receive support from submitters.¹³ We also consider whether any additional adjustments are required for costs that would not otherwise be captured in our forecast.
- 3.3 Our forecasts of operating expenditure have a significant impact on the prices that distributors will be allowed to charge once starting prices are adjusted. A 1% increase in operating expenditure translates into an increase of approximately 0.25% in the revenue that distributors can expect to earn.

¹² However, unlike the approach used in November 2012, the formula we used is multiplicative rather than additive.

¹³ Submissions are generally supportive of our general approach to forecasting operating expenditure, for example, “Unison is supportive of the general framework to take a base level of operating expenditure and escalate it forward for price, quantity and productivity movements. We have not seen evidence that an absolute approach would provide forecasts that reflect EDB’s reasonable operating expenditure requirements. Wellington Electricity also noted that “WELL considers that the base year, trend and step approach to forecasting operating expenditure is appropriate for the 2015-20 DPP reset”. See Unison Networks Limited “Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper” (30 April 2014), paragraph 26, Wellington Electricity Lines Limited “Draft Decision on 2015-2020 Default Price-quality Path” (15 August 2014), page 16.

- 3.4 The three main drivers used to project forward the initial amount of operating expenditure are:
- 3.4.1 Network scale – changes in the scale of the network affect operating expenditure due to changes in the level of service provided;
 - 3.4.2 Partial productivity – changes in productivity change the amount of operating expenditure needed to provide a given level of service,¹⁴ and
 - 3.4.3 Input prices – changes in input prices affect the cost of providing a given level of service.
- 3.5 Each of these drivers is discussed in the sections that follow. The formula we used is shown in Box 3.1. This formula results in an adjustment to operating expenditure in the previous year based on changes in each of the drivers.

Box 3.1: Formula for calculating operating expenditure

$$\begin{aligned} \text{operating expenditure}_t &= \text{operating expenditure}_{t-1} \times \\ &\quad (1 + \Delta \text{ due to network scale effects}) \times \\ &\quad (1 - \Delta \text{ partial productivity for operating expenditure}) \times \\ &\quad (1 + \Delta \text{ input prices}) \end{aligned}$$

- 3.6 It is appropriate to forecast operating expenditure in this way because the majority of operating expenditure 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.
- 3.7 Our approach recognises that some expenditure may not be recurring. We therefore consider whether any adjustment is required to the forecast to reflect significant expenditure that is not captured by the three main drivers.

¹⁴ The operating expenditure partial productivity measures changes in the ratio of operational expenditure to associated outputs.

Initial level of operating expenditure

3.8 The initial level of operating expenditure is the average of the amounts disclosed by distributors for the 2013 and 2014 disclosure years. This averaging approach is different to the approach proposed in the draft decision. For the draft decision, we relied solely on 2013 information.

3.9 We relied solely on information from 2013 for the draft decision because:

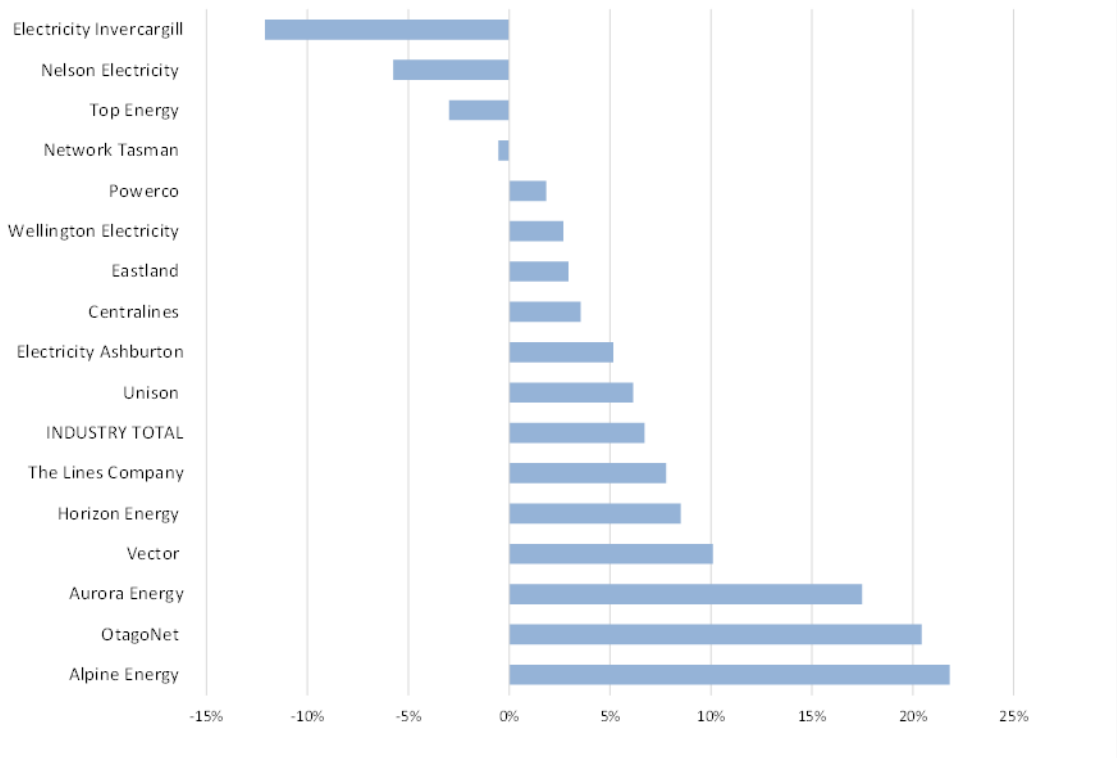
3.9.1 Data had not yet been disclosed for 2014; and

3.9.2 Distributor estimates for 2014 expenditure suggested the year was atypical.

3.10 However, we also noted that, because we are unable to review the efficiency of distributor’s disclosed level of expenditure, the weighting given to 2014 data would ultimately depend on contextual factors. We therefore invited submissions on the factors we should consider alongside the 2014 information when it was disclosed.

3.11 The graph below shows the difference between operating expenditure in 2013 and 2014. As can be seen from this graph, the information disclosed by distributors indicates that 2014 expenditure was significantly higher than that in 2013. These increases are lower, however, than suggested by the estimates disclosed in March 2014.

Figure 3.1: % change in total operating from 2013 to 2014



- 3.12 It is difficult to know whether the increase from 2013 to 2014 is due to anomalies in the 2013 year, the 2014 year, or both. All other things being equal, we would usually prefer to rely on the most recent data. However, our approach in November 2012 is likely to have provided incentives for distributors to advance or defer expenditure to 2014 (or find some other way to artificially inflate expenditure in that year).
- 3.13 Consequently, and as explained further in Attachment B, we have chosen to rely on an average between the two years. The Electricity Networks Association (ENA), PricewaterhouseCoopers (PwC) and Network Tasman supported this approach. The ENA highlighted that this mitigates the impact of anomalies in the data in either year.¹⁵
- 3.14 Historic operating expenditure in 2013 and 2014 has been adjusted to remove the costs associated with the judicial review and merits appeal challenges in those years. This is discussed further below and in Attachment B. In addition, we have updated the 2013 information consistent with our projection approach, eg, for scale growth.

¹⁵ Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 16; PwC "Submission to the Commerce Commission on Low Cost Forecasting Approaches For Default Price-Quality Paths - Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), paragraph 23; Network Tasman Limited "Submission to the Commerce Commission Concerning Low Cost Forecasting Approaches for Default Price Quality Paths" (15 August 2014), paragraph 4. Maui Development Limited and Wellington Electricity suggested a longer term base series be used (an average or weighted average of 2011-2014) to smooth any year-to-year variability. However, we do not prefer a longer time series of information, because it would use data that is less likely to reflect recent efficiency gains or losses. This option would also require re-disclosure of information consistent with input methodologies. See Maui Development Limited "Submission on the process and issues paper: Default price-quality paths from 1 April 2015 for 17 electricity distributors" (30 April 2014), p.1; Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" (15 August 2014), page 18.

Forecast change due to network scale effects

- 3.15 To estimate the impact of changes in scale on operating expenditure, we separately modelled the relationship between operating expenditure and network scale for:
- 3.15.1 Expenditure operating the network (network operating expenditure); and
 - 3.15.2 Expenditure to support network operations (non-network operating expenditure).
- 3.16 To estimate the impact of changes in network scale on each category, we used an econometric model to understand the relationships observed across the industry as a whole. As noted by Frontier Economics (on behalf of the ENA), such an approach “is reasonable” within our framework.¹⁶

Understanding the relationship between network scale and operating expenditure

- 3.17 Using econometric modelling, we identified two variables that appear to explain a reasonable proportion of changes in operating expenditure: changes in network length, and changes in the number of connections. A brief overview of our econometric modelling can be found in Attachment A.
- 3.18 For network operating expenditure, our econometric modelling suggests that:
- 3.18.1 A 1 % change in the length of the network is associated with a 0.44% change in network operating expenditure holding the number of connections fixed, on average; and
 - 3.18.2 A 1% change in the number of connections is associated with a 0.49% increase in network operating expenditure holding network length fixed, on average.
- 3.19 For non-network operating expenditure, our modelling suggests that a 1% change in the number of connections is associated with a 0.82% change in non-network operating expenditure, on average.
- 3.20 These coefficients have changed very slightly from the draft decision because we have updated the econometric model to include 2014 data. This data was not available at the time of the draft decision. The econometrics was independently reviewed as part of our draft decision.

¹⁶ Frontier Economics Limited “Output 1: Top-down approaches for forecasting EDB costs under a DPP framework - a report prepared for the Electricity Networks Association of New Zealand” (April 2014), p. 15.

Applying knowledge of relationship between network scale and operating expenditure

3.21 The next step in our modelling was to forecast the changes in the two variables, and then apply our knowledge about the relationship with operating expenditure.

3.21.1 Changes in network length were forecast by extrapolating historic trends for each distributor.

3.21.2 Changes in connection numbers were forecast by using independent forecasts of population growth as a proxy, and tailoring those forecasts to the area served by each distributor.

3.22 Some submitters suggested that the forecasts of population growth do not appropriately proxy changes in the number of connections.¹⁷ As discussed in Attachment A, we have considered alternatives to the population forecasts suggested by submitters. However, we still consider these forecasts to be the most appropriate proxy available at this time.

¹⁷ Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 30; PwC "Submission to the Commerce Commission on Low Cost Forecasting Approaches For Default Price-Quality Paths - Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), paragraph 26; Vector "Default Price-Quality Path 2015-2020 Draft Decision: Correction to submission on Forecasting Approaches" (29 August 2014), paragraph 51.

- 3.23 Information on historic network length was obtained from distributor's information disclosure. However, we note that there appears to be some data anomalies:
- 3.23.1 The Lines Company informed us of issues with historic line length data disclosures but has been unable to provide a series that is more accurate. To address this, we have used a combination of 2010, 2012, 2013 and 2014 disclosed data to determine a growth trend. We have excluded 2011 because a changing of asset management systems resulted in a clear anomaly.
 - 3.23.2 Powerco and Aurora informed us of issues with previously disclosed line length data and have submitted revised figures. We have used the resubmitted data in our analysis.
 - 3.23.3 Otagonet has confirmed that there is an error in their 2013 disclosed line length. We have omitted this number from our analysis and based the growth trend on 2010, 2011, 2012 and 2014 line length disclosures.
 - 3.23.4 Unison has informed us that their 2014 line length includes hot water circuits that were not counted in previous disclosures. We have derived a growth trend based on data from 2010 to 2013.

Forecast change in partial productivity

- 3.24 We have assumed a -0.25% annual change in operating expenditure partial productivity during the next regulatory period. This assumption is different to the 0% assumption that we proposed to rely on in the draft decision.
- 3.25 Our view has been informed by historical changes in partial productivity for New Zealand and overseas distributors. Our decision also takes into account future expectations of productivity growth as well as the potential incentives created by our decision.
- 3.26 Consistent with the productivity-based X factor, we have set the operating expenditure partial productivity to be the same for each distributor.

Estimates of historical changes in partial productivity in New Zealand

- 3.27 Alongside our draft decision, we published a copy of the study that Economic Insights undertook on the long run partial productivity improvement rate in New Zealand. Economic Insights estimated the long-term trend in operating expenditure partial productivity was between -1.4% and -0.45% over 2004 to 2014.¹⁸ We had previously hosted a workshop on this study, and in our draft decision we invited submissions on the report.
- 3.28 In response to our draft decision, the ENA provided a report from the Pacific Economics Group on the historical trend in partial productivity. This study identified a historical downward trend in operating partial productivity between -1.58% and -2.04% over 1998 to 2008.¹⁹
- 3.29 A key point of difference between the two studies is that Economic Insights have argued that the negative trend in partial productivity growth will not necessarily continue. The report by Economic Insights notes that cyclical factors may lead to periods of negative growth. However negative growth in partial productivity would be expected to be very much the exception.²⁰
- 3.30 We note Pacific Economics Group critiqued specific aspects of Economic Insights' draft report, and acknowledge the technical input this provided toward Economic Insights' final report.²¹
- 3.31 Economic Insights have also highlighted a number of fundamental issues with the model and data used by Pacific Economics Group to obtain its estimates.²²

¹⁸ Economic Insights "Electricity Distribution Industry Productivity Analysis: 1996–2013" (30 October 2014). A copy of the final report prepared by Economic Insights has been released alongside this paper.

¹⁹ Pacific Economics Group LLC "Productivity Trends of New Zealand Electricity Distributors" (June 2014).

²⁰ See Economic Insights "Review of submissions on electricity distribution productivity" (4 November 2014), p. 9.

²¹ Pacific Economics Group "Review of Economic Insights' Report *Electricity Distribution Productivity Analysis: 1996-2013*" August 2014.

²² Economic Insights "Review of submissions on electricity distribution productivity" 4 November 2014, pp. 2-7.

Other factors considered in reaching our decision

- 3.32 Our decision takes into account the historical negative productivity growth estimated for New Zealand distributors. However, we have also taken into account the following factors in reaching our decision of -0.25%:
- 3.32.1 Partial productivity growth may be underestimated as a result of step changes in expenditure. Distributors have submitted that their responsibilities have increased in recent years as a result of new regulatory obligations. These additional responsibilities have not been explicitly considered in the outputs used to estimate productivity estimates;²³
- 3.32.2 The potential adverse incentives created by adopting a negative growth rate. This may entrench recent declines in partial productivity and weaken incentives to improve efficiency. Economic Insights have noted that negative growth is expected to be the exception and that ongoing productivity decline is not typically a feature of workably competitive markets;²⁴ and
- 3.32.3 There have been generally positive improvements in productivity in the electricity distribution industry overseas. For example, operating expenditure partial productivity in the US was estimated to have improved by 1.5% annually over a similar period.²⁵

²³ Due to difficulties measuring the outputs associated with compliance activities, Economic Insights also recommend adopting a higher partial productivity growth rate than that calculated from the reported data. Economic Insights "Review of submissions on electricity distribution productivity" (4 November 2014), p. V.

²⁴ Economic Insights "Electricity Distribution Industry Productivity Analysis: 1996–2013" (30 October 2014), pp. 38 - 39.

²⁵ Economic Insights found only two instances where estimates of historic improvements in total factor productivity overseas were estimated to be negative, with the remaining estimates ranging from 0% to 1.5%. See Economic Insights "Electricity Distribution Industry Productivity Analysis: 1996–2013" (30 October 2014), p.30-31. We discuss the X-factor and allowable rates of change in price in: Commerce Commission, Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main policy paper, (28 November 2014).

- 3.33 Submissions generally supported a greater reliance on the historic-based productivity assessment provided by Economic Insights and the Pacific Economics Group.²⁶ However, we are mindful that these productivity estimates reflect past economic conditions which may not necessarily reflect future economic conditions.²⁷ Therefore while we have based our productivity decisions on historic information we have also taken a forward-looking view.
- 3.34 It is not feasible to undertake quantitative analysis that incorporates the factors discussed above. Therefore, it is necessary to use regulatory judgement to determine the partial productivity figure based on the qualitative and quantitative evidence available.

Forecast change in input prices

- 3.35 Consistent with our approach in November 2012 and in our draft decision, we inflate operating expenditure using a weighted average of:²⁸
- 3.35.1 Forecast changes in the all industries labour cost index; and
 - 3.35.2 Forecast changes in the all industries producer price index.
- 3.36 We have used the latest available forecasts produced by the New Zealand Institute of Economic Research. These forecasts have been updated since our draft decision.
- 3.37 We have weighted the forecast labour cost index by 60% and the forecast producer price index by 40%. This is based on analysis of labour expenditure in the Australian power industry, and is consistent with the weightings used in the previous reset.²⁹
- 3.38 Further explanation of our approach to forecasting changes in input price can be found in Attachment C.

²⁶ See, for example, Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 38; PwC "Submission to the Commerce Commission on Low Cost Forecasting Approaches For Default Price-Quality Paths - Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), paragraph 32.

²⁷ Past economic conditions were also considered for the 2010 initial reset of the default price-quality path. See Commerce Commission "Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses" (30 November 2009), paragraphs 5.38 – 5.43.

²⁸ These forecasts were sourced from the New Zealand Institute of Economic Research.

²⁹ Pacific Economics Group "TFP Research for Victoria's Power Distribution Industry: 2005 Update" report prepared for Essential Services Commission, 2006. Meyrick and Associates "The Total Factor Productivity Performance of Victoria's Gas Distribution Industry", report prepared for Envestra, Multinet and SP AusNet, Denis Lawrence, 2007.

Additional adjustments for costs not captured in our forecast

3.39 We have decided not to include any additional adjustments for costs not captured in our forecast. We considered suggestions from stakeholders of additional adjustments to the forecast operating expenditure, and assessed these against the criteria set out previously.³⁰ Based on the evidence provided, we were not persuaded that any of the proposed adjustments met these criteria.

Criteria used to assess the proposed additional adjustments

3.40 These criteria are that the costs must meet all of the following:

3.40.1 Be significant;

3.40.2 Be robustly verifiable;

3.40.3 Not be captured in the other components of our projection;

3.40.4 Be largely outside the control of the distributor; and

3.40.5 In principle, be applicable to most, if not all, distributors.

3.41 Our criteria for including an additional adjustment are intended to ensure that any additional adjustment meets the following objectives:

3.41.1 Reflects efficient expenditure;

3.41.2 Is consistent with the relatively low cost nature of the default price-quality path; and

3.41.3 Does not result in double-counting of operating expenditure.

3.42 We do not consider that allowing suppliers to submit anticipated step changes on the basis of director certification alone, as suggested by Horizon Electricity, would achieve the same outcomes.³¹

3.43 A number of additional adjustments have been suggested by stakeholders throughout the consultation process.

³⁰ Commerce Commission "Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors" (30 November 2012), paragraph C40; Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Low cost forecasting approaches " (4 July 2014), paragraph 3.30.

³¹ Horizon Energy Distribution Limited "Submission on Low Cost Forecasting Approaches For Default Price-Quality Paths" (15 August 2014), paragraph 11.

Additional costs of compliance

- 3.44 Some submitters expect a step change in operating expenditure due to additional compliance costs, including changes in health and safety regulation and meeting enhanced information disclosure requirements.³² The ENA suggest an additional adjustment of \$140,000 per distributor.³³
- 3.45 We consider that these compliance costs are already captured in other components of our projections and do not therefore fulfil the criteria set out above. Any expenditure resulting from the additional compliance requirements will likely be reflected in the initial level of operating expenditure, which uses distributor's actual costs in 2013 and 2014. It will therefore include:
- 3.45.1 Any step change in the costs of complying with the Part 4 regulatory regime as distributors have been disclosing information under the new information disclosure requirements since 2013; and
- 3.45.2 Recent and ongoing increases in health and safety costs. Distributors have indicated that new health and safety regulations have contributed to an increase in operating expenditure in recent years.³⁴
- 3.46 MEUG suggested that distributors will face decreased legal and compliance costs in the next regulatory period, as they will not have to bear the costs of setting up the Part 4 regime, and the costs of bringing judicial review and merits appeals of the Commission's decisions.³⁵
- 3.47 We have removed the legal costs associated with the legal challenges to the 2010 input methodology determinations from the data used to establish the initial level of operating expenditure. As discussed in Attachment B, these costs should not be borne by consumers.

³² For example, Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" (30 April 2014), paragraph 38. Vector "Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper" (30 April 2014), paragraphs 111-112.

³³ Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 44.

³⁴ See, for example, Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 40.

³⁵ Major Electricity Users' Group "Low cost forecasting approaches for DPP" (15 August 2014), paragraph 3.

- 3.48 Our understanding is that some of the legal costs associated with the appeals currently comprise a component of reported operating expenditure in 2013 and 2014. An adjustment is necessary to ensure these costs are not automatically reflected in the initial level of operating expenditure, and therefore the projected operating expenditure for the 2015-2020 regulatory period.

Additional operating expenditure for spur assets

- 3.49 Some submitters suggested an additional adjustment for operating expenditure associated with spur assets.³⁶
- 3.50 As discussed in our Main Policy Paper, distributors have an incentive to purchase spur assets as a result of the recoverable cost for the Avoided Cost of Transmission. They are therefore already compensated for the additional operating expenditure associated with spur assets over the regulatory period.
- 3.51 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.
- 3.52 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.

Additional expenditure for earthquake resilience

- 3.53 Wellington Electricity submitted that they expect a step change in operating expenditure due to strengthening buildings for increased earthquake resilience requirements. No other submitter has stated this as a step change and therefore we do not consider that this meets the criteria of being applicable to most distributors.³⁷

³⁶ The ENA and PwC suggest an additional allowance should be included where these assets are transferred during or after the disclosure years used in calculating the initial level of operating expenditure. Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 47; and PwC "Submission to the Commerce Commission on Low Cost Forecasting Approaches For Default Price-Quality Paths - Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), paragraph 69.

³⁷ Wellington Electricity Lines Limited "Submission on issues paper on 2015-2020 Default Price-quality Path" (30 April 2014), p.4.

An ex-ante allowance for customer service lines

- 3.54 The ENA submitted on our issues paper about increased responsibilities around customer service lines.³⁸
- 3.55 We have not created an ex-ante allowance for customer lines services because:
- 3.55.1 The uncertainty of potential costs over the next regulatory period make them unable to be robustly verified; and
- 3.55.2 We have not been persuaded that the potential costs to distributors over the next regulatory period are significant or immediate enough to warrant the introduction of either an ex-ante allowance or an ex post recovery mechanism.

Summary of information sources for forecasts of operating expenditure

- 3.56 Table 3.1 below provides a summary of the information sources that we have relied on to produce our forecast of operating expenditure.

Table 3.1: Information for forecasting operating expenditure

Item	Information used	Source
Initial level of operating expenditure	2013 and 2014 actual operating expenditure	Electricity distributors' information disclosures
Changes in scale – individual connection points (ICPs)	2011-2021 population growth statistics are used as a proxy	Statistics New Zealand October 2012
Changes in scale – network length	Extrapolation of historic network length (2010-2014)	Electricity distributors' information disclosures
Impact of changes in scale on operating expenditure	Historic ICP and network length data (2004-2014)	Electricity distributors' information disclosures
Changes in partial productivity for operating expenditure	Partial productivity estimate for operating expenditure	Economic Insights "Electricity Distribution Industry Productivity Analysis: 1996–2013" October 30 2014
Changes in input prices	Labour price index Producer price index	New Zealand Institute of Economic Research September 2014

³⁸ Sapere Research Group Limited "Report for the Electricity Networks Association - Recommended Approach to Address Customer Service Lines Issues" (9 December 2013).

4. Capital expenditure

Purpose of chapter

- 4.1 This chapter outlines and explains our approach for forecasting capital expenditure, which differs for the periods before and after 1 April 2015. We explain in this chapter:
- 4.1.1 Our approach to forecasting capital expenditure up to 31 March 2015 (ie, before the start of the regulatory period);
 - 4.1.2 Our approach to forecasting capital expenditure for the period 1 April 2015 onwards;
 - 4.1.3 How we set the size and apply a limit to capital expenditure forecasts for network and non-network expenditure; and
 - 4.1.4 The information sources used to calculate the capital expenditure forecasts.
- 4.2 Our capital expenditure forecasts are important for setting the default price-quality path because they are used to determine the allowable revenue from assets commissioned during the regulatory period.

Capital expenditure forecasts prior to 31 March 2015

- 4.3 As well as determining the capital expenditure forecast for the forthcoming regulatory period we are also required to determine a forecast of expenditure for the last year of the current regulatory period. This forecast is used to determine the value of commissioned assets that will have entered the regulatory asset base by the start of the next default price-quality path, ie, 1 April 2015.
- 4.4 For the final decision we have used the forecast of capital expenditure disclosed by distributors in March 2014 without applying any limit. We consider that this is the most appropriate forecast because:
- 4.4.1 The March 2014 forecast is likely to provide greater accuracy for the final year of the current regulatory period as it is closer to the year of actual expenditure than forecasts for later years; and
 - 4.4.2 We have introduced an amendment to input methodologies that introduces an additional recoverable cost term to correct (or 'wash-up') for the difference between the forecast of capital expenditure up to 31 March 2015 against the out-turn value of commissioned assets.

- 4.5 The additional recoverable cost term means that neither consumers nor distributors gain or lose from the difference between forecast and out-turn expenditure prior to the start of the regulatory period.

Forecasts of capital expenditure for the period 1 April 2015 onwards

- 4.6 Within certain limits, we relied on each distributor's forecast to model their capital expenditure. Each distributor's forecast provided a good starting point because distributors have access to the best information on:
- 4.6.1 Current and future demand drivers for its services;
 - 4.6.2 How to efficiently meet this demand; and
 - 4.6.3 The costs incurred in providing the services.
- 4.7 In addition, the risk to consumers of providing distributors with a higher than necessary allowance for capital expenditure is lower than it is for operating expenditure. This is because, compared to operating expenditure, capital expenditure has a lower impact on allowed prices.³⁹

³⁹ For example Unison estimate that difference in distribution revenues between providing an allowance equivalent to historical capital expenditure and allowance based on 120% of historical expenditure is approximately 1.5% of total revenues. Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" (30 April 2014), paragraph 52.

Limit applied to distributor forecasts

- 4.8 We have applied a limit to distributor's forecasts because:⁴⁰
- 4.8.1 By relying on each distributor's forecast in the past, we provided distributors with an incentive to systematically bias their forecast to increase their starting price, eg, by adopting low risk assumptions when forecasting future asset needs; and
 - 4.8.2 Applying a limit is consistent with the overall regulatory regime where customised price-quality paths are the mechanism to address a material business-specific step change in investment.
- 4.9 The limit was applied to the forecast that each distributor disclosed in March 2014. This data was supplied in constant prices for the years ending 2014 to 2020.⁴¹
- 4.10 The size and nature of the limit is explained in paragraphs 4.26 to 4.87.

⁴⁰ The option of using the distributor's forecast (with no limit) was rejected for two main reasons. First, it creates a strong incentive for the distributor to incorporate low risk assumptions or use approaches that result in systematic bias. This bias might only be countered by the incentives created by our requirements on distributors to publically disclose information about the performance of their business and our summary and analysis of that information. Second, it may reduce the incentives to achieve efficiencies in capital expenditure. A distributor would be able earn an acceptable return without achieving efficiencies in the amount of capital expenditure incurred in providing electricity lines services.

⁴¹ Commerce Commission "Notice to Supply Information to the Commerce Commission under section 53ZD of the Commerce Act 1986" (22 June 2012).

Impact of capital expenditure limit on smaller suppliers

- 4.11 Submissions in response to both the Process and Issues Paper and draft decision expressed concerns that placing a limit on forecast capital expenditure might particularly disadvantage smaller distributors.⁴²
- 4.12 We explain in Attachment B of our Main Policy Paper how we weighed up the costs and benefits of including an additional allowance to reduce the probability of a distributor earning less than a normal return, and making a customised price-quality path proposal.⁴³
- 4.13 This approach ensures that smaller distributors who require a large one-off expenditure increase are compensated in the event that applying for a customised price-quality path would not be beneficial over the longer term to consumers. An alternative way of looking at this approach is that it provides the equivalent to a higher cap on capital expenditure under these circumstances.

Forecast of capital expenditure was based on two categories

- 4.14 We separated the forecast for capital expenditure into two categories:
- 4.14.1 'Network capital expenditure' involves assets that form part of the distribution or transmission network; and
 - 4.14.2 'Non-network capital expenditure' involves assets employed in supplying regulated services that do not form part of the distribution or transmission network.
- 4.15 The forecasts for each category of capital expenditure were combined in each year, and then adjusted to reflect forecast changes in input prices.

⁴² For example: Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" (30 April 2014), paragraph 57; and OtagoNet "Submission of the OtagoNet Joint Venture To the Commerce Commission On the Proposed Default-Price Quality Paths" (15 August 2014), paragraph 4.4.

⁴³ Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Main policy paper" (28 November 2014), Attachment B.

Retention factor in the incentive scheme to control capital expenditure

- 4.16 Through an amendment to input methodologies, we have put in place an incentive to control capital expenditure that has a constant strength in each year of a default price-quality path.⁴⁴
- 4.17 Under the capital incentive scheme we are required to set a retention factor that applies to capital expenditure incurred during the forthcoming default price-quality path.
- 4.18 For the draft decision we proposed to apply a retention factor of 20%, ie, distributors would retain 20% of each dollar of capital expenditure they save.⁴⁵
- 4.19 Submissions on the whole suggest that the capital expenditure retention factor is too high and should be lowered. The ENA, Vector, Powerco and PwC all suggested a retention factor of between 5% and 10% if a symmetric incentive was applied.⁴⁶ The exception was Wellington Electricity who submitted that the retention factor should increase to align it with the incentives for operating expenditure.⁴⁷
- 4.20 Submitters also suggested that we should consider asymmetric retention factors that would be applied at different rates for overspend and underspend, or at different rates for different levels of overspend. However, an asymmetric approach has been ruled out for reasons explained in the accompanying paper on incentives to control expenditure.⁴⁸
- 4.21 The draft decision set a retention factor lower than the equivalent operating expenditure incentive due to the limitations inherent in the low cost approach to forecasting capital expenditure in the default price-quality path.

⁴⁴ Commerce Commission "Input methodology amendments for electricity distribution services and Transpower New Zealand: Incremental Rolling Incentive Scheme" (27 November 2014).

⁴⁵ Commerce Commission "Low-cost forecasting approaches for default price-quality paths" (4 July 2014), paragraph 4.12.

⁴⁶ For example see: Powerco "Submission on proposed amendments to amendments to input methodologies: Incremental Rolling Incentive Scheme" (29 August 2014), paragraph 48.

⁴⁷ Wellington Electricity "Proposed amendment to input methodologies: Incremental Rolling Incentive Scheme" (29 August 2014), p.2.

⁴⁸ Commerce Commission "Input methodology amendments for electricity distribution services and Transpower New Zealand: Incremental Rolling Incentive Scheme" (27 November 2014).

- 4.22 There has also been a historic tendency for out-turn capital expenditure to be lower than distributor's forecasts.⁴⁹ These factors outweighed the objective of fully aligning the incentive rate for capital expenditure with operating expenditure as per the submission from Wellington Electricity.
- 4.23 This is the first default price-quality path to which we are applying a capital incentive scheme. As such, we believe it is prudent for the capital expenditure retention factor to be broadly consistent with the average capital expenditure incentive that would occur without the capital expenditure incentive mechanism.
- 4.24 Our draft decision set the retention factor at 20%. This was considered in line with the average retention factor for capital expenditure under a price path without a capital expenditure incentive mechanism.⁵⁰ However the introduction of a wash-up for capital expenditure that takes place prior to the start of the price-quality path reduces the average natural incentive.⁵¹ Differences between forecast and actual expenditure over this period are no longer borne by the distributor.
- 4.25 The reduction in the equivalent retention factor that would occur without the capital expenditure incentive mechanism has resulted in us reducing the retention factor applied in the default price-quality price to 15% for the final decision. This decision is consistent with the majority of submitters who indicated they thought a lower retention factor was more appropriate.

Network capital expenditure — size and application of limit

- 4.26 We have limited forecast network capital expenditure for all distributors to 120% of historical expenditure. This is a change from the draft decision in which the limit was dependent on the reliability of the forecast used for the previous reset in November 2012.
- 4.27 We have retained the historical reference period against which the limit is applied. It remains a 5 year period from 2010–2014 but we have updated the data from which we calculate this reference amount to provide consistency with the current definitions of capital expenditure outlined in the input methodologies.

⁴⁹ Commerce Commission "Low-cost forecasting approaches for default price-quality paths" (4 July 2014), paragraph 4.14.

⁵⁰ The actual retention factor under a price-quality path without a capital expenditure incentive scheme depends on the WACC applied and the asset lifetime assumption.

⁵¹ This wash-up corrects for the difference between forecast and actual commissioned assets in the year prior to the start of the default price-quality path on 1 April 2015. See: Commerce Commission "Input methodology amendments for electricity distribution services: Default price-quality paths" (27 November 2014), chapter 7.

Inclusion of financing costs in network capital expenditure

- 4.28 Network capital expenditure forecasts for the draft decision were based on the forecasts provided in distributor's asset management plans. The forecasts used in the draft decision were of 'Expenditure on Network Assets' and we netted off forecasts of any capital contributions.
- 4.29 Submissions from Horizon and Powerco⁵² suggested that an additional allowance for the cost of financing should be included in the capital expenditure forecasts. This would ensure consistency with the definition of capital expenditure in the input methodologies.
- 4.30 We agree with these submissions and have therefore ensured that the forecast of financing costs provided by distributors in their asset management plans is added to the forecast of capital expenditure. For the same reason we have also included forecasts of the value of vested assets provided in the asset management plan.
- 4.31 Forecasts of financing costs and the value of vested assets are only available in nominal terms from the asset management plans and are not split between network and non-network capital expenditure.
- 4.32 Given the general low materiality of financing costs and the value of vested assets in relation to total capital expenditure we have made two simplifying assumptions in order to include these costs in the capital expenditure forecasts:
- 4.32.1 We have deflated the nominal price forecasts using our forecast of the capital goods pricing index (CGPI); and
- 4.32.2 We have assumed that all of the financing costs and value of vested assets is related to network capital expenditure.⁵³

We are applying a single limit across all distributors

- 4.33 The draft decision proposed that the limit applied to forecasts of network capital expenditure for this reset would depend on the reliability of the distributor's forecast that was used for the previous reset in November 2012.

⁵² Horizon Energy Distribution Limited "Submission on Low Cost Forecasting Approaches For Default Price-Quality Paths" (15 August 2014), paragraph 27; and Powerco "Submission on proposed amendments to amendments to input methodologies: Incremental Rolling Incentive Scheme" (29 August 2014), paragraph 66.

⁵³ This has been done for practical reasons, given that network capital expenditure is by far the largest on the two types of capital expenditure and likely to contain the biggest investments.

- 4.34 A number of submissions were made on our proposed evaluation of the previous forecast against out-turn. These included views on both the conceptual validity of the approach and also the practical implementation proposed in the draft decision.
- 4.35 Vector, Castalia and PwC had concerns on the conceptual approach. They suggested that it was retrospective and would confuse the incentives associated with cost minimisation. They also suggested that distributors could face future penalties for efficiency gains.⁵⁴
- 4.36 Unison were concerned about retrospective evaluation of forecasts which was not known about when the forecasts were made.⁵⁵
- 4.37 A different view was put forward by MEUG who supported the approach.⁵⁶ Powerco supported the approach in principle, but consistent with a number of other submissions thought the current implementation had flaws.⁵⁷
- 4.38 Submitters suggested that certain firms are unfairly penalised due to the change in capital expenditure reporting following the introduction of the input methodologies, in particular from the impact on the treatment of related party transactions and capital contributions.⁵⁸
- 4.39 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.
- 4.40 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.

⁵⁴ Castalia Strategic Advisors "Review of Electricity Default Price-Quality Path Determination 2015 - Report to Vector" (August 2014), p.17; Vector "Submission on DPP low-cost forecasting approaches" (15 August 2014), paragraph 14; and PwC "Submission to the Commerce Commission on Low Cost Forecasting Approaches For Default Price-Quality Paths - Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), paragraph 44.

⁵⁵ Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Draft Decisions" (15 August 2014), paragraph 75.

⁵⁶ Major Electricity Users' Group "Low cost forecasting approaches for DPP" (15 August 2014), paragraph 8.

⁵⁷ Powerco "Submission on Default price-quality paths for electricity distributors from 1 April 2015 and Low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 5.

⁵⁸ PwC "Submission to the Commerce Commission on Low Cost Forecasting Approaches For Default Price-Quality Paths - Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), paragraph 43

- 4.41 In response to Unison's submissions, we consider that it is appropriate for us to assess a previous capital expenditure forecast, even if we did not outline that at the time at the time the forecast was made. We would not expect the knowledge of any future assessment to have an impact on the forecasting performance of distributors.
- 4.42 We also note the concern from relying on only one forecast in evaluating distributor performance. However the low cost context of the default price-quality path means that it would be inappropriate to spend significant time evaluating a series of forecasts or investigating particular distributor circumstances that may have led to an inaccurate forecast.
- 4.43 Submissions also suggest that changes to the reporting of capital expenditure, as part of the introduction of the input methodologies, could potentially penalise distributors whose 2010 asset management forecasts were not on a consistent basis with actual expenditure reported at a later date.
- 4.44 We have weighed up the concern over the implementation of the forecast evaluation against the incentives it could provide to improve forecasting accuracy.
- 4.45 Given this trade-off we have decided for this reset not to introduce the forecasting assessment for the purposes of setting the capital expenditure cap for the default price-quality path. This is because some distributors could be unfairly penalised through changes to capital expenditure definitions.
- 4.46 All distributors will therefore be subject to the same limit against historical expenditure for this reset of the default price-quality path.
- 4.47 We believe evaluating the forecast capital expenditure against out-turn is a useful assessment to make and we expect to undertake this type of assessment in future.

The single limit applied to distributors is equivalent to 120% of historical expenditure

- 4.48 The draft decision proposed that the network capital expenditure forecasts should be capped at 120% of historical capital expenditure (unless the cap was reduced to reflect forecast inaccuracy).
- 4.49 The approach taken in the draft took into account a number of competing factors including the trade-off between allowing a higher limit, which may result in greater incentives to bias upwards future forecasts, and a lower limit that could restrict future investment required by the network.⁵⁹

⁵⁹ Commerce Commission "Low-cost forecasting approaches for default price-quality paths" (4 July 2014), paragraph 4.18.

- 4.50 Submitters provided a range of views on the limits that we had proposed for capital expenditure.
- 4.51 The majority of ENA members accept that a limit should apply.⁶⁰ Exceptions who made submissions were Wellington, The Lines Company, and OtagoNet who were not in favour of limits being applied to asset management plans. They believed these published plans were the best source of information for future network investment requirements.⁶¹
- 4.52 Powerco suggested a limit should be applied but at a higher rate.⁶² However both Unison and Vector suggested a 120% limit could be appropriate for the purposes of default price-quality path.⁶³
- 4.53 Following submissions we have decided to set the single limit on capital expenditure at the higher rate of 120% set in the draft decision. In our view a limit at this level strikes an appropriate balance.
- 4.54 It allows distributors to increase capital expenditure to a certain degree in order to cope with short-term fluctuations and longer term increases in expenditure requirements, but at the same time does not allow large increases without the greater scrutiny of a customised price-quality path.

⁶⁰ Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 52.

⁶¹ See, for example, Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" (15 August 2014), p.22.

⁶² Powerco "Submission on Default price-quality paths for electricity distributors from 1 April 2015 and Low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 9.

⁶³ Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Draft Decisions" (15 August 2014), paragraph 73; and Vector "Submission on DPP low-cost forecasting approaches" (15 August 2014), paragraph 85.

4.55 In making this decision we considered that:

- 4.55.1 The distributor has the most information about future capital expenditure required by the network and the 120% limit allows a significant increase against historical expenditure without the further scrutiny of a customised price-quality path;
- 4.55.2 There is benefit in maintaining broad consistency across various sectors subject to price-quality path regulation as it provides greater certainty on expectations of suitable step changes in expenditure under a default price-quality path;⁶⁴
- 4.55.3 Evaluation of historical trends in capital expenditure shows that it has been increasing at approximately 4-5%⁶⁵ per annum across the non-exempt distributors. A 120% limit allows a significant proportion of these historic trends to continue without requiring application for a customised price-quality path; and
- 4.55.4 The approach is also consistent with the intent of using customised price-quality paths for business-specific step changes in expenditure.

⁶⁴ The 120% limit was applied for the gas default price path where it was considered an appropriate the limit for capital expenditure increases without applying for a customised price-quality path.

⁶⁵ The exact percentage increase depends of the time period analysed.

The historical reference period has been retained as 2010–2014

- 4.56 Following the draft decision we also received submissions suggesting that the historical reference period against which we calculate the capital expenditure limit should be changed. For example:
- 4.56.1 Horizon suggested we should use the average of 2013 and 2014 because the historical reference period on which we applied the cap in the draft decision used data from the original reporting schedules which was not compliant with the 2012 input methodologies;⁶⁶
 - 4.56.2 Powerco suggest we should use the average of 2012 to 2014 as it is more reflective of current expenditure;⁶⁷ and
 - 4.56.3 Wellington suggest that 2010 should be excluded for them as it was an abnormally low year due to management transition following the ownership change.⁶⁸
- 4.57 The ENA also mention that we should ensure we take into account the regulatory environment at the time of the historical reference period.⁶⁹
- 4.58 We can speculate on the incentives on suppliers in each of these years, but given the uncertainty over this period amidst the introduction of the input methodologies, it would be difficult to identify the exact details of all the incentives on the distributors and correct for them in the data.

⁶⁶ Horizon Energy Distribution Limited "Submission on Low Cost Forecasting Approaches For Default Price-Quality Paths" (15 August 2014), paragraph 25.

⁶⁷ Powerco "Submission on Default price-quality paths for electricity distributors from 1 April 2015 and Low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 21.

⁶⁸ Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" (15 August 2014), p.22.

⁶⁹ Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 52.

- 4.59 Other reasons mean that we think it is appropriate to have a relatively large number of years as the reference period:
- 4.59.1 The ‘lumpy’ nature of capital expenditure investment, as described in the Process and Issues Paper, means that averaging it over the period does not result in large distortions from one or two years of particularly large expenditure;⁷⁰ and
- 4.59.2 The broad natural incentives in a regulatory period to delay investment towards the end of the period, means that we would have reservations in focussing the reference period on a small number of years close to the end of the previous regulatory period.
- 4.60 We also describe later in this chapter how we are applying a ‘floor’ on capital expenditure in the first year of the regulatory period. This is calculated as the average of the last three years of capital expenditure. This ensures that we do take into account the more recent information to ensure there is not a large fall in allowed capital expenditure relative to recent history.⁷¹
- 4.61 The reasons outlined above convince us that it is appropriate to have a relatively large number of years as the reference period. We therefore see no reason to move from the current period of 2010 to 2014.
- 4.62 The data issues associated with the historical capital expenditure (prior to 2012) do not have the same influence as they did for the forecasting evaluation applied in the draft decision.
- 4.63 Historical capital expenditure for the years 2010 to 2012, consistent with the definitions under the input methodologies, was provided as part of the 2013 information disclosure requirements (Schedule 5h(iv)). We have therefore used this source to obtain historical expenditure over the period 2010–2012 rather than the originally disclosed data used in the draft decision.⁷²
- 4.64 We have not been persuaded that we should make a special allowance for Wellington in 2010 as making exemptions of this type that apply to one distributor are not consistent with the low cost approach of a default price-quality path.

⁷⁰ Commerce Commission “Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues paper” (21 March 2014), paragraph 2.27–2.29.

⁷¹ Distributors have the option of a CPP if, as a consequence of applying ‘the floor’, capital expenditure in later years is below what is required. We understand Powerco are considering this option currently.

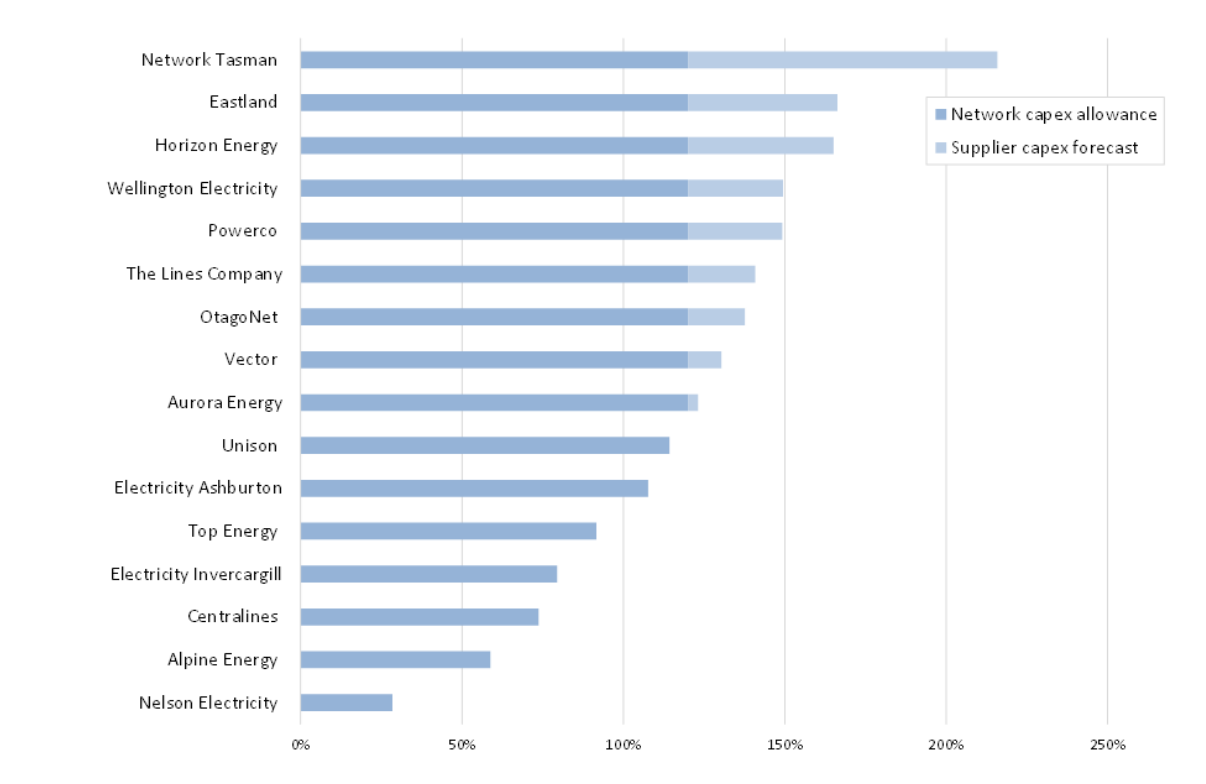
⁷² Note that the expenditure provided in Schedule 5h(iv) is not split between network and non-network capital expenditure. To obtain this split we have assumed that the proportion of network and non-network expenditure is the same as provided in the original (FS2) schedules.

4.65 In the decision for the 2012 default price-quality path we removed 2008 operating expenditure data for Wellington when developing the operating expenditure econometric forecasts. However this was because the data was not fully separable and not because a year was considered abnormally low.

Impact of the 120% limit on distributor forecasts

4.66 Figure 4.1 shows how applying the 120% limit affects the disclosed forecasts of capital expenditure for each distributor. All calculations were performed in constant prices with the CGPI used to convert out-turn expenditure into a comparable series.

Figure 4.1: Proposed forecast of network capital expenditure



Our forecast reflects the profile of the distributor’s forecast

4.67 The profile of our forecast of network capital expenditure in the draft decision was the same as the profile of the distributor’s forecast. This is because we scaled the distributor’s forecast if the limit was exceeded.

- 4.68 Powerco noted that this created an issue for companies that were bound by the limit but had an increasing capital expenditure profile over the regulatory period as it implies a drop off in expenditure in the first year of the regulatory period.⁷³ Their suggestion for remedying the issue was to introduce a floor on capital expenditure so that it does not drop below actual 2014 levels of expenditure.
- 4.69 As outlined above:
- 4.69.1 We believe a 120% limit on historical forecasts reflects an appropriate level for the step change in investment; and
- 4.69.2 We do not think a shorter, more recent period is suitable because the reference point for historical expenditure as capital expenditure is variable over time.
- 4.70 However we agree it is not desirable to reduce capital expenditure forecasts to a level significantly below current expenditure. We therefore applied additional scaling to the capital expenditure forecasts for the final decision in order to help mitigate this impact.
- 4.71 This additional scaling:
- 4.71.1 Determines a floor for the first year of expenditure (2016) equal to the average expenditure in the historical years 2012–2014; and
- 4.71.2 For distributors subject to the floor, we scaled the forecast in later years by re-indexing those years by an equal amount relative to the floor.⁷⁴
- 4.72 For businesses forecasting increasing capital expenditure over the period, the impact of applying scaling in this way is to allow higher amounts in the early years of the period, and lower amounts towards the end. This treatment provides a slight benefit to suppliers in present value terms relative to the approach outlined in the draft decision.
- 4.73 We consider that the revised approach his is consistent with the operation of default/customised price-quality regulation, where businesses have the opportunity (with a lag) to propose a customised price-quality path to accommodate the higher levels of expenditure.

⁷³ Powerco "Submission on Default price-quality paths for electricity distributors from 1 April 2015 and Low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraph 34.

⁷⁴ For example, if the scaling factor was 20%, and year 5 forecast was 50% higher than the floor before further scaling, then it would be 40% higher than the floor after scaling. Similarly, if year 4 was 100% higher than the floor before scaling then it would be 80% higher than the floor after scaling.

Non-network capital expenditure — size and application of limit

- 4.74 We have applied a limit to forecasts of non-network capital expenditure equivalent to 200% of the distributor's historic average, unless non-network capital expenditure represents more than 5% of capital expenditure.
- 4.75 For those distributors who are forecasting non-network capital expenditure to be more than 5% of total capital expenditure, we have adopted a sliding scale approach to calculating the limit.
- 4.76 We apply a higher limit due to the much higher variability historically seen in non-network expenditure compared to network expenditure.⁷⁵
- 4.77 Submissions were varied on our proposed approach to non-network capital expenditure.
- 4.77.1 ENA, Unison and others noted that the sliding scale approach penalised companies who undertook more work in-house.⁷⁶
- 4.77.2 Vector submitted that they would prefer it if all companies were subject to the same cap, while Powerco said they were happy with our proposed approach.⁷⁷
- 4.77.3 MEUG were concerned with the wide variation in the level of non-network expenditure relative to total expenditure and suggested a lower limit was required.⁷⁸
- 4.77.4 PwC note that the sliding scale proposed in the draft decision was not linear and thus is too punitive on distributors with higher levels of non-network capital expenditure. They believe that the sliding scale should be removed and replaced with a standard 200% cap.⁷⁹

⁷⁵ As suggested in Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" (30 April 2014), paragraph 62.

⁷⁶ Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraph 53 e) and Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Draft Decisions" (15 August 2014), paragraph 86.

⁷⁷ Vector "Submission on DPP low-cost forecasting approaches" (15 August 2014), paragraph 88; and Powerco "Submission on Default price-quality paths for electricity distributors from 1 April 2015 and Low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 10.

⁷⁸ Major Electricity Users' Group "Low cost forecasting approaches for DPP" (15 August 2014), paragraph 9.

⁷⁹ PwC "Submission to the Commerce Commission on Low Cost Forecasting Approaches For Default Price-Quality Paths - Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), paragraph 48.

We have maintained the variable limit outlined in the draft decision

- 4.78 We believe that on balance the sliding scale approach is appropriate, even though a flat cap would be more straightforward. We believe it is preferable to have a larger cap for non-network capital expenditure due the one-off nature of non-network investment, but at the same time we have provided greater constraints on distributors with large levels of non-network capital expenditure.
- 4.79 MEUG suggested a lower cap due to the wide variation in the level of non-network expenditure. However, the wide variation means that we do not believe we should bind all distributors to the same percentage limit. A single limit approach could penalise businesses with low initial levels of non-network capital expenditure from relatively small increases in absolute terms.
- 4.80 We are also of the view that the limit applied to large amounts of non-network capital expenditure should be broadly consistent with that provided for network capital expenditure, as wildly different limits could incentivise inefficient trade-offs from one type of expenditure to the other.
- 4.81 The sliding scale cap is only binding for a small number of distributors, but it makes it clear that increasing levels of non-network expenditure would result in greater scrutiny of those forecasts.
- 4.82 The cap provides a greater restriction on non-network capital expenditure for businesses that have a large proportion of non-network capital expenditure (e.g. those that provide a lot of contracting work in-house) however we think that this additional restriction is appropriate under a default price-quality path given the larger amounts of money involved.
- 4.83 Finally, we agree with PwC that it would more appropriate for the sliding scale to be linear. We revised the calculation for the final decision to be linear. The non-network caps under the revised sliding scale approach are shown in Table 4.1.

How the limit would be determined

- 4.84 For those distributors who are forecasting non-network capital expenditure to be more than 5% of total capital expenditure, we have adopted a sliding scale approach to calculating the limit. This ensures that the materiality of any allowable increase in expenditure remains consistent with the principles of a default price-quality path.
- 4.85 The sliding scale ensures that any distributor who has forecast non-network capital expenditure to be higher than 25% of total capital expenditure will be subject to the same limit that is applied to network capital expenditure, ie, 120%. The limit for distributors with a proportion between 5% and 25% has been set in a proportional manner using a linear scale.

- 4.86 Table 4.1 shows the limit for each distributor used in the final decision. The cap is only binding on two distributors: Electricity Invercargill and the Lines Company. All calculations are in constant prices.

Table 4.1: Non-network capital expenditure limits

	% of non-network as a proportion of total capital expenditure	Proposed limit
Unison Networks	22%	131%
Electricity Invercargill	14%	162%
Centralines	12%	173%
Horizon Energy	8%	187%
The Lines Company	8%	190%
Vector Lines	7%	193%
Alpine Energy	7%	194%
Powerco	6%	196%
Wellington Electricity	5%	200%
Network Tasman	4%	200%
Electricity Ashburton	4%	200%
Eastland Network	3%	200%
Top Energy	2%	200%
Nelson Electricity	2%	200%
Aurora Energy	0%	200%
OtagoNet	0%	200%

Our forecast reflects the profile of the distributor's forecast

- 4.87 The profile of our forecast of non-network capital expenditure over the regulatory period is the same as the profile of the distributor's forecast. This is because we scaled each year of the distributor's forecast if the limit was exceeded.

Forecast changes in input prices

4.88 Consistent with our draft decision we have used a forecast of the all industries CGPI to forecast changes in input prices for capital expenditure.⁸⁰ Further explanation of the reasoning for our approach can be found in Attachment B.

Summary of information sources

4.89 Table 4.2 and Table 4.3 set out the information sources that we have relied on to produce our forecast of capital expenditure.

Table 4.2: Information for forecasting network capital expenditure

Item	Information used (supplier specific unless otherwise stated)	Source
Current forecast	Expenditure on network assets + Cost of financing - Value of capital contributions +Value of vested assets - Acquisition and direct capital expenditure on transmission assets acquired from Transpower (2015-2020)	Schedule 11a (2014) 53ZD request (Sep 2014)
Historic average (2010–2012)	Capital expenditure ⁸¹ - Acquisition and Direct Capital Expenditure on transmission assets acquired from Transpower (2010-2012) Total Capital Expenditure on System Fixed Assets, Capital Contributions, and Capital Expenditure on Non-System Fixed Assets ⁸²	Schedule 5h(iv) 2013 53ZD request (Sep 2014) Schedule FS2 and FS1 (2010-2012)
Historic average (2013–2014)	Expenditure on network assets + Cost of financing - Value of capital contributions +Value of vested assets - Acquisition and direct capital expenditure on transmission assets acquired from Transpower (2013-2014)	Schedule 6a (2013-2014)
Input prices	All goods CGPI: historical (2010-2014) and forecast (2015-2020)	Statistics New Zealand (historical) and NZIER (forecast)

⁸⁰ These forecasts were sourced from the New Zealand Institute of Economic Research. We have updated these forecasts for our final decision.

⁸¹ We estimated the proportion of capital expenditure which was network expenditure using the data below.

⁸² This data is used to estimate the proportion of capital expenditure disclosed in schedule 5h(iv) which is network expenditure and which is non-network expenditure.

Table 4.3: Information for forecasting non-network capital expenditure

Item	Information used (supplier specific unless otherwise stated)	Source
Current forecast	Non-network assets	Schedule 11a (2014)
Historic average (2010–2012)	Capital expenditure ⁸³ Total Capital Expenditure on System Fixed Assets, Capital Contributions, and Capital Expenditure on Non-System Fixed Assets ⁸⁴	Schedule 5h(iv) 2013 Schedule FS2 and FS1 (2010-2012)
Historic average (2013–2014)	Non-network assets	Schedule 6a (2013-2014)
Input prices	All goods CGPI: historical (2010-2014) and forecast (2015-2020)	Statistics New Zealand (historical) and NZIER (forecast)

⁸³ We estimated the proportion of capital expenditure which was non-network expenditure using the data below.

⁸⁴ This data is used to estimate the proportion of capital expenditure disclosed in schedule 5h(iv) which is network expenditure and which is non-network expenditure.

5. Revenue growth

Purpose of chapter

5.1 This chapter outlines and explains our approach for forecasting revenue growth.

Revenue growth depends on changes in price and quantity

5.2 A distributor's revenue growth depends on two effects:

5.2.1 Changes in price allowed under the CPI-X% price limit; and

5.2.2 Changes in the quantities billed.

5.3 A higher forecast of revenue growth would reduce a distributor's starting price based on current and projected profitability. This is because a lower starting price would be offset by future increases in price, quantities billed, or both. Likewise, lower forecasts of revenue growth would imply higher starting prices.

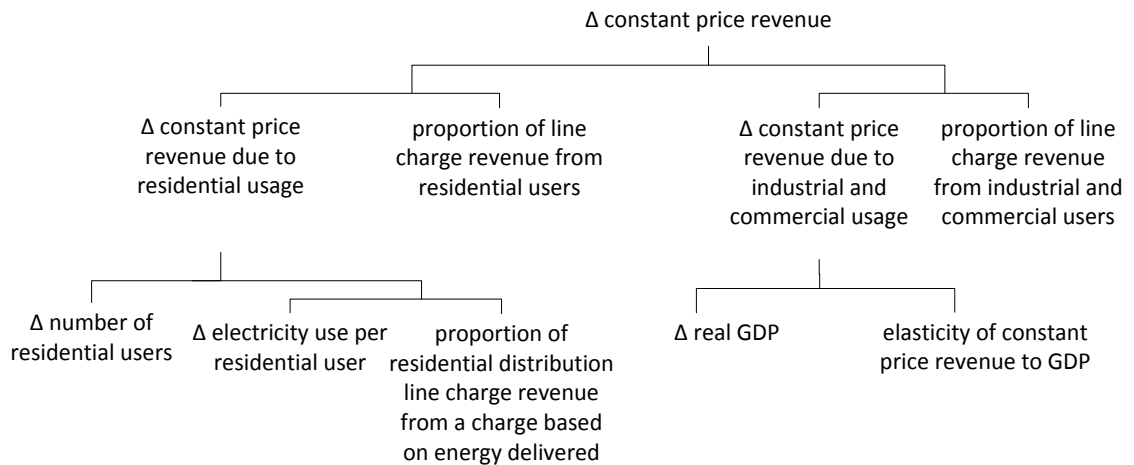
5.4 Notably, relative to other forecasts, the forecast of revenue growth arguably has a more material impact on a starting price set based on current and projected profitability.⁸⁵ This is because the forecast of revenue growth affects revenue, in aggregate, rather than any individual cost component.

⁸⁵ The growth rate for the two years prior to the regulatory period is also relevant as to assess compliance with the price-quality path in the first year of the regulatory period.

Overall approach to forecasting revenue growth

5.5 Revenue growth can be forecast in constant prices before making a separate adjustment for forecast changes in price. We refer to the forecast of revenue growth in constant prices as ‘constant price revenue growth’. Figure 5.1 provides a high level overview of our forecasting approach.

Figure 5.1: Approach to modelling revenue growth for electricity distributors



5.6 Consistent with our draft decision and as shown in Figure 5.1, our overall approach involves modelling constant price revenue growth separately for residential users, and industrial and commercial users.⁸⁶ We have classified revenue into those two categories based on information provided by distributors in response to an information gathering request.

5.7 Box 5.1 sets out the formula for calculating the change in constant price revenue based on separate modelling of two user groups—residential users and industrial and commercial users.⁸⁷

⁸⁶ We use users throughout this paper to describe the technical term installation control point (ICP). An installation control point is the physical point of connection on a local network or an embedded network which the distributor nominates as the point at which a retailer will be deemed to supply electricity to a consumer. (Source: Electricity Authority).

⁸⁷ We use Δ to denote the % change in data from one information disclosure year to the next.

Box 5.1: Change in revenue for each distributor

$$\begin{aligned}
 \Delta \text{ revenue} = & \\
 & \Delta \text{ revenue due to residential usage} \\
 & \times \\
 & \text{proportion of line charge revenue from residential users} \\
 & + \\
 & \Delta \text{ revenue due to industrial and commercial usage} \\
 & \times \\
 & \text{proportion of line charge revenue from industrial and commercial users}
 \end{aligned}$$

- 5.8 Our analysis of information from an information request showed that there is significant variation among distributors in the structure of their charges, and the amount of revenue they get from different types of quantities they bill for.⁸⁸ However:
- 5.8.1 For residential users, distributors tend to get a greater share of their revenues from charges based on the quantity of energy delivered; whereas
 - 5.8.2 For industrial and commercial users, a greater share of revenues is from demand or capacity based charges.
- 5.9 Our approach reflects information from each distributor based on their current charging approach. However, distributors can restructure their tariffs as long as they can demonstrate compliance with the weighted average price cap. Our approach assumes that the structure of tariffs stays constant over the regulatory period.

⁸⁸ Distributors choose what type of quantities they charge for, including the quantity of energy delivered to users, quantities relating to peak demand, measures of the quantity of capacity provided by the network connection, and annual charges per user.

Revenue growth assumptions received rigorous testing in submissions

- 5.10 Given the materiality of the revenue growth assumptions to the revenues that distributors are allowed to earn, we welcomed the testing that our constant price revenue growth model received in submissions. In particular, regulated suppliers:
- 5.10.1 expressed concerns regarding the overall performance of the revenue growth model during the previous regulatory period, and cited differences between actual and allowed returns; and
 - 5.10.2 identified specific assumptions in our model that were considered to be inconsistent with recent experience, and provided evidence on recent trends.
- 5.11 With respect to the overall performance of the model, the analysis presented by ENA indicated that between 2009/10 and 2013/14:⁸⁹
- 5.11.1 9 distributors had higher constant price revenue growth than our model predicted in November 2012; and
 - 5.11.2 5 distributors had lower constant price revenue growth than our model predicted in November 2012.
- 5.12 We were not surprised by these findings because, although we aim to forecast revenue growth as accurately as possible, we recognise that actual and allowed revenues will differ. Under a price cap, distributors are exposed to volume risk.⁹⁰ The fact that actual and allowed revenue are different therefore does not in itself imply any issues with our approach. Comparisons against actual revenue are therefore of limited value in assessing the overall performance of the model, especially given the limitations of the data available. However, they can be helpful in identifying individual components of the model which could be improved.

⁸⁹ Alpine Energy and The Lines Company were excluded from ENA's analysis as they were unable to supply the required data, due to tariff design and restructure. Refer: Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraph 95.

⁹⁰ In addition, it is not clear how much of the variation between actual and allowed returns was due to the revenue growth forecast, relative to other factors.

- 5.13 We have, however, made changes to our model in response to new information and submissions about specific assumptions in our model. Most attention focussed on:
- 5.13.1 for revenue growth from residential users, our invitation for evidence about future trends that would justify moving away from an assumption that there would be no change in energy intensity per ICP; and
 - 5.13.2 for revenue growth from industrial and commercial users, our estimate of the elasticity of distribution revenue to GDP had increased from 0.52 in November 2012 to 0.73 in July 2014.
- 5.14 Distributors generally considered that these two assumptions in particular were flawed, and consequently submitted that extrapolating historic trends would be more appropriate for:⁹¹
- 5.14.1 industrial and commercial growth revenue growth; or
 - 5.14.2 revenue growth overall.
- 5.15 We are grateful to submitters for their suggestions, and in the sections that follow we provide our responses. For example, we explain why we have:
- 5.15.1 decreased our assumption about future changes in energy intensity per ICP from 0% per annum to -0.8% per annum; and
 - 5.15.2 decreased our assumption about the elasticity of distribution revenue to GDP from 0.73 to 0.50.

⁹¹ Wellington Electricity and Aurora support an approach that relies on historic trends in constant price revenue growth. Refer: Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" 15 August 2014, p.6; Aurora Energy Limited "Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015 and Low Cost Forecasting Approaches for Default Price-Quality Paths" 15 August 2014, p.29. Meanwhile, Vector and Orion suggest that the Commission could use historic trends in underlying volumes to forecast future constant price revenue growth. Refer: Vector "Submission on DPP low-cost forecasting approaches" 15 August 2014, paragraph 34; Orion New Zealand Limited "Submission on the low cost forecasting approaches for DPP" 15 August 2014, paragraph 23. The ENA submits that using historic trends would better capture the characteristics and customer base of each region. Refer: Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraph 109. Horizon suggests that constant price revenue growth for industrial users is estimated by extrapolating historical trends. Refer: Horizon Energy Distribution Limited "Submission on Low Cost Forecasting Approaches For Default Price-Quality Paths" 15 August 2014, paragraphs 43-44.

- 5.16 As a consequence of making these changes, we are satisfied that our model remains preferable to a model based entirely on extrapolating historic trends. Using a mechanical extrapolation of historic trends may be appropriate if a clear trend is observable over a long period of time, and is expected to be sustained over the forecast period. But our approach allows us to take into account these trends where relevant, while also allowing us to factor in information about future trends where appropriate.⁹²
- 5.17 It is worth noting that the reason the assumption around revenue growth is required for the regulatory period is that input methodologies require that a price cap be applied to electricity distribution services, rather than a revenue cap. During consultation on input methodologies, the decision to apply a price cap to electricity distribution services was generally supported by electricity distributors.
- 5.18 Some submitters suggested that an ex post wash-up mechanism be applied to account for any forecasting errors.⁹³ We consider that this is not consistent with the purpose of applying a price cap which is intended to expose distributors to demand risk.

⁹² For further discussion of our analysis of trend models refer to Attachment D.

⁹³ For example refer to: Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraphs 109-110; Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" 15 August 2014, p.15.

Modelling revenue growth from residential users

- 5.19 Box 5.2 sets out the formula for calculating the change in revenue from residential users.

Box 5.2: Change in revenue from residential users

Δ revenue due to residential usage =
 Δ number of residential users
 x
 Δ electricity use per residential user
 x
 proportion of residential distribution line charge revenue from a charge based on energy delivered

- 5.20 The way we forecast revenue growth from residential users was the subject of a number of submissions.

Change in the number of residential users

- 5.21 One of the drivers of the forecast change in revenue from residential users is the change in number of residential users, because this affects the number of fixed charges collected by the distributor. Consistent with our draft decision, to model the impact from changes in residential users, we have used population projections from Statistics New Zealand as a proxy for changes in the number of residential users.
- 5.22 Vector and Wellington Electricity submitted that population growth is an inappropriate proxy for changes in the number of connections. In their recent experience population growth has exceeded the growth in number of connections, ie, household size (or people per connection) is increasing.⁹⁴ They assume that this will continue and therefore will result in an overestimation of the growth in connections in our model.

⁹⁴ Refer: Vector "Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper" 30 April 2014, paragraphs 73-76; Vector "Default Price-Quality Path 2015-2020 Draft Decision: Correction to submission on Forecasting Approaches" 29 August 2014, paragraph 51; Wellington Electricity Lines Limited "Submission on issues paper on 2015-2020 Default Price-quality Path" 30 April 2014, pp.10-12; Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" 15 August 2014, p.8.

- 5.23 Both distributors provided suggestions on alternatives to using population projections. Vector suggested the projections of household growth provided by Statistics New Zealand are a better proxy, on the basis that household growth has historically been closer to actual number of connections for many of the 29 distributors. Wellington Electricity suggests using recent historical growth in residential connections as an indicator of likely future growth.
- 5.24 In response to the suggestion from Vector, we considered that using household growth projections may be appropriate. However, the most recent update to regional household projections from Statistics New Zealand was in 2010, two years before the more recent population projections. In addition, between the 2006 and 2013 censuses, population growth and household growth have been similar for most distributors as shown in Table 5.1. Therefore, we consider that population growth is a reasonable proxy for residential ICP growth, given the limited availability of other data.

Table 5.1: Average annual growth in population and households between 2006 and 2013

Name	Population growth (%)	Household growth (%)	Difference (percentage points)
Alpine Energy	0.5	0.8	-0.3
Aurora Energy	1.0	1.0	0.0
Centralines	0.0	0.5	-0.5
Eastland	-0.4	0.2	-0.6
Electricity Ashburton	1.9	1.7	0.1
Electricity Invercargill	0.4	0.8	-0.4
Horizon Energy	-0.5	0.2	-0.7
Nelson Electricity	0.9	1.2	-0.3
Network Tasman	0.9	1.1	-0.2
Orion	0.0	-0.1	0.1
OtagoNet	0.3	0.5	-0.2
Powerco	0.5	1.0	-0.4
The Lines Company	-0.5	0.2	-0.7
Top Energy	-0.4	0.9	-1.3
Unison	0.2	0.7	-0.5
Vector	1.2	1.1	0.1
Wellington Electricity	0.6	0.6	0.0

Source: Statistics New Zealand 2006 and 2013 census data.

- 5.25 We note that relying on population projections will generally be more beneficial to distributors than relying on household growth projections. This is because population projections are generally lower than population projections.⁹⁵
- 5.26 In response to the suggestion by Wellington Electricity, our view is that population growth projections are likely to be more reliable than extrapolating historical residential ICP growth as:⁹⁶
- 5.26.1 population projections take into account information on future expectations of fertility, mortality, and migration; and
 - 5.26.2 not all distributors have consistently defined residential ICPs over any reasonable length of time.
- 5.27 Wellington Electricity indicated that an increase in the number of embedded connections is a main driver for slower ICP growth.⁹⁷ We consider that our model does not materially disadvantage distributors with embedded residential connections. This is because such connections will likely have significantly higher revenue associated with them, ie, the underlying activity from an embedded connection is the same as if they were separate connections.
- 5.28 Therefore, we do not consider that either of the alternatives proposed by submitters would be superior to relying on population projections. The use of population projections was also supported by some distributors.⁹⁸

⁹⁵ Covec, on behalf of Vector, suggested that the Commission should adjust the population growth rates implied by Statistics New Zealand to reflect the difference in historic forecasts and historic actuals. Refer: Covec "Auckland Connections Forecasts" 12 August 2014, p.2. We do not consider it appropriate to retrospectively adjust forecasts based on the historical performance of that forecast.

⁹⁶ Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" 15 August 2014, p.15.

⁹⁷ An embedded connection is an individual connection that links to several users, for example, some apartment complexes.

⁹⁸ Refer, for example: Horizon Energy Distribution Limited "Submission on Low Cost Forecasting Approaches For Default Price-Quality Paths" 15 August 2014, paragraph 34.

Change in electricity use per residential user

- 5.29 For the purposes of this reset, we have assumed that electricity consumption by the average residential user will fall by 0.8% per year over the next 5-7 years. This is a change from the assumption proposed in the draft decision, which reflected our November 2012 decision.
- 5.30 Our assumption reflects the fact that electricity use per residential user may change over time. The trend will depend on the impact of changes in consumption, eg, from increases in income, relative to the impact of improvements in energy efficiency, or substitution towards other energy sources, such as gas, due to relative price movements.
- 5.31 In response to our Process and Issues Paper, distributors submitted that electricity use per residential user has declined in the recent past, and that the trend was therefore likely to continue. Both Unison Networks and Vector proposed that the value was approximately -1.0%, while Wellington Electricity proposed a value of -2.8% for its network.⁹⁹
- 5.32 At the draft decision stage, we invited evidence on the likely pattern of future trends, rather than historical analysis, and in the interim we relied on an assumption that electricity use per residential user will remain broadly constant. We noted that electricity price increases were starting to moderate, economic activity was picking up, and electric cars are becoming viable.
- 5.33 In response to our draft decision, submitters argued that a negative adjustment should be included, within a range of 0.8 to 1.5%, to account for the downward trend in electricity use per residential user. This range was proposed on the basis that for most distributors electricity use per residential user has declined by over 1% per year in the recent past.

⁹⁹ Refer: Vector Lines "Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper" 30 April 2014, paragraph 69. Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" 30 April 2014, paragraph 23. Wellington Electricity Lines Limited "Submission on issues paper on 2015-2020 Default Price-quality Path" 30 April 2014, p.11.

- 5.34 Distributors also raised many factors that would continue to drive residential electricity consumption down which we have considered.¹⁰⁰ We consider that a number of these are valid, including the following:
- 5.34.1 continued switching to more energy efficient electronics, appliances and lighting, which is likely to be partially offset by a higher proliferation of electronics;
 - 5.34.2 uptake of solar photovoltaic panels, albeit from a very low base; and
 - 5.34.3 the implementation of smart meters allowing users to monitor electricity consumption and potentially modify behaviour.
- 5.35 Our view of expected residential use for the regulatory period is broadly consistent with other external sources, for example:
- 5.35.1 Energy Link forecasts electricity use per household to decline by approximately 0.8% per year between 2015 and 2020,¹⁰¹ and
 - 5.35.2 Castalia, using Statistics population forecasts and MBIE electricity forecasts, estimates electricity use per capita to decline by around 0.8% per year.¹⁰²
- 5.36 Our analysis indicates that residential energy use per capita has declined on average by 0.8% per year since 2004. We note that much of this decline occurred between 2010 and 2013 with minimal change in the 2014 year to date.
- 5.37 On balance, our expectation is that electricity use per user will continue to decline in the short-term but at a lower rate than that experienced over the last five years. The basis for this position is an expectation of diminishing marginal returns from future energy efficiency initiatives, which would imply a diminishing rate of decline in electricity use per residential user.

¹⁰⁰ For example refer to Sapere Research Group Limited "Trends in Residential Electricity Consumption" 5 August 2014, pp. 27-28; Powerco "Submission on Default price-quality paths for electricity distributors from 1 April 2015 and Low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraph 80.

¹⁰¹ Energy Link Ltd. "Electricity Demand Forecasts to 31 March 2030" prepared for the Commerce Commission, October 2014, p.12.

¹⁰² Refer: Castalia Strategic Advisors "Review of Electricity Default Price-Quality Path Determination 2015 - Report to Vector" August 2014, p.15.

Modelling revenue growth from industrial and commercial users

- 5.38 Industrial and commercial users comprise a wide range of users in terms of their demand for energy and network capacity. Their demand for electrical energy and capacity may vary from being similar to that of residential users (for example, small shops) to being significantly greater than that of residential users (for example, energy intensive industrial users).
- 5.39 Box 5.3 sets out the formula for calculating the change in revenue applicable to industrial and commercial users. We have not separated industrial and commercial users as information provided by distributors did not split revenue between industrial and commercial users consistently.

Box 5.3: Change in revenue from industrial and commercial users

$$\begin{aligned} \Delta \text{ revenue due to industrial and commercial usage} = \\ \Delta \text{ real GDP} \\ \times \\ \text{elasticity of industrial and commercial energy use to GDP} \end{aligned}$$

- 5.40 Our model is based on an assumed relationship between revenue growth from industrial and commercial users, and changes in GDP. By and large, the relationship between GDP and commercial electricity use has not changed since 1992. We recognise, however, that various factors appear to have affected industrial electricity use in recent years.¹⁰³
- 5.41 These factors include:
- 5.41.1 the recession and slow recovery from 2008; and
 - 5.41.2 improving energy efficiency along with a gradual shift away from more energy intensive industries.

¹⁰³ For example, the Electricity Authority finds little evidence of a structural break of electricity demand and that the flattening of electricity demand in recent years can be explained with the explanatory variable used in their econometric modelling, including GDP. Refer to: Electricity Authority “Modelling Electricity Demand in New Zealand: Market performance enquiry” 14 April 2014; <http://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/electricity-consumption/>

- 5.42 Although we recognise that the relationship may appear to have changed in recent years, we disagree with suggestions that there is no longer any relationship between GDP and line charge revenue or electricity use.¹⁰⁴ This view is supported by the submission from Meridian Energy that stated that the key drivers adopted by the Commission were consistent with what it uses to forecast demand.¹⁰⁵
- 5.43 The Electricity Authority has recently concluded that there is no evidence of any major structural change in the determinants of electricity demand in New Zealand. They also note that “real GDP and electricity price are the most important variables in explaining the flattening of electricity demand.”¹⁰⁶

Change in real Gross Domestic Product

- 5.44 We have used regional GDP growth forecasts to help forecast revenue applicable to industrial and commercial users. To forecast change in GDP applicable to each distributor, we have obtained independent forecasts from Infometrics, rather than relying on the NZIER forecasts that we proposed in the draft decision.
- 5.45 We mapped the forecast of GDP growth by territorial local authority to the area covered by each distributor’s network to determine the forecast of GDP growth in their region. The approach to mapping is therefore consistent with our draft decision but we have updated the approach to reflect differences in the regions covered by the GDP forecasts provided by Infometrics and NZIER.
- 5.46 Several submitters raise concerns about the accuracy of the mapping between the areas they operate in and the regions used in the GDP and population forecasts. For example, NZIER, on behalf of Wellington Electricity, highlights that its GDP forecast for the Wellington region includes areas which are not part of Wellington Electricity’s network.¹⁰⁷
- 5.47 We note that many of the 67 local authority regions fall entirely within one distributor’s coverage area. In local authority regions that are served by multiple distributors, we consider that assuming GDP growth is similar in each area within the region is a reasonable low cost approach.

¹⁰⁴ For example Castalia Strategic Advisors “Review of Electricity Default Price-Quality Path Determination 2015 - Report to Vector” August 2014, pp.3-4.

¹⁰⁵ Refer: Meridian Energy Limited “Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015” 15 August 2014, p.1.

¹⁰⁶ <http://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/electricity-consumption/>

¹⁰⁷ Refer to: NZIER “Limitations in regional GDP projections - Implications for forecasting non-residential electricity demand” August 2014, pp.4-5; Wellington Electricity Lines Limited “Draft Decision on 2015-2020 Default Price-quality Path” 15 August 2014, pp.12-13.

- 5.48 We have moved away from relying on the GDP forecasts provided by NZIER due to a range of concerns associated with the NZIER forecasts.¹⁰⁸ These include:
- 5.48.1 the changes in their forecasts between July and October;
 - 5.48.2 the narrow range of forecast GDP growth between regions;
 - 5.48.3 mapping large regions to distributors, as raised by Wellington Electricity.¹⁰⁹

¹⁰⁸ NZIER submitted that it is inappropriate to map their regional GDP forecasts to distributor's networks. given that their forecasts are a generalisation of economic trends across an entire region. Therefore they consider that a sub-set of any region that is mapped to a distributor's network cannot be assumed to have same growth rate as the region. Refer: NZIER "Limitations in regional GDP projections - Implications for forecasting non-residential electricity demand" August 2014, pp.4-5. Aurora also had concerns over the accuracy of NZIER's forecasts of GDP for the draft, which suggested that forecast annual change in real GDP for Otago-based EDBs was only slightly less than Auckland. Refer: Aurora Energy Limited "Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015 and Low Cost Forecasting Approaches for Default Price-Quality Paths" 15 August 2014, p.28.

¹⁰⁹ WELL submitted that GDP growth for the Wellington region includes areas that are not covered by their network, and therefore does not necessarily reflect their circumstances. Refer: Wellington Electricity Lines Limited "Submission on issues paper on 2015-2020 Default Price-quality Path" 30 April 2014, p.10; Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" 15 August 2014, p.13.

Table A1: Comparisons of GDP forecasts for each distributor

Name	NZIER forecast July 2014 (%)^A	NZIER forecast October 2014 (%)^B	Infometrics forecast October 2014 (%)^C
Alpine Energy	1.2	2.7	1.5
Aurora Energy	3.2	2.7	2.7
Centralines	0.8	2.6	-1.8
Eastland	0.8	2.6	0.8
Electricity Ashburton	1.2	2.7	0.9
Electricity Invercargill	-0.7	2.4	2.0
Horizon Energy	2.3	2.8	1.6
Nelson Electricity	1.5	2.7	2.1
Network Tasman	1.5	2.7	2.2
Orion	1.2	2.7	3.3
OtagoNet	3.2	2.7	2.1
Powerco	1.7	2.7	1.5
The Lines Company	1.6	2.6	-0.2
Top Energy	2.3	2.5	3.0
Unison	1.1	2.6	2.1
Vector	3.2	2.8	2.7
Wellington Electricity	2.1	3.1	2.6

A – forecast relied on for draft decision

B – update to forecast relied on for draft decision

C – forecast relied on for final decision

Elasticity of industrial and commercial revenue to Gross Domestic Product

- 5.49 We have reduced our assumption about the elasticity of revenue from industrial and commercial users to GDP, from 0.73 to 0.50. We have made this change in response to a number of concerns raised by submitters, and the further analysis we have undertaken in response to those concerns.
- 5.50 The main concerns raised by submitters at the draft decision stage were that the econometric model we used to derive the estimate of 0.73 was not robust, and the resulting coefficient was counter-intuitive. In particular, submitters:
- 5.50.1 pointed to the relatively large increase in the coefficient between November 2012 and July 2014 as evidence that the coefficient was not robust to changes in the time period for analysis;
 - 5.50.2 a stronger relationship between GDP and non-residential electricity is counter-intuitive given that electricity demand has been static in recent years; and
 - 5.50.3 considered that 0.73 was higher than estimates from other agencies.
- 5.51 With respect to the change in the estimated co-efficient between November 2012 and July 2014, we have found that November 2012 estimate was not directly comparable. We therefore revised both the November 2012 estimate and the July 2014 estimate to allow a like-for-like comparison. For example, we:
- 5.51.1 took into account the suggested improvements for deflating historical revenue figures;
 - 5.51.2 removed pass through costs and recoverable costs from the historical revenue growth figures;
 - 5.51.3 changed the source of GDP data to Infometrics, and applied the same source in each set of analysis; and
 - 5.51.4 improved the mapping of GDP forecasts to the areas covered by each network.
- 5.52 Table 5.2 shows the results of updating the econometric analysis to allow a like-for-like comparison. The most material change was remapping the GDP regions which are now more reflective of the GDP associated with each distributor, and result in a better fitting model.
- 5.53 As a result of these revisions, the estimated coefficients were more comparable on a like-for-like basis. The estimate as at November 2012 would have been 0.77 and the estimate as at July 2014 would have been 0.88.

Table 5.2: Like-for-like comparison of November 2012 and July 2014 results

Panel model	Time period	GDP elasticity
November 2012	2004-2011	0.52
July 2014	2004-2012	0.73
Updated November 2012	2004-2011	0.77
Updated July 2014	2004-2014	0.88

- 5.54 We have also examined an alternative econometric model using a time-series approach. Using electricity throughput applicable to non-residential users as the dependent variable, our modelling suggests that, prior to 2008, the relevant GDP elasticity was 0.65, and between 2008 and 2014, the elasticity has fallen to 0.27.¹¹⁰

Table 5.3: GDP to non-residential electricity throughput time-series results

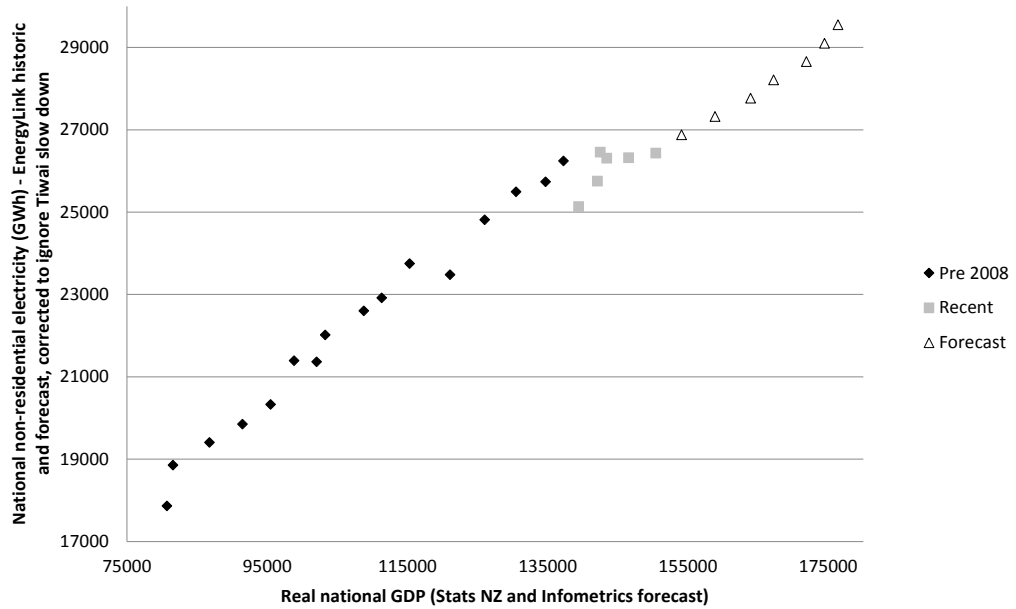
	Time period	GDP elasticity
Historic GDP elasticity	1993-2007	0.65
Recent GDP elasticity	2008-2014	0.27
Overall GDP elasticity	1993-2014	0.57

- 5.55 Common reasons put forth for the flattening of industrial and commercial energy use since 2008 are the global recession and slow recovery, particularly for the industrial sector, and improving energy efficiency.
- 5.56 Looking forward, Energy Link forecasts that industrial electricity demand will return to approximately 60% of the historical trend prior to the global financial crisis.

¹¹⁰ We use non-residential electricity throughput as a proxy for non-residential constant price revenue. This has the advantage of only capturing industrial and commercial users as used in our revenue growth forecast. The main drawback is that revenues based on charging other than demand may not be adequately captured, such as capacity and fixed charges.

5.57 Figure 5.2 shows the historic relationship between national GDP and non-residential electricity use from 1975 to 2014, and the relationship between EnergyLink’s forecast of electricity use and Infometric’s forecast of national GDP from 2015 to 2020.¹¹¹

Figure 5.2: National GDP vs. Non-residential electricity throughput 1975 to 2020



Source: Statistics New Zealand, Ministry of Business, Innovation and Employment, Infometrics, EnergyLink, and Commission analysis.

¹¹¹ This figure is provided for illustrative purposes. The forecast electricity demand series is based on an EnergyLink forecast, which we have adjusted to remove the effect of changes to large industrial users because these changes dominate the chart without directly affecting distributors.

- 5.58 We also have taken into account of views from other agencies including:
- 5.58.1 the Energy Efficiency and Conservation Authority (EECA) have signalled that there is scope for further efficiencies in the industrial and commercial sectors;¹¹²
 - 5.58.2 a 2012 business survey from Statistics New Zealand indicated that energy efficiency was not as high priority in 2012 compared to 2009 with less businesses indicating there were further electricity savings to be made;¹¹³ and
 - 5.58.3 the Electricity Authority considered there was little evidence of any major structural change in the determinants of electricity demand, including GDP, which they note as an important determinant of electricity demand.¹¹⁴

¹¹² A step change in the relationship is apparent since 2008 . In addition, the Energy Efficiency and Conservation Authority (EECA) have signalled that there is scope for further efficiencies in the industrial and commercial sectors. Refer to: <http://www.eeca.govt.nz/eeca-programmes-and-funding/programmes/business>

¹¹³ http://www.stats.govt.nz/browse_for_stats/industry_sectors/Energy/EnergyUseSurvey_HOTP12.aspx

¹¹⁴ <http://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/electricity-consumption/>

- 5.59 We have also considered comparable studies on the relationship between GDP and electricity measures, which are summarised in Table 5.4. This illustrates that there is a large range of elasticities modelled by various organisations, and each estimate provides information that is useful but by no means conclusive. Each estimate is dependent on the time period of analysis, the specification of the model, and the choice of explanatory variable.
- 5.60 Ultimately, given the uncertainty regarding the future of electricity demand, judgement is required to determine the elasticity assumption that would be most appropriate for the present purpose. In our view, the judgement comes in when we consider whether the elasticity will remain at that estimated between 2008 to 2014 (around 0.3), will return to a higher state consistent with pre-2008 data, or something else.
- 5.61 As we apply an estimated elasticity to forecasts of GDP, we require an estimate of elasticity that would be appropriate over the forecast horizon of 2015 to 2020. Therefore, we have:
- 5.61.1 surveyed other Government agencies research;
 - 5.61.2 looked at official survey data on energy efficiency for industrial and commercial groups; and
 - 5.61.3 commissioned forecasts from reputable industry forecasters of energy demand.

- 5.62 The overall impression we are left with is nobody knows exactly what has happened in the electricity market for industrial and commercial users (though it seems to be related to the global financial crisis, with some energy efficiency) between 2008 and 2014. More importantly, there is uncertainty about how electricity demand will develop over the next five years. What we can say is that we agree with submitters that elasticity estimates of 0.7 would be high, almost certainly implausibly so.
- 5.63 As we do not know how much of what we observe is because of permanent factors like energy efficiency initiatives relative to temporary cyclical recession effects we have essentially chosen the point on the spectrum that seems most reasonable (0.5) in light of the available evidence. It is difficult to strongly argue that an alternative value is better supported by that evidence.
- 5.64 An elasticity of 0.5 is consistent with empirical findings. It is therefore preferable to relying on a simple extrapolation of historic trends.¹¹⁵

¹¹⁵ To assist us in our decision making, we requested an independent review both of our econometric modelling, and the submissions received on our July 2014 draft decision. A copy of Professor Jeff Borland's report has been published on our website alongside this paper.

Table 5.4: Published estimates of the econometric relationship between GDP and electricity demand

Model	Functional form	Dependent variable	Measure of GDP	Additional explanatory variables	Coefficient
Transpower	Log-log	National electricity demand (excl. Tiwai)	National GDP	Population, energy intensity	0.46
MBIE (commercial)	Log-log	Commercial electricity demand	Commercial sector GDP (excluding lag)	Commercial demandt-1	0.38
MBIE (commercial)	Log-log	Commercial electricity demand	Commercial sector GDP (including lag effect)	Commercial demandt-1	0.84
MBIE (industrial)	Levels	Annual % growth in industrial electricity demand (excl. large users)	Annual % growth in industrial sector GDP	Annual % growth in price of industrial energy	0.63
Electricity Authority	Logs	Annual % growth in national electricity demand	National GDP	Price change, price of gas, population budget share, unemployment, temperature	1.2
Commerce Commission (2012 reset)	Log-log	Line charge revenue by EDB	Regional GDP	N/A	0.52

Note: MBIE's estimate of commercial electricity demand includes a lagged variable (which is related to lagged GDP) – this implies a long-term elasticity of 0.84.

Information sources for modelling of constant price revenue

5.65 This section provides the information used to model constant price revenue.

Table 5.5: Information for modelling residential users

Item	Information used	Source
Δ number of residential users	Supplier-specific population forecasts for 2011	Statistics NZ Information from s 53ZD request Commission calculations and assumptions to match data to each supplier's operational area
Δ electricity use per residential user	Industry-wide historic trends	Commission analysis Ministry of Business, Innovation and Employment Energy Link Submissions
Proportion of residential distribution line charge revenue from a charge based on energy delivered	Supplier-specific information on different categories of line charge revenue	Section 53ZD information request Commission calculations
Proportion line charge revenue from residential users	Supplier-specific information on different shares of line charge revenue	Section 53ZD information request Commission calculations

Table 5.6: Information for modelling industrial and commercial users

Item	Information used	Source
Δreal GDP	Supplier-specific forecast of GDP growth by territorial local authority region Energy used by GXP	Infometrics Electricity Authority Commission calculations and assumptions to match data to the area of each supplier's network
Elasticity of constant price revenue to GDP	Industry-wide estimate Historic information on real GDP and electricity use	Statistics NZ Ministry of Business, Innovation and Employment Econometric modelling undertaken by Commission
Proportion of line charge revenue from industrial and commercial users	Supplier-specific information on different shares of line charge revenue	Section 53ZD information request Commission calculations

6. Disposed assets and other regulated income

Purpose of chapter

- 6.1 This chapter outlines and explains the approach we have taken to forecast disposed assets and other regulated income.

Disposed assets

- 6.2 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 regulatory asset base (RAB) when rolling forward the RAB value.
- 6.3 Often, a distributor will make a loss on disposal of an asset, e.g., if the asset is disposed for scrap. Consequently, we need to consider the appropriate treatment of losses on disposal.

Forecast value of assets disposed from RAB

- 6.4 To reach our final decision, the forecast value of disposed assets in each year of the regulatory period is equal in real terms to the average value of disposed assets between 2011 and 2014. The value of disposals is the average of constant price historic disposals from 2011 to 2014, forecast forward using CPI as a price inflator.
- 6.5 This forecast of disposed assets reduces each distributor's starting price, because the value of a disposed asset must be removed from the regulatory asset base when it is rolled forward over time. Consequently, the implied return on and of capital is lower than it otherwise would be.
- 6.6 We received submissions from Vector, ENA and PwC noting general support for using distributor specific historic averages to forecast disposals.

Forecast of losses on disposal

- 6.7 To forecast losses on disposal, we derived an average ratio of gains/losses on disposed assets to disposed assets for each distributor based on 2013-2014 and 2014-2015 actual disposals. We have generally applied this ratio against our disposals forecast to determine a forecast of gains/losses on disposal.¹¹⁶

¹¹⁶ When we calculated ratios for each distributor we used information disclosure data from 2013-2014 and 2014-2015. Aurora and Centralines data resulted in ratios of 345% and 2450% respectively as they had disposed of assets with nil RAB value. In both these cases we have changed the forecast of gains/losses on disposal to nil as the data is not considered representative of an ongoing trend and the historic

- 6.8 This is a change from the approach we proposed in our draft decision where we used an industry average ratio. We received submissions from Vector, ENA, PwC and Powerco recommending that we use a distributor specific ratio. We have observed that there is a great degree of variation in disposal activity between distributors and believe that distributor specific ratios would result in better forecasts.
- 6.9 Powerco and Vector losses on disposals increase the most resulting in a 0.4% and 0.1% increase in starting prices.¹¹⁷
- 6.10 We have included the forecast loss on disposal as negative other regulated income. This approach means that distributors will recover revenue, based on a forecast of the loss on disposal, in the regulatory period that the disposal is forecast to occur. Such an approach is similar in effect to the approach applied in November 2012, when the losses on disposal were included in the forecast of operating expenditure.

Other regulated income

- 6.11 Our modelling requires a nominal forecast of other regulated income from 2014-2015 to 2019-2020. Other regulated income is income from the provision of regulated services that is recovered in a different manner from line charges. For example, it includes lease or rental income from regulated assets.
- 6.12 A forecast of other regulated income should be netted off in the calculation of building blocks allowable revenue. While building blocks allowable revenue generally relates to income received from standard electricity distribution line charges, other income they receive is also relevant to determining a distributor's revenue requirement.
- 6.13 We used the arithmetic average of each distributor's historical other income as a forecast, scaled up for the effects of inflation. We consider that the historic average is likely to provide a reasonable guide to the future. As outlined above, we also intend to include forecast losses on disposals as negative other regulated income.

gains/losses on disposal are not large (on average a \$0.222 million loss for Aurora and \$0.020 million gain for Centralines).

117 Powerco losses increase by \$1.144 million per annum resulting in a 0.4% impact on starting prices and Vector losses increase to \$0.526 million per annum resulting in a 0.1% impact on prices.

Attachment A: Econometric analysis of operating expenditure

Purpose of attachment

- A1 This attachment outlines and explains our approach to modelling the relationship between operating expenditure and scale factors, network line length and number of connections. This attachment:
- A1.1 Summarises the results of our econometric modelling of network operating expenditure to line length and number of connections, and non-network operating expenditure to number of connections;
 - A1.2 Gives an overview of our approach to our econometric modelling;
 - A1.3 Summarises the data that we used in our analysis and the observations that have been excluded;
 - A1.4 Provides more detailed results of our econometric modelling; and
 - A1.5 Summarises the peer review that has been done on our modelling.
- A2 The result of our modelling is used to forecast operating expenditure in Chapter 3 of this report.

Summary of results

- A3 We modelled network operating expenditure and non-network operating expenditure separately, consistent with the previous report, using the latest available data.
- A4 Network operating expenditure is modelled using network line length and number of connection points as explanatory variables. Our model shows that 1% increase in the network line length increases network operating expenditure by 0.44%. It also indicates that a 1% increase in the number of connections increases network operating expenditure by 0.49%.
- A5 Non-network operating expenditure is modelled using number of connection points as the explanatory variable. Our model shows that 1% increase in the number of connections increases non-network operating expenditure by 0.82%, on average.
- A6 A summary of the results are shown in Table A1.

Table A1: Network and non-network operational expenditure econometric results

	Network operating expenditure	Non-network operating expenditure
ln (network length)	0.444***	
ln (number of connections)	0.493***	0.822***
Constant	-0.406	0.053
Adjusted R ²	0.89	0.91
F-statistic	567	1329
N	142	140

Notes: *** significant at 1% confidence level, *significant at 10% confidence level.

Source: Commission analysis

- A7 We have updated the econometrics since the draft decision to include the data for the 2014 disclosure year, which was disclosed in August.¹¹⁸ The resulting coefficients and results of statistical diagnostic tests are very similar to the draft decision.¹¹⁹

Overview of our approach

- A8 The purpose of our econometric modelling is to establish what the relationship is between operational expenditure and scale factors.
- A9 This relationship is expected to be positive, for example, it is expected that any growth in the size in the network will increase operating expenditure to maintain and manage the network. We also suspect that there may be economies of scale resulting in expenditure growth being less than scale growth.
- A10 We consider that it is appropriate to model network and non-network operating expenditure separately as they are driven by different factors.
- A11 For network operating expenditure our exploratory and econometric analysis suggests that network line length and number of connections are appropriate drivers. We have therefore regressed network operating expenditure for these two variables.

¹¹⁸ Some submitters, including the ENA and PwC, submitted that the econometrics should be updated to include 2014 data for the final decision. Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 30; PwC "Submission to the Commerce Commission on Low Cost Forecasting Approaches For Default Price-Quality Paths - Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), paragraph 26.

¹¹⁹ For reference the coefficients on network length and number of connections in the model of network operating expenditure in the draft decision were 0.451 and 0.490 respectively. The coefficient on the number of connections in model of non-network operating expenditure was 0.821.

A12 For non-network operating expenditure our exploratory and econometric analysis suggests that the number of connections is the sole and appropriate driver. We have therefore regressed network operating expenditure on this variable.

A13 The split into network and non-network operating expenditure, and the explanatory factors we have identified for each type of operating expenditure are intuitive.

A13.1 Network operating expenditure, ie, expenditure on maintaining the network, reflects the activity that takes place on the physical network. Line length and the number of connections act as suitable proxies for the scale of the network and, therefore, the level of direct activities needed to maintain that network. The regression equation is:

$$\ln(\text{network opex}) = \beta_0 + \beta_1 \ln(\text{length}) + \beta_2 \ln(\text{ICPs})$$

A13.2 Non-network operating expenditure (ie, expenditure on business support activities) is more related to the size of each business. The number of connections is a suitable proxy for the size of the business and is therefore associated with overhead costs. The regression equation is:

$$\ln(\text{non network opex}) = \beta_0 + \beta_1 \ln(\text{ICPs})$$

A14 We estimate the relationship between costs and cost drivers using a log-log model specification. This specification can be interpreted as estimating the elasticity of an explanatory variable to the dependent variable. Estimated elasticities are required to project the growth in operating expenditure for the 2015-2020 regulatory period, as discussed in Chapter 3.

A15 We have tested a range of regressions and diagnostic tests to assess the robustness of our modelling.¹²⁰ The results of these diagnostic tests indicate that the econometric model used is statistically robust. As discussed below, we find that the models we have used are also statistically preferred to alternative specifications suggested by Frontier Economics.

¹²⁰ We use Stata for our operating expenditure econometric modelling and the associated do-files accompanying this paper explain the models and tests that we ran. This includes tests for model misspecification, heteroscedasticity, normality, poolability, and whether the coefficients differ for exempt and non-exempt distributors.

Data used for modelling

- A16 All electricity distributor specific information was obtained from their information disclosures.¹²¹ This includes data on network and non-network operating expenditure, network line length, number of connection points, and other possible explanatory variables tested in our modelling.
- A17 Labour cost indices and producer price indices were produced by Statistics New Zealand and supplied by the New Zealand Institute of Economic Research. These indices were used to convert the historic nominal operating expenditure into constant prices.
- A18 We used data from 2010 to 2014 for the model as these are the years for which we have reliable information on network and non-network operating expenditure.
- A19 We have undertaken data cleaning on the information disclosure data. This process includes:
- A19.1 Adjusting Aurora Energy’s network line length for 2010 to 2012 as dedicated street lighting appears to have been included for these years;
 - A19.2 Adjusting Powerco’s network line length for 2010 to 2012 as dedicated street lighting appears to have been inconsistently treated;
 - A19.3 Adjusted data on network line length for The Lines Company prior to 2013 due to issues highlighted by The Lines Company;
 - A19.4 Adjusting the network line length disclosed by Unison Networks and Centralines in 2014. Both distributors reported an unusually large increase in their line length between 2013 and 2014; and
 - A19.5 Removing Orion from the modelling for 2011 given the distortionary impact of the major earthquakes in their network zone that financial year.
- A20 We also removed outliers discovered during the modelling process. Generally, observations that failed three or more of the four statistical outlier tests were considered to be an outlier, and removed.¹²² These observations have a disproportionate impact on the coefficients estimated by the econometric model. Consequently:

¹²¹ Some of the data on network line length was subsequently adjusted as part of the data cleaning process using additional information provided by distributors.

¹²² We tested for outliers using four outlier tests. These are DFITS, Cook’s Distance, Welsch’s Distance, and Leverage outlier tests and are included in the do-file.

- A20.1 Nelson Electricity was considered an outlier in 2011 and 2012 for our network operating expenditure model; and
- A20.2 Observations for Buller Electricity were removed from our non-network operating expenditure model.¹²³
- A21 Operating expenditure has been modelled using all electricity distributors, not only those subject to price-quality regulation. We consider this appropriate as there appears to be no reason for scale effects to affect exempt distributors differently. Using as many observations as possible also helps to improve the robustness of the estimated coefficients.

Results of modelling operating expenditure

- A22 We have explored alternative models including different measures of scale and other potential operating expenditure drivers, and assessed the statistical robustness of the results and the intuition of the resulting coefficients.¹²⁴

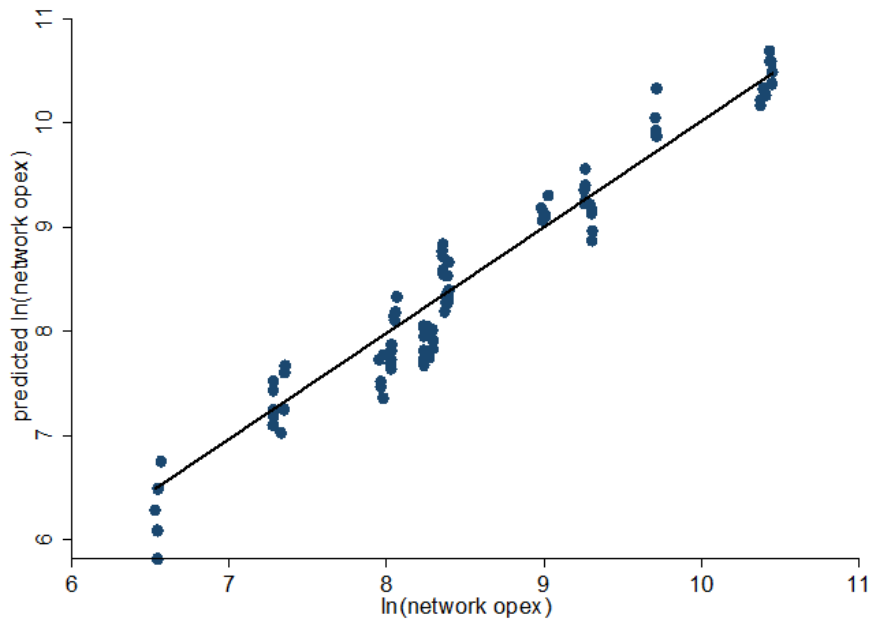
Network operating expenditure

- A23 Frontier Economics suggested an alternative model specification, and the exclusion of Nelson Electricity and Buller Electricity from the econometric model. As discussed in the reasons paper for the draft decision, we consider the existing specification to be more transparent, and that the exclusion of these distributors is statistically unsupported.¹²⁵ Statistical diagnostic tests also prefer our specification.
- A24 Figure A1 illustrates how well our model fits network operating expenditure with actual data between 2010 and 2014.

¹²³ Vector was found to fail three of the four statistical tests for outliers when its 2014 observation was included in the non-network model. However, we decided not to exclude this observation. This was because we concluded it did not have a significant impact on the estimated coefficients, and there was no other reason to suggest that this observation was an outlier.

¹²⁴ Refer to the accompanying do-file for the draft decision for further details of our alternative scenarios.

¹²⁵ Commerce Commission " Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Low cost forecasting approaches " (4 July 2014), paragraphs A20 to A23.

Figure A1: Predictive power of our network operating expenditure model

Note: For readability, the origin of the graph is not set at zero.

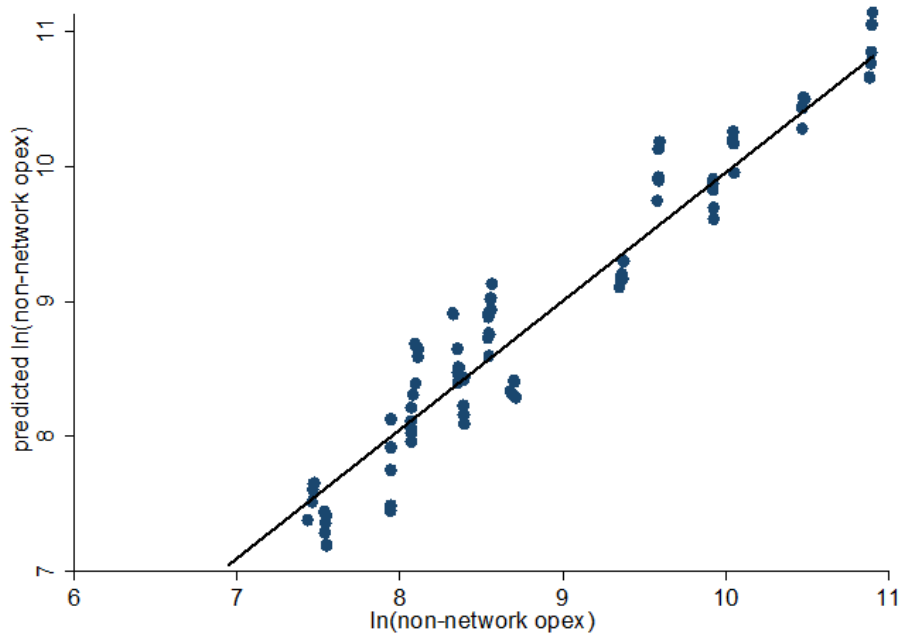
Source: Commission analysis

Non-network operating expenditure

- A25 For non-network operating expenditure, Frontier consider including a measure of network density in addition to the number of connections, and excluding Nelson Electricity and Buller Electricity from the model. As discussed in the draft decision, we found that the statistical diagnostic tests preferred our specification, and that the exclusion of the distributors was statistically unsupported.¹²⁶
- A26 Figure A2 illustrates how well our model fits non-network operating expenditure with actual data between 2010 and 2013.

¹²⁶ Commerce Commission "Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020: Low cost forecasting approaches " (4 July 2014), paragraphs A25 to A28. We updated the Frontier Economics model using 2014 data and found that the diagnostic tests still supported our model specification. The adjusted R^2 for the Frontier Economics model was 90% compared to 91%, for our model while the F-statistic was 583 compared to 1329 for our preferred specification.

Figure A2: Predictive power of our non-network operating expenditure model



Note: For readability, the origin of the graph is not set at zero.

Source: Commission analysis

- A27 There is insufficient data to test the appropriateness of the econometric model using time-series data, as suggested by the ENA.¹²⁷
- A28 Furthermore, such tests are of limited value as there is a range of reasons why actual expenditure may differ from any forecast. This includes unforeseen events, efficiency changes and, changes in strategy. The existence of any differences does not suggest that there is an alternative approach that is systematically more accurate.

External review of econometric modelling

- A29 Professor Jeff Borland has acted as an external reviewer and consultant on our econometric modelling. Professor Borland's report to the Commission was published alongside the draft decision.¹²⁸
- A30 Professor Borland's report is generally supportive of our proposed approach to modelling network and non-network operating expenditure. We have taken Professor Borland's report into consideration when making our decision.

¹²⁷ Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 31.

¹²⁸ Jeff Borland "Comments on NZCC approach for forecasting opex" (26 June 2014).

Attachment B: Initial level of operating expenditure

Purpose of attachment

- B1 The initial level of operating expenditure is calculated as the average of 2013 and 2014 operating expenditure for each distributor. This is change from our draft decision, which was to use 2013 operating expenditure only.
- B2 We have decided not to rely solely on 2014 data. Although, in principle, we would prefer to rely on the most recently available year of data, we remain concerned that expenditure in 2014 was atypical. Using 2013 data, in addition to 2014 data, limits the impact of any atypical expenditure in 2014.
- B3 Historic operating expenditure in 2013 and 2014 has been adjusted to remove the costs associated with the judicial review and merits appeal challenges. Now that the Part 4 regulatory regime is in place, we do not expect distributors to continue to incur these costs.

We explored whether 2013 and 2014 were atypically high or low cost years

- B4 In principle, relying on data for the most recently available year prior to the reset (in this case, 2014) helps ensure efficiency gains achieved prior to the start of the regulatory period are passed onto consumers. Relying on data for earlier years may reduce the extent to which efficiency gains are shared with consumers.
- B5 However, as noted in the Process and Issues Paper, two reasons suggest it may be inappropriate to rely solely on 2014 data to set the initial level for the forthcoming reset:¹²⁹
- B5.1 Atypically high or inefficient costs in 2014 may lead to a forecast that is biased in favour of the distributors. By the same reasoning, an atypically low cost year may bias the forecast to the disadvantage of distributors; and
- B5.2 In November 2012, we relied on the most recently available year of data prior to the start of the regulatory period, which may have created an adverse incentive for distributors to advance or defer expenditure to 2014 (or to find some other way to inflate costs in that year).
- B6 We therefore assessed whether 2014 was an atypically high or low cost year.

¹²⁹ Commerce Commission “Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues paper” (21 March 2014), paragraph A14.

- B7 The actual expenditure information disclosed for the 2014 disclosure year indicates that 2014 was atypical.¹³⁰ We had previously expressed concern that the forecasts of expenditure of 2014 indicated that it would be atypical. Actual expenditure in 2014 was only 1% less than the forecast considered for the draft decision.
- B7.1 Total operating expenditure for the 16 non-exempt distributors in 2014 was 7% higher than in 2013.
- B7.2 Eight distributors had increases of more than 5% relative to 2013, of which four had increases of more than 10%.
- B8 Figure 3.1 in Chapter 3 shows the difference between total operating expenditure for each distributor between 2013 and 2014.
- B9 Many stakeholders disagree that 2014 was an atypically high cost year or a response to adverse incentives to inflate costs in that year. They submitted that:
- B9.1 There are a number of factors that have resulted in a general upward trend in operating expenditure. This includes new health and safety regulations and enhanced reporting requirements under Part 4;¹³¹ and
- B9.2 There is no evidence that the increase in operating expenditure in 2014 was in response to the incentive to inflate expenditure.¹³²
- B10 It is extremely difficult to determine whether the observed increases in expenditure in 2014 were efficient, or a response to the adverse incentives discussed in paragraph B5. This is because of the asymmetry of information present, and our inability to review of the efficiency of each distributor's disclosed levels of expenditure under the low cost approach to setting the default price-quality path. Our decision to use both 2013 and 2014 data is a reflection of this.

¹³⁰ Actual expenditure in the 2014 disclosure year was disclosed in August.

¹³¹ See, for example, Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 40.

¹³² See, for example, Aurora Energy Limited "Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015 and Low Cost Forecasting Approaches for Default Price-Quality Paths" (15 August 2014), p. 10; PwC "Submission to the Commerce Commission on Low Cost Forecasting Approaches For Default Price-Quality Paths - Made on behalf of 19 Electricity Distribution Businesses" (15 August 2014), paragraph 25.

- B11 Distributors also implied that the increase in operating expenditure between 2013 and 2014 is misleading. Many distributors considered 2013 was an atypically low cost year due to mild temperatures and that 2014 operating expenditure is more representative of their future expenditure requirements.¹³³
- B12 We disagree with submitters that 2013 was an atypically low cost year. We observe a decline in network operating expenditure in 2013 for the industry as a whole, as well as for a number of individual distributors. This may be a reflection of benign weather conditions. However, we also observe a large increase in non-network operating expenditure at the same time.
- B13 In fact, total operating expenditure for the 16 non-exempt distributors increased by 2% between 2012 and 2013, largely due to an 11% increase in non-network operating expenditure. 2013 does not therefore appear to be a low cost year. As discussed above, it is extremely difficult to determine whether such increases reflect efficient expenditure.

How we calculated the initial level of operating expenditure

- B14 The initial level of operating expenditure is calculated for each distributor as the arithmetic average of 2013 and 2014 expenditure after adjustment to remove the costs associated with the judicial review and merits appeal challenges to the input methodology determinations. We therefore give equal weight to both years' of data. Due to the concerns expressed above, we do not consider it appropriate to give more weight to 2014.¹³⁴
- B15 Section 52T(1)(c)(i) of the Act indicates an intention that consumers should not bear the cost of legal challenges by distributors to the input methodology determinations. We therefore did not specify such costs as 'pass-through costs' or 'recoverable costs' when we determined input methodologies in December 2010.

¹³³ See, for example, Powerco "Submission on Default price-quality paths for electricity distributors from 1 April 2015 and Low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 45; Aurora Energy Limited "Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015 and Low Cost Forecasting Approaches for Default Price-Quality Paths" (15 August 2014), p. 16; The Lines Company "Submission on Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015" (15 August 2014), p. 4.

¹³⁴ Aurora Energy suggested that more weight should be given to 2014 relative to 2013. See Aurora Energy Limited "Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015 and Low Cost Forecasting Approaches for Default Price-Quality Paths" (15 August 2014), p. 19.

- B16 Consistent with a previous decision for the gas default price-quality path, we therefore consider it appropriate to exclude these costs from the base year level of operating expenditure.¹³⁵
- B17 We have adjusted the 2013 data to account for changes in input prices between 2013 and 2014, but have not adjusted for changes in scale. We consider this would add an unnecessary level of complexity given that the change in network scale between 2013 and 2014 was small.¹³⁶

The choice of initial level of operating expenditure in future resets

- B18 The implementation of a successful time consistent incentive for operating expenditure will allow us to use the most recently available year to set the initial level of operating expenditure in future resets. This will help ensure efficiency gains are shared with consumers and remove the adverse incentives to inefficiently defer or advance expenditure to a particular year.

¹³⁵ See: Commerce Commission “Setting Default Price-Quality paths for Suppliers of Gas Pipeline Services” (28 February 2013), paragraphs C10-C13.

¹³⁶ Total network length for the 16 distributors increased by less than 0.5% between 2013 and 2014 while the number of connections increased by 0.6%.

Attachment C: Changes in input prices

Purpose of attachment

- C1 This attachment outlines and explains our approach for forecasting changes in input prices for operating and capital expenditure.

Changes in input prices for operating and capital expenditure

- C2 As noted in the previous chapters on forecasting operating and capital expenditure, we forecast changes in input prices:¹³⁷
- C2.1 For operating expenditure, by relying on independent forecasts of changes in the all industries labour cost index and producer price index. We apply a weight of 60% on labour inputs, and 40% on non-labour inputs; and
 - C2.2 For capital expenditure, by relying on independent forecasts of changes in the all goods capital goods price index.
- C3 In the sections that follow, we explain our reasons for relying:
- C3.1 On indices that reflect changes across all industries, rather than changes that are more sector specific; and
 - C3.2 On a 60:40 weighting for labour and non-labour operating inputs.
- C4 We also explain our reasons for rejecting the option of relying on an average of a number of different forecasts.

¹³⁷ The New Zealand Institute of Economic Research provided forecasts of these indices. Under commercial terms between the Commission and the New Zealand Institute of Economic Research, forecasts of the producer price index and the labour cost index may be shared with the industry, but not more widely. Suppliers may request this information from the Commission.

Comparison with forecasts implied by distributor forecasts of expenditure

- C5 For operating expenditure, the New Zealand Institute of Economic Research's forecasts of input prices translate into an annual average growth rate of 2.46% between 2015 and 2020. This assumption appears reasonable based on the input price forecasts implied by each distributor's forecast of operating expenditure. In particular:
- C5.1 Nine out of 16 distributors forecast less growth in input prices than the New Zealand Institute of Economic Research; and
 - C5.2 Seven out of 16 distributors forecast higher growth in input prices than the New Zealand Institute of Economic Research.
- C6 For capital expenditure, the New Zealand Institute of Economic Research's forecasts of input prices translate into an annual average growth rate of 2.13% between 2015 and 2020. Again, this assumption appears reasonable based on the input price forecasts implied by each distributor's forecast of capital expenditure. In particular:
- C6.1 Five out of 16 distributors forecast less growth than the New Zealand Institute of Economic Research;
 - C6.2 Seven out of 16 distributors forecast growth within 0.75 percentage points higher than the New Zealand Institute of Economic Research,¹³⁸ and
 - C6.3 Four out of 16 distributors forecast in excess of 0.75 percentage point higher growth than the New Zealand Institute of Economic Research.
- C7 The forecasts provided by the New Zealand Institute of Economic Research therefore appear reasonable relative to the forecasts implied by distributor forecasts of expenditure.

¹³⁸ Applying an input price assumption of 2.88% for capital expenditure instead of 2.13% results in a very small change in the amount of revenue allowed over a regulatory period. It is the return on and of capital in the regulatory asset base that is most relevant to the starting price.

Our decision not to use sector specific indices

- C8 A number of distributors have argued that sector specific indices should be used instead of indices for all industries. In particular, distributors suggested that the labour cost index for electricity, gas, water and waste services should be used.
- C8.1 Frontier Economics' view (on behalf of the ENA) is that, in principle, forecast errors can be reduced though using projections as specific to the industry or asset class as possible.¹³⁹
- C8.2 Submitters, including the ENA, Wellington Electricity and Unison do not consider the all industries labour cost index takes into account sector specific labour costs.^{140 141}
- C9 In our view, it is appropriate to rely on forecasts of the all industries labour cost index because changes in this index are less dependent on the behaviour of regulated suppliers.
- C10 The electricity, gas, water and waste services labour cost index is composed of a sample of 30 employers, half of which are electricity distribution businesses.¹⁴² Using an index that is, to a large extent, determined by the performance of the regulated businesses may weaken incentives to improve efficiency,¹⁴³

¹³⁹ Frontier Economics Limited "Output 1: Top-down approaches for forecasting EDB costs under a DPP framework - a report prepared for the Electricity Networks Association of New Zealand" (April 2014), p. 6.

¹⁴⁰ The ENA provided a late submission which examined in more detail the difference between industry's historic labour costs, the all industries labour cost index and the electricity, gas, water and waste services labour cost index. However, this submission was provided after the consultation period and so has not been considered.

¹⁴¹ Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraph 87; Wellington Electricity Lines Limited "Submission on issues paper on 2015-2020 Default Price-quality Path" (30 April 2014), p.3; Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" (30 April 2014), paragraph 49.

¹⁴² Frontier Economics Limited "Output 1: Top-down approaches for forecasting EDB costs under a DPP framework - a report prepared for the Electricity Networks Association of New Zealand" (April 2014), p.93.

¹⁴³ We agree with the ENA that regulated business still have some incentive to control their labour costs so as to maximize profits. However, we still consider the incentive to improve efficiency would be weakened. The ENA also submitted that regulated suppliers have limited control over their labour costs as they compete with each other and with Australian distributors for labour. However, the ENA did not provide evidence to support this assertion. Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraphs 81 to 82.

- C11 In addition, the all industries index generally provides a good proxy for sector specific indices. Submitters have highlighted historic differentials between the all industries labour cost index and the electricity, gas, water and waste services labour cost index in New Zealand and in Australia.¹⁴⁴ However, we note that:
- C11.1 The historic average percentage point difference between the actual all industries labour cost index and the electricity, gas, water and waste services labour cost index is small at around 0.14% from 2008 to 2013; and
- C11.2 Forecast changes in the all industries labour cost index are similar to those for the electricity, gas, water and waste services labour cost index. Based on New Zealand Institute of Economic Research's 2013 forecast, the geometric mean of forecast changes over the period 2015–2020 is 2.2% for both indices.¹⁴⁵
- C12 The ENA proposes that, if the all industries labour cost index is used, a ‘wedge’ should be added to the forecast to account for the wage pressures the industry faces. It does not consider these pressures are also captured in the all industries labour cost index.¹⁴⁶
- C13 However, the ENA did not provide any details in its submissions for us to consider how we could adjust the forecast all industries labour cost index to account for industry specific labour costs.
- C14 Meanwhile, the use of all industries producers price index is supported by Vector, who suggest that for this reset:¹⁴⁷

Although using more industry specific PPI [Producer Price Index] projections can help reduce forecasting error, they can also be much more volatile; on this basis Vector considers that using the “All industry” PPI for this reset would be the better option.

¹⁴⁴ See, for example, Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraph 81; Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" (15 August 2014), p.19.

¹⁴⁵ New Zealand Institute of Economic Research "Cost Escalation Forecasts – Frameworks Forecasts and Forecast Methods" October 2013, submitted as part of Transpower's Individual Price-Quality Path proposal. We have not commissioned new electricity, gas, water and waste services labour cost index forecasts to update this comparison.

¹⁴⁶ Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" (15 August 2014), paragraph 7.

¹⁴⁷ Vector "Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper" (30 April 2014).

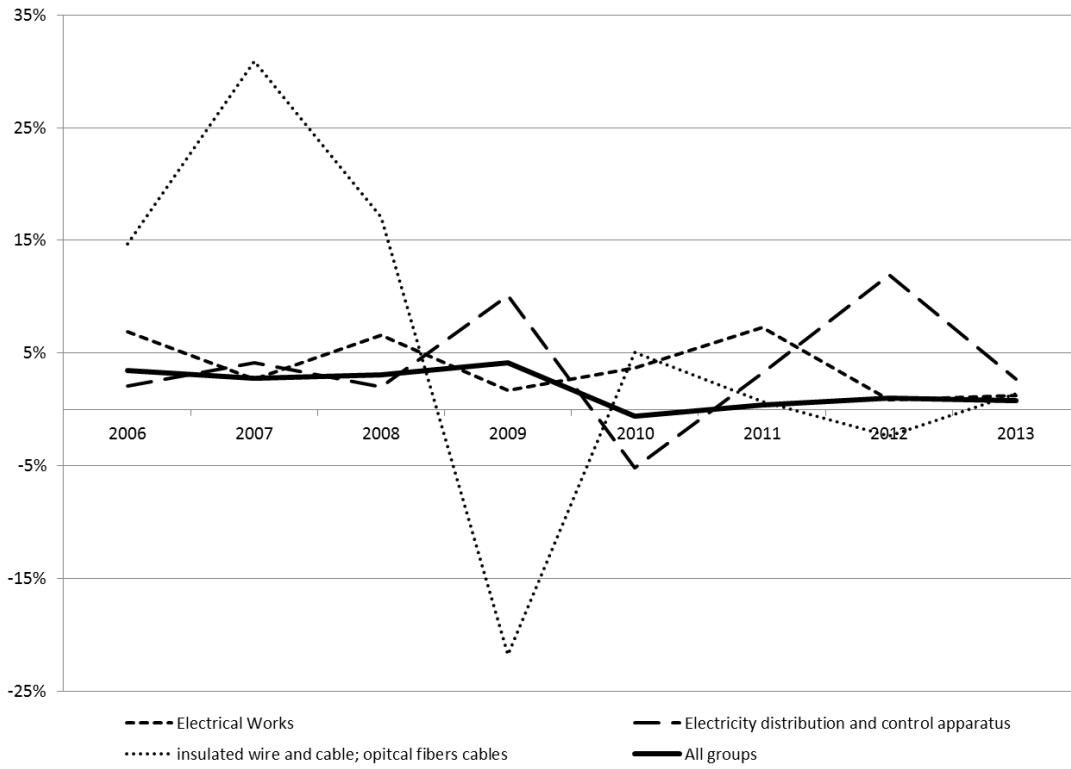
Our decision not to use a composite index for capital expenditure

- C15 A number of submitters on the Process and Issues Paper, including Frontier Economics, recommended a composite index for capital expenditure.¹⁴⁸ They suggested the composite index should consist of capital goods price sub-indices and forecasts of the price of raw inputs, such as steel and copper.
- C16 Figure C1 shows a historical time-series of each of the capital goods price index and various sub-indices considered by Frontier Economics (on behalf of the ENA). Frontier Economics noted that the capital goods price index sub-indices illustrated here all have historical growth rates greater than the all industries capital goods price index.¹⁴⁹

¹⁴⁸ For example, Wellington and Unison considered that the all groups capital goods price index is not reflective of industry specific cost changes. Wellington Electricity Lines Limited “Submission on issues paper on 2015-2020 Default Price-quality Path” (30 April 2014), p.8; Unison Networks Limited “Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper” (30 April 2014), paragraph 61; Frontier Economics Limited “Output 1: Top-down approaches for forecasting EDB costs under a DPP framework - a report prepared for the Electricity Networks Association of New Zealand” (April 2014), p.97.

¹⁴⁹ Frontier Economics Limited “Output 1: Top-down approaches for forecasting EDB costs under a DPP framework - a report prepared for the Electricity Networks Association of New Zealand” (April 2014); Frontier Economics Limited “Output 3: Development of approaches to forecast EDB costs under a DPP framework - a report prepared for the Electricity Networks Association of New Zealand” (May 2014). This included the sub-indices of capital goods price index labelled: electrical works; electricity distribution and control apparatus; insulated wire and cable, and optical fibre cables.

Figure C1: Capital Goods Price Index – all groups and sub-indices



Source: Statistics New Zealand

- C17 We do not consider that moving away from the all groups capital goods price index would be appropriate for the default price-quality path for a number of reasons:¹⁵⁰
- C17.1 There is no capital goods price sub-index that covers all relevant asset groups;
 - C17.2 The development of a composite approach is likely to have a large degree of subjectivity in terms of the weights used to combine separate forecasts. Neither forward-looking weights nor the data required to calculate historic weights are readily available. Even if they were, it can be difficult to calculate and verify weights for composite indices,¹⁵¹ and
 - C17.3 The impact on the starting price of moving away from the all industries capital goods price index will be small, and even less than that for operating expenditure. It is the return on and of capital in the regulatory asset base only that is most relevant to the starting price.
- C18 By contrast, it may be appropriate to apply a composite approach when setting price-quality paths that allow for detailed consideration of the particular circumstances of individual distributors.
- C19 We previously applied a composite approach for the customised price-quality price path for Orion New Zealand. We also accepted the composite price index proposed by Transpower New Zealand as part of its individual price-quality path. Where relevant, we expect future proposals for customised price-quality paths to transparently derive and justify the weights applied under the composite approach to cost escalation.

¹⁵⁰ Vector has submitted that it supports this proposed approach: Vector “Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper” (30 April 2014), paragraph 107.

¹⁵¹ Errors in the weightings could be substantial and would make the forecast less accurate overall than the status quo.

Weightings for labour and non-labour operating inputs

C20 We agree with Frontier Economics who have suggested that the proposed 60:40 weighting for labour and non-labour operating inputs may not be ideal.¹⁵² However:

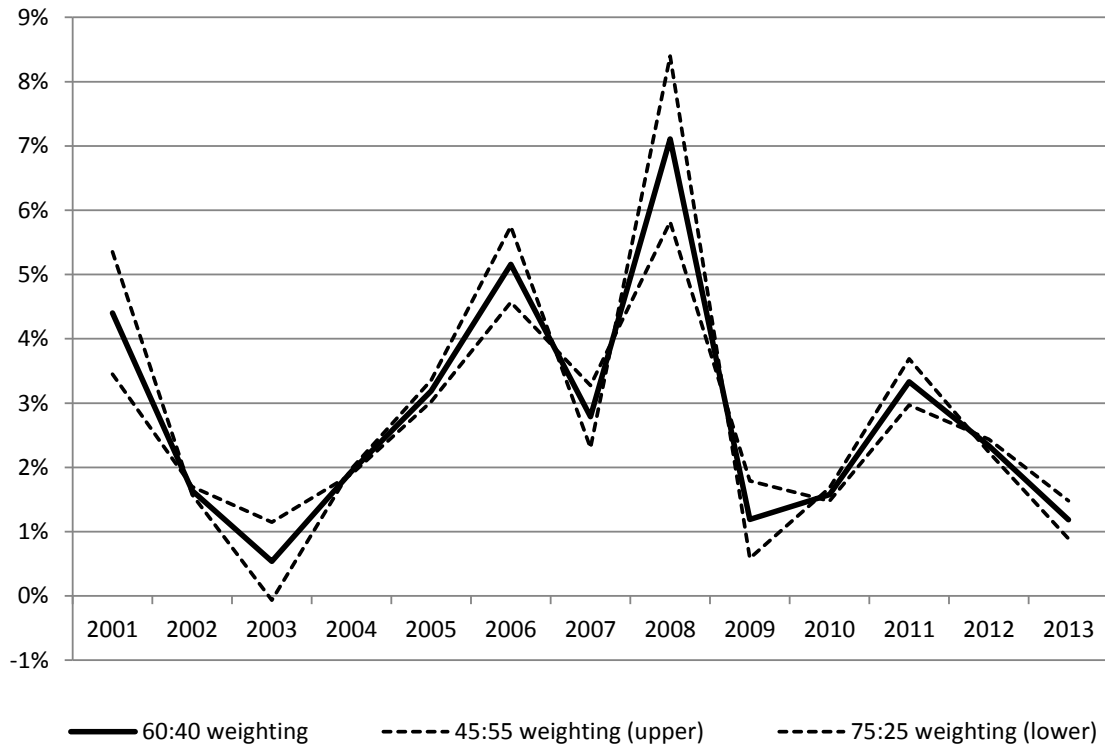
C20.1 At this time, we have no better information on the composition of each distributor's expenditure split between labour and non-labour operating expenditure. The 60:40 split reflects the best information available to us at this time;¹⁵³ and

C20.2 A sensitivity analysis around the impact on the choice of weighting parameter does not raise serious concerns on the robustness of the parameter.

C21 Figure C2 illustrates the impact of altering the 60:40 weighting applied to the labour cost index and producer price index respectively. The two dotted lines cover a 45:55 to 75:25 range of weightings.

¹⁵² Frontier Economics Limited "Output 1: Top-down approaches for forecasting EDB costs under a DPP framework - a report prepared for the Electricity Networks Association of New Zealand" (April 2014), p.110.

¹⁵³ The 60:40 weighting was used in the November 2012 reset and was based on an analysis of labour expenditure by Australian distributors as no data was available for New Zealand. See Commerce Commission "Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors" (30 November 2012), paragraph C39.

Figure C2: Sensitivity analysis of the operating expenditure weighting parameter

Source: New Zealand Institute of Economic Research, Commission analysis

Averaging of different forecasts

C22 We propose to use forecasts from a single independent forecasting agency.¹⁵⁴ Our view is that forecast averaging does not guarantee improved forecast accuracy. Distributors did not put forward alternative forecasts as part of their submissions on our draft decision.

¹⁵⁴ Horizon and PwC had submitted that they support averaging forecasts from different sources as this may reduce forecasting error. Horizon Energy Distribution Limited "Submission on the Default Price-Quality Paths from 1 April 2015 for 17 Electricity Distributors: Process and Issues Paper" (24 April 2014), paragraph 18; PwC "Submission to the Commerce Commission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues paper - Made on behalf of 20 Electricity Distribution Businesses" (30 April 2014), paragraph 49.

Attachment D: Technical analysis of constant price revenue growth

Purpose of attachment

- D1 This attachment outlines and explains our analysis to estimate the relationship between GDP and constant price revenue growth for industrial and commercial users over the regulatory period. The result of our analysis is used to forecast commercial and industrial constant price revenue in Chapter 5 of this report.

Overview of this attachment

- D2 This attachment:
- D2.1 summarises the results of our econometric modelling of line charge revenue to GDP;
 - D2.2 summarises and responds to submissions on our econometric approach for the draft decision;
 - D2.3 details our approach to and results of the econometric modelling;
 - D2.4 overviews the external estimates and expectations of the electricity consumption in the future; and
 - D2.5 gives an overview of the alternative approaches that we considered, including trending historic constant price revenue growth for each distributor.

Summary of results

- D3 Using a time-series regression approach, we modelled the relationship between GDP and industrial and commercial electricity use at a national level. Our modelling estimates that, historically, a 1% increase in real GDP is associated with a 0.64% increase in industrial and commercial electricity, on average, while over the 2008 to 2014 period our model estimates the estimated increase has been 0.27%
- D4 Given the recent past we have adopted an elasticity of GDP to constant price revenue growth of 0.50. This is based on our analysis and forward-looking expectations over the regulatory period. This elasticity approximately represents the midpoint between the more recent and more historic estimates of the elasticity of GDP to industrial and commercial electricity use revenue. We also have considered external views of the likely trend over the regulatory period to inform our decision.

Draft approach

- D5 For the draft decision we used a panel regression specification to estimate the elasticity of real GDP to constant price revenue for commercial and industrial users. As we do not observe constant price revenue we relied on total line charge revenue, provided by distributors' information disclosures, as a proxy for constant price revenue.¹⁵⁵
- D6 We tested a number of panel regression models that make use of both time-series and cross-sectional variations, making different explicit or implicit assumptions about the relation between individual data points, ie, the observed variation in explanatory and dependent variables, and the error term. The use of panel data allows us to estimate and test for robustness for a range of model specifications.¹⁵⁶
- D7 Using our preferred dataset, and a range of model specifications, resulted in a range of estimates between 0.72 and 1.22. We used the random effects model for cross-sections, which was consistent with the model used for the 2012 decision, and estimated an elasticity of 0.73.

Submitters reaction to draft decision

- D8 Submitters expressed concern that the increase in elasticity from 0.52 for the 2012 reset to 0.73 for the draft 2015 reset with the addition of one extra year of data was large and counter-intuitive.¹⁵⁷ The Centre for International Economics (CIE) and Frontier Economics, for Wellington Electricity, find that the resulting coefficient is very sensitive to the data points included in the model.¹⁵⁸

¹⁵⁵ We refer to 'line charge revenue' as the revenue the distributors receive from line charges which can be affected by prices and quantities. We refer to 'constant price revenue' as the revenue which are impacted by quantities only.

¹⁵⁶ We use Stata for our constant price revenue growth econometric modelling and the associated do-files accompanying this paper explain the models and tests that we ran.

¹⁵⁷ For example refer: Castalia Strategic Advisors "Review of Electricity Default Price-Quality Path Determination 2015 - Report to Vector" August 2014, pp.3-4; NZIER "Limitations in regional GDP projections - Implications for forecasting non-residential electricity demand" August 2014, pp.3-4.

¹⁵⁸ Refer: Frontier Economics "Review of Constant Price Revenue Growth model for 2015-20 Default Price-Quality Path" August 2014, pp.6; The Centre for International Economics "A review of the Commerce Commission's constant price revenue model" August 2014, p.34.

- D9 Issues that submitters have identified as potential problems with our draft econometric model include:
- D9.1 misspecification by using total revenue when the coefficient is applied to industrial and commercial customers only;¹⁵⁹
 - D9.2 excluding Vector and OtagoNet given that they represent a large portion of the industry, and applying the estimation to those distributors;¹⁶⁰
 - D9.3 line charge revenue includes pass-through and recoverable costs and excludes discretionary discounts and rebates;¹⁶¹
 - D9.4 that there is no longer a relationship between industrial revenue and GDP and therefore relationship should only apply to commercial revenue;¹⁶²
 - D9.5 relationship between GDP and revenue is spurious as they are non-stationary and are not co-integrated;¹⁶³
 - D9.6 estimating the model in levels but applied as a growth rate is not appropriate when the model is non-stationary;¹⁶⁴
 - D9.7 using line charge revenue introduces circularity given that revenue is influenced by regulation;¹⁶⁵ and
 - D9.8 line charge revenue should be adjusted by CPI-X, rather than just CPI.¹⁶⁶

¹⁵⁹ Refer: Frontier Economics "Review of Constant Price Revenue Growth model for 2015-20 Default Price-Quality Path" August 2014, pp.8-9; The Centre for International Economics "A review of the Commerce Commission's constant price revenue model" August 2014, p.36.

¹⁶⁰ Refer: Castalia Strategic Advisors "Review of Electricity Default Price-Quality Path Determination 2015 - Report to Vector" August 2014, p.6; Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraph 107.

¹⁶¹ Refer: Castalia Strategic Advisors "Review of Electricity Default Price-Quality Path Determination 2015 - Report to Vector" August 2014, p.5; Electricity Networks Association "Submission on low cost forecasting approaches for default price-quality paths" 15 August 2014, paragraph 107.

¹⁶² Refer: Horizon Energy Distribution Limited "Submission on Low Cost Forecasting Approaches For Default Price-Quality Paths" 15 August 2014, paragraph 43.

¹⁶³ Refer: Frontier Economics "Review of Constant Price Revenue Growth model for 2015-20 Default Price-Quality Path" August 2014, pp.9-10; The Centre for International Economics "A review of the Commerce Commission's constant price revenue model" August 2014, pp.34-35.

¹⁶⁴ Refer: The Centre for International Economics "A review of the Commerce Commission's constant price revenue model" August 2014, p.35.

¹⁶⁵ Refer: Castalia Strategic Advisors "Review of Electricity Default Price-Quality Path Determination 2015 - Report to Vector" August 2014, p.5.

¹⁶⁶ Refer: Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" 15 August 2014, p.11.

- D10 We thank submitters for their input regarding our econometric modelling for industrial and commercial revenue growth. In the following sections we address these submissions and in particular explain:
- D10.1 why we modified our approach to estimating a national elasticity of GDP to constant price revenue growth;
 - D10.2 the reasons we considered electricity throughput an appropriate proxy for constant price revenue;
 - D10.3 what changes we made to the panel regression in response to submissions and further analysis; and
 - D10.4 why we did not consider an extrapolation of historic revenue growth trend as appropriate.

Our approach for the final decision

- D11 We have modified our econometric approach for determining the relationship between GDP and industrial and commercial revenue growth.
- D12 We use a time-series approach to determine the relationship between national GDP and national industrial and commercial electricity use, and applied judgement to reflect expectations for the 2015-2020 regulatory period.
- D13 We have estimated this relationship between 1992 and 2014 using the following regression specifications, which are used to inform our judgement:

$$\text{Spec 1: } \ln(\text{electricity}) = \beta_0 + \beta_1 \ln(\text{GDP}_t) + \beta_2 \text{post2007} + \beta_3 \ln(\text{GDP}_t) * \text{post2007}$$

and;

$$\text{Spec 2: } \ln(\text{electricity}) = \beta_0 + \beta_1 \ln(\text{GDP}_t) + \beta_2 \text{post2007}$$

where:

- D13.1 “electricity” is New Zealand industrial and commercial electricity use, sourced from MBIE,¹⁶⁷
- D13.2 “GDP_t” is national real GDP, sourced from Statistics New Zealand,¹⁶⁸ and
- D13.3 “post2007” is a dummy variable for years after 2007.

¹⁶⁷ We note that industrial electricity throughout does include users that are directly connected to Transpower, but we consider this is a reasonable approach given the data available. Refer to www.med.govt.nz/sectors-industries/energy/energy-modelling/data/electricity

¹⁶⁸ <http://www.stats.govt.nz/infoshare>

D14 This approach uses industrial and commercial electricity throughput as a proxy for industrial and commercial constant price revenue. This captures changes in volumes which drive changes in constant price revenue. We recognise that this does not completely capture capacity based charging which is a common pricing mechanism for industrial users, but note that electricity use is necessarily related with capacity, in that capacity can be expected to increase as electricity use increases.¹⁶⁹

Results of our modelling

- D15 Spec 1 indicates that the historical elasticity of constant price revenue to GDP was 0.65, ie, a 1% change in real GDP is associated with a 0.65% change in industrial and commercial electricity use, on average between 1993 and 2007. However, the implied elasticity between 2008 and 2014 is 0.27%, on average.
- D16 Spec 2, which ignores the interaction, estimates a single elasticity of 0.64 over the whole period (1993 to 2014) with a single level shift in electricity throughput in 2008.
- D17 Figure D1 summarises the results of modelling the relationship between national GDP and electricity use using a time-series approach.¹⁷⁰

¹⁶⁹ This reduces any potential circularity issues, as raised by Vector and Castalia, as electricity throughput is less likely to be subject to regulatory influence than line charge revenue.

¹⁷⁰ We also considered other time-series model specifications with various alternative or additional explanatory variables and alternative applications of the time-related dummy variable. Our modelling was done in Stata and published alongside this paper.

Figure D1: GDP to electricity throughput time-series regression results

Dependant variable: Natural log of energy throughput			
<i>Specification</i>	1	2	3
Constant	2.5 (0.26)***	2.6 (0.3)***	3.4 (0.26)***
$\ln(\text{GDP}_t)$	0.65 (0.023)***	0.64 (0.025)***	0.57 (0.023)***
Post2007	4.5 (1.9)**	-0.040 (0.01)***	
$\ln(\text{GDP}_t) \cdot \text{Post2007}$	-0.38 (0.16)**		
n	22	22	22
\overline{R}^2	0.99	0.98	0.97
Implied $\varepsilon_{1992-2007}$	0.65	0.64	0.57
Implied $\varepsilon_{2008-2014}$	0.27	0.64	0.57
RESET p-value	0.61	0.20	0.0027

Notes: standard errors in parenthesis. The data covers the period 1993-2014.

* indicates statistical significance at 10%, ** at 5% and *** at 1%.

The variable Post2007 is set equal to one for years after 2007, zero otherwise.

D18 A dummy variable and interaction term are included in our regression to capture any changes in the relationship between real GDP and industrial and commercial electricity consumption between 2008 and 2014. We note that the estimated coefficient on:

D18.1 $\ln(\text{GDP}_t)$ reflects the elasticity of electricity use to GDP;

D18.2 Post2007 reflects a level shift occurring in 2008;

D18.3 $\text{Post2007} \cdot \ln(\text{GDP}_t)$ indicates the change in elasticity from 2007; and

D18.4 $\ln(\text{GDP})$ and $\text{Post2007} \cdot \ln(\text{GDP}_t)$ taken together equals the implied elasticity of electricity use to GDP between 2008 and 2014.

- D19 As indicated in our draft decision we would prefer to model industrial and commercial constant price revenue growth separately as they are likely to have different elasticities and may be affected by different drivers. This separation was supported by some submitters.¹⁷¹
- D20 While we have modelled industrial and commercial users separately as part of our analysis, which indicated that elasticity between GDP and commercial electricity use was greater than that of industrial electricity use, they cannot be applied to our forecast of constant price revenue growth as data provided by distributors do not separate industrial and commercial revenue consistently. For this reason we model and apply an elasticity for combined industrial and commercial.
- D21 Using this approach addresses some concerns raised by submitters, including:¹⁷²
- D21.1 the model is reasonably stable with only minor changes in the GDP coefficients when applying alternative time periods or dummy variables;
 - D21.2 the residential component can be removed so that only industrial and commercial electricity use is modelled for a relationship with GDP, this is then applied to industrial and commercial forecast;
 - D21.3 as is based on national data, this implicitly includes all distributors including Vector, OtagoNet, and exempt distributors; and
 - D21.4 robustness, in that adding or excluding data or changing the time dummy variable has little impact on the elasticity and find the Ramsey reset test supports our specifications.

External estimates of relationship between GDP and electricity use

- D22 We have reviewed previous econometric models of electricity demand to help understand whether the coefficients produced by our model(s) are intuitive, and consistent with previous research in this area.¹⁷³

¹⁷¹ Refer: Major Electricity Users' Group "Low cost forecasting approaches for DPP" 15 August 2014, paragraph Horizon Energy Distribution Limited "Submission on Low Cost Forecasting Approaches For Default Price-Quality Paths" 15 August 2014, paragraph 43.

¹⁷² The issue of whether log GDP and log electricity throughput are cointegrated is difficult to ascertain with such limited degrees of freedom (thus, Dickey-Fuller statistics not reported). RESET test: H_0 model has no omitted variables.

¹⁷³ Our review examines studies from New Zealand organisations. We have not considered studies based on economies overseas. Their findings are unlikely to be relevant to the New Zealand electricity industry due to their different economies and/or different stages of economic development.

D23 Table D1 summarises the estimated coefficients from these models. Some of these estimated coefficients are not directly comparable with each other or with the Commission's latest model due to differing functional forms and dependent variables. However, we consider they still provide a broad benchmark against which to assess the coefficients resulting from the Commission's latest econometrics.

Table D1: Published estimates of the econometric relationship between GDP and electricity demand

Model	Functional form	Dependent variable	Measure of GDP	Coefficient	Additional explanatory variables
Transpower	Log-log	National electricity demand (excl. Tiwai)	National GDP	0.46	Population, energy intensity
MBIE (commercial)	Log-log	Commercial electricity demand	Commercial sector GDP (excluding lag)	0.38	Commercial demand _{t-1}
MBIE (commercial)	Log-log	Commercial electricity demand	Commercial sector GDP (including lag effect)	0.84	
MBIE (industrial)	Levels	Annual % growth in industrial electricity demand (excl. large users)	Annual % growth in industrial sector GDP	0.63	Annual % growth in price of industrial energy
Electricity Authority	Logs	Annual % growth in national electricity demand	National GDP	1.2	Price change, price of gas, population budget share, unemployment, temperature
Commerce Commission (2012 reset)	Log-log	Line charge revenue by EDB	Regional GDP	0.52	N/A

Note: MBIE's estimate of commercial electricity demand includes a lagged variable (which is related to lagged GDP) – this implies a long-term elasticity of 0.84.

- D24 MBIE has estimated separate econometric models for residential, commercial and industrial demand.¹⁷⁴ These form part of its Supply and Demand Energy Model. MBIE find that GDP is a statistically significant driver of electricity demand in each model. Price is also found to be a statistically significant driver in the residential and industrial models.¹⁷⁵ They estimate that:
- D24.1 a \$1 increase in GDP per household will lead to an increase in demand per household of 0.11MJ, holding prices constant;
 - D24.2 a 1% increase in year-on-year commercial sector GDP will lead to 0.38% increase in commercial demand for electricity, however, given this model also includes a lagged variable this will imply a 0.84% increase in commercial demand for electricity over the long-term; and
 - D24.3 a 1% annual increase in industrial sector GDP will lead to a 0.63% increase in annual industrial demand for electricity, holding prices constant.
- D25 The Electricity Authority, using a vector error correction model, estimates that at 1% increase in national GDP will lead to a 1.2% increase in electricity demand, holding their other modelled explanatory variables constant.¹⁷⁶
- D26 Using data from 1974 to 2011, Transpower estimated the relationship between national electricity demand and GDP, population and energy intensity. It estimates that a 1% increase in GDP will lead to a 0.46% increase in national demand for electricity.¹⁷⁷

Applying forward-looking expectations

- D27 Given the historical elasticity of 0.65 and a recent elasticity of 0.27, a view is required on the expected relationship between GDP and non-residential electricity throughput for the 2015-2020 regulatory period.
- D28 Common reasons put forth for the decline in industrial and commercial energy use since 2008 are the global recession and slow recovery, particularly for the industrial sector; and improving energy efficiency.¹⁷⁸

¹⁷⁴ Refer: <http://www.med.govt.nz/sectors-industries/energy/pdf-docs-library/energy-data-and-modelling/technical-papers/Energy-Outlook-2013-Technical-Modelling-Guide.pdf>

¹⁷⁵ MBIE's models are not consistently specified so the coefficient on GDP has a slightly different interpretation in each model.

¹⁷⁶ Refer: <http://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/electricity-consumption/>

¹⁷⁷ Refer: <https://www.transpower.co.nz/sites/default/files/plain-page/attachments/transpower-demand-forecast-sept-2011.pdf>

¹⁷⁸ For example, refer to <http://www.med.govt.nz/sectors-industries/energy/pdf-docs-library/energy-data-and-modelling/publications/changes-in-energy-use/changes-in-energy-use.pdf>

- D29 We have consulted external sources for information on expectations of electricity consumption over the next seven years. These include:
- D29.1 Energy Link forecasts that industrial electricity demand will return to approximately 60% of the historical trend prior to the global financial crisis;¹⁷⁹
 - D29.2 Statistics New Zealand survey that energy efficiency was not as high a priority in 2012 compared to 2009, with more businesses indicating there were further electricity savings to be made.¹⁸⁰
 - D29.3 EECA have signalled that there is scope for further efficiencies in the industrial and commercial sectors;¹⁸¹ and
 - D29.4 the Electricity Authority find that there was little evidence of any major structural change in the determinants of electricity demand, including GDP, which they note as an important determinant of electricity demand.¹⁸²
- D30 Ultimately, given the uncertainty regarding the future of electricity demand, judgement is required to determine the elasticity assumption that would be most appropriate for the present purpose. In our view, the judgement comes in when we consider whether the elasticity will remain at that estimated between 2008 to 2014 (around 0.3), will return to a higher state consistent with pre-2008 data, or something else.
- D31 As we apply an estimated elasticity to forecasts of GDP, we require an estimate of elasticity that would be appropriate over the forecast horizon of 2015 to 2020. Therefore, we have:
- D31.1 surveyed other Government agencies research;
 - D31.2 looked at official survey data on energy efficiency for industrial and commercial groups; and
 - D31.3 commissioned forecasts from reputable industry forecasters of energy demand.

¹⁷⁹ Commission correspondence with Energy Link

¹⁸⁰ http://www.stats.govt.nz/browse_for_stats/industry_sectors/Energy/EnergyUseSurvey_HOTP12.aspx

¹⁸¹ <http://www.eeca.govt.nz/eeca-programmes-and-funding/programmes/business>

¹⁸² <http://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/electricity-consumption/>

- D32 The overall impression we are left with is nobody knows exactly what has happened in the electricity market for industrial and commercial users (though it seems to be related to the global financial crisis, with some energy efficiency) between 2008 and 2014. More importantly, there is uncertainty about how electricity demand will develop over the next five years. What we can say is that we agree with submitters that elasticity estimates of 0.7 would be high, almost certainly implausibly so.
- D33 As we do not know how much of what we observe is because of permanent factors like energy efficiency initiatives relative to temporary cyclical recession effects we have essentially chosen the point on the spectrum that seems most reasonable (0.5) in light of the available evidence. It is difficult to strongly argue that an alternative value is better supported by that evidence.
- D34 An elasticity of 0.5 is consistent with empirical findings. It is therefore preferable to relying on a simple extrapolation of historic trends.

Our draft approach – panel regression

- D35 A panel approach was used for the draft decision which takes into account time effects and cross-sectional effects. We continued to analyse panel specification for the final decision, with amendments made subsequent to the draft as a result of submissions and further analysis.
- D36 Consistent with the draft decision, line charge revenue was obtained from the distributors' information disclosures and was converted to constant prices. The changes we considered following the draft are:
- D36.1 using CPI-X to adjust line charge revenue to constant prices, rather than CPI only;
 - D36.2 excluding transmission charges from line charge revenue;¹⁸³
 - D36.3 using total electricity demand and total revenue to estimate a relationship;
 - D36.4 adding 2013 and 2014 data to the model;
 - D36.5 applying regional GDP data sourced from Infometrics instead of NZIER;¹⁸⁴ and
 - D36.6 remapping the GDP applicable to each distributor.

¹⁸³ ENA suggested pass through and recoverable costs are excluded from revenue. We note that pass through and recoverable costs are not available in information disclosures in 2004-2007. However as transmission charges make up most of pass through and recoverable costs we excluded these instead.

¹⁸⁴ This change had minor effects on our modelled coefficients.

- D37 Ideally, we would use line charge revenue specifically relating to commercial and industrial user groups. However, distributors do not consistently define users groups between commercial and industrial and therefore restricting the usefulness of such a model.¹⁸⁵
- D38 Some observations were excluded from our modelling. These are:
- D38.1 Orion from 2011 due to major earthquakes in 2011 and 2012 which may bias the modelling given the impact on revenues;
 - D38.2 Wellington Electricity before 2010 as this was their first full financial;
 - D38.3 Vector Lines in 2009 as they sold off their Wellington network in this year;
¹⁸⁶
 - D38.4 OtagoNet for all years as our exploratory analysis of the relationship between GDP growth and revenue growth for distributors shows that OtagoNet is anomalous and distorts the results significantly; and
 - D38.5 All electricity distributors that are exempt from price-quality regulation as they may have different revenue incentives given their ownership structure which would likely bias our modelling.

Results of our modelling

- D39 We were able to identify the most robust models using total revenue and total electricity demand as disclosed in information disclosure;

¹⁸⁵ However, we also acknowledge the general advantages of a panel approach such as it maximises the number of observations available to estimate an econometric model, attaches equal weighting to all distributors and is able to separate the impact on revenue of changes in GDP from changes in EDB-specific factors

¹⁸⁶ We note that Vector is not considered an outlier like it was in the draft. This is a result of remapping the data and adding the GDP applicable to Wellington network prior to the selloff in 2009.

D40 Table D2 summarises results of modelling revenue from information disclosures.

Table D12: ID revenue econometric modelling results

Item	Fixed effects model			Random effects model		
	Cross-sections	Time	Two-way effects	Cross-sections	Time	Two-way effects
ln GDP	1.94 ***	0.83 ***	0.61 ***	0.90 ***	0.83 ***	0.77 ***
Constant	-4.90 **	3.79 ***	5.03 ***	3.24 ***	3.82 ***	4.26 ***
R ²	0.84	0.85	0.99	0.84	0.84	n/a
F/χ ² stat	46	166	1587	119	894	116
N	164	164	164	164	164	164

Notes: *** significant at 1% confidence level; **significant at 5% confidence level

Source: Commission analysis

- D41 Using alternative panel regression specifications resulted in most estimates being between 0.61 and 0.90. For the 2012 reset and the draft decision we used the random effects model for cross-sections which produces elasticities of 0.52 and 0.73 respectively. The updated model updated produces an elasticity of 0.90, however we consider that the time effects and two-way models perform better.
- D42 We note that changes, especially the remapping, have resulted in more statistically significant results. For example, Castalia stated that our draft model was a poor predictor of revenue growth with only 17% of the variation explained.¹⁸⁷ The R-squared and other statistical tests perform better than previously.
- D43 Given concerns raised by Vector and Wellington Electricity that revenue may not be a suitable proxy for constant price revenue growth, we also tested for a relationship between GDP and total electricity throughput.¹⁸⁸ Results of these estimates ranged between 0.83 and 1.92.

¹⁸⁷ Refer: Castalia Strategic Advisors "Review of Electricity Default Price-Quality Path Determination 2015 - Report to Vector" August 2014, p.3.

¹⁸⁸ Refer: Vector "Submission on DPP low-cost forecasting approaches" 15 August 2014, paragraph 61; Wellington Electricity Lines Limited "Draft Decision on 2015-2020 Default Price-quality Path" 15 August 2014, p.11.

Trend analysis of constant price revenue growth

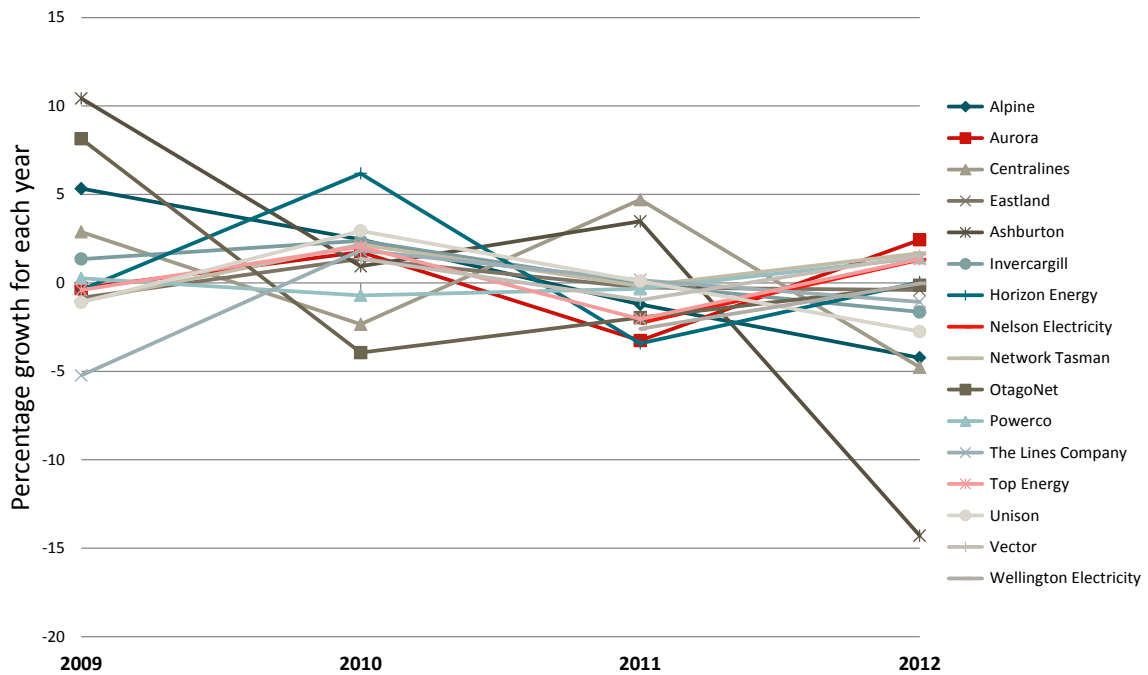
- D44 As discussed in Chapter 5, Wellington Electricity submitted that the Commission should forecast constant price revenue growth based on an extrapolation of recent trends for each distributor.
- D45 We have estimated historic constant price revenue growth (CPRG) for each distributor between 2008 and 2014 using data provided by distributors in response to two information requests. However our modelling suggested that CPRG varied significantly between distributors and over time for each specification.
- D46 The specifications we considered to determine historical constant price revenue growth included:
- D46.1 CIE's approach using from data provided in information disclosure from 2008 to 2012,¹⁸⁹
 - D46.2 using two sets of s53ZD data, being from 2012 and 2014 data requests;
 - D46.3 using information from annual compliance statements from the years ending 2012 and 2013;
 - D46.4 using total revenue data and backing out price changes by deflating by CPI; and
 - D46.5 splicing input data trend data to remove the large offsets between the 2012 s53ZD data and the 2014 s53ZD data
- D47 Overall, we consider using a mechanical extrapolation of historic trends to be inappropriate unless a clear trend is observable over a long period of time, and is expected to be sustained over the forecast period. The volatility and the short time periods considered by the trend analysis suggests that this is not a reasonable approach.

¹⁸⁹ Refer: The Centre for International Economics "A review of the Commerce Commission's constant price revenue model" August 2014, pp.9-10.

Trends based on CIE approach

D48 The CIE approach estimated constant price revenue growth for each distributor between 2008 and 2012. They use disaggregated revenue data from information disclosure to determine growth attributable to small, medium and large users. Figure D2 shows the results of CIE’s model.

Figure D2: Constant price revenue growth for each distributor between 2009 and 2012 based on CIE’s specification



D49 CIE’s approach was restricted to data from 2008 to 2012 as information disclosures had the data suitable for their model for these years, a disaggregation of revenue between small, medium and large connections. They suggest that the Commission uses a similar approach using data obtained from information requests which we consider below.

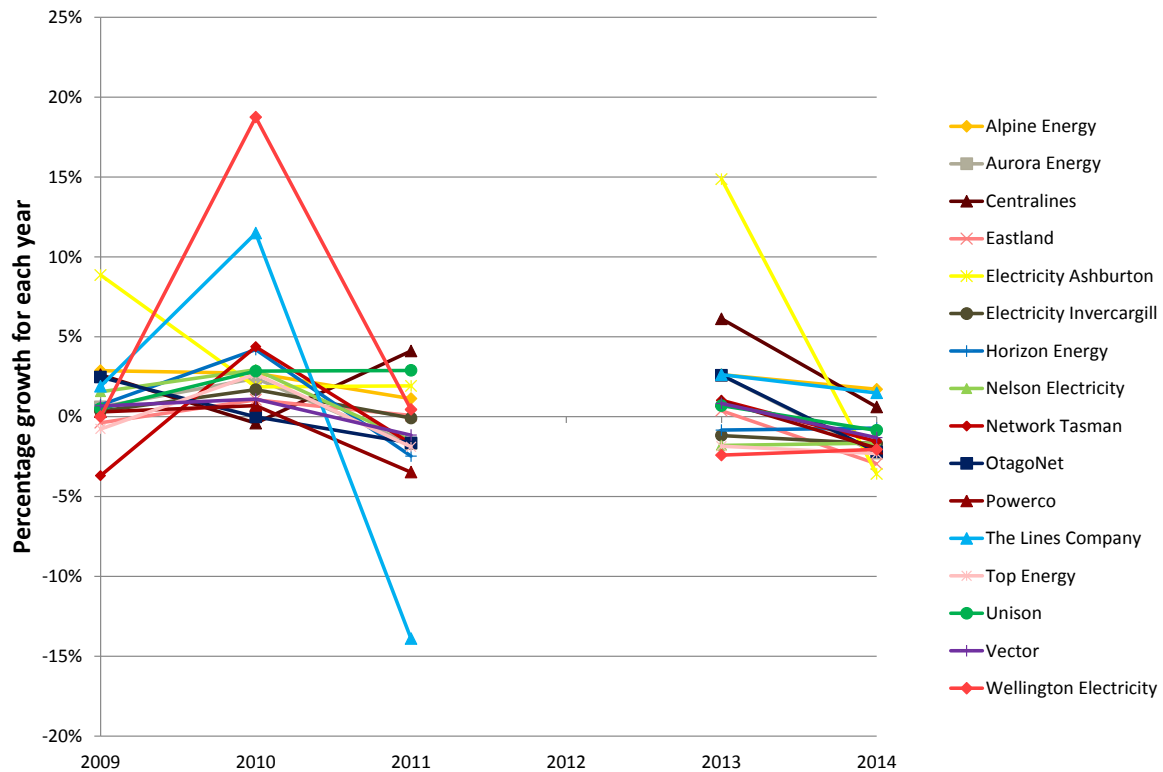
Trends based on s53ZD information

D50 Using data obtained from two information requests, we have estimated constant price revenue growth for each distributor between 2008 and 2014.¹⁹⁰ This approach allows constant price revenue growth to be estimated using revenue data split between residential, commercial and industrial. Figure D3 shows the results of our modelling of total constant price revenue growth.¹⁹¹

¹⁹⁰ As part of setting the 2012 and 2015 default price-quality path we requested information relating to revenue disaggregated by residential, commercial, and industrial users.

¹⁹¹ Total refers to revenue growth from all sources—residential, commercial, and industrial.

Figure D3: Constant price revenue growth for each distributor between 2009 and 2014 using s 53ZD disclosures



- D51 We have excluded 2012 from our analysis as there was a break in the series between the two s 53ZD information requests. Our analysis indicates that this approach is also very volatile ranging between +15 and -15 percent between years.¹⁹²
- D52 We consider that using s 53ZD data avoids some of the assumptions that the CIE approach had to make. In particular, the CIE approach assumed that all non-residential consumers are charged solely on a c/kWh basis with no fixed charges. However, in practice, many distributors charge their larger consumers on a fixed rather than on a variable tariff which may provide misleading CPRG results.
- D53 A problem with both the CIE and our own approach is that the tariff structures of a distributor cannot be accurately captured. Assumptions, which may be unrealistic, are required to allocate revenue between different possible pricing mechanisms.
- D54 We also considered CPRG relating only to industrial and commercial users for each distributor and the results were similarly volatile.¹⁹³

¹⁹² We note that CPRG for Wellington Electricity spiked in 2010 can be explained as they only existed for a part year in 2009, however the reasons for large volatility for other distributors is not known.

¹⁹³ Our analysis of estimated constant price revenue growth is published alongside this paper.

CPRG based on annual compliance statements or information disclosure

- D55 We considered information provided by distributors as part of their annual compliance statement. However, while this approach provides would provide a more precise calculation of CPRG, it is limited to just two years which are not recent (2010 and 2011).
- D56 Data from information disclosures from 2013 breakdown revenues and quantities by individual tariff structures which would also provide the most precise calculation of CPRG, however growth is limited to one year (2014).

Attachment E: Timing assumptions

Purpose of attachment

- E1 This attachment outlines and explains our assumptions concerning representative times during the year that different cash flows occur. We use these assumptions when we calculate the present values of the forecast cash flows to determine starting prices.

Our assumptions improve the accuracy of our modelling

- E2 Cash flow timing assumptions recognise that distributors incur and receive cash flows continuously throughout the year. To simplify data requirements for the modelling we make assumptions on representative times that these cash flows occur. These assumptions are applied to components of the building block formula we use to calculate the revenue each distributor should be allowed to recover.
- E3 By default, the model assumes a year-end timing. To improve the accuracy of our modelling, we have made the assumptions below. Assumptions described in paragraphs E4, E5, E6, E7 and E8 are unchanged from the approach used in the 2012 reset.

Operating expenditure

- E4 We have assumed that operating expenditure is spread throughout the year at regular intervals, so the same amount is paid in the first and second half of the year. This is equal in net present value terms to all costs being incurred mid-year. This assumption is consistent with those specified in the input methodologies for preparing customised price-quality paths.¹⁹⁴

Capital expenditure

- E5 Capital expenditure is commissioned mid-year, on average. This reflects an assumption that assets are commissioned evenly throughout the year. We have made this assumption because the seasonal trends cannot be reliably forecast.¹⁹⁵

¹⁹⁴ *Electricity Distribution Services Input Methodologies Determination 2012 [2012] NZCC 26 as amended, clause 5.3.2.*

¹⁹⁵ The timing assumption for capital expenditure is a simplification of the assumptions used to prepare customised price-quality paths which require individual commissioning dates for commissioned assets.

Tax costs

E6 Tax costs are incurred mid-year, on average. We have made this assumption for the purposes of simplicity. In reality tax should be able to be paid at the provisional tax dates, which average out to later than mid-year. Mid-year timing is, therefore, favourable to distributors because they are able to make payments, on average, later than the mid-year assumption.¹⁹⁶

Revenue

E7 We assume that all revenues are received on 3 November. That is because monthly revenue from lines charges is expected to be received on the 20th of the month following billing. Discounting a stream of monthly revenues received in equal increments throughout the year from 20 April to 20 March will give the same result as discounting a single payment received on 3 November. This assumption is consistent with those specified in the input methodologies for preparing customised price-quality paths.¹⁹⁷

Other regulated income

E8 Other regulated income¹⁹⁸ is received mid-year, on average. This assumption is made for simplicity, because seasonality cannot be reliably forecast. This assumption is consistent with those specified in the input methodologies for preparing customised price-quality paths.¹⁹⁹

Notional deductible interest

E9 To improve the accuracy of the treatment of regulatory tax adjustments, the formula in the input methodologies for calculating notional deductible interest has been amended. The formula now applies a mid-year cash flow timing assumption to the calculation of notional deductible interest payments.²⁰⁰

¹⁹⁶ The timing assumption for tax is a simplification of the assumptions used to prepare customised price-quality paths which involve a more complicated building block formula that accounts for specific factors such as permanent differences and utilised tax losses.

¹⁹⁷ *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 as amended, clause 5.3.2.

¹⁹⁸ Other regulated income is forecast income associated with the supply of electricity distribution services other than-(i) through prices; (ii) investment-related income; (iii) capital contributions; or (iv) vested assets, as determined by the Commission

¹⁹⁹ *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26 as amended, clause 5.3.2.

²⁰⁰ Commerce Commission "Electricity Distribution Input Methodology Amendments Determination 2014" (28 November 2014), clause 4.3.3(2).

- E10 This timing assumption recognises that suppliers will pay interest during the year, and the amount paid will be less than if payments were made at year-end. The difference in amount paid is known to equal to 6 months interest payment.

Attachment F: Revisions to information

Purpose of attachment

- F1 This attachment outlines and explains revisions and treatment of data, used in modelling for the default price-quality path reset, provided by distributors where errors had been identified.

Data issues identified and actions taken

- F2 The following issues with data provided to the Commission from distributors were identified during testing and dealt with accordingly.

Nelson Electricity stated incorrect RAB tax value without revaluations

- F3 In its 2014 information disclosure Nelson Electricity stated their 2014 opening sum of RAB tax values without revaluations as being \$40,093,000. Testing identified the figure as a likely error. Nelson Electricity advised that the 2014 figure had been incorrectly entered and subsequently restated opening RAB tax values without revaluations as being \$28,617,000.

- F4 The updated data has been used for modelling purposes.

Unison stated incorrect closing RAB excluding revaluations figure

- F5 Unison's 2014 information disclosure included a decrease in opening RAB excluding revaluations compared to a derived 2013 Closing RAB excluding revaluations figure. The figure initially provided was \$442,776,000. This was checked with Unison who reviewed the figure and found it to be incorrect, restating it as \$462,687,000. Accordingly, the also restated their adjusted depreciation figure, changing it from \$18,964,000 to \$20,012,000.

- F6 The updated data has been used for modelling purposes.

Inconsistency identified in Aurora's circuit length data

- F7 An inconsistency was identified in Aurora's 2014 information disclosure regarding circuit length data between 2010 and 2014. This was queried with Aurora who subsequently provided new data for line length covering 2010 – 2014. Aurora attributed the error to circuit lengths still being optimised according to outdated rules.

- F8 The updated data has been used for modelling purposes.

Inconsistency identified in Centraline's circuit length data

F9 An inconsistency was identified in Centraline's 2014 information disclosure regarding circuit length data for 2013. This was queried with Centralines who subsequently provided new data for 2013.

F10 The updated data has been used for modelling purposes.

Inconsistency identified in Powerco's circuit length data

F11 An inconsistency was identified in Powerco's 2014 information disclosure regarding circuit length between 2010 and 2014. This was queried with Powerco who subsequently provided new data for line length covering the 2010 to 2014 period. Powerco attributed the error to the inadvertent inclusion some service length data in their disclosed circuit length figures.

F12 The updated data has been used for modelling purposes.

Inconsistency identified in The Lines Company's circuit length data

F13 An inconsistency was identified in The Lines Company's 2014 information disclosure regarding circuit length. The issue was queried with The Lines Company (TLC) who found it to relate to historical misinterpretation of the definition of line length. TLC subsequently advised it is unable to provide restated data.

F14 The Commission has used a combination of 2010, 2012, 2013 and 2014 disclosed data to determine a growth trend knowing that 2011 includes an anomaly from changing asset management systems. This approach results in a growth rate of -1.91% which, if used in the draft decision would have resulted in a 0.3% decrease in starting prices.

Unison stated incorrect non-network capex figures

F15 Data provided by Unison for non-network capex under information disclosure covering the years 2010 to 2012 did not include non-network capex incurred by Unison's related party contractor, UCSL. From the 2013 disclosure year onwards Unison reported its costs on a consolidated basis. Unison has restated the 2010 to 2012 figures to include UCSL's non-network capex data from 2010 to 2012 to ensure a consistent basis is used for calculating the historical average.

F16 The updated data has been used for modelling purposes.

Unison stated incorrect asset disposal figures

F17 Unison's previously disclosed data on asset disposals was based on a mistaken interpretation of the input methodologies. Unison had understated the level of disposals (and losses on disposals) incurred. This information has subsequently been restated.

F18 The updated data has been used for modelling purposes.

Nelson Electricity stated incorrect nominal and constant price forecast figures

F19 Nelson Electricity inadvertently transposed its nominal and constant price forecasts in schedules 11a and 11b of its 31 March 2014 Asset Management Plan. It also incorrectly included a small amount of capex forecast on solar panels in 2014/2015. Nelson subsequently provided revised versions of the relevant schedules.

F20 The updated data has been used for modelling purposes.

Electricity Invercargill incorrectly stated their cost of financing forecast figure

F21 Electricity Invercargill incorrectly stated their cost of financing forecast in their information disclosure and subsequently confirmed the number used should.

F22 The updated data has been used for modelling purposes.

Modelling assumption relating to disposed assets has been changed

F23 The decision taken for the draft decision to forecast losses on disposal used an underlying assumption that disposed assets will be sold for 11% of their regulatory net book value, reflecting an industry-wide average of losses on the sale of assets in proportion to disposals of 89%. We noted, however, it is difficult to determine a forecast, and distributors have some control over whether to dispose of an asset or retain it in their possession. A change was then made to adopt an approach of using distributor specific historic ratios as the forecast basis.

F24 Data used in Model 20 (other regulated income) was modified to use a specific ratio of gains/losses on sale of assets to disposals as the basis for projecting an allowance for gains/losses on sale of assets. The ratio was based on the average of 2012/2013 and 2013/2014 data.

Updated capex figures have been used in modelling

- F25 Capex figures used in the draft were taken from earlier 2008 ID reporting schedules – specifically schedule 5H. Submissions were received from a number of electricity distributors against this. These EDBs felt that more recent ID data should be used. However, the newer information does not separate the data into network and non-network capex.
- F26 The capex figures used for the final decision haven been taken from the newer information disclosure – specifically schedule 6. Network and non-network capex are not split in this disclosure as they are in the older disclosure. For modelling purposes the newer figures have been split in accordance with ratios in the older disclosures.

Historic asset disposal figures were incorrectly stated for Eastland

- F27 Historical asset disposal figures for Eastland covering 2009/2010 to 2013/2014 were incorrectly stated.
- F28 Updated disposal figures have been used in modelling.

Historic asset disposal figures were incorrectly stated for Otagonet

- F29 Historical asset disposal figures for OtagoNet covering 2011/2012 were incorrectly stated.
- F30 Updated disposal figures have been used in modelling.

Update of data used in modelling for constant price revenue growth

- F31 Improvements were identified to inputs used to model constant price revenue growth including improving the mapping of regional GDP to electricity distributors and using Infometrics data as a source for historical real GDP.
- F32 The improved data has been used in modelling.

Unison restated Asset Management Plan (AMP) data

- F33 As a result of customer delays in a large project, Unison considered that data provided in its AMP was no longer accurate with regard to capex and commissioned asset values and therefore restated that data to include the details of the large project.
- F34 As the data resubmitted by Unison related to a forecast which was accurate at the point in time it was made, the Commission elected not to use Unison's restated figures.

Attachment G: Summary of changes since our draft decision

Purpose of attachment

- G1 This attachment shows the key differences between the draft decision, and this final decision. It begins with an analysis of the outputs of our modelling before providing a breakdown of the changes in the key inputs. It then summarises the changes to the quality incentive scheme parameters.²⁰¹
- G2 A number of the components of the price-quality path that are referred to in this attachment are explained in the companion papers rather than this Main Policy Paper.

Minor changes to the price path from our draft decision for most suppliers

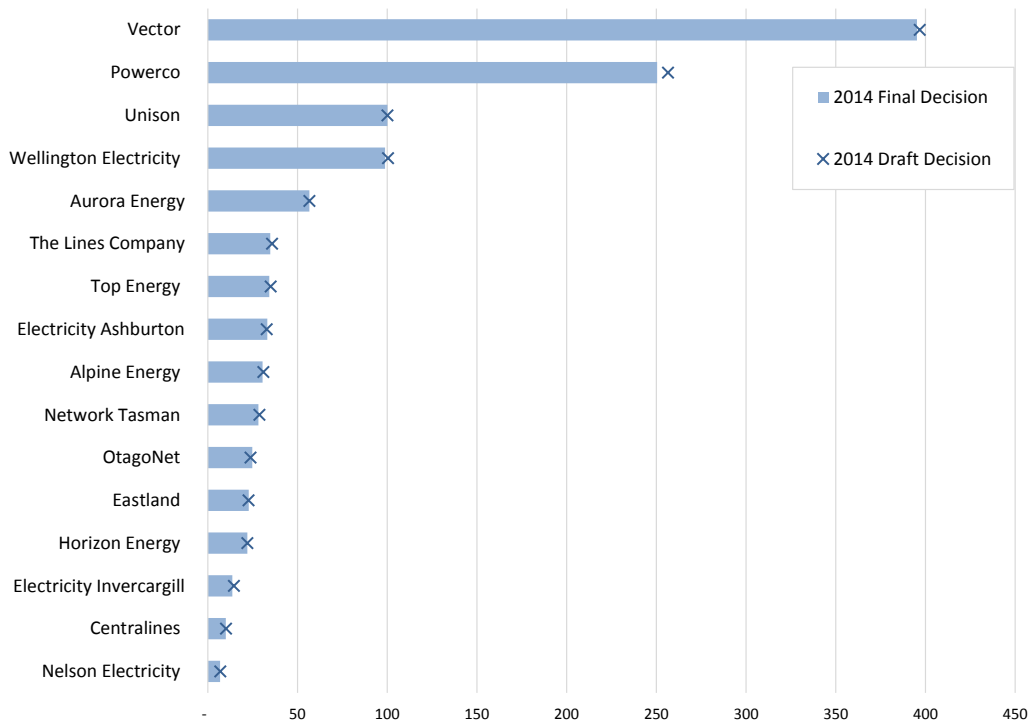
- G3 The changes implemented between the draft decision and the final decision have largely balanced each other out for most suppliers. This section sets out:
- G3.1 The changes in the amount suppliers are expected to earn over the regulatory period; and
- G3.2 The changes in the allowable starting prices and allowable annual price changes.
- G4 These comparisons demonstrate the similarity of the overall price path between our draft and our final decision for most distributors.

The amount suppliers are expected to earn over the regulatory period is largely unchanged

- G5 Figure G1 shows the difference in the amount we expect distributors to earn over the regulatory period compared to the amount we expected in our draft decision. As can be seen, there is generally little difference between the final and draft decision.
- G6 One of the largest changes is for Alpine Energy, which is primarily due to an increased operating expenditure allowance.

²⁰¹ A number of the components of the price-quality path that are referred to in this attachment are explained in the companion papers rather than this main policy paper: see Commerce Commission "Low cost forecasting approaches for default price-quality paths for electricity distributors from 1 April 2015" (28 November 2014) and Commerce Commission "Quality targets and incentives for default price-quality paths for electricity distributors from 1 April 2015" (28 November 2014).

Figure G1: Expected total MAR for period (NPV, millions of dollars) – draft vs. final



G7 The values in the chart above are important because they are one of the two key outputs from our modelling that are reflected in the determination. The other key output is the starting prices and their annual change.

Reasonably minor changes to the starting price and annual price changes

G8 Table G1 compares the initial price change and the annual price changes thereafter for the regulatory period from the draft and final decisions, excluding claw back. Chapter 4 provides more detail on the allowable prices.

Table G1: Initial price limit changes and annual changes thereafter – draft decision vs. final

Supplier	Starting price adjustment		Annual adjustment (in addition to CPI)	
	Draft decision	Final decision	Draft decision	Final decision
Alpine Energy	13.5%	12.5%	10.0%	11.0%
Aurora Energy	-6.5%	-4.3%	0.0%	0.0%
Centralines	7.1%	8.8%	6.0%	7.0%
Eastland	4.9%	6.7%	3.5%	3.0%
Electricity Ashburton	3.5%	5.7%	2.0%	0.0%
Electricity Invercargill	5.2%	-2.8%	0.5%	0.0%
Horizon Energy	4.7%	6.8%	0.5%	0.0%
Nelson Electricity	-8.6%	-9.0%	0.0%	0.0%
Network Tasman	-18.1%	-14.0%	0.0%	0.0%
OtagoNet	-13.4%	-6.9%	0.0%	0.0%
Powerco	0.6%	0.2%	0.0%	0.0%
The Lines Company	-5.8%	-7.2%	0.0%	0.0%
Top Energy	8.4%	8.3%	7.0%	7.0%
Unison	-0.6%	-0.1%	0.0%	0.0%
Vector	-1.1%	0.8%	0.0%	0.0%
Wellington Electricity	-13.2%	-13.7%	0.0%	0.0%

G9 The overall starting price adjustment for the industry is -1.1% for the final decision, whereas it was -0.6% for the draft.

Changes to key inputs since our draft decision

G10 This section shows the changes to the key inputs, which are:

G10.1 Capital expenditure allowances;

G10.2 Operating expenditure allowances;

G10.3 Forecast asset revaluations and cost of capital (CPI and WACC); and

G10.4 Constant price revenue growth.

G11 While there are some large changes to some of the inputs, these largely offset each other so the overall impact on the price path is generally small. However, there were some exceptions, as described in paragraphs **Error! Reference source not found.** to **Error! Reference source not found.**

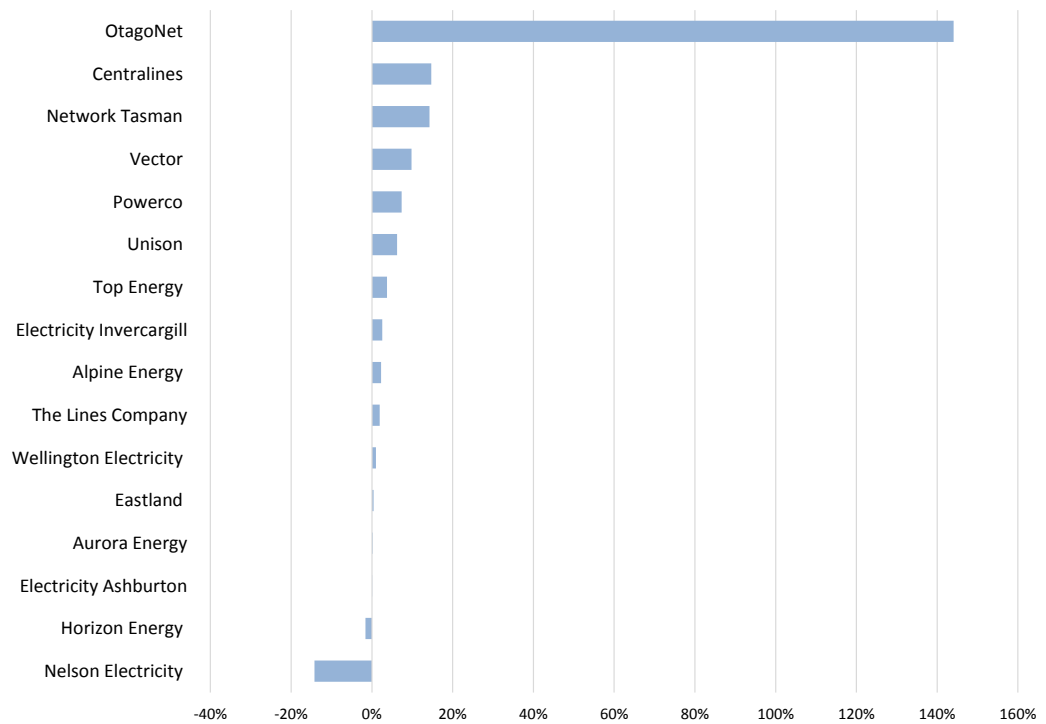
Capital expenditure allowances

G12 Figure G2 shows the percentage change in constant price capital expenditure allowance over the regulatory period from the draft decision to the final decision. The changes have resulted from:

- G12.1 the capital expenditure caps for most distributors were increased from the draft to the final;
- G12.2 inclusion of the value of vested assets in the final decision has affected the capital expenditure allowance of several distributors (particularly Centralines and Nelson Electricity);
- G12.3 inclusion of forecast cost of financing, which was not included in the draft;
- G12.4 we referred to the wrong value for Otagonet in the draft; and
- G12.5 Nelson Electricity re-disclosed their forecasts since the draft as there were some issues with their original forecasts.

G13 However, we have not made any changes to our overall approach for modelling capex since our draft decision was published.

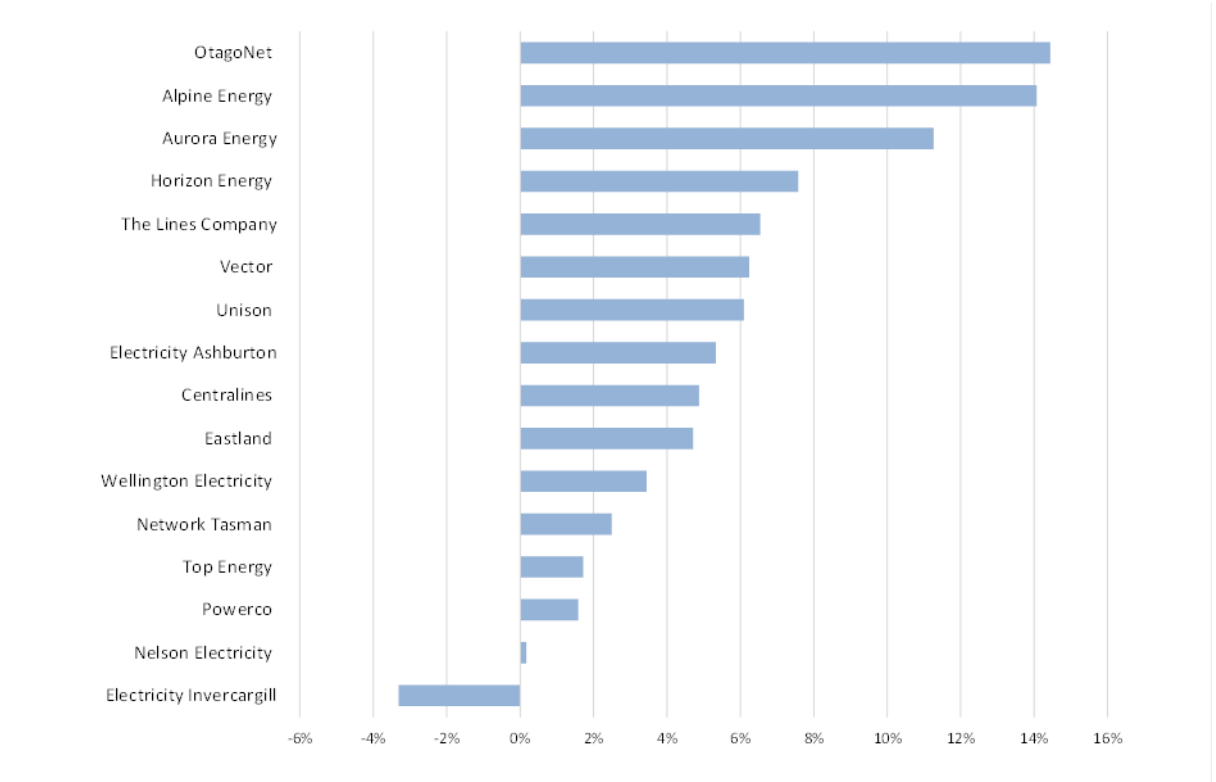
Figure G2: Constant price capex allowance – difference between draft and final



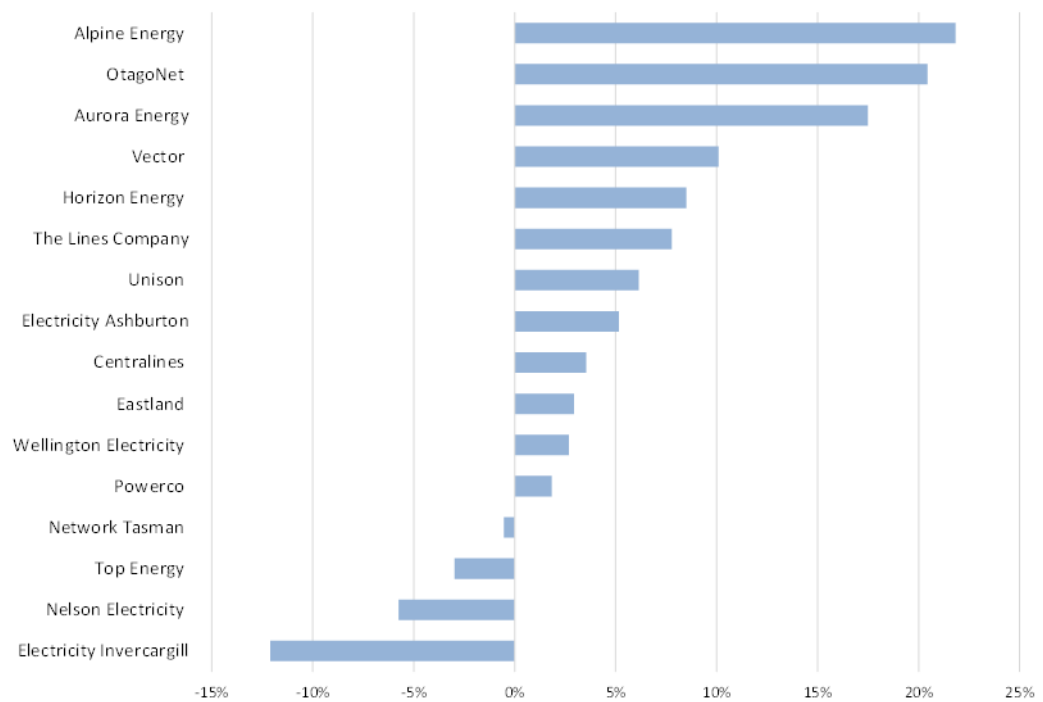
Operational expenditure allowances

G14 Figure G3 shows the percentage change in the allowances for opex over the regulatory period from the draft decision to the final decision.

Figure G3: Constant price opex allowance – difference between draft and final



G15 The main change from the draft to the final is the change of the base year from 2012/13 to an average of 2012/13 and 2013/14. The difference in 2012/13 and 2013/14 constant price operating expenditure is shown in Figure G4. The rank of the distributors is similar between the two charts due to the base year change being the main driver of the change in operating expenditure allowance between the draft and final.

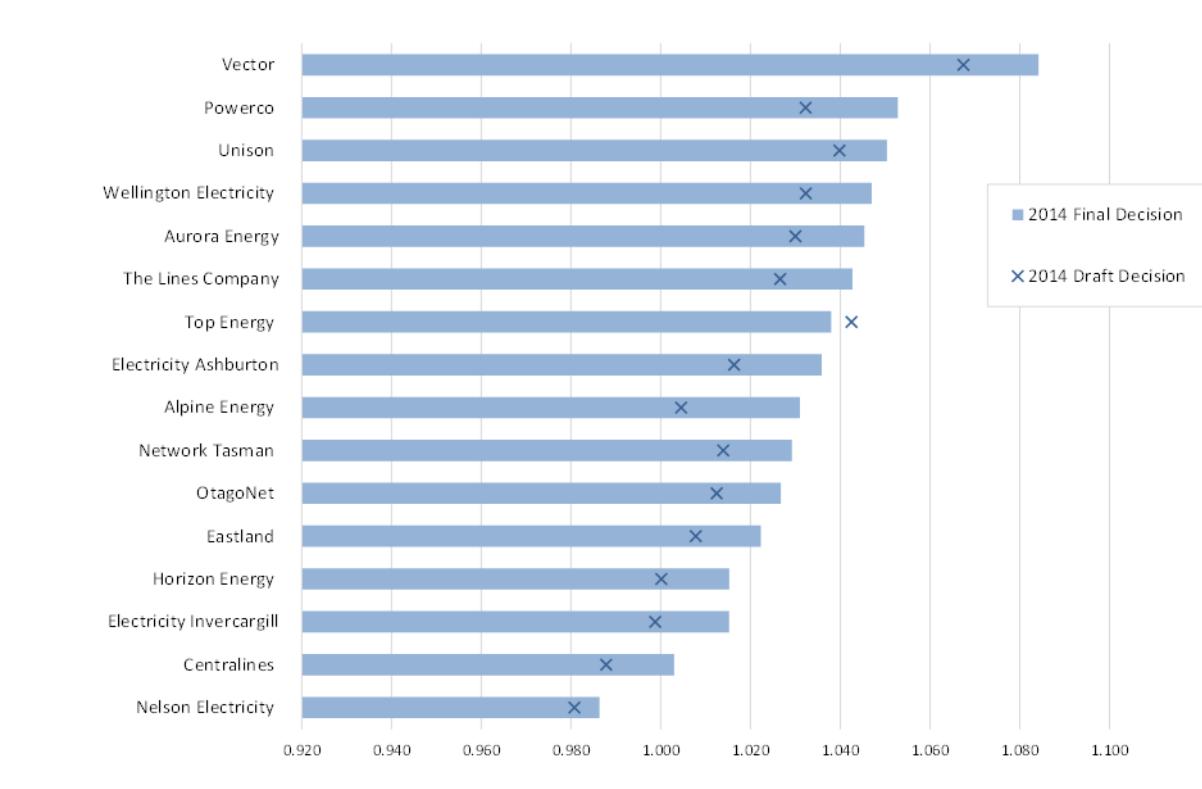
Figure G4: Percentage change in constant price opex from 2013 – 2014

G16 Other changes between the draft and final, which had less effect than the base year change include an update of network line lengths and the removal of merits appeal legal costs. The merits appeal legal cost amounts are shown in Table F2.

Table G2: Legal costs relating to merits appeal (\$m)

Supplier	2013	2014	Total
Powerco	0.63	0.13	0.77
Vector	2.44	0.29	2.73
Wellington Electricity	0.43	0.01	0.44

G17 Figure G5 compares the draft and final decisions in terms of the change in opex from initial levels to 2020 levels. The change has increased for all distributors except one since the draft decision. One reason for the increases is the change in the partial productivity assumption from 0% to -0.25%.

Figure G5: Indexed change in opex from initial levels to 2020 – draft vs final*Forecast asset revaluations*

G18 The direct effect of the use of updated CPI forecasts on the amount that distributors are expected to earn over the regulatory period is minimal. This excludes the effect of price index forecasts on input prices and secondary effects. The CPI forecasts from the draft decision are compared to those in the final decision in Table G3.

Table G3: CPI forecasts – draft vs final

Assessment period	Draft	Final
2013/2014	1.53%	1.53%
2014/2015	1.85%	1.43%
2015/2016	1.81%	1.74%
2016/2017	2.10%	2.11%
2017/2018	2.07%	2.17%
2018/2019	2.03%	2.11%
2019/2020	2.00%	2.06%
Average growth rate (2015/2016 to 2019/2020)	2.00%	2.04%

Cost of capital

G19 Figure G6 and Figure G7 show the effect of the updated WACC figure on the amount that distributors are expected to earn over the regulatory period.

Figure G6: Difference in expected MAR for period (NPV) – draft WACC vs. final WACC (\$m)

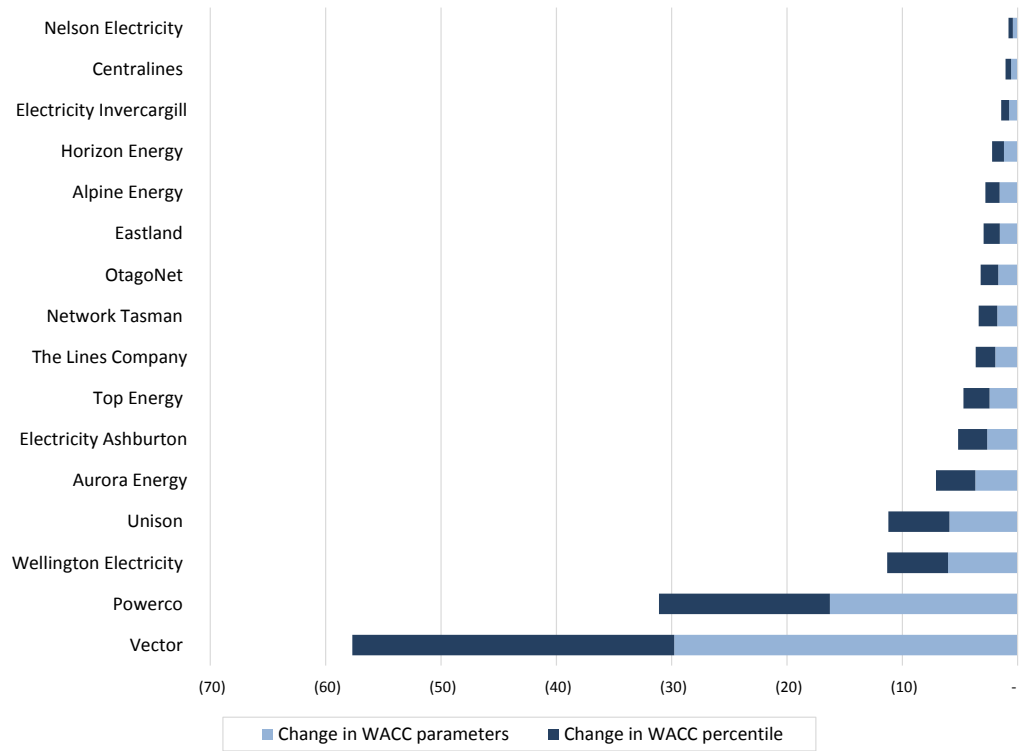
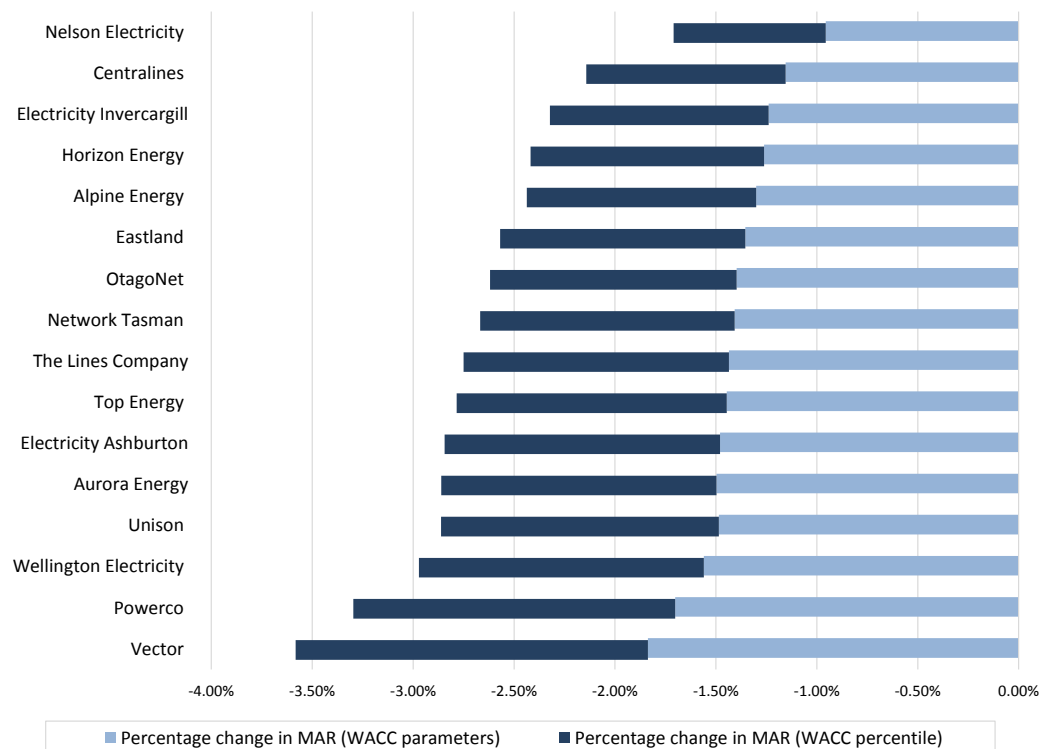


Figure G7: Difference in expected MAR for period (NPV) – draft WACC vs. final WACC (%)



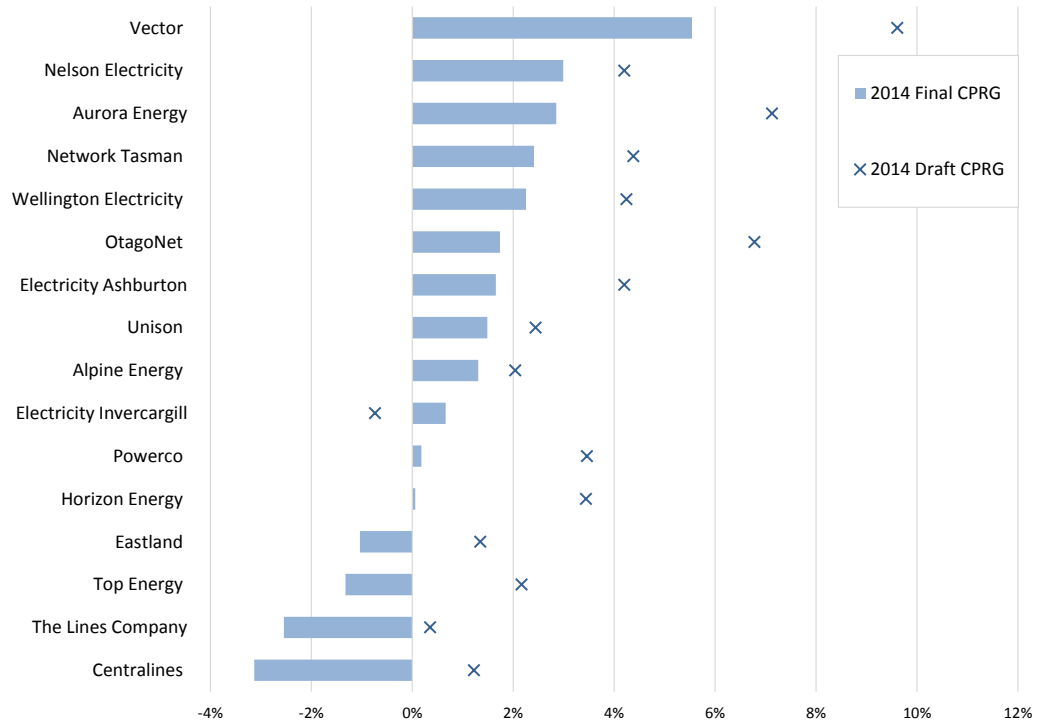
Constant price revenue growth

G20 Figure G8 compares our forecasts of constant price revenue growth between the draft and final decisions. The overall approach to forecasting constant price revenue growth has been retained; however, several significant changes have been made to the model inputs in response to submissions. The main improvements are:

- G20.1 NZIER regional GDP growth figures (historic and forecast) have been replaced with Infometrics figures;
- G20.2 the mapping of GDP figures to the different network areas has been improved;
- G20.3 the estimate of non-residential revenue growth elasticity to GDP has been revised downwards;
- G20.4 updated data from distributors has been used; and
- G20.5 the residential electricity intensity forecast has been revised downwards.

G21 These improvements have resulted in a lower forecast of constant price revenue growth for all distributors except for Electricity Invercargill.

Figure G8: Annual constant price revenue growth forecasts – draft vs. final



G22 The constant price revenue growth forecasts are affected by CPI forecasts as well as growth assumptions. The CPI forecasts used in forecasting constant price revenue growth are shown in Table F4.

Table G4: CPI forecasts for constant price revenue growth

Assessment period	Draft (%)	Final (%)
2015/16	1.53	1.59
2016/17	1.51	1.84
2017/18	1.77	1.87
2018/19	2.11	2.09
2019/20	2.15	2.08

Changes to quality incentive scheme parameters since our draft decision

G23 This section compares the draft and final decisions on the quality incentive scheme parameters.

Quality targets

G24 Table G5 shows the SAIDI and SAIFI reliability targets calculated for the draft and final decisions for each distributor. The main change between the draft and the final has been the revision of the normalisation methodology.

Table G5: Reliability targets – draft vs. final

Supplier	SAIDI target		SAIFI target	
	Draft	Final	Draft	Final
Alpine Energy	147.6	132.8	1.37	1.30
Aurora Energy	86.8	74.5	1.37	1.29
Centralines	137.2	119.1	4.05	3.52
Eastland	246.6	242.1	3.15	3.09
Electricity Ashburton	139.6	132.8	1.41	1.39
Electricity Invercargill	29.2	24.1	0.65	0.59
Horizon Energy	170.6	150.1	2.04	1.92
Nelson Electricity	15.1	16.2	0.20	0.18
Network Tasman	126.0	112.5	1.34	1.23
OtagoNet	233.6	224.6	2.30	2.52
Powerco	222.3	188.9	2.17	2.11
The Lines Company	238.8	208.8	3.21	3.07
Top Energy	446.0	405.4	5.59	5.28
Unison	111.4	99.1	2.05	1.94
Vector	106.6	96.0	1.33	1.29
Wellington Electricity	37.1	35.4	0.53	0.55

Reliability caps and collars

G25 Table G6 and Table G7 show the SAIDI and SAIFI caps and collars for the draft and final decisions for each distributor. The caps for the revenue-linked quality incentive scheme are equal to the reliability limits for the quality standards. In line with the quality targets, the largest changes from the draft are due to the revision of the normalisation methodology.

Table G6: SAIDI caps and collars – draft vs. final

Supplier	SAIDI cap		SAIDI collar	
	Draft	Final	Draft	Final
Alpine Energy	216.4	154.2	78.8	111.5
Aurora Energy	112.2	83.4	61.4	65.6
Centralines	173.4	139.3	100.9	98.8
Eastland	287.2	274.1	206.0	210.2
Electricity Ashburton	169.8	151.0	109.3	114.7
Electricity Invercargill	40.8	31.1	17.5	17.0
Horizon Energy	216.7	175.8	124.5	124.4
Nelson Electricity	24.7	22.2	5.6	10.2
Network Tasman	149.5	129.8	102.5	95.1
OtagoNet	295.7	254.9	171.5	194.2
Powerco	278.4	210.6	166.2	167.1
The Lines Company	276.3	234.2	201.3	183.4
Top Energy	527.7	470.8	364.2	340.1
Unison	135.3	110.2	87.5	88.1
Vector	131.8	104.2	81.5	87.9
Wellington Electricity	49.3	40.6	24.9	30.2

Table G7: SAIFI caps and collars – draft vs. final

Supplier	SAIFI cap		SAIFI collar	
	Draft	Final	Draft	Final
Alpine Energy	1.65	1.51	1.09	1.09
Aurora Energy	1.60	1.45	1.14	1.14
Centralines	5.38	4.20	2.72	2.84
Eastland	3.47	3.53	2.82	2.64
Electricity Ashburton	1.71	1.61	1.11	1.16
Electricity Invercargill	0.89	0.77	0.41	0.42
Horizon Energy	2.32	2.21	1.76	1.63
Nelson Electricity	0.28	0.24	0.11	0.11
Network Tasman	1.52	1.42	1.17	1.04
OtagoNet	2.74	2.93	1.87	2.12
Powerco	2.65	2.27	1.69	1.94
The Lines Company	3.95	3.47	2.47	2.67
Top Energy	7.21	6.06	3.97	4.50
Unison	2.61	2.15	1.50	1.74
Vector	1.66	1.40	0.99	1.19
Wellington Electricity	0.69	0.62	0.37	0.47

Boundary values

G26 Table G8 shows the SAIDI and SAIFI boundary values used in the draft and final decisions for the quality incentive scheme. The largest change for the boundary values from draft to final was also caused by the revised normalisation methodology.

Table G8: SAIDI and SAIFI boundary values – draft vs. final

Supplier	SAIDI boundary value		SAIFI boundary value	
	Draft	Final	Draft	Final
Alpine Energy	14.03	9.17	0.13	0.13
Aurora Energy	10.92	3.38	0.26	0.26
Centralines	9.67	8.52	0.48	0.48
Eastland	17.13	13.07	0.21	0.21
Electricity Ashburton	8.98	8.08	0.11	0.11
Electricity Invercargill	4.18	3.24	0.12	0.12
Horizon Energy	17.85	10.77	0.25	0.25
Nelson Electricity	2.12	2.70	0.04	0.04
Network Tasman	19.02	6.98	0.16	0.16
OtagoNet	13.43	13.24	0.16	0.16
Powerco	11.31	11.21	0.13	0.13
The Lines Company	15.84	10.97	0.26	0.26
Top Energy	39.56	28.43	0.64	0.64
Unison	10.95	4.54	0.19	0.19
Vector	9.88	3.37	0.14	0.14
Wellington Electricity	6.85	2.10	0.11	0.11

Other main changes since the draft

G27 Since the draft we have changed the calculation of other regulated income for losses on asset disposals. For the draft an industry-wide average of losses was applied to asset disposals, whereas the final decision uses supplier specific information. This has affected Powerco in particular because Powerco has historically had a higher rate of losses on its asset disposals than the industry average.