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# Low Cost Forecasting Approaches For Default Price-Quality Paths

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# 1. Introduction

### Purpose of paper

1.1 This paper outlines and explains the low cost forecasting approaches that we propose to use for default price-quality paths. Details on how you can provide your views can be found in Chapter 7.

1.1.1 Submissions are due by **15 August 2014**.

1.1.2 Cross-submissions are due by **29 August 2014**.

1.2 This paper should be read in conjunction with the paper that outlines and explains the default price-quality paths that we propose to put in place from 1 April 2015 (Main Policy Paper).[1]

### Profitability-based adjustment to price limits

1.3 As explained in our Main Policy Paper, we propose to 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 prices that applied for the previous default price-quality paths.

1.4 To adjust prices 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.

1.5 Alongside this paper, we published a model that sets out the approach we propose to use to set starting prices based on the current and projected profitability of each distributor.[2] That 'financial model' reflects the input methodologies that must be applied when default price-quality paths are reset.[3]

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1 Commerce Commission "Proposed default price-quality paths for electricity distributors from 1 April 2015" (30 June 2014).

2 Previously, we published two mostly blank versions of the financial model, which allowed interested persons the opportunity to assess the impact of amendments that we have proposed to input methodologies for default price-quality paths. The version of the financial model that we have published alongside this paper reflects the draft amendments, and is populated with data. For an overview of the model, please refer: Commerce Commission "Preliminary version of the financial model for electricity default price-quality paths from 2015: Technical consultation" (29 November 2013).

3 We have included in this version of the model an Internal Rate of Return calculation. We are also happy to share a version of the financial model on request that includes a revision that we are likely to propose to the specification of the annual Return on Investment calculation. In our view, the revised specification

*Seeking stakeholder feedback on the inputs to our analysis*

1.6 We are now seeking views on the low cost approaches we propose to use to generate the inputs to our financial model. These inputs include:

1.6.1 Forecasts of operating expenditure;

1.6.2 Forecasts of capital expenditure;

1.6.3 Forecasts of other line items, such as asset disposals; and

1.6.4 Forecasts of revenue growth.

1.7 To develop these inputs, we have relied on a combination of low cost techniques, eg, reliance on suppliers' own forecasts, independent forecasts, and simplifying assumptions. This is because we are required to adopt relatively low cost approaches when resetting default price-quality paths.

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would correct errors that have previously been identified in the formula used under information disclosure regulation.

*Material released alongside this paper*

1.8 Alongside this paper, we published the following models that are referred to in this paper:

1.8.1 Financial model for setting starting prices based on the current and projected profitability of each distributor;

1.8.2 Forecasts of operating and capital expenditure plus supporting calculations, eg, changes in line length and input prices;

1.8.3 Forecasts of revenue growth plus supporting calculations, eg, changes in number of connections;

1.8.4 Forecasts of inflation for asset revaluations and price changes;

1.8.5 Forecasts of disposed assets and other regulated income;

1.8.6 Industry-wide forecast of asset replacement and renewal expenditure;

1.8.7 Historical analysis of distributors' returns on investment;

1.8.8 Calculation of additional allowances; and

1.8.9 Forecasts of, and supporting calculations for, impact on consumer electricity bills.

# 2. Summary of main inputs

### Purpose of this chapter

2.1 This chapter summarises the main inputs used in our proposed approach to set starting prices for each electricity distributor.[4] 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 other line items, such as asset disposals;

2.1.4 Weighted average cost of capital and forecast of asset revaluations; and

2.1.5 Forecasts of revenue growth.

### Forecasts of operating expenditure

2.2 As discussed in Chapter 3, we forecast each distributor's operating expenditure by projecting forward an initial amount based on the expected changes in the three main drivers. The three main drivers are:

2.2.1 Network scale – the scale of the network may affect operating expenditure because the volume of service provided will change.[5]

2.2.2 Operating efficiency – changes in operating efficiency will affect the amount of operating expenditure needed to provide a given level of service.

2.2.3 Input prices – changes in input prices will affect the cost of providing a given level of service over time.

2.3 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.

[4] 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.

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

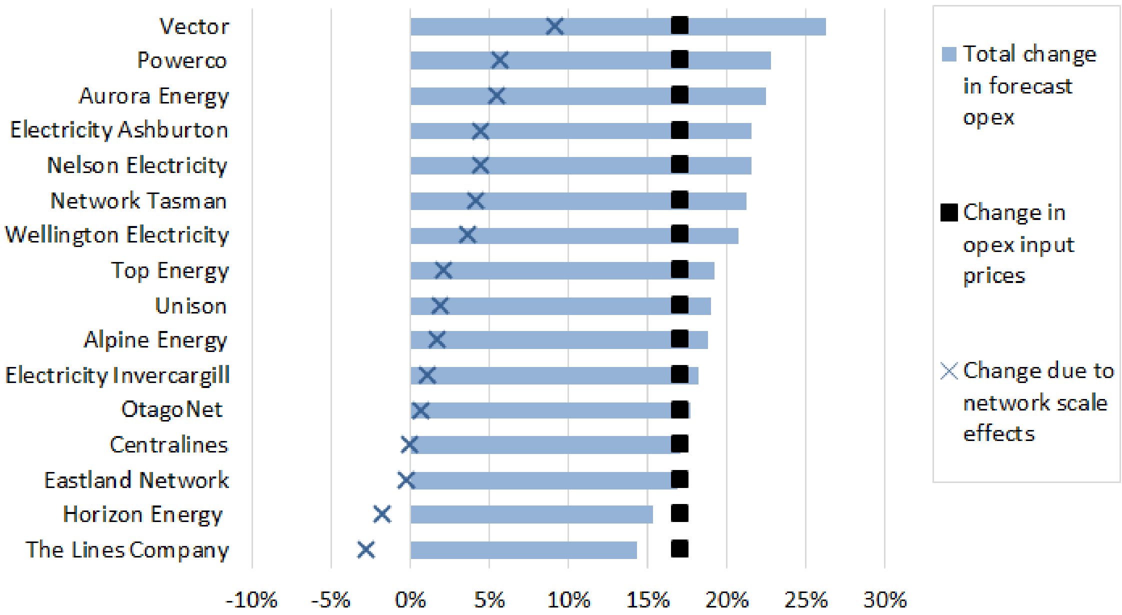
**Table 2.1: Nominal operating expenditure forecasts 2016 to 2020 ($m)**

| Distributor | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Alpine Energy | 13.3 | 13.7 | 14.0 | 14.3 | 14.6 |
| Aurora Energy | 20.4 | 21.1 | 21.7 | 22.3 | 22.8 |
| Centralines | 4.4 | 4.5 | 4.6 | 4.7 | 4.8 |
| Eastland | 8.0 | 8.2 | 8.4 | 8.5 | 8.7 |
| Electricity Ashburton | 8.4 | 8.6 | 8.9 | 9.1 | 9.3 |
| Electricity Invercargill | 5.8 | 6.0 | 6.1 | 6.2 | 6.4 |
| Horizon Energy | 7.4 | 7.6 | 7.8 | 7.9 | 8.1 |
| Nelson Electricity | 2.5 | 2.6 | 2.7 | 2.8 | 2.8 |
| Network Tasman | 9.2 | 9.5 | 9.7 | 10.0 | 10.2 |
| OtagoNet | 6.7 | 6.9 | 7.1 | 7.2 | 7.4 |
| Powerco | 71.5 | 74.0 | 76.2 | 78.2 | 80.3 |
| The Lines Company | 10.3 | 10.6 | 10.8 | 11.0 | 11.1 |
| Top Energy | 13.8 | 14.2 | 14.6 | 14.9 | 15.2 |
| Unison | 34.8 | 35.9 | 36.7 | 37.5 | 38.3 |
| Vector | 105.3 | 109.4 | 113.1 | 116.6 | 120.1 |
| Wellington Electricity | 30.8 | 31.8 | 32.6 | 33.4 | 34.2 |
| **Industry total** | **352.6** | **364.6** | **375.1** | **384.6** | **394.3** |

*Main drivers of operating expenditure for each distributor*

2.4 Figure 2.1 shows the cumulative growth forecast from 2013 to 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. Partial productivity growth is assumed to be 0%, ie, we have assumed there will be no change in operating efficiency relative to the rest of the economy.

**Figure 2.1: Cumulative growth in operating expenditure from 2013 to 2020**




2.5 Cumulative growth in distributors' forecast operating expenditure over the 7 year period from 2013 to 2020 ranges from 14% for The Lines Company to 26% for Vector.

2.6 Negative changes due to network scale effects can be observed for Horizon Energy and The Lines Company. 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 two distributors serve will experience population declines from 2013 to 2020.

2.7 In contrast, a relatively significant positive change due to network scale effects can be observed for Vector. This is also due in large part to projections that population will increase in Vector's network area, ie, Auckland, from 2013 to 2020.

*Comparison with distributor forecasts*

2.8 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 | 20.5 | 6.0 | 41.3% |
| Electricity Invercargill | 23.2 | 27.1 | 3.9 | 16.8% |
| Network Tasman | 39.6 | 43.2 | 3.6 | 9.0% |
| Top Energy | 65.3 | 64.6 | - 0.7 | -1.1% |
| The Lines Company | 50.3 | 47.8 | - 2.5 | -5.0% |
| Vector | 529.2 | 501.6 | - 27.5 | -5.2% |
| Powerco | 361.9 | 337.9 | - 24.1 | -6.7% |
| Unison | 175.6 | 162.9 | - 12.7 | -7.2% |
| Aurora Energy | 103.9 | 96.3 | - 7.6 | -7.3% |
| Nelson Electricity | 12.9 | 11.9 | - 1.0 | -7.7% |
| OtagoNet | 34.9 | 31.4 | - 3.4 | -9.9% |
| Horizon Energy | 39.5 | 34.6 | - 4.9 | -12.5% |
| Electricity Ashburton | 45.6 | 39.4 | - 6.2 | -13.5% |
| Wellington Electricity | 170.0 | 144.6 | - 25.3 | -14.9% |
| Alpine Energy | 73.7 | 62.2 | - 11.5 | -15.6% |
| Eastland Network | 53.5 | 37.1 | - 16.3 | -30.5% |
| **Industry total** | **1,793.6** | **1,663.2** | **- 130.4** | **-7.8%** |

Note: Total for 2016 to 2020 in 2013 constant prices

2.9 We are allowing higher operating expenditure compared to distributor forecasts for three distributors (Centralines, Electricity Invercargill and Network Tasman). For some distributors however, our allowances are significantly lower than the operating expenditure they have forecast, eg, Eastland Network and Alpine Energy.[6]

[6] Distributor forecasts of operating expenditure do not include expected expenditure on assets purchased from Transpower.

**Forecasts of capital expenditure**

2.10 As explained in Chapter 4, our forecasts of capital expenditure are based on forecasts of network, and non-network capital expenditure.

2.10.1 Network capital expenditure is expenditure on assets that form part of the distribution network.

2.10.2 Non-network capital expenditure is expenditure on assets that do not form part of the distribution network.

2.11 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)**

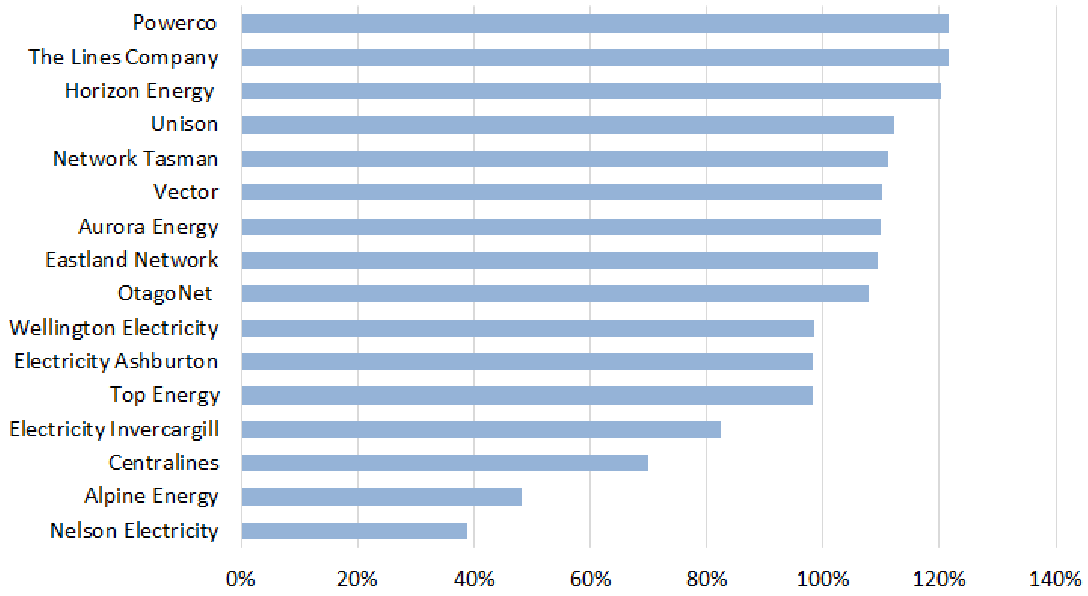
| Distributor | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Alpine Energy | 9.6 | 9.4 | 10.7 | 7.8 | 8.6 |
| Aurora Energy | 26.5 | 17.1 | 16.0 | 17.3 | 13.1 |
| Centralines | 2.8 | 2.7 | 2.6 | 2.7 | 2.8 |
| Eastland | 9.9 | 14.7 | 8.3 | 6.7 | 7.1 |
| Electricity Ashburton | 16.2 | 23.6 | 19.1 | 18.4 | 13.1 |
| Electricity Invercargill | 5.5 | 3.2 | 2.8 | 2.1 | 3.0 |
| Horizon Energy | 8.5 | 7.6 | 7.2 | 6.6 | 6.8 |
| Nelson Electricity | 1.0 | 1.2 | 1.7 | 1.9 | 2.3 |
| Network Tasman | 5.7 | 8.0 | 10.9 | 6.1 | 4.7 |
| OtagoNet | 4.7 | 4.0 | 4.4 | 4.4 | 4.3 |
| Powerco | 85.5 | 88.7 | 110.8 | 109.1 | 119.2 |
| The Lines Company | 13.8 | 9.7 | 10.2 | 9.7 | 11.4 |
| Top Energy | 16.5 | 19.1 | 17.8 | 16.2 | 18.3 |
| Unison | 45.5 | 36.6 | 35.4 | 35.1 | 32.2 |
| Vector | 141.0 | 145.1 | 148.0 | 151.4 | 146.5 |
| Wellington Electricity | 27.6 | 28.6 | 35.0 | 30.9 | 30.6 |
| **Industry total** | **420.2** | **419.3** | **441.0** | **426.2** | **424.0** |

2.12 Our forecasts of nominal capital expenditure provide for investment by distributors of over $400 million in each year of the regulatory period (and around $2 billion for the entire regulatory period in today’s prices.

*Forecast relative to historic levels of investment*

2.13 Figure 2.2 shows the forecast of capital expenditure relative to each distributor's historic levels of investment.

**Figure 2.2: Allowances for total capital expenditure relative to historic expenditure**




2.14 Figure 2.2 shows that our allowances for total capital expenditure relative to historic capital expenditure range from almost 40% for Nelson Electricity to 120% for Powerco. Our forecasts below 110%, relative to historic capital expenditure, are equivalent to the distributor's own forecasts.

*Comparison with distributor forecasts*

2.15 Table 2.4 compares the allowances for capital expenditure to each distributor's own forecasts of capital expenditure for 2016 to 2020.

**Table 2.4: Capital expenditure allowance compared to distributor forecasts ($m)**

| Distributor | Distributor forecast | Our allowance | Difference ($m) | Difference (%) |
|---|---|---|---|---|
| Alpine Energy | 42.0 | 42.0 | - | 0.0% |
| Centralines | 12.4 | 12.4 | - | 0.0% |
| Electricity Ashburton | 82.5 | 82.5 | - | 0.0% |
| Nelson Electricity | 7.3 | 7.3 | - | 0.0% |
| Top Energy | 79.9 | 79.9 | - | 0.0% |
| Aurora Energy | 84.5 | 82.5 | - 2.0 | - 2.3% |
| Electricity Invercargill | 15.9 | 15.3 | - 0.6 | - 3.8% |
| Unison | 177.1 | 168.8 | - 8.3 | - 4.7% |
| Vector | 748.6 | 666.2 | - 82.4 | - 11.0% |
| The Lines Company | 59.0 | 50.0 | - 9.0 | - 15.3% |
| Wellington Electricity | 165.7 | 138.8 | - 26.9 | - 16.3% |
| Powerco | 586.8 | 465.2 | - 121.5 | - 20.7% |
| Horizon Energy | 43.3 | 33.5 | - 9.8 | - 22.6% |
| Eastland Network | 36.9 | 28.1 | - 8.8 | - 23.9% |
| Network Tasman | 57.2 | 28.9 | - 28.4 | - 49.6% |
| OtagoNet | 54.8 | 19.9 | - 34.9 | - 63.7% |
| **Industry total** | **2,253.8** | **1,921.1** | **- 332.7** | **-14.8%** |

Note: Total for 2016 to 2020 in 2013 constant prices

2.16 Table 2.4 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 six distributors, and are up to 63% less than forecasts for the remaining distributors.

2.17 Notably, OtagoNet and Network Tasman are forecasting network capital expenditure to be 303% and 225% respectively from 2016 to 2020, when expressed as a percentage of their historic average between 2010 and 2014. Our reasons for limiting these forecasts are explained in Chapter 4.

### Forecasts of other line items

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

2.18.1 Asset disposals; and

2.18.2 Other regulatory income.

2.19 These factors are further explained in Chapter 6.

*Asset disposals*

2.20 The value of disposals is the average of constant price historic disposals from 2010 to 2013 forecast forward using Consumer Price Index (CPI) as a price inflator. Table 2.5 shows the value of disposed assets that we have forecast for distributors from 2016 to 2020.

**Table 2.5: Nominal asset disposal forecasts 2016 to 2020 ($m)**

| Distributor | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Alpine Energy | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Aurora Energy | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Centralines | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Eastland | 0.7 | 0.7 | 0.7 | 0.7 | 0.8 |
| Electricity Ashburton | 1.2 | 1.3 | 1.3 | 1.3 | 1.3 |
| Electricity Invercargill | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Horizon Energy | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 |
| Nelson Electricity | - | - | - | - | - |
| Network Tasman | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| OtagoNet | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Powerco | 8.9 | 9.1 | 9.3 | 9.5 | 9.6 |
| 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 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Vector | 8.9 | 9.1 | 9.3 | 9.5 | 9.7 |
| Wellington Electricity | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Industry total** | **21.6** | **22.1** | **22.5** | **23.0** | **23.5** |

2.21 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. An underlying assumption is that, on average, disposed assets will be sold for 11% of their regulatory net book value. This reflects an industry-wide average of losses on the sale of assets in proportion to disposals of 89%.

*Other regulated income*

2.22 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.

2.23 Table 2.6 shows our forecasts of distributors' other regulated income from 2016 to 2020.

**Table 2.6: Nominal other regulated income 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 | 1.1 | 1.1 | 1.2 | 1.2 | 1.2 |
| Centralines | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 |
| Eastland | –0.3 | –0.3 | –0.3 | –0.3 | –0.3 |
| Electricity Ashburton | –0.6 | –0.6 | –0.6 | –0.6 | –0.6 |
| Electricity Invercargill | –0.1 | –0.1 | –0.1 | –0.1 | –0.1 |
| Horizon Energy | –0.2 | –0.2 | –0.2 | –0.2 | –0.2 |
| Nelson Electricity | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Network Tasman | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| OtagoNet | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Powerco | –7.7 | –7.8 | –8.0 | –8.1 | –8.3 |
| The Lines Company | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Top Energy | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Unison | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Vector | 3.0 | 3.1 | 3.1 | 3.2 | 3.3 |
| Wellington Electricity | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| **Industry total** | **–3.0** | **–3.1** | **–3.1** | **–3.2** | **–3.2** |

**Weighted average cost of capital and forecast of asset revaluations**

2.24 This section sets out our assumptions about:

2.24.1 The weighted average cost of capital; and

2.24.2 The forecast rate of inflation for predicting asset revaluations.

*Weighted average cost of capital — 7.60% used for draft decision*

2.25 The weighted average cost of capital (WACC) that we have used in reaching our draft decision was 7.60%, which was our estimate of the WACC as at 1 April 2014. We published this estimate of the WACC on 30 April 2014.[7]

2.26 Table 2.7 sets out the key parameters from the WACC determination.

**Table 2.7: Main components of the Vanilla WACC**

| Parameter | Value | Parameter | Value |
|---|---|---|---|
| Risk free rate (5 years) | 4.21% | Debt premium (5 years) | 1.80% |
| Equity beta | 0.61 | Tax adjusted market risk premium | 7.00% |
| Average corporate tax rate | 28% | Average investor tax rate | 28% |
| Debt issuance costs (5 years) | 0.0035 | Leverage | 44% |
| Standard error of debt premium | 0.0015 | Standard error of WACC | 0.011 |
| Cost of debt (5 years; pre corporate tax) | 6.36% | Cost of equity (5 years) | 7.30% |
| Vanilla WACC (5 years, midpoint) | | | 6.36% x 0.44 + 7.30% x (1–0.44) = 6.89% |
| Vanilla WACC (5 years, 75th percentile estimate) | | | 7.60% |

2.27 The WACC that we have relied on is the 75th percentile Vanilla WACC. The corresponding midpoint estimate is 6.89%.

7 *Cost of capital determination for information disclosure year 2015 for specified airport services (March year-end) and electricity* [2014] NZCC 10.

*Forecast rate of inflation for predicting asset revaluations*

2.28 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:

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

2.28.2 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.

2.29 The CPI data that we used to predict changes in asset values are shown in Table 2.8.

**Table 2.8: Inflation adjustment for revaluations**

| Year ending | Forecast change in CPI |
|---|---|
| 2013 | 0.86% |
| 2014 | 1.53% |
| 2015 | 1.85% |
| 2016 | 1.81% |
| 2017 | 2.10% |
| 2018 | 2.07% |
| 2019 | 2.03% |
| 2020 | 2.00% |

2.30 The series in Table 2.8 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%.

2.31 Vector argued in its submission that, if actual inflation is different to forecast inflation, then Financial Capital Maintenance may not be achieved on an ex post basis. However, as we have noted a number of times in the past, in a regulatory setting Financial Capital Maintenance is applied on an ex ante basis. Therefore, we do not intend to wash up for any historical difference between actual and forecast inflation.[8]

[8] We do not consider that a wash up would be appropriate in future, as a similar outcome could be achieved in a more straightforward way. For example, the value of the Regulatory Asset Base could be rolled forward for forecast inflation instead of actual inflation. Amending the way that the asset base is

**Forecasts of revenue growth**

2.32 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*

2.33 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.

2.34 The inflation forecasts that we relied on for our draft decision are shown in Table 2.9.

**Table 2.9: Forecast of inflation for predicting changes in revenue**

| Year ending | Forecast change in CPI |
|---|---|
| 2016 | 1.59% |
| 2017 | 1.84% |
| 2018 | 1.87% |
| 2019 | 2.09% |
| 2020 | 2.08% |

2.35 The figures shown in Table 2.9 are different to the inflation figures shown in Table 2.8 because they are calculated on a slightly different basis. In particular, the values shown in Table 2.9 are calculated consistent with the way the price or revenue path will be updated during the regulatory period.[9] However, the values in Table 2.8 are calculated consistent with the input methodology for rolling forward asset values during the regulatory period.[10]

rolled forward under information disclosure regulation could be addressed through an amendment to the information disclosure requirements. We invite you to provide your views on this option.

9 The price or revenue 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.

10 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*

2.36 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.

2.37 The forecast of each distributor's revenue growth in constant prices is shown in Table 2.10. This table shows the revenue growth that is forecast to occur as a result of changes in the quantities billed by each distributor.

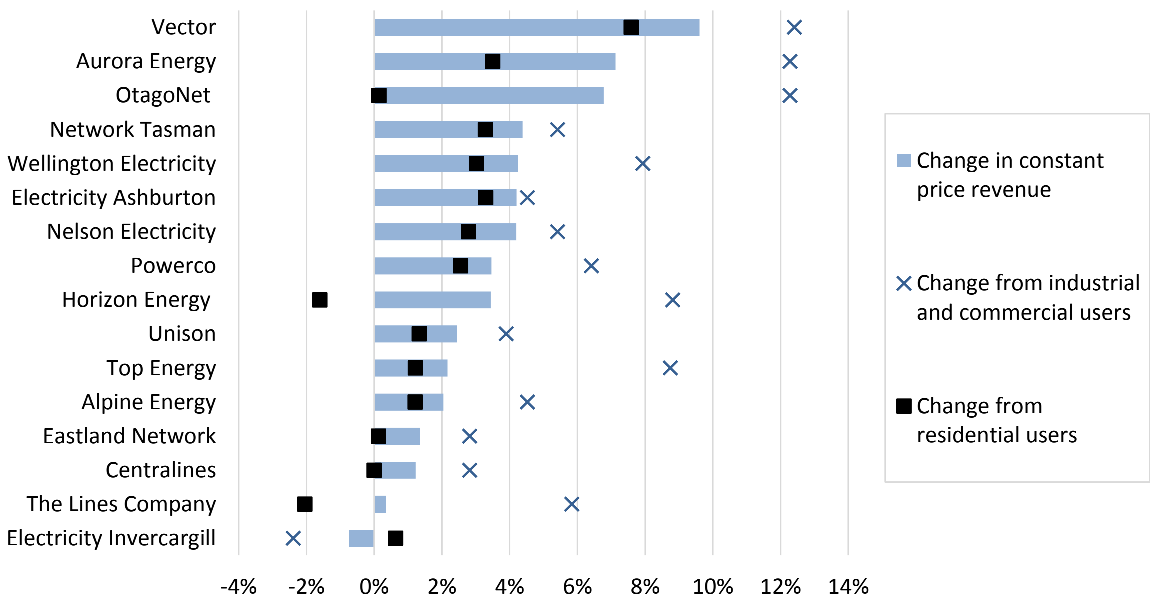
**Table 2.10: Constant price revenue growth forecasts (%)**

| Distributor | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Alpine Energy | 0.42% | 0.40% | 0.40% | 0.40% | 0.40% |
| Aurora Energy | 1.38% | 1.39% | 1.39% | 1.39% | 1.39% |
| Centralines | 0.24% | 0.24% | 0.24% | 0.24% | 0.24% |
| Eastland | 0.21% | 0.28% | 0.28% | 0.28% | 0.28% |
| Electricity Ashburton | 0.84% | 0.82% | 0.82% | 0.82% | 0.82% |
| Electricity Invercargill | -0.12% | -0.16% | -0.16% | -0.16% | -0.16% |
| Horizon Energy | 0.64% | 0.69% | 0.69% | 0.69% | 0.69% |
| Nelson Electricity | 0.85% | 0.82% | 0.82% | 0.82% | 0.82% |
| Network Tasman | 0.89% | 0.86% | 0.86% | 0.86% | 0.86% |
| OtagoNet | 1.34% | 1.31% | 1.31% | 1.31% | 1.31% |
| Powerco | 0.59% | 0.71% | 0.71% | 0.71% | 0.71% |
| The Lines Company | -0.02% | 0.09% | 0.09% | 0.09% | 0.09% |
| Top Energy | 0.34% | 0.45% | 0.45% | 0.45% | 0.45% |
| Unison | 0.47% | 0.49% | 0.49% | 0.49% | 0.49% |
| Vector | 1.80% | 1.87% | 1.87% | 1.87% | 1.87% |
| Wellington Electricity | 0.83% | 0.83% | 0.83% | 0.83% | 0.83% |

*Main drivers of revenue growth in constant prices*

2.38 Figure 2.3 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 2.3: Constant price revenue growth forecasts**




2.39 Figure 2.3 shows that the driver of revenue growth in constant prices for Vector is an increase in demand from industrial and commercial users. This reflects forecasts supplied by NZIER, which indicate that Auckland's GDP is expected to grow faster than other regions in New Zealand between 2016 and 2020.

2.40 Figure 2.3 also shows a forecast decrease from residential users for Horizon Energy and The Lines Company. This reflects projected declines in population for the network areas that these two distributors serve.

# 3. Operating expenditure

### Purpose of chapter

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

### Overview of proposed approach

3.2 Consistent with the approach used in November 2012, we propose to forecast operating expenditure for each distributor by projecting forward an initial level based on changes in three main expenditure drivers.[11] We have not made any additional adjustments for the reasons given in paragraphs 3.30 to 3.34.

3.3 Our forecasts of operating expenditure have a significant impact on the prices that distributors would be allowed to charge if starting prices are adjusted. A 1% increase in operating expenditure translates into a 0.25% increase in the revenue that distributors can expect to earn.

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;[12] 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.[13] This formula results in an adjustment to operating expenditure in the previous year based on changes in each of the drivers.

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11 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." Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" 30 April 2014, paragraph 26.

12 The operating expenditure partial productivity measures changes in the ratio of operational expenditure to associated outputs. Historical operating expenditure partial productivity changes for New Zealand and overseas distributors, as well as future expectations, inform our views on operating expenditure partial productivity. Consistent with the productivity-based X factor, we previously set the operating expenditure partial productivity to be the same for each distributor.

**Box 3.1: Formula for calculating operating expenditure**

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

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.

### Initial level of operating expenditure

3.7 The initial level of operating expenditure for our projection was the amount disclosed by the distributor for the 2013 disclosure year. Estimates of expenditure in the 2014 disclosure year were disclosed in March. The actual amount of expenditure in the 2014 disclosure year is due to be disclosed in August.

3.8 We have relied on the amounts for 2013 on the basis that:

3.8.1 Data has not yet been disclosed for 2014; and

3.8.2 Distributor estimates of expenditure in 2014 suggest the year was atypical.

3.9 Therefore, we do not currently expect to give much, if any, weight to the amounts disclosed in August 2014.

*Issues with relying on estimated or actual data for 2014*

3.10 In principle, relying on data for the most recently available year prior to the reset would help 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.

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[13] Unlike the approach used in November 2012, the formula we used is multiplicative rather than additive. We applied a multiplicative approach based on a submission from CEG on our November 2012 approach.

3.11 However, as noted in the Process and Issues Paper, two reasons suggest it may be inappropriate to give much weight to data for 2014 for the forthcoming reset:

3.11.1 Atypically high or inefficient costs in 2014 may lead to a forecast that is biased in favour of the distributors and, by the same reasoning, an atypically low cost year may bias the forecast to the disadvantage of distributors; and

3.11.2 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).

3.12 Consequently, in the Process and Issues Paper, we proposed to rely on an average of 2013 and 2014 data to smooth the impact on the data of atypical events and incentives to inflate costs. A number of distributors agreed that such an approach could potentially offset any abnormalities that may exist in any one year.[14]

3.13 Shortly after our Process and Issues Paper was published, distributors disclosed estimates for operating expenditure in 2014, and in many cases the data seemed atypical relative to historic levels. Figure 3.1 compares the estimate of operating expenditure for 2014 to actual operating expenditure for 2013.

3.14 We invite views on the reasons for the differences shown in Figure 3.1. In particular, we would be interested in receiving evidence as to why either year would be atypical for any or all distributors.[15] At present, we are not aware of any reasons that would explain why there was a difference of 10% or more for 7 distributors, and significant increases for a few other distributors as well.[16]

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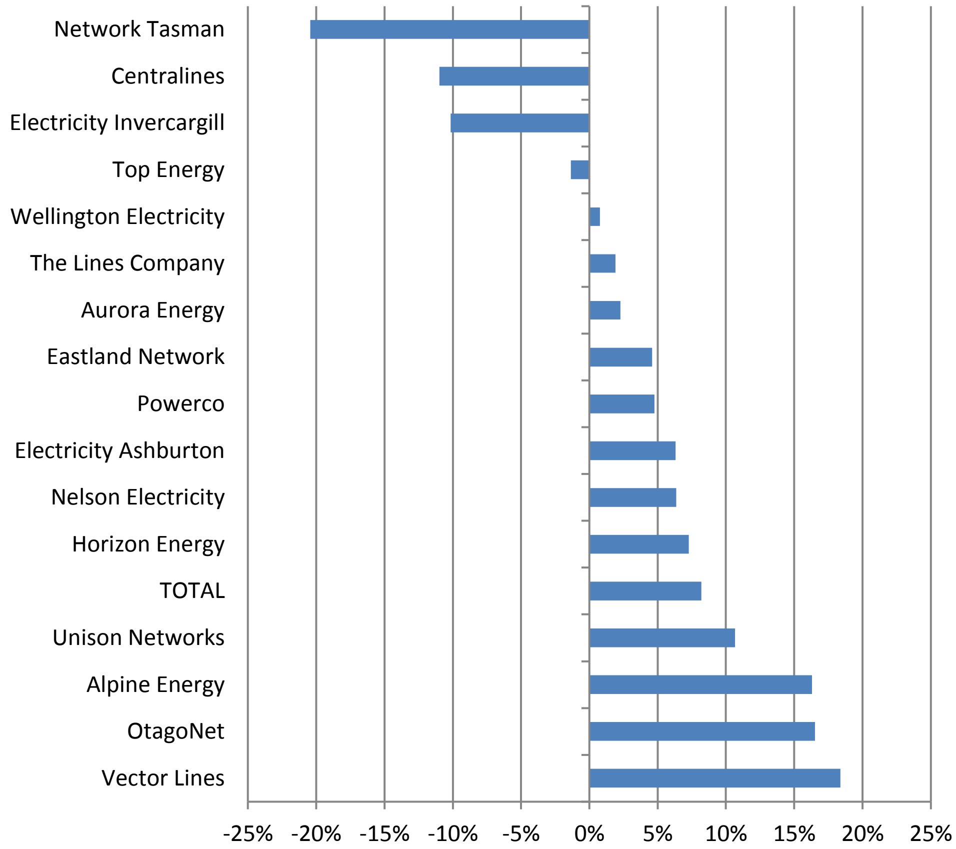
[14] Maui Development Limited suggested a longer term base series be used (an average or weighted average of 2011-2014) to smooth any year-to-year variability, Maui Development Limited "Submission on the process and issues paper: Default price-quality paths from 1 April 2015 for 17 electricity distributors" 30 April 2014, p.1. 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.

[15] For example, Unison Networks submitted that 2013 was benign year in relation to weather, leading to less operating expenditure required for emergency works. Refer: Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" 30 April 2014, paragraph 31.

[16] Distributor estimates of expenditure have often proved to be an unreliable guide to actual expenditure. We are interested in understanding the reasons why estimates disclosed on 31 March have previously proved to be unreliable guide for the disclosure year ending on the same date.

**Figure 3.1: Change in estimated 2014 expenditure relative to actual 2013 actual expenditure (constant prices)**




3.15 Because we are unable to review of the efficiency of each distributor's disclosed levels of expenditure, the weighting given to 2014 data may ultimately depend on contextual factors.[17] We invite submissions on any factors we should consider, alongside the data disclosed in August 2014, when exercising our judgement in relation to the appropriate weightings.[18]

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17 We are precluded from using comparative benchmarking on efficiency. Refer: s 53P(10).

18 We note that, if we rely on a weighted average between 2013 and 2014 data, we will adjust the data for 2013 consistent with our projection approach. An adjustment of this nature would appear to be consistent with the submission by the ENA Refer: Electricity Networks Association "Submission on default price-quality paths from 1 April 2015 for 17 electricity distributors: process and issues paper" 30 April 2014, paragraph 22.

**Forecast change due to network scale effects**

3.16 To estimate the impact of changes in scale on operating expenditure, we separately modelled the relationship between operating expenditure and network scale for:

3.16.1 Expenditure operating the network (network operating expenditure); and

3.16.2 Expenditure to support network operations (non-network operating expenditure).

3.17 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.[19]

*Understanding the relationship between network scale and operating expenditure*

3.18 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.

3.19 For network operating expenditure, our econometric modelling suggests that:

3.19.1 A 1 % change in the length of the network is associated with a 0.45% change in network operating expenditure, holding the number of connections fixed; and

3.19.2 A 1% change in the number of connections is associated with a 0.49% increase in network operating expenditure, holding network length fixed.

3.20 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.

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[19] Refer: 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 each variable, 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 Information on historic network length was obtained from distributor's information disclosure. However, we note that there appears to be some data anomalies:

3.22.1 The treatment of dedicated street lighting should be excluded from network length for supply. Where dedicated street lighting appears to be included in network length we have made an adjustment to exclude it for consistency

3.22.2 We have assumed that The Lines Company's network length has been constant at 4340 kilometres between 2010 and 2013.[20]

*Independent review of submissions on econometric modelling*

3.23 To assist us in our decision making, we requested an independent review of submissions on econometric modelling. Following his review of submissions, Professor Jeff Borland concluded that:

> the empirical approach being followed … is appropriate and the analysis has been done in a way that reflects standard practice in undertaking econometric analysis.

3.24 A copy of Professor Borland's report has been published alongside this paper.[21] We invite you to provide your views on the contents of that report.

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20 We contacted The Lines Company regarding a discrepancy in its line length data. The company has advised us that this has not grown or shrunk in recent years and that 2013 line length would be accurate. We intend to follow up on this before the final decision.

21 Refer to: Jeff Borland "Comments on NZCC approach for forecasting opex" 26 June 2014.

**Forecast change in partial productivity**

3.25 We propose to assume that there will be no change in partial productivity for operating expenditure during the next regulatory period. We have based this assumption on the recommendation of Economic Insights. A copy of the report prepared by Economic Insights has been released alongside this paper.

3.26 Before the report was prepared, we hosted a workshop for stakeholders to ensure they could understand and input into the productivity study by Economic Insights. This workshop was well attended and we thank stakeholders for their participation.

**Forecast change in input prices**

3.27 Consistent with our approach in November 2012, we propose to inflate operating expenditure using a weighted average of:[22]

3.27.1 Forecasts changes in the all industries labour cost index; and

3.27.2 Forecast changes in the all industries producer price index.

3.28 We propose to weight the forecast labour cost index by 60% and the forecast producer price index by 40%. This is based on labour expenditure analysis in Australian power industry, consistent with that used in the previous reset.[23]

3.29 Further explanation of our approach to forecasting changes in input price can be found in Attachment B.

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22 These forecasts were sourced from the New Zealand Institute of Economic Research. We propose to update these forecasts before reaching our final decision.

23 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**

3.30 Consistent with our approach in November 2012, we are open to considering whether any additional adjustments are required for other costs that are not captured in our forecast. To qualify for consideration, the costs must:

3.30.1 Be significant;

3.30.2 Be robustly verifiable;

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

3.30.4 Be largely outside the control of the distributor; and

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

3.31 Any adjustments for step changes in future operating expenditure may be downward, as well as upward.

*Consideration of adjustments proposed to date*

3.32 To date, we have not been persuaded that any additional adjustments are required. In our Process and Issues Paper, we invited stakeholders to suggest costs that may meet the criteria. We also requested that stakeholders provide evidence to demonstrate that the criteria had been met.

3.33 The adjustments that have been suggested include:

3.33.1 Some submitters expect a step change in operating expenditure due to expected changes in health and safety regulation. There is concern that as this is not planned before the next reset begins any extra costs resulting from a legislative change will not be accounted for.[24]

3.33.2 We are currently giving effect to the High Court merits appeal judgment which requires us to provide for default price-quality path reopener provisions consistent with those for customised price-quality paths, which would allow for a change in path for any material change in legislative or regulatory requirements.

3.33.3 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 is applicable to most distributors.[25]

3.34 We would welcome submissions on step changes in operating expenditure, either positive or negative, that meets the above criteria and could be considered for the final decision.

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24 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.

25 Wellington Electricity Lines Limited “Submission on issues paper on 2015-2020 Default Price-quality Path” 30 April 2014, p.4.

### Summary of information sources for forecasts of operating expenditure

3.35 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 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 |
| Changes in scale – network length | Extrapolation of historic network length (2010-2013) | Electricity distributors' information disclosures |
| Impact of changes in scale on operating expenditure | Historic ICP and network length data (2004-2012) | |
| Changes in partial productivity for operating expenditure | Partial productivity estimate for operating expenditure | Economic Insights "Electricity Distribution Industry Productivity Analysis: 1996–2013" 10 June 2014 |
| Changes in input prices | Labour price index<br>Producer price index | NZIER |

# 4. Capital expenditure

### Purpose of chapter

4.1 This chapter outlines and explains our proposed approach for forecasting capital expenditure, which differs for the periods before and after 1 April 2015.

### Forecasts of capital expenditure for the period 1 April 2015 onwards

4.2 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:

4.2.1 current and future demand drivers for its services;

4.2.2 how to efficiently meet this demand; and

4.2.3 the costs incurred in providing the services.

4.3 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.[26]

*Limit applied to distributor forecasts*

4.4 We applied a limit to some distributor's forecast because:

4.4.1 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 forecasting assumptions; and

4.4.2 applying a limit is consistent with the overall regulatory regime where customised price-quality paths are the mechanism to address material step change in investment.[27]

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[26] 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 Network Ltd, *Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper, 30 April 2014, para 52.*

[27] 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 that would only be countered by the incentives created by summary and analysis. Second, it may reduce the incentives to achieve efficiencies in capital expenditure, because a distributor would be able earn an acceptable return without achieving efficiencies.

4.5 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.[28]

*Impact of capital expenditure limit on smaller suppliers*

4.6 Submissions outlined how placing a limit on forecast capital expenditure might be particularly damaging to smaller distributors. For example, Unison suggested:[29]

> We do observe, however, that for some EDBs (particularly smaller businesses) a 20% cap may be unduly restrictive, because lumpy capital expenditure requirements (e.g., building a substantial new line or new substation) may dwarf base-line historic expenditure levels.

4.7 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.

4.8 The approach ensures that smaller distributors who require a large one-off expenditure increases 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 allowable revenues equivalent to a higher cap on capital expenditure under these circumstances.

*Forecast of capital expenditure was based on two categories*

4.9 We separated the forecast for capital expenditure into two categories:

4.9.1 'Network capital expenditure' involves assets that form part of the distribution or transmission network; and

4.9.2 'Non-network capital expenditure' involves assets employed in supplying regulated services that do not form part of the distribution or transmission network.

4.10 The forecasts for each category of capital expenditure were combined in each year, and then adjusted to reflect forecast changes in input prices.

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28 Commerce Commission, *Notice to Supply Information to the Commerce Commission under section 53ZD of the Commerce Act 1986*, 22 June 2012.

29 Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" 30 April 2014, paragraph 57.

*Retention factor in the incentive scheme to control capital expenditure*

4.11 Through an amendment to input methodologies, we propose to put in place an incentive to control capital expenditure that has a constant strength in each year of a default price-quality path. The proposed amendment will be outlined in a paper that we will release during consultation on this paper. [30]

4.12 For this reset, we propose to apply a retention factor of 20%, ie, distributors would retain 20% of each dollar of capital expenditure they save. A constant 20% retention factor is broadly in line with the current average retention factor for capital expenditure, ie, under a price path without any additional capital expenditure incentive mechanism.

4.13 Our reasons for favouring a retention factor of 20% are related to our low cost forecasting approach, which may not reflect the prudent and efficient level of capital expenditure. A retention factor above 20% may therefore result in significant gains to distributors in future regulatory periods, over and above those that arise from genuine efficiencies in capital expenditure.[31]

4.14 Our concerns are based on the following:[32]

4.14.1 Our low cost approach is reliant on using the capital expenditure forecasts provided by the distributors, and we provided distributors with an incentive to systematically bias their forecast to increase their starting price, eg, by adopting low risk forecasting assumptions; and

4.14.2 For a large number of distributors, expenditure in the current regulatory period was below their own forecasts, which may be the result of inaccurate forecasting, or systematically biased forecasts.

4.15 Moreover, a higher strength of incentive to economise on capital expenditure may result in the incentive to defer or economise on expenditure being stronger than the incentives to maintain quality.

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30 Further information on the issues that are addressed by this type of scheme is available in a previously published paper: Commerce Commission “Incentives for Suppliers to Control Expenditure During a Regulatory period: Process and Issues Paper” (20 September 2013).

31 A lower retention factor reduces the financial impact on a distributor needing to spend more than our forecast of capital expenditure.

32 Some these concerns may be mitigated in the future through the application of menu regulation as noted by Frontier in their report to the ENA forecasting working group: 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.

**Network capital expenditure—Size and application of limit**

4.16 The limit that we propose to apply to forecasts of network capital expenditure is equivalent to 120% or 110% of the historic average, depending on the reliability of the forecast relied on for the previous reset in November 2012. The proposed limit is therefore dependent on the difference between:[33]

4.16.1 The distributor's 2010 forecast of network capital expenditure; [34] and

4.16.2 The amount of network capital expenditure incurred since 2010.[35]

4.17 Distributors for which the 2010 forecast was no more than 10% higher than out-turn would be permitted up to 120% of the historic level. Distributors for which the 2010 forecast was over 10% higher than out-turn would only be permitted up to 110% of the historic level.

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33 An approach that takes in into account the reliability of previous forecasts was suggested by Powerco in their submission to the process and issues paper. Powerco, *Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper*, 30 April 2014, Section 3.3.5.

34 If this forecast was revised for the purposes of the 2012 reset, eg, because the forecast of capital contributions was removed, then it is the revised forecast that is used in this calculation.

35 Incurred capital expenditure is calculated net of capital contributions to ensure that it is consistent with the forecast used in November 2012.

*Limit of 120% of historic levels based a number of factors*

4.18 We determined the 120% limit and its application by taking into account a number of factors. For example, we considered that:

4.18.1 The distributor has the most information about future capital expenditure required by the network and the asset management plan provides their estimate of future capital expenditure;

4.18.2 Network capital expenditure has been increasing over recent years and has tended to be quite variable on a year-to-year basis;

4.18.3 Relying exclusively on distributor forecasts provides an incentive to systematically bias disclosed forecasts, eg, by adopting conservative forecasting assumptions;[36]

4.18.4 A distributor is be able to achieve higher revenues from systematically biased forecasts because:

4.18.4.1 forecasts of capital expenditure are used to set the forecast value of commissioned assets that enter the regulated asset base in each year of the regulatory period; and

4.18.4.2 the proposed incentive scheme to control expenditure would be unable to distinguish between lower than forecast expenditure that is a result of efficiency gains and that which is a result of systematically biased forecasts;

4.18.5 Previously, distributors, on average, have forecast higher capital expenditure than has been required;[37]

4.18.6 Distributors are able to apply for a customised price-quality path in the event that their capital expenditure allowance is less than required.

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36 This incentive was discussed in the reasons paper for the November 2012 price reset. Commerce Commission, *Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors*, 30 November 2012, section B8. It was also outlined by Powerco in their submission: Powerco "Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper" 30 April 2014, paragraph 27.

37 The difference between out-turn capital expenditure against predicted has been estimated to be 13% in a recent working paper published by the Commission. Commerce Commission, *Regulatory Incentives and the Cost of Capital, Working Paper*, 23 June 2014.

4.19 Given the factors outlined above, our view is that a limit of 120% generally strikes an appropriate balance. This limit is also consistent with both the previous decision for capital expenditure under the gas default price quality path and submissions made by Unison Networks and Vector.[38]

4.20 As part of this decision we have taken into account submissions that suggest a higher limit should be applied due to a trend of increasing capital expenditure.[39] We agree that increases in capital expenditure have taken place and average annual increases in network capital expenditure seen in recent years have been in the region of 5% per annum.[40] These increases will be reflected in the baseline for applying the limit.

4.21 However, for capital expenditure, past trends may not be a good guide to future trends, and we have no reason to believe that capital expenditure should increase to the same extent over the forthcoming regulatory period. The limit of 120% provides some allowance for increasing capital expenditure, but this is limited under the default price quality path due to the reasons outlined above.

*Lower limit for distributors that have previously forecast significantly more than they spent*

4.22 Our view is that a lower limit of 110% should apply to distributors that have previously forecast significantly higher capital expenditure than the actual out-turn. This limit compares to the general limit of 120% that is provided to distributors that have previously shown that they are able to provide a relatively accurate forecast of network capital expenditure.

4.23 Distributors for which the previous forecast significantly exceeded out-turn have enjoyed benefits during the current regulatory period. The revenues they received during this period corresponded to the return *on* and *of* capital on their forecast rather than the out-turn capital expenditure. The application of a lower limit is intended to ensure distributors who have previously forecast higher than out-turn capital expenditure do not benefit in the event that this characteristic continues in the most recent capital expenditure forecasts.

4.24 The limit is also intended to provide a general incentive to improve the forecasting accuracy of distributors when providing asset management plans. We do not scrutinise the businesses' forecasts, and are concerned to not impose a significant risk on consumers paying for investments that are forecast but never needed.

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38 Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" 30 April 2014, paragraph 56 and Vector "Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper" 30 April 2014, paragraph 124.

39 For example, see Powerco "Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper" 30 April 2014, paragraph 3.3.4.

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

4.25 There can be a number of reasons why out-turn capital expenditure may not be equivalent to forecast expenditure. Therefore, we have included a tolerance of 10% when determining the previous reliability of capital expenditure forecasts before we apply the additional limit. This also provides scope for businesses to achieve and retain efficiency gains during the regulatory period.

4.26 The lower limit of 110% has been informed in part by the variability in historical forecasts. An additional 10% is added here on the basis that capital expenditure tends to vary up to a maximum of 50% year-on-year compared to the average historical capital expenditure, excluding certain outliers. The 110% limit allows 1 year out of 5 to have a 50% increase against the historical average.

*Example of how the limit would be determined based on the 2010 forecast*

4.27 This section provides an example of how the limit would be determined based on reliability of the 2010 forecast as used in the November 2012 price reset. We propose to update this analysis once data is disclosed for the 2014 disclosure year. For the draft decision, we have relied on data for the three disclosure years since the forecast was disclosed, ie, 2011, 2012, and 2013, as well as the most recent estimate of expenditure in 2014.[41]

4.28 Table 4.1 shows the limit propose for each distributor based on the expenditure incurred relative to the 2010 forecast. All calculations were performed in constant prices with capital goods price index (CGPI) used to convert out-turn expenditure into a comparable series.

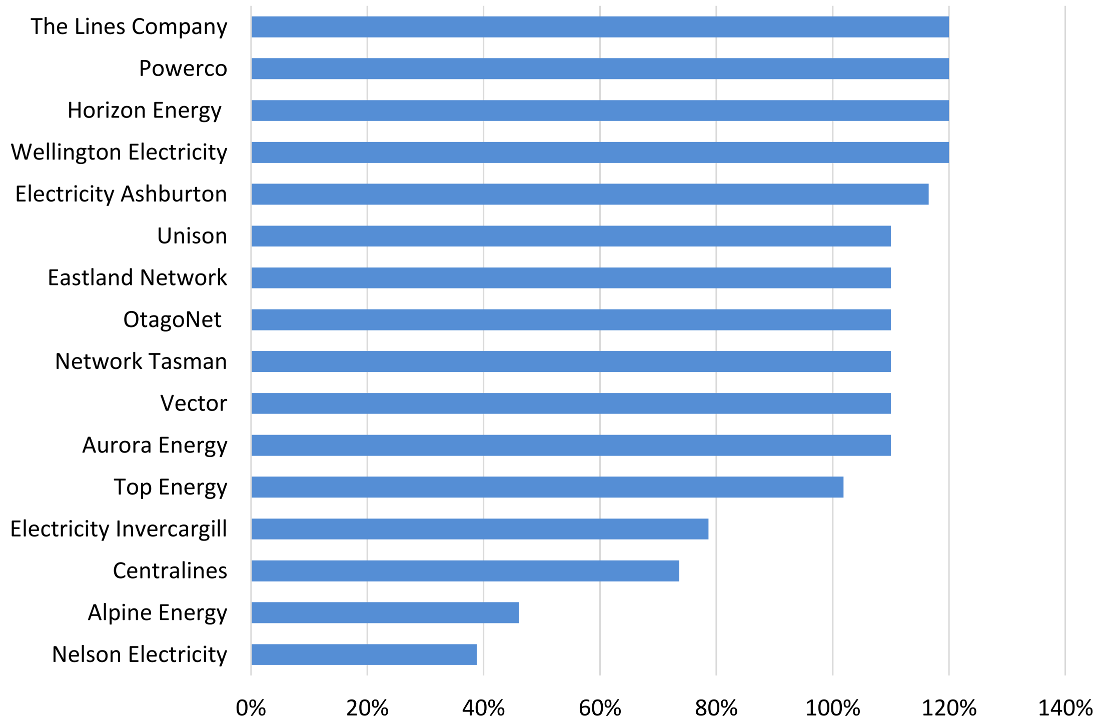
41 This was taken from distributor’s most recent asset management plan provided in March 2014.

**Table 4.1: Example of how limit would be determined for network capital expenditure**

| | Excess of forecast compared to out-turn (%) | Proposed limit |
|---|---:|---:|
| Unison Networks | 37% | 110% |
| Aurora Energy | 27% | 110% |
| Centralines | 25% | 110% |
| Network Tasman | 24% | 110% |
| Alpine Energy | 21% | 110% |
| OtagoNet | 16% | 110% |
| Vector Lines | 14% | 110% |
| Eastland Network | 12% | 110% |
| Powerco | 1% | 120% |
| Wellington Electricity | 1% | 120% |
| The Lines Company | 1% | 120% |
| Horizon Energy | nil | 120% |
| Electricity Invercargill | nil | 120% |
| Nelson Electricity | nil | 120% |
| Electricity Ashburton | nil | 120% |
| Top Energy | nil | 120% |

4.29 The consequence of applying the limits would be the forecasts shown in Figure 4.1.

**Figure 4.1: Proposed forecast of network capital expenditure**




*Our forecast reflects the profile of the distributor's forecast*

4.30 The profile of our forecast of network capital expenditure is the same as the profile of the distributor's forecast. This is because we scaled the distributor's forecast if the limit was exceeded. We therefore propose to use as much information in the distributor's forecast as possible.

**Non-network capital expenditure—Size and application of limit**

4.31 The limit that we propose to apply to forecasts of non-network capital expenditure is equivalent to 200% of the distributor's historic average, unless non-network capital expenditure represents more than 5% of capital expenditure. We have proposed this higher limit due to the much higher variability historically seen in non-network expenditure.[42]

42 Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" 30 April 2014, paragraph 62.

*Example of how the limit would be determined*

4.32 For those distributors who are forecasting non-network capital expenditure to be more than 5% of total capital expenditure, we propose to adopt 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.

4.33 The sliding scale ensures that any distributor who forecasts 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% will have a limit set in a proportional manner.

4.34 Table 4.2 shows the limit proposed for each distributor based on the non-network expenditure forecast disclosed in March 2014 for the period 2016 to 2020. All calculations are in constant prices.

**Table 4.2: Example of how limit for non-network capital expenditure would be determined**

| | % of non-network as a proportion of total capital expenditure | Proposed limit |
|---|---|---|
| Unison Networks | 24% | 121% |
| Electricity Invercargill | 14% | 135% |
| Horizon Energy | 8% | 160% |
| The Lines Company | 8% | 166% |
| Vector Lines | 7% | 173% |
| Alpine Energy | 7% | 175% |
| Powerco | 6% | 181% |
| Wellington Electricity | 5% | 200% |
| Network Tasman | 4% | 200% |
| Electricity Ashburton | 4% | 200% |
| Eastland Network | 3% | 200% |
| Top Energy | 2% | 200% |
| Nelson Electricity | 1% | 200% |
| Aurora Energy | 0% | 200% |
| Centralines | 0% | 200% |
| OtagoNet | 0% | 200% |

*Our forecast reflects the profile of the distributor's forecast*

4.35 The profile of our forecast of non-network capital expenditure is the same as the profile of the distributor's forecast. This is because we scaled the distributor's forecast if the limit was exceeded. We therefore propose to use as much information in the distributor's forecast as possible.

**Forecast changes in input prices**

4.36 Consistent with our approach in November 2012, we propose to use a forecast of the all industries capital goods price index to forecast changes in input prices for capital expenditure.[43] Further explanation of the reasoning for our approach can be found in Attachment B.

**Capital expenditure forecasts up to 31 March 2015**

4.37 As well as determining the capital expenditure forecast for the 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 regulatory period, ie, 1 April 2015.

4.38 For this forecast we propose to use 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:

4.38.1 The 2014 forecast is likely to provide greater accuracy for the final year of the regulatory period as it is closer to the year of actual expenditure than forecasts for later years; and

4.38.2 We will propose an amendment to input methodologies on 18 July 2014 that would introduce an additional recoverable cost term to correct (or 'wash-up') the difference between the forecast of capital expenditure up to 31 March 2015 against the out-turn value of commissioned assets.

4.39 The additional recoverable cost term would mean that neither consumers or distributors would gain or lose from the difference between forecast and out-turn expenditure prior to the start of the regulatory period.

**Other options proposed by stakeholders**

4.40 The Process and Issues Paper outlined how we were exploring a number of options in which we could potentially improve our forecasts of capital expenditure for the forthcoming regulatory period.

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43 These forecasts were sourced from the New Zealand Institute of Economic Research. We propose to update these forecasts before reaching our final decision.

4.41 We are grateful for the submissions in this area which enabled us to carefully consider a range of available options. Following this deliberation we determined that the capital expenditure forecasts for the forthcoming regulatory period should be based on forecasts from each distributor's most recent forecast, subject to certain limits, as described previously.

4.42 Other options that we considered included using:

4.42.1 A model for asset replacement and renewal;

4.42.2 An econometric approach; and

4.42.3 Historic averages for non-network capital expenditure.

4.43 We rejected these options for the reasons set out below.

*Model of asset replacement and renewal*

4.44 The Process and Issues Paper outlined potential modelling approaches that would enable us to independently determine distributor forecasts of capital expenditure. This includes models for asset replacement and renewal and system growth.

4.45 Although we have the framework for an asset replacement model, we note the submissions that cautioned that obtaining and refining appropriate data for use in the model should be a longer term process in order to have confidence in the results. We are grateful for the submissions received on these models and helpful suggestions for development.

4.46 As an example Vector suggests:[44]

> …given the untested and experimental nature of these models the best option for forecasting capex for the next regulatory period is to use distributor capex forecasts, subject to a cap based on historical average expenditure.

4.47 Given the submissions received we are not intending to apply any independent modelling of capital expenditure to the current reset. We instead plan to develop capital expenditure models with the expectation that they would be used as part of summary and analysis in the first instance.

44 Vector "Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper" 30 April 2014, paragraph 15.

*Econometric approach*

4.48 We received two submissions outlining econometric models of network capital expenditure. They were provided by Frontier on behalf of the ENA and Network Strategies on behalf of Vector.

4.49 We note with interest the models provided; however, we have decided that they would not be appropriate for determining capital expenditure forecasts for this reset. The reasons for this are that:

4.49.1 A significant amount of capital expenditure is dependent on current asset ages and conditions, which is not directly observable from the recent data available under information disclosure from which the econometric models have been constructed;

4.49.2 As noted by Frontier, large and lumpy expenditure is not normally suitable for econometric forecasting;[45] and

4.49.3 As noted by Vector, the econometric models for capital expenditure provided by Frontier and Network Strategies are untested and should not be used to set capital expenditure forecasts for this reset.[46]

4.50 Econometric models constructed for non-network capital expenditure showed a poor fit and are not recommended by either Frontier or Vector.[47]

*Historic averages for non-network capital expenditure*

4.51 At the previous reset we determined a forecast of non-network capital expenditure on the basis of a historic average. The main reason for this was that a forecast of non-network capital expenditure was disclosed prior to the start of the last regulatory period.

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45 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, p.10.

46 Vector "Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper" 30 April 2014, paragraph 93.

47 Vector "Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper" 30 April 2014, paragraph 91 and 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, p.10.

4.52 For this reset, we are able to refer to a forecast of non-network capital expenditure that was disclosed by distributors in March 2014. We therefore do not propose to rely on a historic average. Instead, we plan to use the distributor forecast of non-network capital expenditure, together subject to the limit described in paragraphs 4.31 to 4.35.

4.53 The decision to no longer use a historic average approach was supported by a number of submissions.[48]

**Summary of information sources**

4.54 Table 4.3 sets out the information sources that we have relied on to produce our forecast of capital expenditure.

**Table 4.3: Information for forecasting capital expenditure**

| Item | Information used (supplier-specific unless otherwise stated) | Source |
|---|---|---|
| Previous forecast | Network capital expenditure forecast (2011-2014) | November 2012 reset |
| Historic average (reference on which forecasting performance is determined) | Capital Expenditure on Network Assets - Capital Contributions (2011-2014) | Schedule FS2 and FS1 (2011-2012)<br>Schedule 6a (2013-2014) |
| Current forecast | Network capital expenditure forecast - Value of Capital Contributions - Acquisition and Direct Capital Expenditure on transmission assets acquired from Transpower (2015-2020) | Schedule 11a (2014)<br>53ZD request (2014) |
| Historic average (reference on which distributor specific limit is applied) | Capital Expenditure on Network Assets - Value of Capital Contributions - Acquisition and Direct Capital Expenditure on transmission assets acquired from Transpower (2010-2014) | Schedule FS2 and FS1 (2010-2012)<br>Schedule 6a (2013-2014)<br>53ZD request (2010-2014) |
| Input prices | All goods CGPI: historical (2010-2014) and forecast (2015-2020 | Statistics New Zealand (historical) and NZIER (forecast) |

48 Unison Networks Limited "Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper" 30 April 2014, paragraph 56 and Vector "Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper" 30 April 2014, paragraph 64.

# 5. Revenue growth

**Purpose of chapter**

5.1 This chapter outlines and explains our proposed 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 tend to 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.

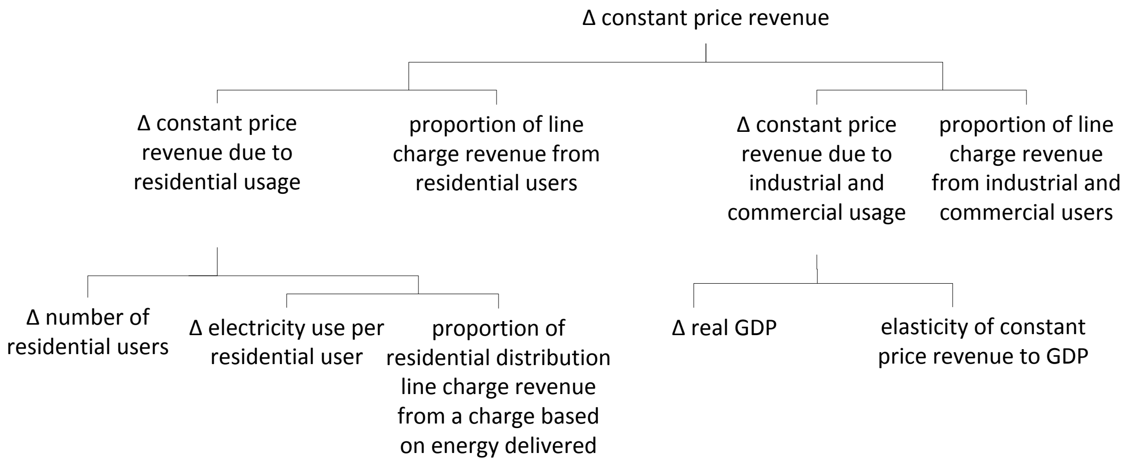
5.4 Notably, relative to other forecasts, the forecast of revenue growth arguably has a more material impact on a starting price set based on current and projected profitability.[49] This is because the forecast of revenue growth affects revenue, in aggregate, rather than any individual cost component.

[49] We require revenue growth forecasts for the regulatory period, ie, 1 April 2015 to 31 March 2020, as well as for the two years that immediately precede the regulatory period. The growth rate for the two years preceding the regulatory period is relevant when assessing compliance with the price-quality path in the first year of the regulatory period.

*Constant price revenue growth—Separate modelling for two user groups*

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.[50]

**Figure 5.1: Approach to modelling revenue growth for electricity distributors**




5.6 As shown in Figure 5.1, we propose to model constant price revenue growth separately for residential users, and industrial and commercial users.[51] 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.[52]

50 The forecasting approach shown in Figure 5.1 was suggested by Nathan Strong, from Unison Networks, during consultation on the November 2012 reset.

51 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).

52 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**

Δ revenue =

Δ revenue due to residential usage

x

proportion of line charge revenue  from residential users

+
Δ revenue due to industrial and commercial usage

x
proportion of line charge revenue  from industrial and commercial users

5.8 Our analysis of information from an information request shows 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.[53] 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 stay under the weighted average price cap. Our approach assumes that the structure of tariffs stays constant over the default price path regulatory period.

[53] 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.

**Modelling revenue growth from residential users**

5.10 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

electricity use per residential user

x

proportion of residential distribution line charge revenue from a charge based on energy delivered

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

*Change in the number of residential users*

5.12 One of the drivers of the forecast change in revenue from residential users is the change in number of residential users. To model the impact from changes in residential users, we have used population forecasts from Statistics New Zealand as a proxy for changes in the number of connections.

5.13 Vector Lines and Wellington Electricity have argued that population growth is a poor proxy for changes in the number of connections; in their experience, population growth has outstripped growth in the number of connections, ie, household size (or residents per connection) is increasing.[54]

5.14 Table 5.1 indicates that household growth was slightly lower than population growth in Auckland and Wellington, but the difference is not as significant as suggested in submissions.

[54] 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; Wellington Electricity Lines Limited "Submission on issues paper on 2015-2020 Default Price-quality Path" 30 April 2014, pp.10-12.

**Table 5.1: Growth in population and households in Auckland and Wellington**

| | AUCKLAND | | WELLINGTON | |
|---|---|---|---|---|
| | Population | Households | Population | Households |
| **2006** | 1,304,958 | 438,609 | 448,956 | 168,849 |
| **2013** | 1,415,550 | 472,041 | 471,315 | 177,162 |
| **Growth** | 1.17% | 1.05% | 0.70% | 0.69% |

5.15 Given there appears to be only a small difference between population growth and household growth for the two submitters that raised the issue, we consider that population growth is a reasonable proxy for residential ICP growth.

5.16 In our view, forecasts of residential population growth are likely to be more reliable than using historical ICP growth to inform the likely trend in future ICP growth. This is because population forecasts will take into account information on future expectations of residential growth.

*Change in electricity use per residential user*

5.17 Electricity use per user may change over time. The trend will depend 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.

5.18 Distributors have argued that electricity use per residential user has declined in the recent past, and that the trend is therefore likely to continue. Both Unison Networks and Vector propose that the value is approximately -1.0%, while Wellington Electricity proposes a value of -2.8% for its network.[55] In addition, Powerco's view is that population growth now has less impact on electricity demand than it did in the past.[56]

55 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.

56 Refer: Powerco "Submission on Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper" 30 April 2014, paragraph 47.

5.19 However, our current view is that electricity consumption by the average residential user is unlikely to fall over the next 5-7 years. Electricity price increases are starting to moderate, economic activity is picking up, and electric cars are becoming viable. Taken together, our expectation is that electricity use per user is more likely to remain broadly constant.

5.20 We therefore invite evidence on the likely pattern of future trends, rather than historical analysis, and in the interim we have relied on an assumption that electricity use per residential user will remain broadly constant.

**Modelling revenue growth from industrial and commercial users**

5.21 Industrial and commercial users comprise a wide range of users in terms of their demand for energy and peak 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).

5.22 Box 5.3 sets out the formula for calculating the change in revenue from industrial and commercial users. We have not modelled industrial and commercial users separately because some distributors were unable to provide the split in revenue from commercial and industrial users in response to our information gathering request.

**Box 5.3: Change in revenue from industrial and commercial users**

Δ revenue due to industrial and commercial usage =

Δ real GDP
x
elasticity of revenue to GDP

5.23 We will investigate separate modelling of industrial and commercial users for our final decision. However, in order to separately model both user groups, we would require additional information from distributors. We therefore intend to request the information from distributors after our draft decision is published.

*Change in real Gross Domestic Product*

5.24 We used regional GDP growth for modelling revenue growth from industrial and commercial users.[57] By using a single driver for different types of quantities charged, we assume that economic growth increases revenue from charges based on maximum assessed or actual capacity demanded and energy consumption in the same proportion.

*Elasticity of revenue to Gross Domestic Product*

5.25 Similar to our approach for operating expenditure, we have undertaken econometric modelling to determine the relationship between GDP and line charge revenue for projecting industrial and commercial revenue. Based on this modelling, we determined that the elasticity of constant price revenue to GDP is 0.73, ie, a 1% change in real GDP is associated with a 0.73% change in industrial and commercial constant price revenue.[58]

5.26 For a discussion of our econometric modelling refer to Attachment C.

**Information sources for modelling of constant price revenue**

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

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57 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. However, more disaggregated data is likely to be highly unreliable. Refer: Wellington Electricity Lines Limited “Submission on issues paper on 2015-2020 Default Price-quality Path” 30 April 2014, p.10.

58 WELL submitted that our econometric modelling of GDP should not exclude electricity distributors that are exempt from price-quality regulation. However we consider that these exempt businesses may have different revenue incentives given their ownership structure which would likely bias our modelling. Refer: Wellington Electricity Lines Limited “Submission on issues paper on 2015-2020 Default Price-quality Path” 30 April 2014, p.11.

**Table 5.2: Information for modelling residential users**

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

**Table 5.3: Information for modelling industrial and commercial users**

| Item | Information used | Source |
|---|---|---|
| Δreal GDP | Supplier-specific forecast of regional GDP growth<br>Energy used by GXP | NZIER<br>Electricity Authority<br>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<br>Historic information on real GDP and line charge revenue | Section 53ZD information requests<br>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 and Commission calculations |

# 6. Disposed assets and other regulated income

**Purpose of chapter**

6.1 This chapter outlines and explains the approach we propose to use 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 RAB when rolling forward the RAB value.

6.3 Often, a distributor will make a loss on disposal of an asset, eg, 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 draft 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 2010 and 2013. The value of disposals is the average of constant price historic disposals from 2010 to 2013, 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.

*Forecast of losses on disposal*

6.6 To forecast losses on disposal, our underlying assumption is that disposed assets will be sold for 11% of their regulatory net book value. This reflects an industry-wide average of losses on the sale of assets in proportion to disposals of 89%.

6.7 We propose to include 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 occurs. 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.

6.8 We note, however, that it is difficult to determine to determine a forecast of losses on disposal, and distributors have some control over whether to dispose of an asset or retain it in their possession. Consequently, we intend to propose an amendment to input methodologies that would help remove the risk of forecasts differing from actual disposals.

**Other regulated income**

6.9 Our modelling requires a nominal forecast of other regulated income from 2014 to 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.

6.10 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.

6.11 We used the arithmetic average of each distributor's historical other income as a forecast, scaled up for the effects of inflation. In the absence of a sensible alternative, we consider that the historic average is likely to provide the best guide to the future.

# 7. How you can provide your views

**Purpose of this chapter**

7.1 This chapter outlines the timeframes, address, and format for responses, as well as explaining how submissions can be made on a confidential basis.

**Responding to this paper**

7.2 As noted in the Introduction, we welcome your views on any aspect of this paper and the paper that outlines and explains the default price-quality paths that we propose to put in place from 1 April 2015 (Main Policy Paper).[59] We also invite you to provide any other material that you think should be considered in reaching our final decision.

*Timeframes for responses*

7.3 We welcome your views in the timeframes set out below.

7.3.1 Submissions are due by **15 August 2014**.

7.3.2 Cross-submissions are due by **29 August 2014**.

7.4 Material provided outside of the timeframes shown may not be considered in reaching our final decision. Any requests for extensions to the timeframe for providing a submission on this process should be provided for consideration, by using the address shown below.

*Address for responses*

7.5 Responses to this paper should be addressed to:

John McLaren (Chief Advisor, Regulation Branch)
c/o regulation.branch@comcom.govt.nz

*Format for responses*

7.6 We prefer responses in a file format suitable for word processing, rather than the PDF file format.

[59] Commerce Commission "Proposed default price-quality paths for electricity distributors from 1 April 2015" (4 July 2014).

*Requests for confidentiality*

7.7 We encourage full disclosure of submissions so that all information can be tested in an open and transparent manner. However, if it is necessary to include confidential material in a submission, we offer the following guidance:[60]

7.7.1 Both confidential and public versions of the submission should be provided; and

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

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

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60 You can also request that we make orders under s 100 of the Act in respect of information that should not be made public. Any request for a s 100 order must be made when the relevant information is supplied to us, and must identify the reasons why the relevant information should not be made public. We will provide further information on s 100 orders if requested by parties. A benefit of such orders is to enable confidential information to be shared with specified parties on a restricted basis for the purpose of making submissions. Any s 100 order will apply for a limited time only as specified in the order. Once an order expires, we will follow our usual process in response to any request for information under the Official Information Act 1982.

# 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. The result of our modelling is used to forecast operating expenditure in Chapter 3 of this report.

## Overview

A2 This attachment:

A2.1 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;

A2.2 gives an overview of our approach to our econometric modelling;

A2.3 summarises the data that we used in our analysis and the observations that have been excluded;

A2.4 provides more detailed results of our econometric modelling; and

A2.5 summarises the peer review that has been done on our modelling

## Summary of results

A3 We modelled network operating expenditure and non-network operating expenditure separately, consistent with the previous reset with updated 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 0.45%. 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%.

A6 A summary of the results are shown in Table A1.

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

| | **Network opex** | **Non-network opex** |
|---|---|---|
| ln (network length) | 0.451*** | |
| ln (number of connections) | 0.490*** | 0.821*** |
| Constant | -0.459* | 0.047 |
| Adjusted $R^2$ | 0.89 | 0.91 |
| F-statistic | 686.7 | 2165.9 |
| N | 113 | 112 |

Notes: *** significant at 1% confidence level. Models have been estimated using heteroscedasticity-robust standard errors.
Source: Commission analysis

### Overview of our approach

A7 The purpose of our econometric modelling is to establish what the relationship is between operational expenditure and scale factors. 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.

A8 We consider that it is appropriate to model network and non-network operating expenditure separately as they are driven by different factors.

A9 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.

A10 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.

A11 The split into network and non-network opex, and the explanatory factors we have identified for each type of opex are intuitive.

A11.1 Network opex, 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:

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

A11.2 Non-network opex (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:

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

A12 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 elasticity's are what are required for network and non-network operating expenditure to project the growth in operating expenditure for the 2015-2020 regulatory period, as discussed in Chapter 3.

A13 We have tested a range of regressions and diagnostic tests to assess the robustness of our modelling.[61]

**Data used for modelling**

A14 All electricity distributor specific information was obtained from their information disclosures, including network and non-network operating expenditure, network line length, number of connection points, and other possible explanatory variables tested in our modelling.

A15 Labour cost indices and producer price indices were supplied by NZIER. These indices were used to convert nominal operating expenditure into constant prices.

A16 We used data from 2010 to 2013 for the model as these are the years for which we have reliable information on network and non-network operating expenditure. We will update our regression to incorporate 2014 data once it is available.

61 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.

A17 We have undertaken data cleaning on the information disclosure data. This process includes:

A17.1 Aurora Energy's network line length has been adjusted for 2010 to 2012 as dedicated street lighting appears to have been included for these years;

A17.2 Powerco's network line length has been adjusted for 2010 to 2012 as dedicated street lighting appears to have been inconsistently treated;

A17.3 The Lines Company's network line length for 2011 spiked has been adjusted for 2010 to 2012 to equal the 2013 value after following this up with The Lines Company;

A17.4 Removing Orion from the modelling for 2011 given the distortionary impact of the major earthquakes in their network zone that financial year; and

A17.5 Removing outliers discovered during the modelling process.[62] Consequently Nelson Electricity for 2011 and 2012 were considered outliers in our network operating expenditure model. Also Buller Electricity observations were removed from our non-network operating expenditure model.

A18 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.

**Results of modelling operating expenditure**

A19 We have explored alternative models including different measures of scale and other potential opex drivers, and assessed the statistical robustness of the results and the intuition of the resulting coefficients.[63]

*Network operating expenditure*

A20 Frontier Economics considered incorporating a customer density explanatory variable in addition to the number of connections. While they recognise that algebraically their preferred model is identical to our model, they argue that it is a superior specification.[64]

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[62] 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. We considered an outlier to be any observation that met three out of the four tests.

[63] Refer to the accompanying do-file for further details of our alternative scenarios.

[64] Refer to 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, pp 28 to 30.

A21 Given we seek to estimate network operating expenditure elasticities, we consider the existing specification is more transparent. Frontiers suggested specification would involve further algebraic steps to calculate the required elasticities. Frontier Economics suggested that Nelson Electricity and Buller Electricity be excluded as they have the smallest network and smallest number of ICPs, respectively.

A22 We consider that this approach for exclusion is statistically unsupported. We therefore propose leaving Nelson Electricity and Buller Electricity as part of the sample.

A23 Table A2 compares the results of our preferred model and Frontier Economics preferred model. We note that Frontier's preferred model that excludes Nelson Electricity and Buller Electricity is accounted for in this comparison.

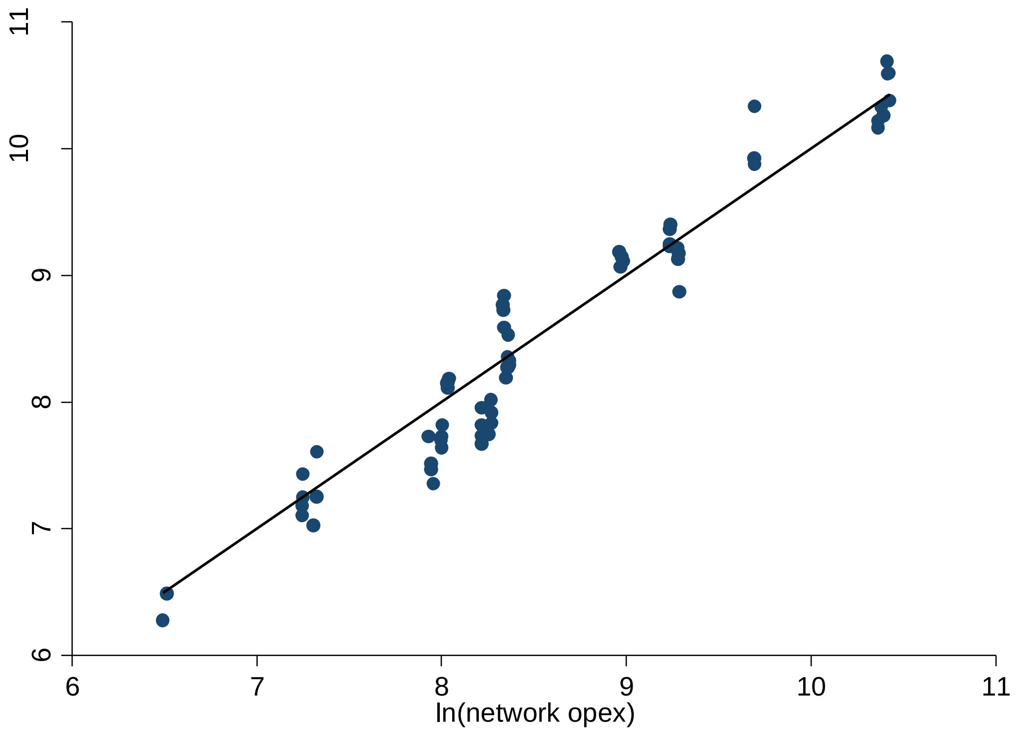
**Table A2: Network operational expenditure econometric results**

| | **Commerce Commission** | **Frontier Economics** |
|---|---|---|
| ln (network length) | 0.451*** | 0.980*** |
| ln (number of connections) | 0.490*** | |
| ln (customer density) | | 0.480*** |
| Constant | -0.459* | -0.763 |
| Adjusted $R^2$ | 0.89 | 0.868 |
| AIC | 72.3 | 70.5 |
| BIC | 80.5 | 78.5 |
| F-statistic | 686.7 | 594.2 |
| N | 113 | 107 |

Notes: *** significant at 1% confidence level. Models have been estimated using heteroscedasticity-robust standard errors. Frontier Economics' model also excludes Nelson Electricity and Buller Electricity.
Source: Commission analysis

A24 Figure A1 illustrates how well our model fits network operating expenditure with actual data between 2010 and 2013.

**Figure A1: Predictive power of our network operating expenditure model**




*Note: For readability, the graph does not start at zero.*
*Source: Commission analysis*

*Non-network operating expenditure*

For non-network operating expenditure, Frontier consider including a measure of network density in addition to ICPs. In effect, this is equivalent to adding network length to our approach. We note that the goodness of fit parameters (ie, the AIC and BIC) both prefer our current approach.

A25 Frontier argues for the inclusion of their network density measure based on their view that a regulatory model should lean towards including more cost drivers, if this can be justified statistically. We note that the adjusted $R^2$ (which places the little weight on parsimony) prefers our approach to modelling non-network operating expenditure.[65]

65 Refer to 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, pp 28 to 30.

A26 Frontier Economics suggested that Nelson Electricity and Buller Electricity be excluded as they have the smallest network and smallest number of ICPs, respectively.[66]

A27 We consider that this approach for exclusion is statistically unsupported. We therefore propose leaving Nelson Electricity and Buller Electricity as part of the sample.

A28 Table A3 compares the results of our preferred model with Frontier Economics preferred model and our model consistent with our specification for network operating expenditure. We note that Frontier's preferred model that excludes Nelson Electricity and Buller Electricity is accounted for in this comparison.

**Table A3: Non-network operational expenditure econometric results**

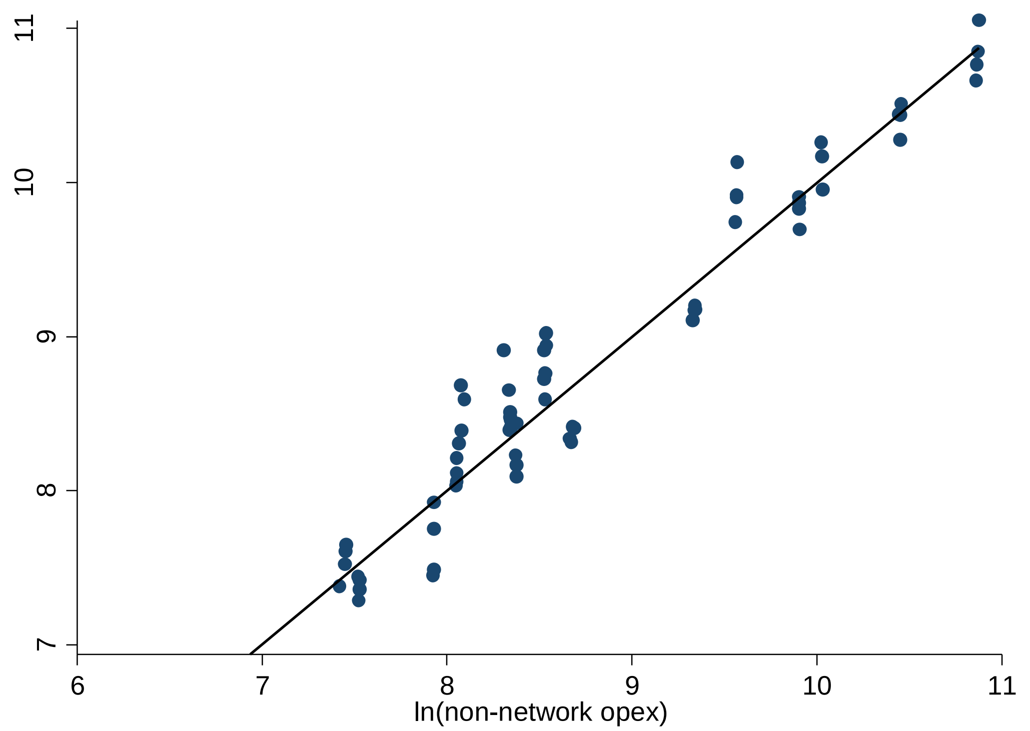
| | **Commerce Commission** | **Frontier Economics** | **Commission (incl. length)** |
|---|---|---|---|
| ln (network length) | | 0.884*** | 0.106*** |
| ln (number of connections) | 0.821*** | | 0.735*** |
| ln (customer density) | | 0.699*** | |
| Constant | 0.047 | -0.200 | 0.090 |
| Adjusted $R^2$ | 0.911 | 0.897 | 0.908 |
| AIC | 34.15 | 41.55 | 36.40 |
| BIC | 39.59 | 49.57 | 44.58 |
| F-statistic | 2165.9 | 883.7 | 879.23 |
| N | 112 | 107 | 113 |

Notes: *** significant at 1% confidence level. Models have been estimated using heteroscedasticity-robust standard errors. Frontier Economics' model also excludes Nelson Electricity and Buller Electricity.
Source: Commission analysis

A29 Figure A2 illustrates how well our model fits non-network operating expenditure with actual data between 2010 and 2013.

66 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 27.

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




*Note: For readability, the graph does not start at zero.*
*Source: Commission analysis*

**External review of econometric modelling**

A30 Jeff Borland has acted as an external reviewer and consultant on our econometric modelling. Mr Borland's report to the Commission is published alongside this draft decision.[67]

A31 Mr Borland's report is generally supportive of our proposed approach to modelling network and non-network opex. We have taken Mr Borland's report into consideration when making our draft decision.

[67] Refer to: Jeff Borland "Comments on NZCC approach for forecasting opex" 26 June 2014.

# Attachment B: Changes in input prices

**Purpose of attachment**

B1 This attachment outlines and explains our proposed approach for forecasting changes in input prices for operating and capital expenditure.

**Changes in input prices for operating and capital expenditure**

B2 As noted in the previous chapters on forecasting operating and capital expenditure, we propose to forecast changes in input prices:[68]

B2.1 For operating expenditure, by relying on independent forecasts of changes in the all industries Labour Cost Index (LCI) and Producer Price Index (PPI), with a weighting of 60% on labour inputs, and 40% on non-labour inputs; and

B2.2 For capital expenditure, by relying on independent forecasts of changes in the all industries CGPI.

B3 In the sections that follow, we explain our reasons for proposing to rely:

B3.1 On indices that reflect changes across all industries, rather than changes that are more sector specific; and

B3.2 On a 60:40 weighting for labour and non-labour operating inputs.

B4 We also explain our reasons for rejecting the option of relying on an average of a number of different forecasts.

[68] The New Zealand Institute of Economic Research (NZIER) provided forecasts of these indices. Under commercial terms between the Commission and NZIER, 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*

B5 For operating expenditure, the NZIER's forecasts of input prices translate into an annual average growth rate of 2.3% between 2014 and 2020. This assumption appears reasonable based on the input price forecasts implied by each distributor's forecast of operating expenditure. In particular:

B5.1 9 out of 16 distributors forecast less growth in input prices than the NZIER; and

B5.2 7 out of 16 distributors forecast higher growth in input prices than the NZIER.

B6 For capital expenditure, the NZIER's forecasts of input prices translate into an annual average growth rate of 2.0% between 2014 and 2020. Again, this assumption appears reasonable based on the input price forecasts implied by each distributor's forecast of capital expenditure. In particular:

B6.1 2 out of 16 distributors forecast less growth than the NZIER;

B6.2 9 out of 16 distributors forecast 0.25 percentage points higher growth than the NZIER;[69] and

B6.3 5 out of 16 distributors forecast in excess of 0.25 percentage points higher growth than the NZIER.

B7 The forecasts provided by the NZIER therefore appear reasonable relative to the forecasts implied by distributor forecasts of expenditure.

[69] Applying an input price assumption of 2.25% for capital expenditure instead of 2.0% results in a very small change in the amount of revenue allowed over a regulatory period (approximately 0.1% impact on revenue allowed in present value terms over the regulatory period).

*All industries indices versus sector specific indices*

B8 A number of distributors have argued that sector specific indices should be used instead of changes in the indices for all industries.

B8.1 Frontier's 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;[70] and

B8.2 A number of submitters, including Wellington Electricity and Unison support moving to away from the all industries LCI to take into account sector specific labour costs.[71]

B9 In our view, however, it is appropriate to rely on forecast changes in input prices across all industries, because:

B9.1 The changes in the all industries index are less dependent on the behaviour of regulated suppliers;

B9.2 It can be difficult to calculate and verify weights for composite indices;[72] and

B9.3 In any event, the all industries index generally provides a good proxy for sector-specific indices, which are harder to predict individually.[73]

B10 Figure B1 provides a comparison of the forecast change in:

B10.1 The labour cost index for all industries; and

B10.2 The labour cost index for electricity, gas, water and waste water.

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70 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.

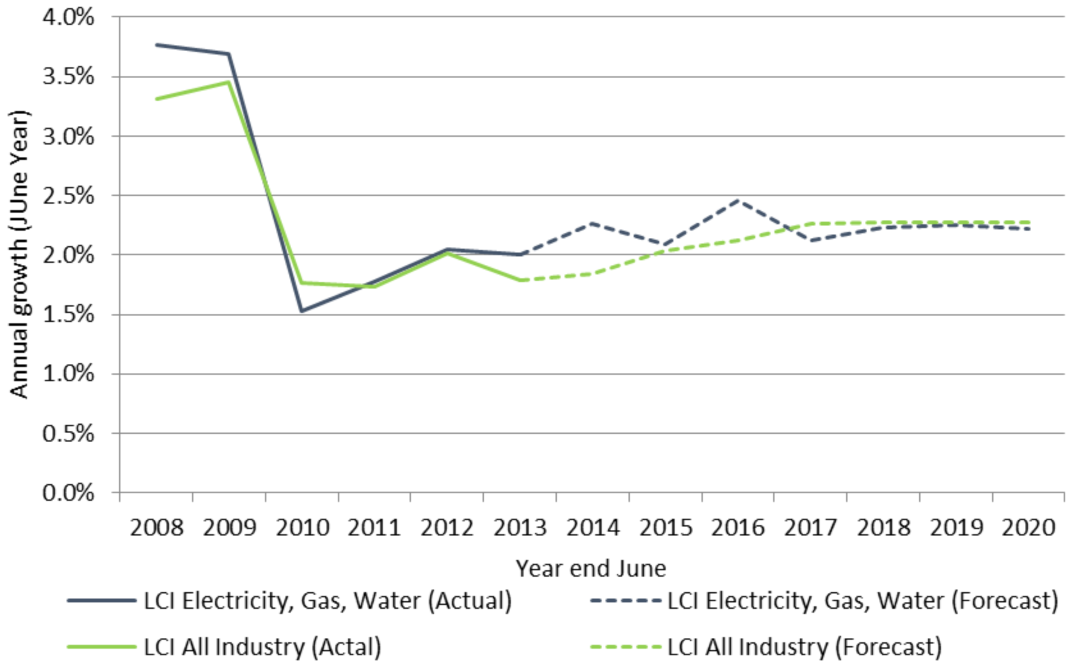
71 Wellington Electricity Lines Ltd, *Issues paper on 2015-2020 Default Price-quality Path*, 30 April 2014 and Unison Network Ltd, Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper, 30 April 2014.

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

73 Commerce Commission "Setting default price-quality paths for suppliers of gas pipeline services" (28 February 2013), paragraph C27.

B11 The geometric mean of forecast changes in the labour cost index for all industries is 2.2% over 2015-2020, while for electricity, gas, water and waste water the forecast change is also 2.2%. In addition, the historic average percentage point difference between the actual all industries labour cost index and the sub-industry labour cost index (electricity, gas, water and waste water) is around 0.14% from 2008 to 2013.

**Figure B1: Labour Cost Index – all industries vs. electricity, gas, waste and wastewater**




B12 The small materiality of the difference between the all industries LCI and the sector specific LCI, together with the concerns outlined above, means that we believe using the all industries would be most appropriate for the default price-quality path reset.

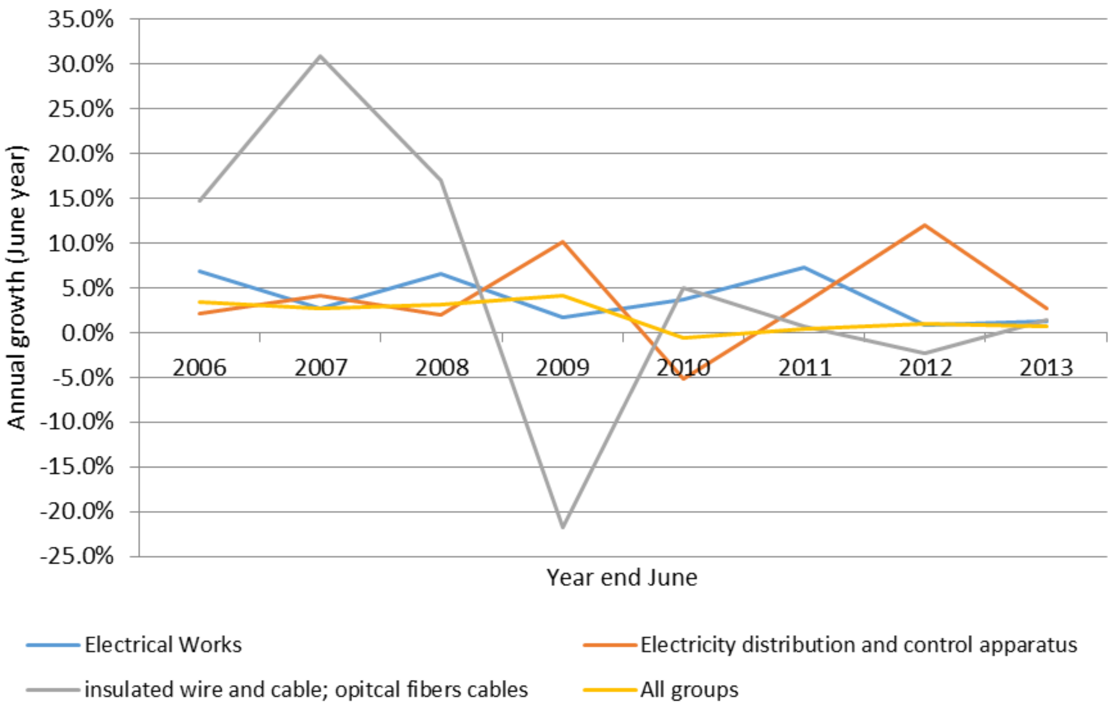
B13 This approach is supported by Vector, who suggest that for this reset:[74]

> Although using more industry specific PPI 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.

[74] Vector, *Submission to Commerce Commission on the Default Price-Quality Paths from 1 April 2015: Process and issues paper,* 30 April 2014.

B14 Figure B2 shows similar analysis for capital expenditure, which shows a historical time series of each of the capital goods price index and various sub-indices considered by Frontier (on behalf of the ENA). Frontier 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.[75]

**Figure B2: Capital Goods Price Index – all groups and sub-indices**




[75] 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 CGPI labelled: electrical works; electricity distribution and control apparatus; insulated wire and cable, and optical fibre cables.

B15 A number of submitters, including Frontier (on behalf of the ENA), recommended a composite index for capital expenditure using a combination of separate capital goods sub-indices or separate price forecasts of raw inputs (copper, aluminium, steel, etc.):

B15.1 Frontier suggest the composite index for network capital expenditure should be based on three asset specific capital goods price index sub-indices, and benchmarking non-network capital expenditure against the all industries capital goods price index; and[76]

B15.2 Wellington and Unison consider the all groups capital goods price index is not reflective of industry specific cost changes and support the development of composite indices.[77]

B16 We have considered these submissions, but remain unconvinced that moving away from the all industries capital goods price index would be appropriate for the default price-quality path because: [78]

B16.1 There is no electricity distribution industry specific capital goods price index sub-index that covers all relevant asset groups;

B16.2 Development of a composite approach using a number of sub-indices or raw price inputs is likely to have a large degree of subjectivity in terms of forecasts and weightings. Neither forward-looking weights or data required to calculate historic weights, at an industry or distributor level, are readily available; and

B16.3 The materiality between using different options for capital expenditure cost escalation on starting price will be even less than that for operating expenditure, as it is the return on and of capital in the regulatory asset base only that is relevant to the starting price.

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76 Where: lines and cables category is benchmarked by the insulated wire and cable, and optical fibre cables CGPI; electricity distribution assets other than lines and cables are benchmarked by electricity distribution and control apparatus CGPI; and electrical works is benchmarked by the electrical works CGPI.

77 Wellington Electricity Lines Ltd, *Issues paper on 2015-2020 Default Price-quality Path*, 30 April 2014 and Unison Network Ltd, Submission on the Default Price-quality paths from 1 April 2015: Process and issues Paper, 30 April 2014.

78 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.

B17 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. For example, we applied a composite approach for the customised price-quality price path for Orion New Zealand, and it was proposed by Transpower New Zealand for the individual price-quality path.

*Weightings for labour and non-labour operating inputs*

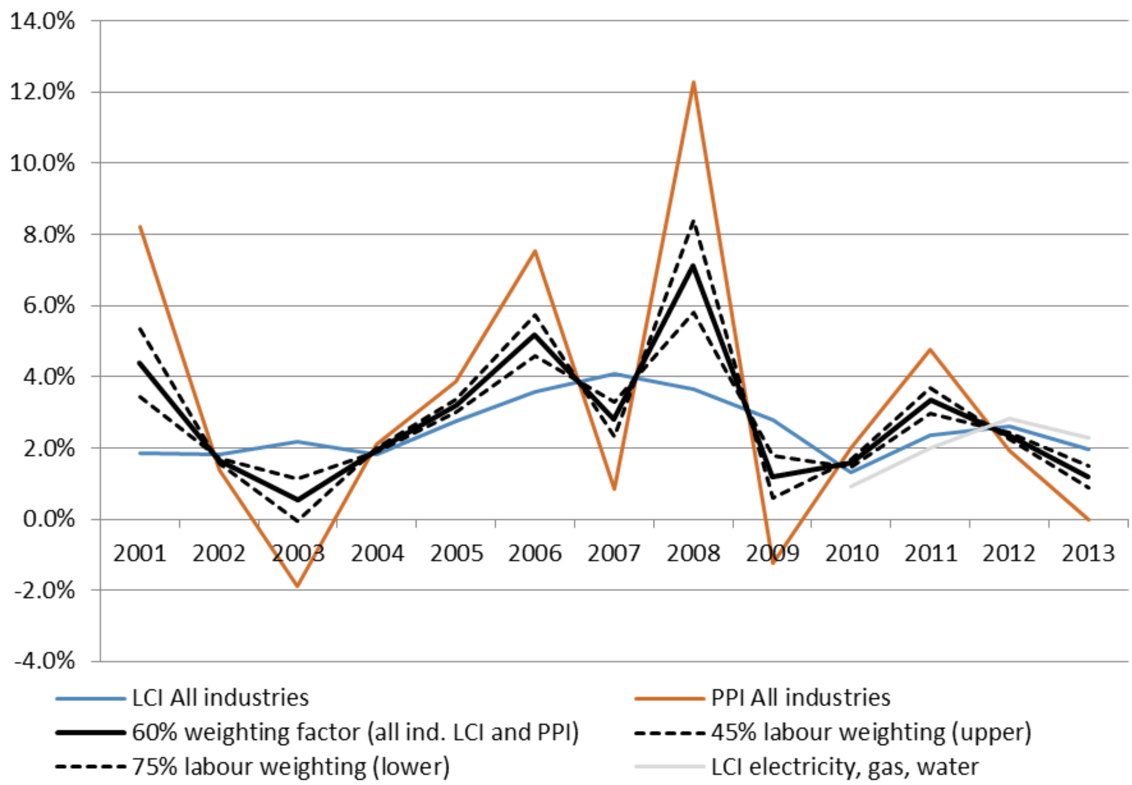
B18 We agree with Frontier (on behalf of the ENA) who suggest that the proposed 60:40 weighting for labour and non-labour operating inputs may not be ideal, but:

B18.1 We have no better information on the composition of each distributor's expenditure split between labour and non-labour operating expenditure; and

B18.2 A sensitivity analysis around the impact on the choice of weighting parameter does not raise serious concerns on the robustness of the parameter.

B19 Figure B3 provides a sensitivity analysis of the operating expenditure weighting parameter, using historic data. The graph shows historic all industries labour cost index and all industries producers price index and the weighted average using a 60/40 weighting, respectively. The labour cost index (electricity, gas, water and waste water) is also plotted for comparison.

**Figure B3: Sensitivity analysis of the operating expenditure weighting parameter**



B20 The dotted lines demonstrate the weighted average for a range of weighting factors, ±30% the 60% weight on labour costs. That is, the two dotted lines cover a 45/55 to 75/25 range of weightings between the all industries labour cost index and producers price index. Therefore, we do not consider that an alternative would be preferable to a 60/40 weighting, which reflects the best information available.[79]

*Averaging of different forecasts*

B21 We propose to use forecasts from a single independent forecasting agency. Our view is that forecast averaging does not guarantee improved forecast accuracy. Distributors are able to provide alternative forecasts as part of their submissions on our draft decision.

B22 Horizon and PWC had submitted that they support averaging forecasts from different sources as this may reduce forecasting error.[80] PWC noted the global economy is undergoing an unpredictable recovery which creates greater uncertainty in many of the underlying inputs to cost escalation.

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[79] The 60:40 weighting was used in the November 2012 reset was based on an analysis of labour expenditure by Australian distributors as no data was available for New Zealand: 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.

[80] Horizon Energy, *Submission on the Default Price-Quality Paths from 1 April 2015 for 17 Electricity Distributors: Process and Issues Paper*, 24 April 2014 and 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.

# Attachment C: Econometric analysis of constant price revenue growth

### Purpose of attachment

C1 This attachment outlines and explains our approach to modelling the relationship between line growth revenue and GDP. The result of our modelling is used to forecast commercial and industrial constant price revenue in Chapter 5 of this report.

### Overview of this attachment

C2 This attachment:

C2.1 summarises the results of our econometric modelling of line charge revenue to GDP;

C2.2 gives an overview of our approach to our econometric modelling;

C2.3 summarises the data that we used in our analysis;

C2.4 summarises what data we excluded from our model and the reasons;

C2.5 provides more detailed results of our econometric modelling; and

C2.6 summarises the peer review previously done on our modelling.

### Summary of results

C3 Our preferred model estimates that a 1% increase in real GDP is associated with a 0.73% increase in line charge revenue.[81] Using our preferred dataset, and alternative model specifications, resulted in a range of estimates between 0.72 and 1.22.

### Overview of our approach

C4 The purpose of our econometric modelling is to establish what the relationship is between constant price revenue from commercial and industrial users and real GDP. This relationship is expected to be positive, for example, it is expected that growth in real GDP will also result in growth in commercial and industrial energy use and revenues.

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[81] Our preferred model is the random effects model for cross sections, consistent with the model used for the 2012 decision.

C5 We do not have any information on constant price revenue. We have relied on line charge revenue, provided by information disclosures, as a proxy for constant price revenue.

C6 We have regressed the relationship between the natural logarithm of real GDP and the natural logarithm of real line charge revenue. This can be interpreted as the elasticity of real GDP to real revenue. This is what is required to forecast the constant price revenue growth for the 2015-2020 regulatory period, as discussed in Chapter 5

C7 We have tested a range of econometric 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.

C8 The use of panel data allows us to estimate and test for robustness for a range of model specifications.[82]

**Data used for modelling**

C9 Line charge revenue was obtained from the distributors information disclosures and was converted to constant prices using the CPI. We note that:

C9.1 Ideally, we would use line charge revenue specifically relating to commercial and industrial user groups;

C9.2 For the 2012 reset we requested commercial and industrial user disaggregated information from electricity distributors. However, a dataset of only two years and data anomalies restricted the usefulness of the model.

C9.3 We intend to request commercial and industrial user disaggregated information from distributors before our final decision. This will allow us to investigate the suitability of modelling commercial and industrial users, both combined and separately, with a larger dataset.

C10 We used real GDP data sourced from NZIER at a regional level for our econometric modelling. These regions were generally mapped to each electricity distributor based on the location of grid exit points as explained in Chapter 5.[83]

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82 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.

83 NZIER have noted that there were errors in the regional real GDP data series that was provided and have provided us a corrected series. However, we did not have time to incorporate this in our econometric modelling for this paper.

C11 Statistics New Zealand supplies a nominal regional GDP series which we may consider for the final decision. While this series is shorter and presented in nominal terms, we consider that this may be more appropriate as it is an official source. We have identified two approaches we could consider for using the Statistics New Zealand nominal series:

C11.1 The series could be converted to real GDP using a national deflator; or

C11.2 modelled with nominal line charge revenue.

C12 We used data from 2004 to 2012 as the data required for the model was available consistently for these years. Preferably 2013 and 2014 will be included, however, at this stage we do not have information on line charge revenue net of discretionary discount and customer rebates for 2013.

**Excluded observations in our model**

C13 We have excluded some observations from our modelling. In summary, these are:

C13.1 Orion in 2011;

C13.2 Wellington Electricity up to 2009;

C13.3 Vector Lines for all years;

C13.4 OtagoNet for all years; and

C13.5 All electricity distributors that are exempt from price-quality regulation.

C14 We consider that it is not appropriate to include Orion in 2011 in the model. They were struck by three major and several minor earthquakes in the 2011 financial year which may bias the modelling given the impact on revenues.

C15 Wellington Electricity was established in 2009. We consider that as 2010 was the first full financial year for Wellington Electricity it is appropriate to remove all years before this.

C16 We originally excluded Vector for two years only, 2008 and 2009, due to likely distortionary impact the sale its Wellington network would have. However, we have removed all other Vector observations as these are considered outliers.[84]

[84] 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. We considered an outlier to be any observation that met three out of the four tests.

C17 Our exploratory analysis of the relationship between GDP growth and revenue growth for distributors shows that OtagoNet is anomalous. We therefore consider it appropriate to exclude OtagoNet from our model as its inclusion distorts the results significantly.[85]

C18 Wellington Electricity submitted that there is no reason to exclude distributors exempt from price-quality regulation from our modelling. However we consider that these exempt businesses may have different revenue incentives given their ownership structure which would likely bias our modelling.[86] Furthermore, we ideally would model commercial and industrial line charge revenue, for we would not be able to get data on from exempt distributors.

**Results of modelling constant price revenue growth**

C19 This section presents the results for our modelling. In summary:

C19.1 We were able to identify the most robust models using the information disclosure revenue variable;

C19.2 Our preferred model has an estimated constant price revenue to GDP elasticity of 0.73. That is, a 1% increase in real GDP is associated with a 0.73% increase in revenue. Using alternative model specifications resulted in a range of estimates between 0.72 and 1.22. Some of these estimates are statistically robust results, others are not; and

C19.3 We identified data observations from Vector and OtagoNet that that had influenced the statistical robustness of the results and we excluded these from the model. As discussed above, we also excluded Orion in 2011 and Wellington Electricity in 2009 from the estimation.

*Results of modelling revenue from information disclosures*

C20 Table C1 summarises results of modelling revenue from information disclosures.

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85 We also excluded Aurora Energy at the previous reset for the same reason, however, with updated data, we no longer consider their observations to be anomalous.

86 Refer: Wellington Electricity Lines Limited “Submission on issues paper on 2015-2020 Default Price-quality Path” 30 April 2014, p.11.

**Table C1: ID revenue econometric modelling results**

| Item | Pooled model | Fixed effects model | | Between effects model | | Random effects model | |
|---|---|---|---|---|---|---|---|
| | | Cross-sections | Time | Cross-sections | Time | Cross-sections | Time |
| ln GDP | 0.75*** | 0.72*** | 0.74*** | 0.87* | 1.22*** | 0.73*** | 0.75*** |
| Constant | 3.88*** | 4.14*** | 3.93*** | 2.84 | -0.29 | 4.07*** | 3.88*** |
| $R^2$ | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 |
| $F/\chi^2$ stat | 25.0 | 29.6 | 3.7 | 4.0 | 23.4 | 33.8 | 25.0 |
| N | 127 | 127 | 127 | 127 | 127 | 127 | 127 |

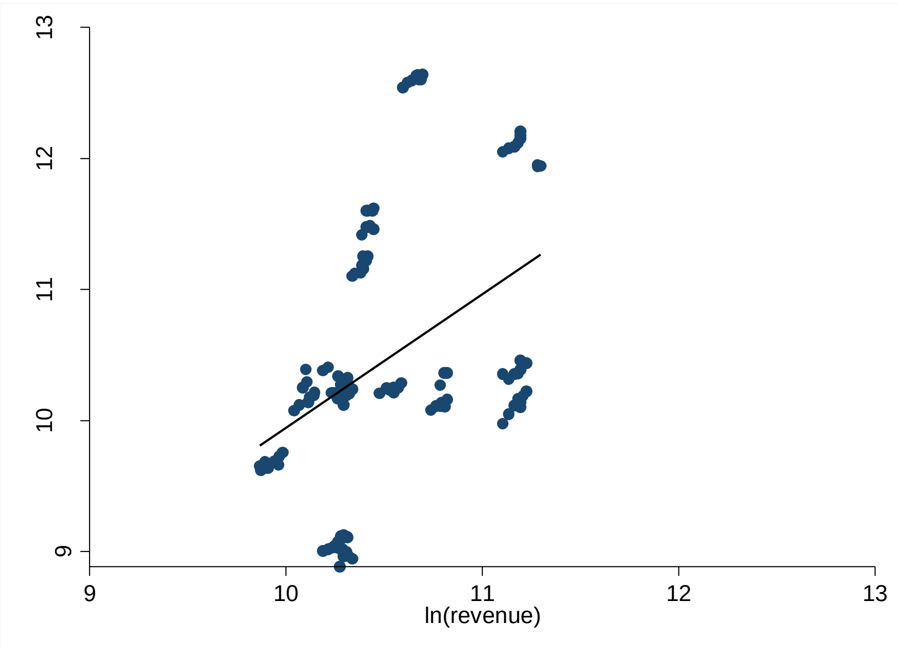
Notes: *** significant at 1% confidence level; **significant at 5% confidence level; * significant at 10% confidence level

Source: Commission analysis

C21 The signs of the estimated coefficient of the relationship between GDP and revenue confirm the findings in the exploratory analysis that the relationship is positive. The estimates are in the range of 0.72 to 1.22. As the variables are measured in logs the coefficient estimate can be interpreted as an elasticity, eg, the pooled model indicates that a 1% change in GDP is related to a 0.75% change in revenue.

C22 Figure C1 illustrates how well our model fits revenue with actual data between 2004 and 2012.

**Figure C1: Predictive power of our non-network operating expenditure model**




*Note: For readability, the graph does not start at zero.*

*Source: Commission analysis*

C23 The estimated relationships are statistically significant (based on the F-statistics) in all models except for the between effects models. We therefore cannot rely on the model specifications for between effects model for time effects.

C24 Our testing indicates that the most robust models are the random effects model for cross-sections of suppliers and time effects, ie, 0.52 (cross-sections) and 0.64 (time effects). These models have been chosen based on the results of a number of statistical tests.[87] On balance, our preferred model is the random effects model for cross-sections

C25 A key assumption for the estimates to be unbiased is that the error needs to be random and uncorrelated with the explanatory variable. There is no evidence that this was an issue with our preferred model.

C26 The random effects models for cross-sections of suppliers assumes that there is unobserved individual heterogeneity between suppliers. As illustrated in the scatter plot most of the variation is between suppliers, ie, cross-sectional, rather than over time.

[87] Refer to the model do-file accompanying this paper.

# Attachment D: Timing assumptions

### Purpose of attachment

D1 This attachment outlines and explains the timing assumptions used to calculate present values when determining starting prices.

### Our assumptions improve the accuracy of our modelling

D2 Timing assumptions are required to recognise that distributors incur and receive cash flows continuously throughout the year. These assumptions are reflected in the 'timing factors' we have included in the formula used to calculate the revenue each distributor should be allowed to recover based on our estimate of their building block costs.

D3 To improve the accuracy of our modelling, we have made the following assumptions.

D3.1 Operating expenditure is incurred mid-year, on average. 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.

D3.2 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.

D3.3 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.[88]

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[88] Powerco submitted that there is a disjoint between the mid-year timing assumption for tax payable and the year-end timing assumption for the increase in deferred taxation. See Powerco "Submission on the Revised Draft Reset of the 2010-15 Default Price-Quality Paths",1 October 2012, p.15. However, we note that, unlike an estimate of the tax payable by a business, the increase in deferred taxation is not an estimate of a cash flow item. The important point is that we have implemented the deferred tax approach in a way that is NPV neutral to the business.

D3.4 Revenue is received on 3 November, on average. Revenue from lines charges are expected to be received on the 20th of the following month. Assuming that revenues are received in equal increments throughout the year is equivalent to assuming that all revenues are received slightly later than mid-year on average, ie, on 3 November rather than 31 September.

D3.5 Other income is received mid-year, on average. This assumption is made for simplicity, because seasonality cannot be reliably forecast.

D4 On 24 June 2014, we proposed to amend input methodologies to apply a mid-year cash flow timing assumption to the calculation of notional deductible interest amounts.[89]

D5 Mid-year timing assumptions recognise that suppliers will pay interest during the year, and the amount paid will be less than if payments were to be made at year-end. An amendment would also align the timing assumptions for the interest tax deductions with the mid-year timing assumptions adopted for other cash flows within the input methodologies.

D6 The mid-year timing assumption improves the accuracy of the treatment of regulatory tax adjustments

[89] Commerce Commission "Proposed amendments to input methodologies for Electricity Distribution Services" (24 June 2014), paragraphs 9-13.