From the Electricity Networks Association

Submission on low cost forecasting approaches for default price-quality paths

Final

15 August 2015

The Electricity Networks Association makes this submission along with the explicit support of its members subject to Default Price-Quality Path regulation, listed below.

Alpine Energy Ltd

Aurora Energy Ltd

Centralines Ltd

Eastland Network Ltd

Electricity Ashburton Ltd

Electricity Invercargill Ltd

Horizon Energy Distribution Ltd

Nelson Electricity Ltd

Network Tasman Ltd

Orion New Zealand Ltd

OtagoNet Joint Venture

Powerco Ltd

The Lines Company Ltd

Top Energy Ltd

Unison Networks Ltd

Vector Ltd

Wellington Electricity Lines Ltd

Contents

1. Introduction

1. The Electricity Networks Association (ENA) appreciates the opportunity to provide feedback to the Commerce Commission (the Commission) on the Forecasting Paper[1], supporting models[2] and accompanying Borland Paper.[3]

2. The ENA has also presented a related submission in response to the Commission's 2015 DPP Main Policy Paper.[4] We will also present submissions by 29 August on a number of other related consultations, which were published on 18 July 2014.[5]

3. The ENA represents the 29 electricity network businesses (ENBs) in New Zealand.

1.1 Summary

4. For the purpose of forecasting opex, the ENA:

   a) Does not support the use of FY13 as the base year for opex. We have previously endorsed an averaging of FY13 and FY14 to avoid the impact of year on year variation. Our analysis shows that maintenance opex was abnormally low in FY13, due to lower outages in that year. A FY13 base year therefore is inconsistent with the proposed quality standards as it does not provide for sufficient opex to maintain underlying reliability performance. To give high or sole weight to FY13 data would result in ENBs systematically being unable to recover their actual and reasonable opex costs over the next regulatory period.

   b) Notes that historical opex, expressed in constant scale and constant price terms, has increased since FY10. This trend is endorsed by EI and PEG who have both measured declining industry opex partial productivity in recent years.

   c) Acknowledges that inaccuracies in the scale and input price adjustments could also contribute to this outcome. Accordingly, the ENA submits that the scaling factors should be recast using FY14 data, to ensure they are as current as possible, and consideration should be given to using historical ICP data rather than population forecasts to generate ICP projections.

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[1] Commerce Commission, Low Cost Forecasting Approaches for Default Price-Quality Paths, 4 July 2014

[2] Models 1a, 1b, 2-5, 3, 4, 6a, 6b, 7, 8, 9, 10, 11, 14, 15 and 20 which are published at http://www.comcom.govt.nz/regulated-industries/electricity/electricity-default-price-quality-path/default-price-quality-path-from-2015

[3] Professor Jeff Borland, Comments on NZCC approach for forecasting opex, 26 June 2014

[4] Commerce Commission, Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015, 4 July 2014

[5] Refer: http://www.comcom.govt.nz/regulated-industries/electricity/electricity-default-price-quality-path/default-price-quality-path-from-2015

d) Submits that the evidence relied on by EI and the Commission in turn to disregard the negative productivity estimates is flimsy. The ENA submits that the opex productivity assumption has significant impact on the allowable revenue calculation and the onus is on the Commission to establish a robust case based on relevant, quantitative evidence to override the empirical results of the EI and PEG reports. In the absence of any such evidence negative productivity estimates for opex PFP and TFP should be adopted:

e) The ENA submits that the Commission should adopt a -2% per annum opex partial factor productivity, consistent with the evidence in the PEG report. The analysis of PEG should be preferred because it is consistent with the Commission's broader forecasting approach (e.g., use of all-industries LCI, and opex forecast drivers) whereas the EI analysis is not.

f) Submits additional opex allowances are provided for:

i. compliance costs not included in the base year opex, equivalent to 1 additional FTE (including on-costs) per ENB

ii. spur assets transferred within and after the base year and prior to the next regulatory period, to be derived from ENB forecasts.

5. For the purpose of forecasting capex for the 2015 DPP:

a) ENA members support using supplier's own forecasts of capex as the basis for determining the DPP forecast capex allowance.

b) The majority of non-exempt ENBs support the use of a cap on historical capex.

c) In relying on historical data, it is important to consider the relevant historical period, the regulatory rules which applied across that period, the proximity to the start of the next regulatory period, and innovation and efficiency gains. Not all of these factors are addressed in the proposal.

d) The ENA submits that in order to remove the inequities in the proposed approach:

i. the forecasting accuracy penalty is only applied where the ENB affected is unable to explain the difference between forecasts and actual, including with reference to changes in the regulatory reporting rules, changes in network investment strategy, efficiency gains and customer driven timing decisions

ii. the sliding scale cap on non network capex is removed because it unduly penalises ENBs with certain structural arrangements and network strategies.

e) In principle the ability or otherwise of a supplier to achieve capex efficiencies relative to the DPP assumptions, will be partly influenced by how realistic the DPP assumptions are in the first place for each supplier. The forecasting approach introduces some bias in this respect and ENA does not support a capex incentive mechanism that would merely carry-over forecasting error.

f) The ENA submits that the capex incentive mechanism retention factor should be set to 5% for actual capex within a band between the Commission's cap and the ENB's AMP forecast. Outside this band, the retention factor should be set to 10%.

g) The ENA supports approaches which improve the accuracy of the information used to set price caps, including making adjustments, where practicable for actual outturns in the year immediately prior to the regulatory period, such as proposed for commissioned assets.

6. The ENA continues to support further consideration of possible refinements to capex forecasting approaches, beyond those which are able to be implemented for the 2015 reset.

7. In order to establish price indices for opex and capex forecasts, the ENA recommends:

a) The Commission adds a wedge to NZIER's forecast of the LCI all industries forecast to reflect sector specific labour cost inflation.

b) The Commission pursues other improvements in input price forecasting prior to the next DPP reset, including using more industry- and asset-specific indices, applying composite escalators and combining the forecasts of more than one forecaster to reduce the risk of forecasting error.

c) In addition, the ENA requests that the Commission release the data underlying Figure B1 and explain the basis for the EGWW index forecast shown in this figure.

8. For the purpose of forecasting real revenue growth, the ENA:

a) Does not support the proposed approach to forecasting real revenue growth for the forthcoming regulatory period. We do not consider that the proposed model has performed well enough in the current regulatory period.

b) Recommends as an alternative, that real revenue growth is projected using actual historical trends for each non exempt ENB, and a volume wash-up is included at the end of the regulatory period to adjust for material forecasting errors.

c) Sapere Research Group has prepared a report for the ENA describing recent changes in consumer behaviour, particularly around increasing energy efficiency, that has driven the trends in residential energy use. Given the permanent changes to the behaviour of households demonstrated in the Sapere report, it is likely that consumption per household will continue to fall over the next regulatory period.

9. When forecasting asset revaluations, the ENA:

a) submits that the Commission should provide for a choice in the use of forecast or actual inflation in RAB roll-forward in the ID requirements. This choice should be certified by the respective Boards in advance, making those businesses accountable for their choices. As long as there is ex ante

commitment at the start of a regulatory period by ENBs to one method or the other, consumers should be indifferent to that choice.

10. In order to forecast other items, the ENA:

a) Supports the use of ENB specific historical data for forecasting asset disposals and other regulated income.

b) Notes that errors in the proposed inflation adjustments have been identified, and understands that these are to be corrected before the final price paths are determined.

c) Submits that a business specific gain/loss on disposal percentage should be derived from historical information which will better align with the disposal forecasts.

11. We provide more detailed comment on these points in the body of our submission.

12. The ENA's contact person for this submission is:

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2. Forecasting opex

2.1 Proposed approach

13. The proposed approach for forecasting opex is similar to that applied in the 2012 reset. The key elements include establishing a base year opex allowance for each ENB, and forecasting this for the next regulatory period using scale adjustments, an assumption regarding opex productivity changes expected during the next regulatory period, and forecasts of input price inflation.

14. Our comments on the proposed approach to establishing forecasts of input price inflation are included in Section 4 of this submission.

2.2 Initial level of opex

15. It is proposed that FY13 opex is used as the base year, from which forecasts of future opex are established. This approach is different to that proposed in the Process and Issues Paper which stated:

> *Our initial view is that it may be appropriate to use an average of 2012/13 and 2013/14 data to set the initial level of operating expenditure for the forthcoming reset. This is because we are concerned that the forecast of operating expenditure for 2013/14 may not represent distributors' future efficient operating expenditure. Distributors have forecast an increase in operating expenditure in 2013/14 relative to historic levels.*[6]

16. The ENA does not support the choice of FY13 as the base year. Our submission on the Process and Issues Paper endorsed the proposed approach to use an average of the FY13 and FY14 data (with scale and input price adjustments for FY13) to avoid anomalies which may be evident for some or all ENBs in either year.

17. As for all other forecasting methods, we support using the most up to date information available. We note that selecting FY13 as the base year is inconsistent with other forecasting methods, for example actual capex data for all years prior to the reset (including FY15) is to be used.

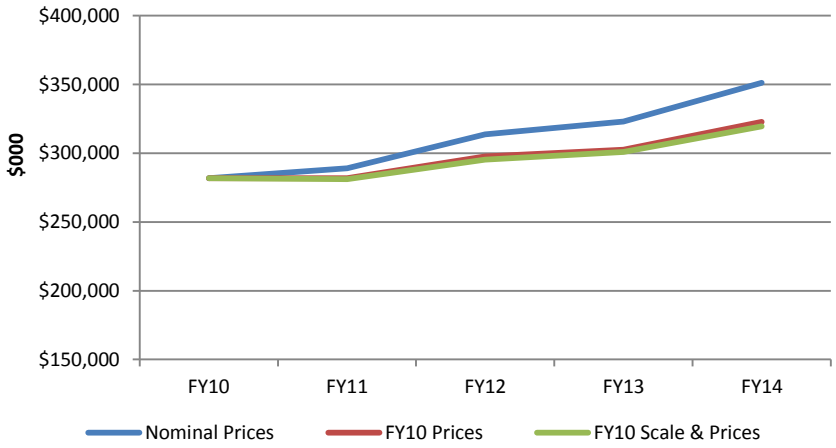
18. The Forecasting Paper suggests that it is not appropriate to use FY14 because FY14 estimates of opex suggest the year is atypical. While we acknowledge that for some ENBs, forecast FY14 opex exceeds FY13 actual opex (as illustrated in Figure 3.1 of the Forecasting Paper), we note that this trend does not apply to all, and the variance is relatively minor for some. As set out below there is clear evidence that it is FY13 opex which is atypical for many networks.

[6] Commerce Commission, Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues paper, 21 March 2014, A10

2.2.1 Historical opex

19. Examination of actual opex data[7] for non-exempt ENBs shows that, after adjusting for input price inflation and scale (using the same methods as proposed in the Low Cost Forecasting Paper), constant price, constant scale opex has increased for ENBs since 2010. This is illustrated in the chart below. This supports the opex partial productivity analysis findings of PEG and EI,[8] who have both identified declining opex productivity in New Zealand ENBs over the past decade.

Figure 1: Total Non-Exempt EDBs - Total Opex

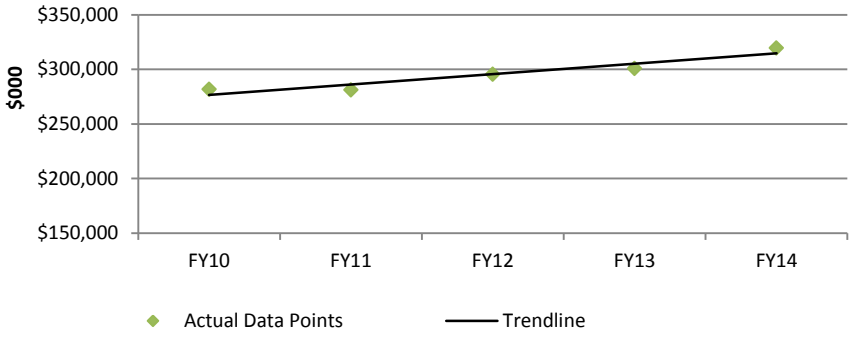


20. As stated above the choice of a base year for opex is an important assumption given the proposed opex forecasting method. A FY13 base year is proposed, however our analysis suggests FY13 is a low opex year, when considered against the FY10-FY14 trend, as illustrated overleaf.

[7] Data is sourced from ID disclosure datasets. Actual FY14 opex data was obtained directly from ENBs, and will shortly be disclosed as part of FY14 year end disclosures. All of the data presented in this section excludes Orion NZ.

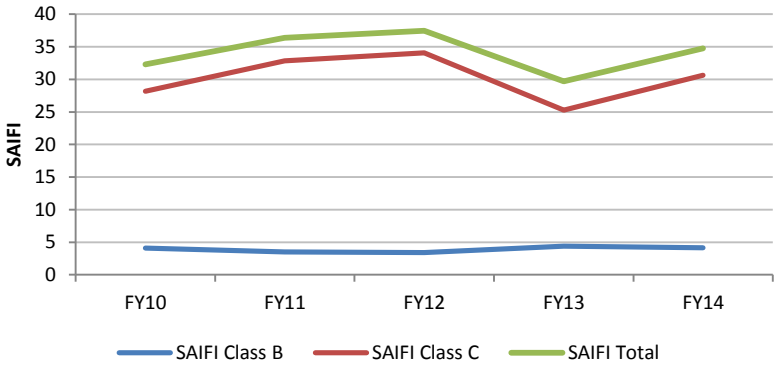
[8] Economic Insights, Electricity Distribution Industry Productivity Analysis: 1996-2013, 24 June 2014 and Pacific Economics Group, Productivity Trends of New Zealand Electricity Distributors, June 2014

Figure 2: Total Non-Exempt EDBs - Total Opex (FY10 Scale & Prices)



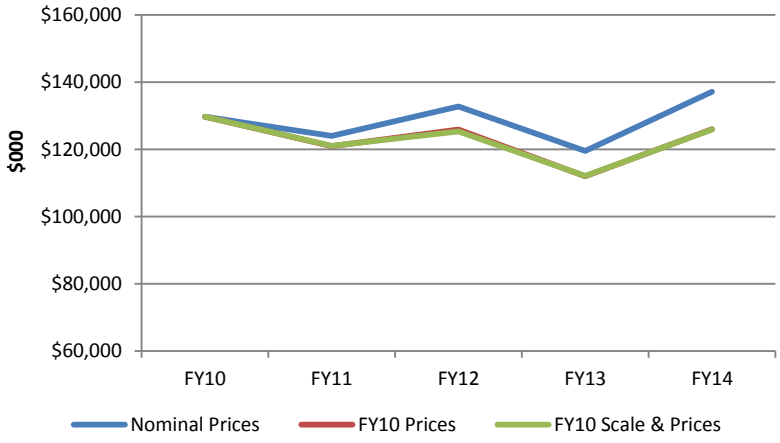
21. One of the key reasons for the lower opex in FY13 is that FY13 was an abnormally benign year for outages, as illustrated below.

Figure 3: Total SAIFI of Non-Exempt EDBs



22. This is reflected in abnormally low maintenance opex in FY13, which is illustrated below (in constant scale, constant price terms).

Figure 4: Non-Exempt EDBs - Total Maintenance Opex



23. We note that FY14 maintenance is back on trend, with similar levels to the years prior to FY13.

24. We recognise that at the time the Forecasting Paper was prepared, actual FY14 opex data was not available. This data will be disclosed by the end of August, and thus will be available for inclusion in the DPP financial models. We submit it should be because it is current and therefore relevant, and reasonable opex allowances are critical to ensuring ENBs are able to maintain quality of supply standards and their other supply obligations.

25. We submit that FY13 opex alone is not an appropriate base year estimate because it reflects abnormal circumstance, in particular unusually low outages in that year. Accordingly the ENA submits that FY14 data must be included in establishing the base opex position to address the year on year variation exhibited in the historical data. To give high or sole weight to FY13 data would result in ENBs systematically being unable to recover their actual and reasonable opex costs over the next regulatory period.

2.2.2 Incentive mechanisms

26. The Main Policy Paper proposes a revenue incentive scheme for quality of supply performance, and the IRIS Paper proposes an expenditure incentive scheme for opex and capex. These proposals are for symmetrical financial incentives which provide EDBs with additional revenue if:

a) actual expenditure falls below the expenditure allowance in the DPP

b) actual quality of supply performance is better than the target included in the DPP.

27. Under both proposals, suppliers incur a financial penalty if actual expenditure exceeds the DPP allowance, and/or actual quality of supply falls below the target.

28. It is the ENA's view that any such penalty is more likely to reflect the Commission's forecast error than ENB inefficiency. We comment further on the incentive mechanisms in our submissions on the specific papers relating to these matters.

2.3 Network scale adjustments

29. It is proposed that a similar approach is adopted for forecasting opex, as adopted for the 2012 DPP reset. Thus base year opex is rolled forward for the next regulatory period, in real terms after adjusting for the expected impact of changes in business scale. An econometric model has been developed for this purpose which suggests that opex will change by 0.45% for every 1% change in circuit kms and 0.49% for every 1% change in ICPs. For each ENB, changes in circuit kms and ICPs are estimated from historical circuit km data and regional population growth (for ICPs).

30. The ENA submits that prior to finalising the opex allowances:

a) The econometric modelling is updated with actual FY14 data

b) Consideration is given to replacing the population forecasts with extrapolation of ENB specific historical ICP data. This would align the projection methods

for the two scale drivers (circuit kms and ICPs). Our analysis suggests that population forecasts have not performed well as a predictor of ICP growth during the current regulatory period (refer to analysis presented in Section 5 of this submission).

31. The ENA notes that the Commission's scale adjustment model in combination with the assumption of zero partial opex productivity growth has led to poor forecast accuracy during this regulatory period. We note that the econometric review in the Borland Paper has not examined time series performance of the scale adjustment models, which is a significant deficiency in the forecasting framework

32. The ENA's view is that there are diverse, unmeasured drivers that have caused ENBs to expend more than what is implied by these two simplistic scale drivers, and this is captured in the difference between the higher rate of input growth relative to measured outputs growth, which is termed 'productivity'. We discuss this further in the next section.

2.4 Forecast change in partial productivity

33. We have included a substantive discussion of the Economic Insights (EI) report and the justification for negative values of productivity, both for the X factor (TFP) and in opex PFP in our submission on the Main Policy Paper. We have not repeated that discussion here. However we note that:

a) Both the EI and PEG reports note that ENBs' productivity has declined over the last decade at least. The only exception to this is EI's specification #1. PEG notes that this output specification is problematic from a conceptual and empirical perspective as it uses the same factor as both an input and an output, and the data is not consistent with the decline in demand over the last decade acknowledged by EI. The ENA submits that the Commission should not give weight to specification #1 in the EI report. We discuss the specification of outputs and input prices below.

b) The data shows that negative productivity is not unreasonable (inputs have consistently grown faster than outputs at an industry-wide level for the last decade).

c) Changes in the operating environment that are independent of output have occurred and are expected to continue, examples include changes in health and safety legislation, and expectations relating to quality.

d) Output growth has slowed and is not expected to recover markedly over the regulatory period.

34. PEG provides a comprehensive discussion of how to choose the specification of output and input prices in its review of the EI paper. PEG sets out in a clear and transparent manner the reasons why it is important to be consistent throughout the opex forecasting formula, and between the two productivity measures. None of the output specifications used by EI is consistent with the outputs that the Commission has indicated it will use to forecast opex. The decision by the Commission to use customer numbers and km of line to determine the scale effect in the opex forecast means that

opex PFP should be estimated using these two outputs. Ensuring this consistency, takes precedence over other principles, for setting output specification (such as not including unbilled outputs).

35. PEG explains that it is important to use only billed outputs to measure outputs for productivity purposes. If unbilled outputs (also called functional outputs) are included, output will grow faster leading to higher measured TFP growth and less rapid growth in prices. But these outputs that result in slower price growth cannot be billed and therefore will not generate revenue for the ENB. Increases in unbilled outputs can in part explain measured productivity declines if consumers demand changes to the service provided that increase costs but are not reflected in the way that the price is set (such as improvements in quality or higher health and safety standards).

36. EI's input prices are also not consistent with the input prices that the Commission has used to project opex. The Commission uses a weighted average of the PPI (all industries) and the LCI (all industries). EI uses the same PPI but the LCI for the Electric Gas Water and Waste sector to deflate opex and estimate opex input quantities. Since the LCI used by EI is higher than the all industries index, this will decrease measured growth in opex quantities, raising productivity growth, and therefore reducing the value of opex projected by the Commission. The inconsistency between the price indexes is likely to under-compensate ENBs for their expected changes in opex.

37. These inconsistencies between the EI output and input price specifications and the rest of the opex forecasting process suggest that the EI opex PFP and TFP estimates are too high (in the context of the price path). These differences and the slight differences in study period, explain why the PEG results are lower than those obtained by EI. The Commission has compounded this error by adjusting the empirical results up without any substantive justification.

38. As we note in our submission on the Main Policy Paper the Commission should set a value for productivity that is consistent with the empirical findings: the consequences of setting opex PFP too low (a delay in consumers benefiting from increases in productivity until the next regulatory period) are less serious than of setting productivity too high (ENBs are unable to attain the productivity 'expected' which means they systematically cannot cover their costs, and either need to inefficiently reduce expenditure to achieve the WACC, or apply for a CPP).

39. As we explained in our submission on the DPP decision, declining productivity is not the same as declining efficiency and is not necessarily something to be avoided. It simply shows that the ratio of outputs to inputs is falling. A key reason for the decline in productivity is changes in ENBs' operating environment that have driven cost increases, but no change in output. For example, most ENBs have a continuous improvement programme in relation to public and employee safety, driven by a legal requirement to take all practicable steps to ensure safety. This drives an increase in opex, but does not lead to a higher ICP count or a longer network, so appears as declining productivity.

40. The ENA submits that in selecting a negative rate of opex PFP growth the Commission should not see this as indicating that inefficiencies are occurring, but rather that there are other factors driving input quantities that do not contribute to the level of output. These trends are likely to continue, and come from diverse sources:

a) Increasing regulatory compliance (for example, the Commission's DPP determination will in itself increase costs as the complexity of the DPP compliance will increase substantially relative to the 2012 reset)

b) Changes to Health and Safety legislation driving higher compliance costs

c) Factors such as the increasing prevalence of cycle lanes, which require extensive traffic management to keep cyclists separate from other traffic. This can drive significant costs in otherwise simple jobs.

d) Improvements in asset management systems leading to higher demands for quality data, systems to manage data etc. These systems are expected to improve longer term asset management decisions (e.g. longer asset lives, more optimal asset replacements etc) but are driving higher opex costs.

41. The evidence relied on by EI and the Commission in turn to disregard the negative productivity estimates is flimsy. The ENA submits that the opex productivity assumption has significant impact on the allowable revenue calculation and the onus is on the Commission to establish a robust case based on relevant, quantitative evidence to override the empirical results of the EI and PEG reports. In the absence of any such evidence a negative productivity estimate should be adopted.

2.5 Additional adjustments

42. The Forecasting Paper asks for submissions on other adjustments which may be made to opex, to reflect costs which will not be captured by the forecasting method proposed. We understand that ENA members will be responding to this request directly.

43. From an industry wide perspective we note that compliance costs have increased and are expected to increase. Additional compliance requirements during the regulatory period will be incurred in:

a) Implementing and reporting on the proposed new DPP incentive mechanisms

b) Meeting enhanced information disclosure requirements (which are not captured in the base year opex)

c) Meeting health and safety regulations.

44. Accordingly, we submit that additional opex allowances equivalent to one FTE ($140k pa inclusive of on-costs) are included for each ENB, to compensate for the compliance functions not evident in the base year data, and for which the econometric scale adjustments provide no allowance. We consider that when combined across all of the compliance activities of each business, an additional person is a reasonable allowance, although in reality, these activities will be shared across different roles, and may be provided by external contractors.

45. In addition we note that the proposed approach for forecast opex does not, in practice provide an appropriate allowance for additional opex associated with assets transferred from Transpower, where those transfers occurred partway through, or after the base year. We do not consider the scale adjustment factors are a reasonable approach to

forecasting the incremental opex where the transmission and distribution boundary changes. The extrapolation methods (using population forecasts and historical circuit kms) will provide no additional opex for the assets transferred.

46. We have highlighted this issue in our accompanying submission on the Main Policy Paper.[9] In order to address this anomaly we suggest that, similar to forecast capex for assets transferred prior to the next regulatory period, ENBs' own forecasts of associated opex are used.

2.6 Recommendations

47. For the purpose of forecasting opex for the 2015 DPP reset the ENA:

a) Does not support the use of FY13 as the base year for opex. We have previously endorsed an averaging of FY13 and FY14 to avoid the impact of year on year variation. Our analysis shows that maintenance opex was abnormally low in FY13, due to lower outages in that year. A FY13 base year therefore is inconsistent with the proposed quality standards as it does not provide for sufficient opex to maintain underlying reliability performance. To give high or sole weight to FY13 data would result in ENBs systematically being unable to recover their actual and reasonable opex costs over the next regulatory period.

b) Notes that historical opex, expressed in constant scale and constant price terms, has increased since FY10. This trend is endorsed by EI and PEG who have both measured declining industry opex partial productivity in recent years.

c) Acknowledges that inaccuracies in the scale and input price adjustments could also contribute to this outcome. Accordingly, the ENA submits that the scaling factors should be recast using FY14 data, to ensure they are as current as possible, and consideration should be given to using historical ICP data in place of population forecasts to generate ICP projections.

d) Submits that the evidence relied on by EI and the Commission in turn to disregard the negative productivity estimates is flimsy. The ENA submits that the opex productivity assumption has significant impact on the allowable revenue calculation and the onus is on the Commission to establish a robust case based on relevant, quantitative evidence to override the empirical results of the EI and PEG reports. In the absence of any such evidence negative productivity estimates for opex PFP and TFP should be adopted.

e) The ENA submits that the Commission should adopt a -2% per annum opex partial productivity factor, consistent with the evidence in the PEG report. The analysis of PEG should be preferred because it is consistent with the

[9] ENA, Submission on Proposed Default Price-Quality Paths for Electricity Distributors from 1 April 2015, 15 August 2014

Commission's broader forecasting approach (e.g., use of all-industries LCI, and opex forecast drivers) whereas the EI analysis is not.

f) Submits additional opex allowances are provided for:

i. compliance costs not included in the base year opex, equivalent to 1 additional FTE (including on-costs) per ENB

ii. spur assets transferred within or after the base year and prior to the next regulatory period, to be derived from ENB forecasts.

3. Forecasting capex

3.1 Proposed approach

48. Capital expenditure forecasts are derived for each non exempt ENB using the supplier's own forecasts (expressed in real terms), which are subject to caps which limit the extent to which future capex is able to increase relative to historical capex. Input price inflation is also forecast in order to generate capex forecasts in nominal terms. The DPP Financial Model[10] uses the capex forecasts as the basis for determining the forecast of commissioned assets, for the purpose of deriving building blocks allowable revenue.

49. Section 4 of this submission contains our response to the input price forecasting approach and assumptions. We address the remainder of the capex forecasting proposal below.

3.2 Suppliers' forecasts

50. ENA members support using supplier's own forecasts of capex as the basis for determining the DPP forecast capex allowance. We consider this is consistent with the low cost intent of the DPP, and has the advantage of reflecting data which is relevant to each business, and is relatively easy to implement.

51. Historical data is used to determine whether supplier's forecast capex is capped. Caps are applied where average annual forecast capex exceeds average annual historical capex by a margin. Caps are also influenced by variance between historical capex and 2010 forecasts of capex, and the relative proportions of non network and network capex.

52. As stated in our submission on the Process and Issues Paper[11] the majority of non-exempt ENBs support the use of a cap on historical capex. In that submission we submitted that in relying on historical data, it was important to consider the relevant historical period, the regulatory rules which applied across that period, the proximity to the start of the next regulatory period, movements in scale and movement in input prices.

53. We note that the Forecasting Paper indicates that some but not all of these factors have been taken into account in the proposal. After examining the capex models supporting the proposed forecasts we make the following observations:

a) The comparison of 2010 forecasts with 2011-2014 actual capex in order to determine forecasting accuracy fails to consider that the forecasts were prepared prior to the Input Methodologies (IMs) coming into effect. Actual capex (and commissioned asset data) has been restated from 1 April 2009

[10] Model 9 - Financial Model draft EDB reset, 4 July 2014

[11] ENA, Submission on default price-quality paths from 1 April 2015 for 17 electricity distributors: process and issues paper, 21 March 2014

onwards to be IM compliant. This data was first published in FY13 disclosures. Thus the value of the capex spent has been prepared on a different basis to the 2010 forecasts. The asset valuation IM includes a number of rules which determine how capex is allocated and valued for regulatory reporting purposes. We note that the related party transaction rules cap the value of capex able to be included under some circumstances.

b) Implementation of new network strategies such as smart grids may lead to changes in expenditure plans. Examples include movement away from investment in traditional network assets, towards non network assets or opex, in addition to deferral of previously planned network investment. The forecasting penalty cap (ie: the step down to 110% from 120%) penalises businesses which are innovating in this way.

c) Some capex is customer driven, and may be funded by significant capital contributions, which would make it appear that the amount of work done by an EDB in a year looks low in comparison to the forecast. An ENB has little control over the timing of customer driven capex, and often poor information about potential projects particularly beyond the short term. We do not consider that ENBs should be penalised for forecasting inaccuracy which reflects customer driven decisions.

d) The sliding scale cap for businesses which have higher proportions of non network capex also potentially penalises innovative businesses which are investing in support systems and new technology in place of traditional network assets.

e) Business which undertake most of their activities in-house are also penalised relative to those which use contracting out models, because these different structural arrangements determine the mix of network/non-network assets (and hence capex) undertaken by each business. The sliding scale non network capex cap unfairly penalises businesses which contract out less.

54. The ENA therefore supports in principle the use of caps derived from historical averages for each ENB, however submits that in order to remove the inequities in the proposed approach:

a) the forecasting accuracy penalty is only applied where the ENB affected is unable to explain the difference between forecasts and actual, including with reference to changes in the regulatory reporting rules, changes in network investment strategy, efficiency gains and customer driven timing decisions. The Commission is making an implicit assumption that EDBs whose 2010 AMPs did not predict actual capex well, are likely to continue to make poor forecasts. This is not a reasonable assumption and the Commission should consider evidence from the affected EDBs of improvements that have been made to achieve better forecasting accuracy. Absent such process, the forecast accuracy penalty is nothing more than a partial claw-back mechanism, which is prohibited under section 53P(4).

b) the sliding scale cap on non network capex is removed because it unduly penalises certain structural arrangements and network investment strategies.

55. Absent these improvements, ENBs are at risk of not being able to maintain their reliability levels where the AMP forecasts are capped without due cause. This potentially leads to increased requirements for opex, which are not provided for, in order to respond to and remediate the impact of outages.

56. We consider that there is sufficient time to engage with the relevant ENBs between now and the end of November, to consider whether the proposed caps are operating as intended. We consider this is consistent with the low cost intent of the DPP because it addresses potential unintended consequences of the proposed new approach. This approach been not been previously applied to ENBs, and for the reasons outlined above, it appears to generate anomalous outcomes for some ENBs.

57. The ENA submits that the cross checking process does not require the same audit and verification processes as a CPP, rather it is targeted at identifying whether the proposed caps are reasonable given the approach to deriving forecasts, and the impact of subsequent regulatory reporting rules and investment drivers.

58. The proposed must be fit for purpose, and we do not consider that the "apply for a CPP" option is a valid response, without further investigation of the reasons why some businesses are subject to harsher caps than other.

59. Further we note that there is no explanation of the method used to determine the proposed caps. We consider in particular that the 10% cap is extremely narrow, and request further explanation as to how this and the other caps have been determined, and justified.

3.3 Retention factor in incentive scheme

60. We note the planned introduction of a capex incentive scheme, and will be responding to the detailed proposals in our forthcoming submission on the Incremental Rolling Incentive Scheme (IRIS) Paper.[12]

61. It is proposed that a retention factor of 20% will be applied, in implementing the IRIS which is intended to equalise the strength of the incentive for capex efficiencies over time, including between regulatory periods as well as making the incentives to undertake capex more similar to the incentive to undertake opex.

62. In principle, the ENA agrees that it is worthwhile to try to provide time consistent incentives to make capital investment, and also to consider the relative strength of incentives to invest in opex or capex and also the relative strength of the incentive to make savings compared to the incentive to maintain quality.

63. The ENA supports in principle, a mechanism (like that proposed) which is neutral on the timing of capex within the regulatory period, that is where differences between the actual and the forecast relate to timing only there is no reward or penalty.

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[12] Commerce Commission, proposed amendments to input methodologies: Incremental Rolling Incentive Scheme, 18 July 2014

64. The Forecasting Paper suggests that this is a relatively low retention factor, which is appropriate given the low cost forecasting approach which may not reflect a prudent and efficient level of capex for an ENB during the regulatory period.

65. We agree in principle that the ability or otherwise of a supplier to achieve capex efficiencies relative to the DPP assumptions, will be partly influenced by how realistic the DPP assumptions are in the first place for each supplier. Thus, prima facie, the opportunity to achieve efficiencies is biased against those which have had their forecasts capped, and in particular those where the cap has a material impact relative to the businesses own forecasts.

66. We note the comment in paragraph 4.14 of the Forecasting Paper which suggests that distributors have incentives to systematically bias their forecasts upwards, and that some distributors have reported actual expenditure below forecast for the current regulatory period, which is suggested may be as a result of inaccurate forecasting or systematically biased forecasts. We note, as mentioned above, actual capex below forecast may also reflect efficiencies which were not able to be forecast, or for some businesses the impact of changes to regulatory reporting rules (for example in relation to establishing the value of related party transactions). Changes in customer requirements and the timing of investments can also contribute to 'inaccurate' forecasting by ENBs.

67. As discussed in our submission on the DPP decision, we do not support a capex incentive mechanism that would merely carry-over forecasting error, particularly where such error is a result of the arbitrary capping of capex by the Commission. The ENA submits that the capex incentive mechanism retention factor should be set to 5% for actual capex within a band between the Commission's cap and the ENB's AMP forecast. Outside this band, the retention factor should be set to 10%. These limited penalties and incentives recognise that the Commission's forecasting approach remains relatively unsettled and somewhat arbitrary and that variations from the forecast have a number of explanations. Similar schemes in Australia are based on much more business specific capex proposals.

68. We will provide more commentary on the retention factor in the context of the DPP capex forecasts our upcoming submission on the IRIS paper.

3.4 2015 wash-up

69. In order to ensure asset related charges are as accurate as possible within the next regulatory period, it is proposed that the FY15 value of commissioned assets assumption will be subject to a wash-up, to adjust for any variance between actual and forecast in this year. The ENA supports approaches which improve the accuracy of the information used to set revenues, including making adjustments, where practicable for actual outturns in the year immediately prior to the regulatory period.

70. We will comment on the proposed wash-up mechanism in our forthcoming submission on the IM Amendments Paper.[13]

71. We note that the proposal will ensure actual values for FY15 will be reflected in the DPP price path. We note that this differs to the proposed approach for opex, for example, which ignores actual opex in FY14 and FY15 for the purpose of setting the price path for the next regulatory period.

72. As stated above, we are concerned at this inconsistency, and remain of the view that information which is as current as possible at the time of the reset, should be used to set prices (and quality standards). We note FY14 data is to be used to set quality standards.

73. In our view the proposed adoption of a FY13 opex base year is the stand-out anomaly in this respect.

3.5 Other options

74. The ENA acknowledges the efforts on behalf of the Commission to consider whether alternative models could be used for forecasting capex. Out forecasting working group has examined similar options. As alternative models are untested at this time, we support the decision not to use them for the forthcoming reset.

75. The ENA continues to support further consideration of possible refinements to forecasting approaches, beyond those which are able to be implemented for the 2015 reset. We encourage the Commission to continue to consider the recommendations of the Output 2 and Output 3 reports, prepared by Frontier Economics for the ENA forecasting working group, in this respect. [14]

3.6 Recommendations

76. For the purpose of forecasting capex for the 2015 DPP:

a) ENA members support using supplier's own forecasts of capex as the basis for determining the DPP forecast capex allowance.

b) The majority of non-exempt ENBs support the use of a cap on historical capex.

c) In relying on historical data, it is important to consider the relevant historical period, the regulatory rules which applied across that period, the proximity to the start of the next regulatory period, and innovation and efficiency gains. Not all of these factors are addressed in the proposal.

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[13] Commerce Commission, Proposed Amendments to Input Methodologies for Electricity Distribution Services, 18 July 2014

[14] Frontier Economics, Output 2: Using EDB AMP forecasts under a DPP framework, April 2014 and Output 3: Development of approaches to forecast EDB costs under a DPP framework, April 2014.

d) The ENA submits that in order to remove the inequities in the proposed approach:

i. the forecasting accuracy penalty is only applied where the ENB affected is unable to explain the difference between forecasts and actual, including with reference to changes in the regulatory reporting rules, changes in network investment strategy, efficiency gains and customer driven timing decisions

ii. the sliding scale cap on non network capex is removed because it unduly penalises certain structural arrangements and network investment strategies.

e) In principle the ability or otherwise of a supplier to achieve capex efficiencies relative to the DPP assumptions, will be partly influenced by how realistic the DPP assumptions are in the first place for each supplier. The forecasting approach introduces some bias in this respect and ENA does not support a capex incentive mechanism that would merely carry-over forecasting error.

f) The ENA submits that the capex incentive mechanism retention factor should be set to 5% for actual capex within a band between the Commission's cap and the ENB's AMP forecast. Outside this band, the retention factor should be set to 10%.

g) The ENA supports approaches which improve the accuracy of the information used to set price caps, including making adjustments, where practicable for actual outturns in the year immediately prior to the regulatory period, such as proposed for commissioned assets.

h) The ENA continues to support further consideration of possible refinements to forecasting approaches, beyond those which are able to be implemented for the 2015 reset.

4. Changes in input prices

4.1 Proposed approach

77. The Forecasting Paper proposes a similar approach to forecasting changes in input prices, as applied in the 2012 DPP Reset. The proposed approach comprises:

a) Weighting forecasts of the all industries labour cost index (60%) and the all industries producer price index (40%) in order to establish an input price index for opex

b) Applying a forecast of the all industries capital goods price index in order to establish an input price index for capex.

78. We understand that these forecasts are sourced from NZIER, and it is intended they will be updated prior to the final determination.

79. The ENA remains concerned at the proposal to apply industry wide indexes for resetting the DPP. Our submission on the Process and Issues Paper,[15] endorsed the recommendations of Frontier Economics for improving the method for forecasting improvements in input costs, including::

a) Basing forecasts of cost escalators on industry-specific and asset-specific inflation indices rather than general inflation indices

b) Applying composite price escalators that reflect broadly the cost structures of ENBs, rather than relying exclusively on forecasts of a single inflation index for each major cost category

c) Combining input cost inflation forecasts from a range of forecasters to reduce the influence of forecasting errors.

4.2 Labour index

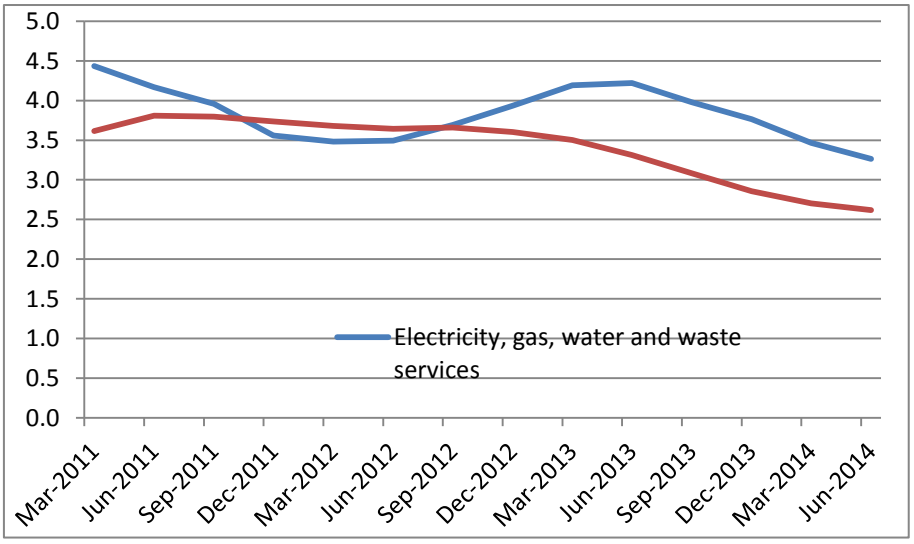
80. ENA members have particular concerns regarding the use of the all industries LCI for the purpose of forecast opex. The Commission states three reasons why it is appropriate to rely on forecast changes in the LCI for all industries rather than the series for electricity, gas, water and waste services (EGWW index); we consider these in turn.

81. The Commission considers that the changes in the all industries index are less dependent on the behaviour of regulated suppliers. While wage changes experienced by ENBs are reflected in the EGWW index, the Commission appears to erroneously assume that these costs are controlled by ENBs. ENBs compete amongst each other and with Australian employers for skilled employees. One way to see this is through the

[15] Supra nX, paragraph 37

changes in the equivalent Australian index. The ENA recognises that there are other drivers of wage growth such as general inflation, and we have not undertaken a detailed analysis of the Australian data, however it is possible to see that there is similar pressure on wages in the EGWW sector in Australia as in New Zealand, i.e. it is markedly higher than the all industries series particularly in the period since 2012.

Figure 5: Australian Wage Price Index (annual average percent change)



Source: Australian Bureau of Statistics

82. Further, even if EDBs wage decisions do have an impact on an index, given the permanent impacts of wage decisions, EDBs do not face incentives to permit higher than required wage increases, as this reduces profitability, given prices are capped.

83. The Commission asserts that it can be difficult to calculate and verify weights for composite indices. The ENA submits that adopting existing industry specific index for the components of input prices, particularly labour costs, would be a good first step and is not dependent on estimating weights.

84. Finally the Commission suggests that the all industries index is a good proxy for the EGWW index, and that the latter is more difficult to predict. Figure B1 is produced in support of this proposition. The ENA requests that the Commission release the data underlying this chart as it appears to be based on two series that have been inappropriately linked.[16] In addition, the ENA requests that the Commission explain the basis for the EGWW index forecast shown in this figure.

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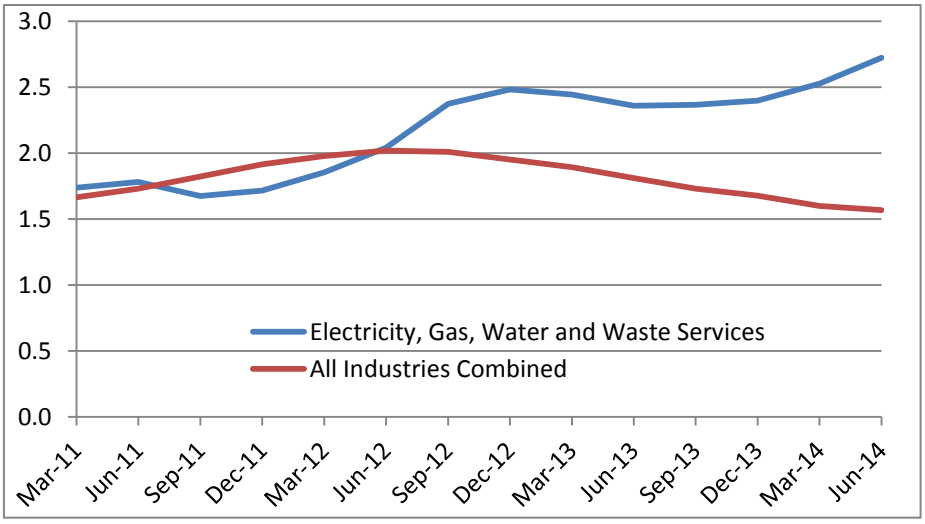
16 In the September 2009 quarter Statistics NZ implemented the 2006 version of the Australian and New Zealand Standard Industrial Classification (ANZSIC06) and the Australian and New Zealand Standard Classification of Occupations (ANZSCO). At the same time the sample was refreshed to better reflect the structure of ANZSIC06, and new positions that were underweight in the old series were added. Statistics NZ stated: "As there is a high level of discontinuity between the old and new occupation and industry breakdowns, the new series were not linked to the old series." (Labour Cost Index (Salary and Wage Rates): June 2010 quarter "Hot off the Press")

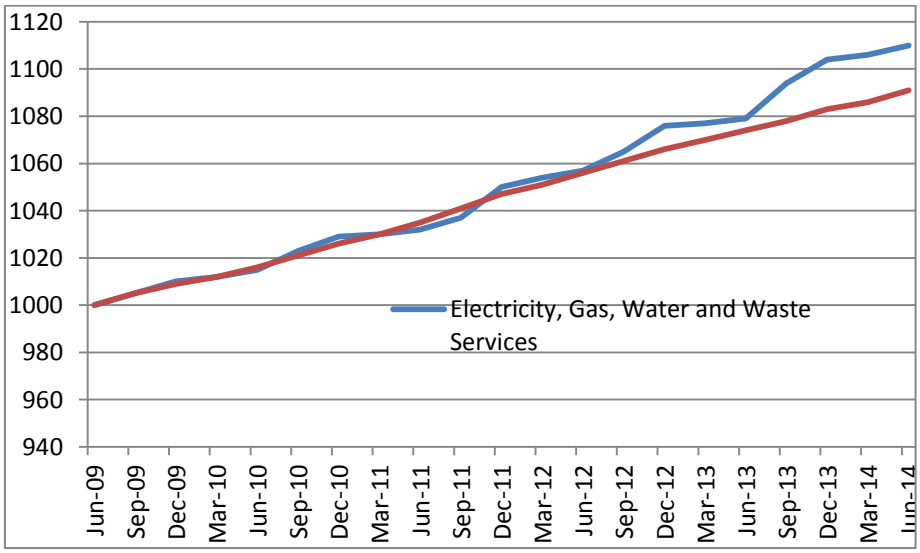
85. The ENA does not agree with the assertion that the all industries index is a reasonable proxy for the EGWW index and hence labour cost inflation for ENBs. While this may be the case when there are no industry specific factors that generate wage pressure, the Commission should undertake specific analysis to check for such pressures. The charts below illustrate.

Figure 6: Labour Cost Index (annual average percent change)



Source: Statistics NZ

Figure 7: Labour Cost Index (index level)



Source: Statistics NZ

86. These charts show a persistent gap between the EGWW sector's labour costs and the average across the economy since mid-2012. As referred to above, this is broadly consistent with wage pressures in the industry in Australia and likely reflects specific skill shortages.

87. The difference between the geometric means of the average annual growth in the EGWW index and the all industries index (since the start of the new series in 2009) is 0.3%; in the June 2014 quarter; the difference was 1.2%. The ENA considers that the Commission should add a wedge to NZIER's forecast of the LCI all industries index to reflect sector specific wage inflation.

88. This conclusion is consistent with the conclusion reached by Economic Insights in their report which suggests that input price inflation for ENBs will be 1% higher than in the general economy in each year of the regulatory period.[17]

4.3 Recommendations

89. The ENA recommends that with regards to specifying input prices for forecasting opex and capex:

a) The Commission adds a wedge to NZIER's forecast of the LCI all industries forecast to reflect sector specific labour cost inflation.

b) The Commission pursues other improvements in input price forecasting prior to the next DPP reset, including using more industry- and asset-specific indices, applying composite escalators and combining the forecasts of more than one forecaster to reduce the risk of forecasting error.

c) In addition, the ENA requests that the Commission release the data underlying Figure B1 and explain the basis for the EGWW index forecast shown in this figure.

[17] Economic Insights, Electricity Distribution Industry Productivity Analysis: 1996-2013, June 2014, p.41

5. Forecasting revenue growth

5.1 Proposed approach

90. It is proposed that real revenue growth is forecast using the same approach as developed in 2012. That is, real revenue growth forecasts are derived for each ENB, using regional and ENB specific data which:

a) For domestic consumers, predicts changes in real revenue using regional forecasts of population growth and assumptions about changes in energy use for domestic consumers.

b) For commercial and industrial consumers, predicts changes in real revenue using regional forecasts of GDP.

5.2 Performance of model

91. The ENA has previously raised concerns about the performance of the real revenue growth model, and we have requested that an ex post review against actual outturn results is undertaken before the model is adopted for the forthcoming regulatory period. We are disappointed that this task was not undertaken prior to this consultation round.

92. We consider that potential errors in this aspect of the price path modelling introduces unnecessary risks for consumers and suppliers.

5.2.1 Empirical evidence

93. We have gathered data from non-exempt ENBs to test, using a top down approach, how well the model has performed in the current regulatory period. We have discovered that the real revenue growth estimates derived from actual ENB data for FY10-FY14 do not align well with the estimates included in the 2012 reset decision.

94. The outputs from our analysis are presented in Attachment A. These demonstrate that:

a) For residential consumers:

i. Actual real revenue growth has diverged significantly from projected, with both positive and negative differences across ENBs

ii. Residential energy use per consumer has generally fallen, and for most ENBs this has been at an average rate of 1% to 3% per annum since FY10

iii. Actual residential connection growth has lagged behind population growth for most ENBs

iv. Actual regional population growth has been greater than forecast, particularly in the South island regions.

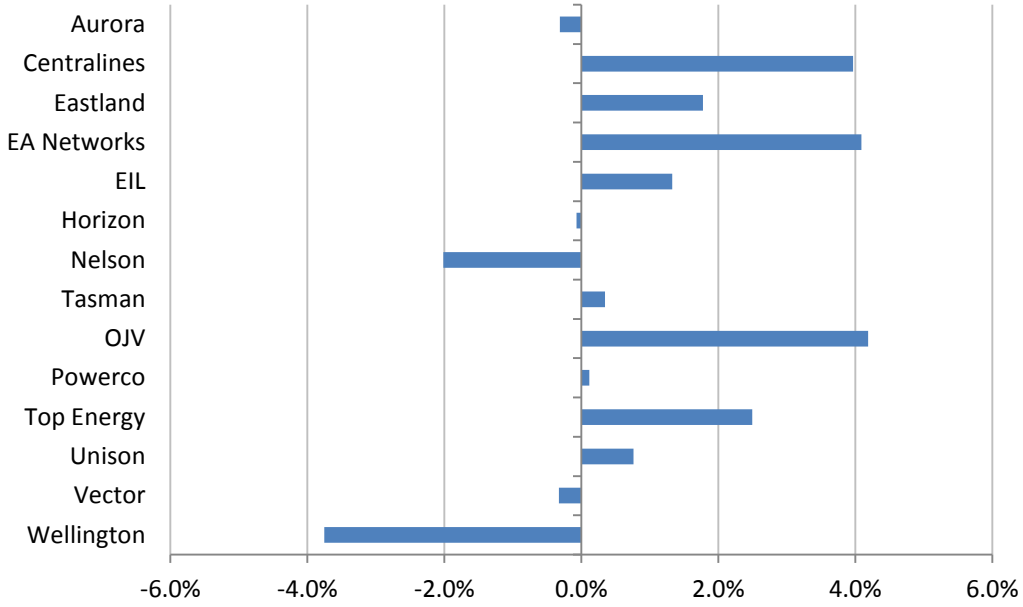
b) For commercial/industrial consumers:

i. Actual real revenue growth has also diverged significantly from projected, with both positive and negative differences across ENBs

ii. Actual regional GDP growth has diverged from the forecasts used in the 2012 reset. Actual GDP has generally been stronger in the regions, and weaker in Wellington and Auckland than predicted.

95. Figure 5 below illustrates the variation between the actual annual average real revenue growth (FY10-14) and the 2012 reset assumption for each non-exempt ENB.

Figure 8: Difference between annual average constant price distribution revenue growth (2010-14) and 2012 DPP forecast



96. Given the outputs of the analysis presented above and in Attachment A, we do not support the proposed approach to forecasting real revenue growth for the forthcoming regulatory period. We do not consider that the proposed model has performed well enough in the current regulatory period.

5.2.2 Energy utilisation

97. Sapere Research Group has prepared a report for the ENA describing recent changes in consumer behaviour, particularly around increasing energy efficiency, that has driven the trends in residential energy use.[18] This report is attached to our submission.

98. There are some factors that drive temporary changes in electricity demand. These include the temperature (measured by the number of days during the year that the

[18] Sapere Research Group, *Trends in Residential Electricity Consumption,* by Dr Stephen Batstone and David Reeve, 5 August 2014

temperature fell below a certain level) and recently the Christchurch earthquakes (although we note that as Orion is not included in the DPP, the effect of the earthquakes on demand, including any subsequent resumption in demand in Christchurch is not relevant to calculating the average consumption per household).

99. However, the Sapere report highlights significant changes in the efficiency of electricity consumption within the home. These changes are almost always permanent and there is evidence that they are as yet incomplete. Key drivers of household electricity consumption are: electronics and appliances (19%), refrigeration (15%) and lighting (12%). Space heating, water heating and ovens comprise the balance:

a) Electronic appliances have proliferated over the last decade. The majority of these (by number) are low energy consumption devices and manufacturers are seeking efficiencies to extend battery life. Also in the appliance space, we have experienced a trend toward larger TVs and a greater number of TVs per household. However offsetting this, these TVs tend to be highly efficient, with an expectation that the move toward digital television would have accelerated this trend. EECA data shows that 84% of televisions purchased in 2013 (165,000 units) were greater than 6 energy stars. The introduction of international standards on standby consumption has dramatically reduced the power consumption of appliances left on standby.

b) A new refrigerator has a 42% lower energy consumption profile compared to one purchased in 2002. Although the stock of refrigerators may have largely been replaced (nearly 2 million have been purchased since 2002, for 1.7 million households), a new refrigerator purchased in 2013 had a 15% efficiency advantage over the sales-weighted average efficiency of the prior 11 years. This suggests that continued life-cycling will continue to reduce electricity consumption for refrigeration.

c) Penetration of compact fluorescent lightbulbs (CFLs) in New Zealand appears to be lagging other countries. This form of lighting offers a 75% reduction in electricity consumption compared to incandescent or halogen bulbs. Reliable data for how many CFLs are in use in New Zealand is not available. EECA data from August 2013 suggests that CFLs had a 27% share of sales. A Canadian Office of Energy Efficiency study suggests that the penetration there was 27% and that this had reduced electricity consumption for lighting by 21%. EECA's sales figures suggest that ongoing replacement will continue to drive reductions in household consumption. At a bulb replacement rate of 10-15%/year average residential consumption would decline by 0.9-1.3%. The availability of LEDs which offer further efficiencies may overtake CFLs and reduce consumption further over the regulatory period.

d) Significant investments in household insulation and heating efficiency have been observed, with 295,000 homes receiving grants under the EECA Warm Up New Zealand scheme. These effects are offset to some extent by increasing house size and improvement in the warmth of homes that have been insulated (rather than a reduction in electricity consumption).

e) Future changes to the technology used to heat water may result in significant efficiencies (water heating comprises 29% of household consumption).

100. Given these permanent changes to the efficiency of households, it is unlikely that changes to prices or economic activity will drive a significant recovery in consumption. This is consistent with a paper presented at the ACCC conference which reflected on the low growth environment.[19] The paper noted that there are five forces shaping the decline in growth in the US. Three of these relate to energy efficiency (changes to consumer values; increased spending on energy efficiency by utilities in response to legislation and standards; and aggressive changes to codes and standards by governments). This suggests that this trend (toward more efficient homes) is widespread.

101. Distributed generation also has the potential to reduce demand growth. The price of solar installations has declined rapidly since 2010. This technology could have significant implications for limiting load growth during the regulatory period. Consumers face an artificial incentive to avoid network use as a result of the Electricity (Low Fixed Charge) Regulations, which require ENBs to offer a tariff that has a maximum daily tariff of 15 cents. Although solar is not economic from a whole economy perspective (compared to other options to supply electricity), an individual facing a marginal unit electricity price in excess of 20c/kWh can find it commercially viable to install solar. There appears to be little political appetite to revoke the regulations.

102. The Commission suggests that electric cars are becoming viable and that this will affect average use. The ENA does not agree. Within the upcoming regulatory period it is highly unlikely that electric vehicles (EV) will have a substantial impact. MBIE analysis suggests that EVs may increase average household consumption by 9% but not until 2040. Sapere's internal analysis suggests that the increase during the regulatory period will be less than 1% in total.

103. MBIE's 2013 publication "Energy Outlook: Electricity Insight" states:

> *Electric vehicles (including plug-in hybrid vehicles are another area of uncertainty for future electricity demand. At the moment, electric vehicles are not economic over the next decade, it will take several decades for electric vehicles to have any significant impact on total electricity energy demand due to slow turnover in the vehicle fleet.*

104. The Commission also suggests that moderating electricity price increases will encourage greater consumption (or at least no less). While there is likely to have been some response to rising electricity prices over the last 7-10 years Sapere suggest that the explanation is richer. Retailer engagement, switching, political scrutiny and general public consciousness of power prices all had a part to play. Further, it is possible that the response to higher prices in part drove the efficiency changes described above.

105. If future price rises moderate then, all else being equal, the consumption response to price is likely to flatten as well – but the key point is that prices are still expected to increase, which unless the Commission considers demand elasticities are zero, will still

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[19] Faruqui, A *Strategies for Surviving sub-one percent growth: an American perspective*, The Brattle Group, 7 August 2014 (http://www.accc.gov.au/system/files/Session%203%20Regulating%20in%20the%20face%20of%20declining%20demand%20%20A%20Faruqui.pdf accessed 12/8/14)

drive consumers to reduce demand. Sapere notes that price is only one factor in declining consumption. Income elasticity is significant with households purchasing new (more efficient appliances). This effect also applies when (real) appliance prices decline (as Sapere reports happened recently).

106. The permanent changes to household efficiency and continuation of efficiency improvements through life-cycling and adoption of new technology (such as lightbulbs) means that average residential consumption will continue to trend downward over the next regulatory period. Sapere concludes "a prediction that consumption per household is unlikely to fall requires a particular (and, we think, unreasonable) view on the nature of changes being experienced by households currently".[20]

5.2.3 Draft model

107. For completeness, we note that in respect of the draft real revenue growth models released alongside the Low Cost Forecasting Paper:

a) The revenue weight data is sourced from FY11, which is now no longer current

b) The revenue data is net of discretionary discounts, which is inconsistent of the definition of lines charge revenue which is subject to the DPP price path (which includes discretionary discounts)

c) The revenue data is gross of transmission charges, which again is inconsistent with the definition of revenue for which a real revenue growth estimate is required

d) The econometric modelling of GDP and revenue uses total revenue, however the GDP coefficient is only applied to commercial and industrial consumers

e) The GDP econometric model excludes Vector because of its scale relative to the rest of the industry, and OtagoNet, on the basis that it is an outlier. Thus the modelling excludes a significant proportion of the sector, in order to determine the GDP coefficient estimates

f) The GDP coefficient used is not that from the preferred model.

5.3 Alternative approach

108. In the absence of an alternative model which can be proven to perform better than the current approach, the ENA submits that, for the next regulatory period:

a) Real revenue growth is projected using actual historical trends for each non exempt ENB; and

b) A volume wash-up is included at the end of the regulatory period to adjust for material forecasting errors.

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[20] Sapere report, p.3.

109. Using actual historical trend data for each ENB is a valid approach as it reflects the characteristics of each region and customer base in a way that the current approach is unable to do. In addition, and as previously submitted, we consider that it may be appropriate to also include a volume wash-up to account for any material forecast error in this instance. We have previously submitted in this regard,[21] as follows:

> *The current approach exposes some ENBs to significant risks from both forecast error (e.g., NZIER regional GDP forecasts which are an input to the model) and model error as even with the right inputs (e.g., actual GDP) the models do not match actual volume experiences. This creates risks for both consumers and ENBs.*
>
> *In addition to improving the forecasting of volumes, the ENA requests the Commission considers sharing, above some threshold, this risk of volume variances with consumers. This could be achieved by using an ex post adjustment factor, either annually or at the end of each regulatory period, along the lines described in section 4.5 above.*

110. We therefore encourage the Commission to consider the revenue adjustment mechanism we proposed in our earlier submission, to address the consequences of forecasting risk with respect to volumes. We consider this is a risk that neither suppliers nor consumers should bear.

5.4 Recommendations

111. For the purpose of forecasting real revenue growth: the ENA

a) Does not support the proposed approach to forecasting real revenue growth for the forthcoming regulatory period. We do not consider that the proposed model has performed well enough in the current regulatory period.

b) Recommends as an alternative, that real revenue growth is projected using actual historical trends for each non exempt ENB and a volume wash-up is included at the end of the regulatory period to adjust for material forecasting errors.

c) Sapere Research Group has prepared a report for the ENA describing recent changes in consumer behaviour, particularly around increasing energy efficiency, that has driven the trends in residential energy use. Given the permanent changes to the efficiency of households demonstrated in the Sapere report, it is likely that consumption per household will continue to fall over the next regulatory period.

[21] ENA Submission on default price-quality paths from 1 April 2015 for 17 electricity distributors: process and issues paper,30 April 2014, para 117-118

6. Forecasting asset revaluations

6.1 Proposed approach

112. Forecast inflation is used to set DPP price paths. Forecast CPI affects the DPP RAB and the revaluations building block. Revaluations are deducted from BBAR in the year of the revaluation, and are assumed to be recovered over the remaining life of the asset, in order to maintain Financial Capital Maintenance (FCM).

113. During the current DPP period, actual inflation has been well below the forecast used to set the DPP allowable revenue. This difference has compromised FCM, to the detriment of ENBs, in nominal terms (estimated to be $196m to the end of FY14 for the 16 non-exempt ENBs which are due to have their DPP price paths reset).[22]

6.1.1 Inflation risk

114. DPP price paths incorporate asset revaluations based on forecast CPI for the years of the DPP period. However RAB values are updated for future DPP regulatory periods, such that future DPP price paths reflect revaluations from previous periods based on actual CPI. The use of both forecast and actual inflation values for the same years exposes ENBs and consumers to differences between actual and forecast inflation.

115. There are two types of potential inflation risk to be considered:

a) The risk that future nominal revenues change if inflation differs from forecast, such that FCM is not maintained. That is, the risk that nominal returns are not maintained over time.

b) The risk that nominal returns remain fixed when inflation changes. That is, the risk that real returns are not maintained over time.

116. Being exposed to some kind of inflation risk is unavoidable in an ex ante price cap regulatory framework. Whether a given framework primarily involves real or nominal risk depends on the details of the framework, and also the extent to which suppliers' underlying cost of capital reflects inflation.

6.2 Possible solutions

117. At paragraph 2.31 of the Main Policy Paper, the Commission states:

> *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.*

[22] PwC, A wash-up mechanism for the DPP revaluation rate, A report prepared for Vector, April 2014

118. Further at footnote 8 of the Low Cost Forecasting Paper the Commission goes on to state:

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 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.

119. The ENA notes that different ENA members have different positions on whether the RAB should be rolled forward with actual or forecast inflation and, in principle, there is no particular reason that the Commission should not allow choice by ENBs at the start of a regulatory period on whether forecast or actual inflation be used.

120. Some EDBs value highly the certainty provided by aligning the movement in the RAB to the forecasts actually used by the Commission in establishing the DPP, or are concerned that there is statistical bias in the Reserve Bank's forecasts, such that inflation forecasts over-state actual inflation.

121. Other ENBs take the view that real financial capital maintenance is better preserved by aligning the movement in the RAB to actual inflation, such that if there is an inflation shock, they (and consumers) are better protected from the effects of inflation over time.

122. Accordingly the ENA submits that the Commission should provide for choice in use of forecast or actual inflation in RAB roll-forward in the ID requirements. This choice should be certified by the respective Boards in advance, making those businesses accountable for their choices. As long as there is ex ante commitment at the start of a regulatory period by ENBs to one method or the other, consumers should be indifferent to that choice. "

6.3 Recommendations

123. For the purpose of forecasting asset revaluations, the ENA:

a) submits that the Commission should provide for choice in use of forecast or actual inflation in RAB roll-forward in the ID requirements. This choice should be certified by the respective Boards in advance, making those businesses accountable for their choices. As long as there is ex ante commitment at the start of a regulatory period by ENBs to one method or the other, consumers should be indifferent to that choice.

7. Forecasting other items

7.1 Proposed approach

124. Asset disposals are deducted from the RAB for the purpose of the DPP revenue building blocks. Thus forecasts of asset disposals are required.

125. Other regulated income is deducted from the revenue building blocks, in order to derive the revenue allowance to be recovered through line charges. Other regulated income also includes gains/losses on disposals. Thus forecasts of other regulated income are also required.

126. It is proposed that historical disposal and other regulated income information for each ENB is used to derive forecast values, after making adjustments for projected inflation.

127. The ENA supports the use of ENB specific historical data for forecasting asset disposals and other regulated income. The Commission should update the forecasting model with data from the 2014 disclosures.[23]

7.1.1 Suggested refinements

128. We note that errors in the proposed inflation adjustments have been identified and previously notified to the Commission. We understand these are to be corrected before the final price paths are determined.

129. The ENA considers that the proposal to assume an industry wide 89% loss on disposal can be improved. We note that the average value of 89% masks significant variation across businesses. This is expected as businesses have different disposals policies, and different methods of disposing of the assets in question.

130. Accordingly the ENA considers that a better approach is to derive a business specific gain/loss on disposal percentage, which will ensure it is more consistent with the disposals forecasts included in eh price path calculations, for each ENB.

7.2 Recommendations

131. In relation to forecasting other income and disposals, the ENA:

a) Supports the use of ENB specific historical data for forecasting asset disposals and other regulated income.

[23] We note that there has been some confusion in the past about what constitutes a disposal, with some ENBs making errors in their treatments. The Commission's workshop in March 2014 clarified the correct treatments and this is likely to be reflected in the 2014 disclosures.

b) Notes that errors in the proposed inflation adjustments have been identified, and understands that these are to be corrected before the final price paths are determined.

c) Submits that a business specific gain/loss on disposal percentage should be derived from historical information which will better align with the disposal forecasts.

Attachment A – Real revenue growth

The top down method which underpins the analysis presented below derives real revenue growth for residential and non-residential consumers for each non-exempt ENB[24] from:

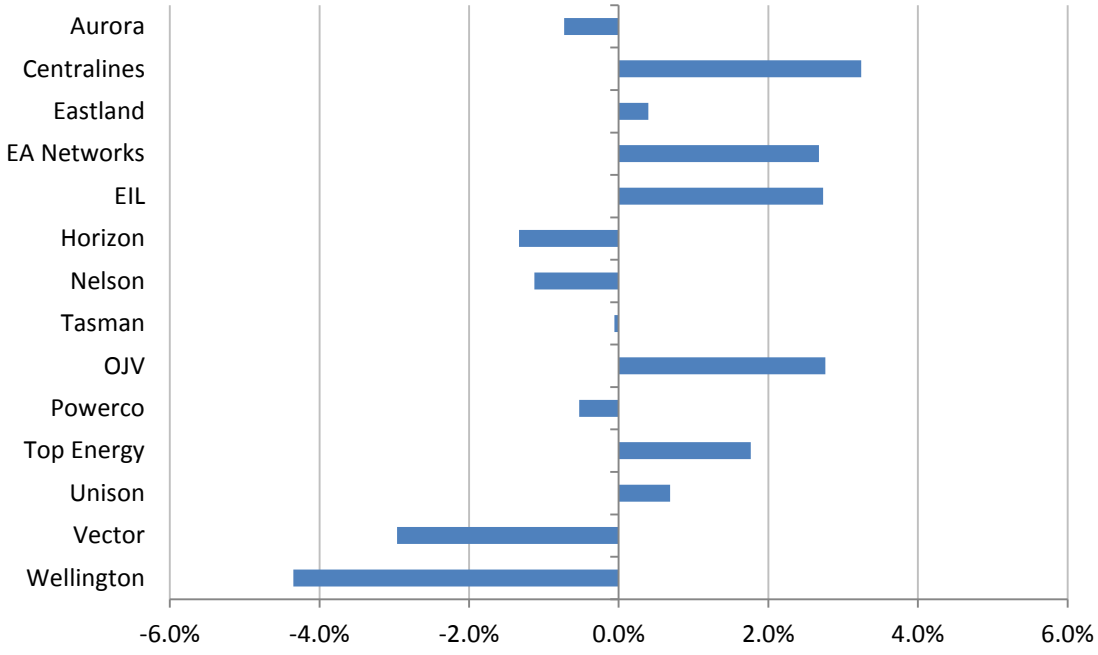
- Total electricity lines charge revenue after the deduction of transmission revenues for:
    - Residential (or small/mass-market customers)
    - Commercial/industrial (other customers)
- Annual price adjustments.

In addition data for ICPs and MWh by consumer group has been sourced from each non-exempt ENB. This, together with regional population and GDP data (sourced from Statistics NZ) has been used to test the performance of each element of the real revenue growth forecasting method over the current regulatory period. Regional allocations have been undertaken using a consistent method to that adopted in the 2012 reset.

A) Residential consumers

Figure A1 shows that the actual real revenue growth for residential consumers has diverged considerably from that assumed in the 2012 reset. There are both positive and negative differences.[25]

Figure A1: Difference between annual average constant price residential revenue growth (2010-14) and 2012 DPP forecast

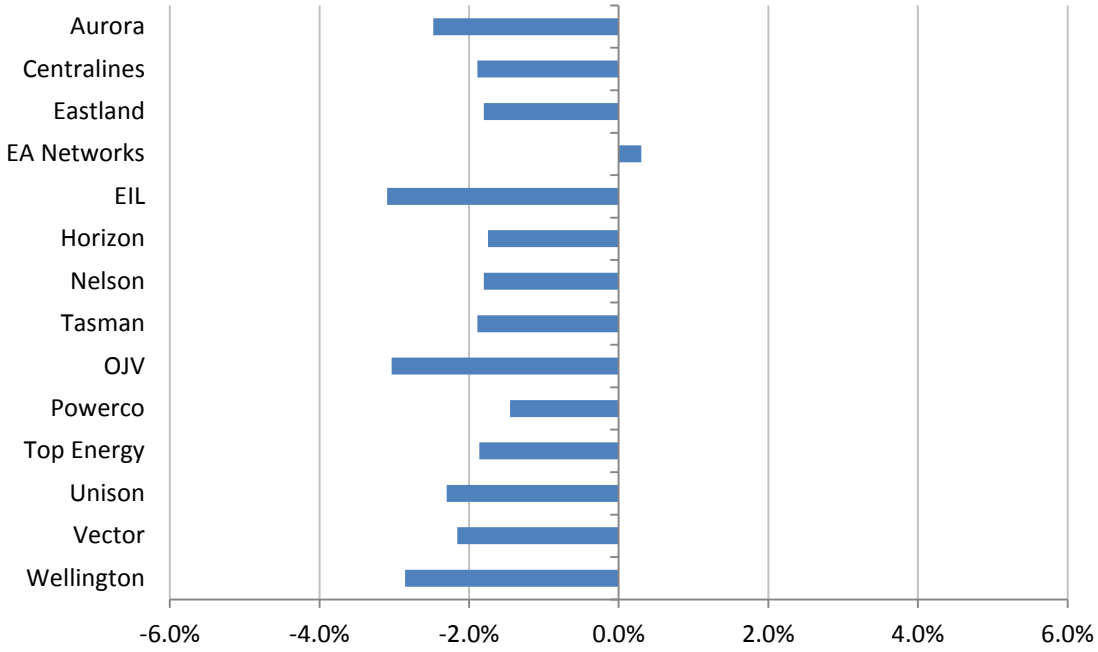


[24] Due to tariff design and restructures undertaken within the current regulatory period, Alpine Energy and The Lines Company have been unable to provide the data we requested within the time available.

[25] Unison has noted that the positive revenue increase results from revenue assurance activities, where retailers have incorrectly assigned consumers to wrong tariff categories. As shown in the following tables underlying volume changes were negative relative to the Commission's forecasts.

One of the assumptions which is not supported by the data is the assumption that residential energy use does not change. Figure A2 below shows that for most ENBs, residential energy use has fallen on a per customer basis, typically between 1% and 3% per annum.

Figure A2: Difference between average annual growth rate in kWh per residential ICP (2010-14) and DPP assumption of 0%



Population forecasts are used to estimate residential ICP growth. This approach appears to have over-estimated actual residential ICP growth for most ENBs in the current regulatory period, as demonstrated in Figure A3.

Figure A3: Average annual difference between growth of residential ICPs and population (2010-14)

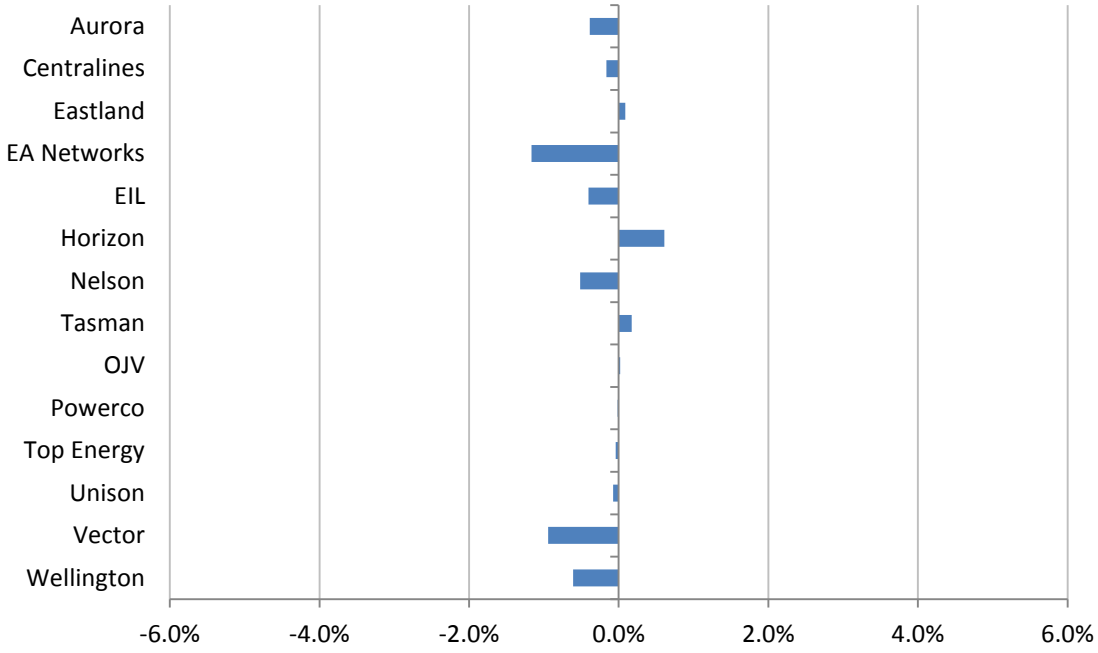
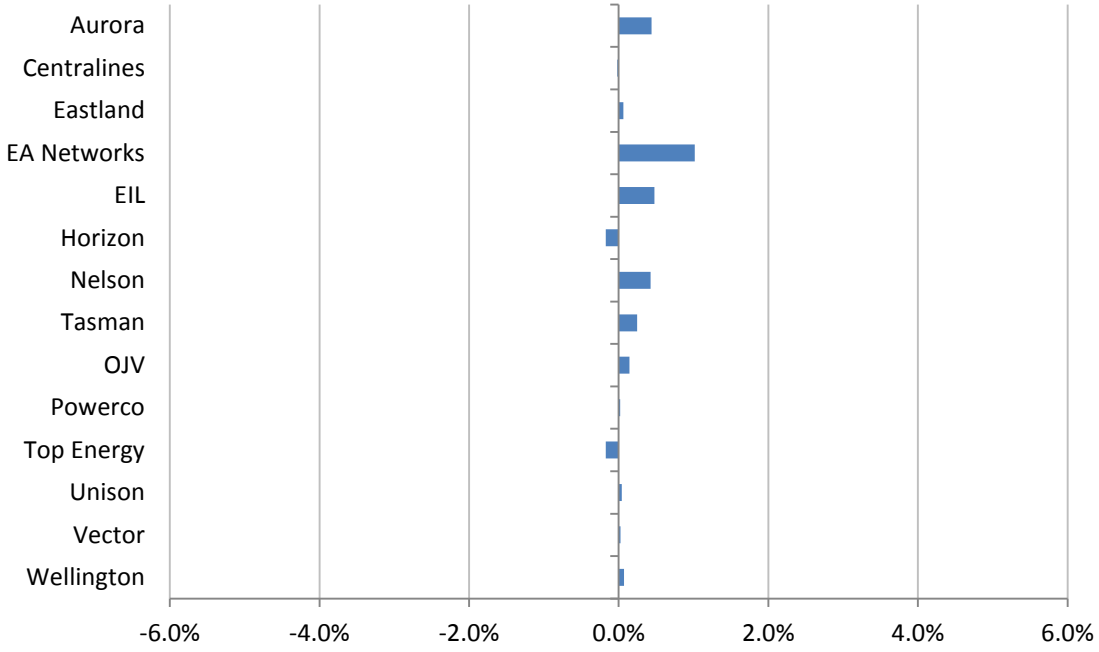


Figure A4 below shows that the population projections applied in the 2012 reset diverged from actual outcomes for some ENBs, notably those located in the South Island.

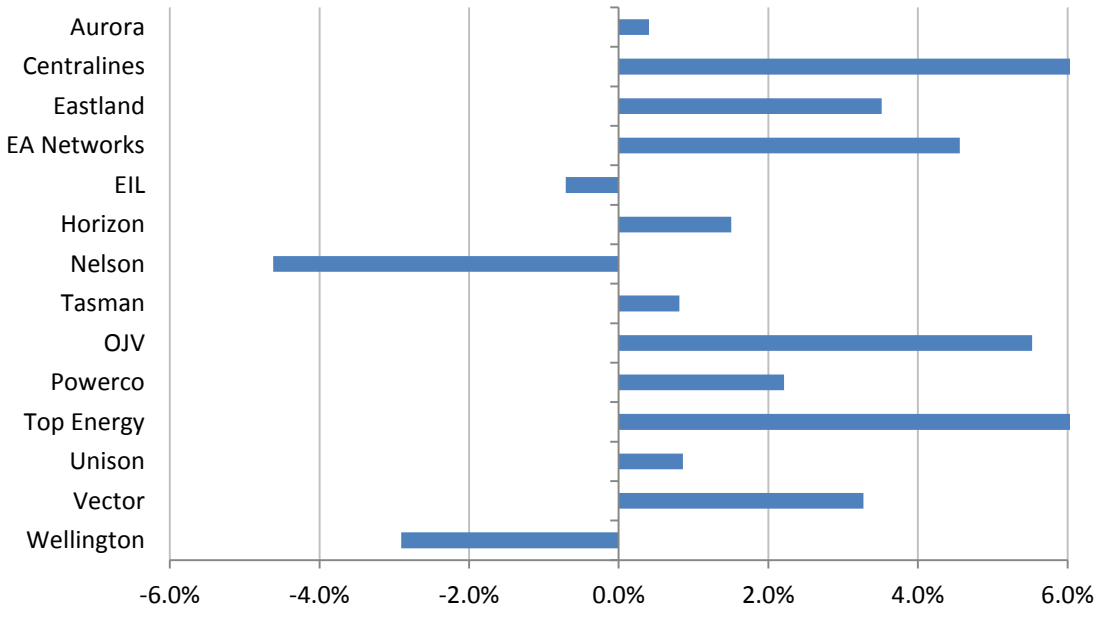
Figure A4: Difference between annual average population growth (2010-14) and 2012 DPP forecast



A2) Commercial and industrial consumers

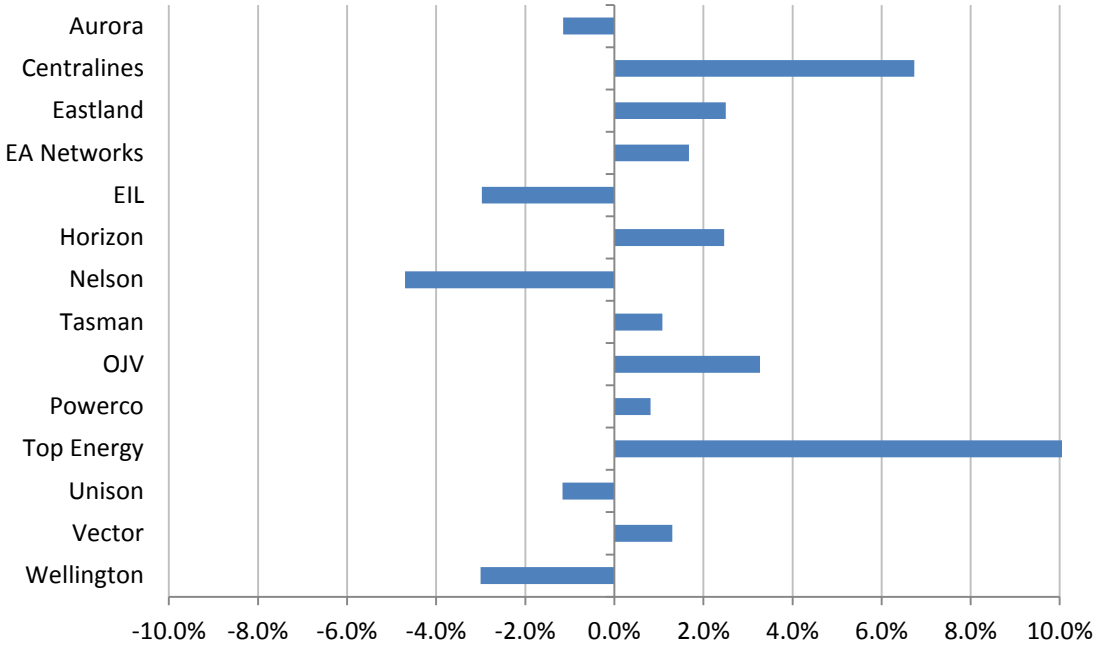
Figure A5 shows that the actual real revenue growth for commercial/industrial consumers has also diverged considerably from that assumed in the 2012 reset. As for residential consumers there are both positive and negative differences.

Figure A5: Difference between annual average constant price commercial & industrial revenue growth (2010-14) and 2012 DPP forecast



The forecasting method assumes regional GDP is the main driver of commercial/industrial real revenue growth. Figure A6 below shows the actual regional GDP growth has not correlated well with the real revenue growth for each business to FY13. Regional GDP data is not yet available for FY14.

Figure A6: Difference between average annual growth of constant price commercial & industrial revenue and real GDP (2010-13)



We also note that, as illustrated in Figure A7 below, the actual regional GDP growth for FY10-FY13 has differed to the projections included in the 2010 reset model. We note it has been generally stronger in the regions, and weaker in Wellington and Auckland than predicted.

Figure A7: Difference between annual average real GDP growth (2010-13) and 2012 DPP forecast