# *Submission to the Commerce Commission*

on

## Low Cost Forecasting Approaches For Default Price-Quality Paths

Made on behalf of 19 Electricity Distribution Businesses

*PwC submission on behalf of group of 19 EDBs*

*15 August 2014*

# Table of contents

# Submission on DPP Reset: Low Cost Forecasting Approaches

## Introduction

1. This paper forms our submission on the Commerce Commission's (Commission) paper, "Low Cost Forecasting Approaches For Default Price-Quality Paths" released on 4 July 2014 (the DPP Forecasting Paper) and accompanying models.[1] This submission has been prepared by PricewaterhouseCoopers (PwC) on behalf of the following 19 Electricity Distribution Businesses (EDBs or distributors):

- Alpine Energy Limited
- Aurora Energy Limited
- Buller Electricity Limited
- Eastland Network Limited
- EA Networks
- Electricity Invercargill Limited
- Horizon Energy Distribution Limited
- MainPower New Zealand Limited
- Marlborough Lines Limited
- Nelson Electricity Limited
- Network Tasman Limited
- Network Waitaki Limited
- Northpower Limited
- OtagoNet Joint Venture
- The Lines Company Limited
- The Power Company Limited
- Top Energy Limited
- Waipa Networks Limited
- Westpower Limited.

2. Together these businesses supply 26% of electricity consumers, maintain 44% of total distribution network length and service 75% of the total network supply area in New Zealand. They include both consumer owned and non-consumer owned businesses, and urban and rural networks located in both the North and South Islands.

[1] As published at http://www.comcom.govt.nz/regulated-industries/electricity/electricity-default-price-quality/default-price-quality-path from 2015

3. The DPP Forecasting Paper outlines the proposed approach to forecasting the inputs necessary to determine price paths, based on the current and projected profitability option for resetting the price path. These price paths are to apply to 16 non-exempt EDBs (all except Orion New Zealand) from 1 April 2015.

4. The DPP Forecasting Paper is one of a number of papers and supporting models which make up the consultation material for the forthcoming DPP reset. We have also submitted today on the DPP Policy Paper.[2] We plan to make further submissions on the remaining papers[3], to be submitted by 29 August.

5. This submission presents the views of the 19 EDBs which support this submission, and largely follows the structure of the DPP Forecasting Paper. We also note and support the ENA's submission on the DPP Forecasting Paper.

6. We trust this submission provides useful input in setting the 2015 DPP. We would be happy to answer any questions you may have regarding this paper.

7. The primary contact for this submission is:

Lynne Taylor
Director
PricewaterhouseCoopers
lynne.taylor@nz.pwc.com
(09) 355 8573

[2] Commerce Commission, Proposed Default Price-Quality Paths For Electricity Distributors From 1 April 2015, 4 July 2014

[3] As published at http://www.comcom.govt.nz/regulated-industries/electricity/electricity-default-price-quality/default-price-quality-path from 2015

# Summary

8. In summary we submit:

   a. The DPP price path should be set using information and estimates which are as current as possible at the time of the reset, and generate reasonable outcomes for each non-exempt EDB.

   b. The proposed forecasting approach contains a number of assumptions and estimates which are not supported by empirical evidence and reflect judgements which we believe result in unreasonably low price paths. These include:

      - A low base year for opex
      - A 0% opex partial productivity estimate contrary to the empirical evidence which supports a negative value
      - A constant energy intensity assumption for residential consumers, contrary to empirical evidence which shows declining energy intensity for households
      - Use of the all industries LCI despite evidence that industry labour cost inflation consistently exceeds economy wide labour cost inflation
      - Capex caps which penalise certain businesses (and not others) depending on structural arrangements and network strategies.

   c. In addition, we believe that the forecasting models used in 2012 have not performed well. Actual real revenue growth to FY14, and actual opex to FY14 have diverged considerably from the forecasts assumed when setting the price path in 2012. We therefore do not consider the same models should be used without further refinement.

   d. For opex, we submit that the following changes are made:

      - Base year opex is derived from an average of FY13 and FY14 opex, with input price and scale adjustments applied to the FY13 data
      - The opex partial productivity assumption is modified to reflect the findings of the empirical analysis undertaken by Economic Insights and Pacific Economics Group, and a value of -2% is adopted
      - The labour cost index forecast is adjusted to reflect the historical differential (which is positive) between industry specific and all industry labour cost inflation
      - Population projections are no longer used to estimate ICP growth. ICP growth should be extrapolated from historical trends for each EDB, in the same way as circuit length growth
      - The econometric analysis which supports the scale adjustments is updated for actual FY14 data.

   e. For capex, we submit that:

      - Any EDB which has a 110% 'forecasting penalty' cap applied to their network capex forecast has the opportunity to explain why their actual capex was less than forecast. Businesses with reasonable explanations (such as the impact of the related party rules, or capex efficiencies due to innovation) should have the penalty removed
      - The proposed sliding scale for non network capex is non linear, and thus increases quickly immediately after the 5% cap is reached. We therefore submit that the 5% trigger for the

sliding scale cap for non-network capex is removed, and all non network capex is subject to the 200% cap. This is required as otherwise some networks with certain types of business structures or investment strategies are unduly penalised.

f. For real revenue growth we submit:

- The proposed model is abandoned, because it has performed poorly in the current regulatory period
- In its place historical data for each EDB is used to extrapolate real revenue growth by consumer type, and an end of period wash-up is introduced to adjust for differences between actual and forecast volumes.

g. For disposals and other regulated income:

- The errors identified in converting historical data to nominal forecasts are corrected
- Gains/losses on disposals are derived for each EDB from historical data, to improve consistency with disposals forecasts.

h. For CPI revaluations, we submit:

- A wash-up for the errors between actual and forecast inflation is included in the price path, to ensure neither suppliers or consumers are exposed to inflation forecasting risk
- The wash-up is applied at the reset to adjust for the significant error, in favour of consumers, in the current regulatory period. This preserves financial capital maintenance over the life of the assets, which is the condition on which the revaluation approach relies.

9. The body of this submission explains the rationale supporting our key submission points, summarised above.

# Proposed approach

10. It is proposed that the price path is to be reset with reference to current and projected profitability, using similar methods used to set the price path in 2012. A number of refinements are proposed to improve the forecasting methods, and update the information which is relied on.

11. Key forecasts include:

    - operating expenditure
    - capital expenditure
    - revenue growth
    - asset disposals
    - other regulatory income
    - cost of capital
    - asset revaluations.

12. We comment on the proposed methods, assumptions and data in the remainder of this submission.

# Opex forecasts

## Methodology

13. It is proposed that the opex forecasting methodology which was developed for the 2012 DPP price path reset is retained for the forthcoming reset. In applying this method, it is proposed that the data is updated with current estimates and recent historical actuals in order to generate more up to date forecasts.

14. The opex forecasting method involves establishing a base level of opex (prior to the regulatory period) for each non-exempt EDB, and projecting it forward with adjustments for:

- changes in scale
- changes in input prices
- changes in expected operating efficiency.

## Opex in the next period

15. We understand that the DPP is intended to apply relatively low cost forecasting approaches that do not necessarily reflect the specific requirements of each business. However we would expect that a forecasting method would generate variances that fall within a reasonable range. If that is not the case, then as previously submitted, we believe that the approach should be re-considered and refined before it is applied in subsequent regulatory periods.

16. The proposed opex allowances for the next regulatory period demonstrate notable variances to the forecasts prepared by EDBs, as part of their annual asset management planning exercise.

**Figure 1: DPP Opex and AMP Forecasts (FY16-FY20)**

| | Total Opex Forecast (FY16-FY20): DPP vs AMP Forecast | | | |
|---|---|---|---|---|
| $000 nominal | DPP Forecast | 2014 AMPs | Variance | Variance (%) |
| Alpine Energy | 69,917 | 78,430 | -8,513 | -12.2% |
| Aurora Energy | 108,310 | 113,242 | -4,932 | -4.6% |
| Centralines | 23,099 | 15,649 | 7,450 | 32.3% |
| Eastland Network | 41,777 | 59,055 | -17,278 | -41.4% |
| EA Networks | 44,313 | 49,538 | -5,225 | -11.8% |
| Electricity Invercargill | 30,449 | 25,583 | 4,866 | 16.0% |
| Horizon Energy Distribution | 38,890 | 43,566 | -4,676 | -12.0% |
| Nelson Electricity | 13,431 | 11,962 | 1,469 | 10.9% |
| Network Tasman | 48,622 | 42,747 | 5,875 | 12.1% |
| OtagoNet Joint Venture | 35,342 | 38,100 | -2,758 | -7.8% |
| Powerco | 380,117 | 396,114 | -15,997 | -4.2% |
| The Lines Company | 53,777 | 56,557 | -2,780 | -5.2% |
| Top Energy | 72,674 | 69,379 | 3,295 | 4.5% |
| Unison Networks | 183,277 | 188,994 | -5,717 | -3.1% |
| Vector | 564,478 | 618,183 | -53,705 | -9.5% |
| Wellington Electricity Lines | 162,693 | 191,712 | -29,019 | -17.8% |
| **Total** | **1,871,167** | **1,998,812** | **-127,645** | **-6.8%** |

17. The data summarised above demonstrates that:

- 9 of the 16 EDBs have opex forecast variances of more than 10%
- another 3 of the 16 EDBs have opex variances of between 5 and 10%
- 11 of the 16 EDBs have opex allowances lower than their own forecasts.

18. We are concerned that this outcome may reflect deficiencies in the forecasting approach. We note that a strengthened opex incentive mechanism is proposed to be introduced into the DPP for the next regulatory period.[4] We will be submitting on this proposal in a forthcoming submission however we note that it is critically important that the baseline opex allowance is reasonable before the proposed incentive scheme will operate effectively. Otherwise the incentive adjustment is at risk of penalising or rewarding EDBs and consumers for forecast error.

19. Accordingly we have examined the elements of the proposed opex forecasting approach, which is presented below. We also note and support the analysis of opex undertaken by the ENA and the recommendations included in the ENA's submission on the DPP Forecasting Paper.

## Base year opex

20. One of the key issues identified with the proposed approach is the reliance on the data used to determine the base year opex. We have previously submitted that, as a general principle, base year data should include recent opex information because it better reflects current operational and structural arrangements, recent productivity improvements, actual input costs and current network scale. We have also supported the use of data drawn from more than one year to potentially offset abnormalities that may exist in a single year of data, with appropriate scale and input price adjustments. This option was signalled in the Process and Issues Paper.

21. We are surprised at the Commission's proposal to ignore FY14 data in favour of relying solely on FY13 data. We are concerned that the main reason for this appears to be that actual FY13 opex is lower than expected FY14 opex. We refer the Commission to the ENA's analysis in this respect which demonstrates that it is FY13 which is off trend, due primarily to abnormally low maintenance. The outage statistics presented show that FY13 was an unusually benign year for unplanned outages for the majority of non-exempt EDBs.[5]

22. This year on year trend suggests that a combination of more than one year of data is a reasonable approach to avoid bias in the forecasts which may arise from annual variation. The table below shows the potential base year opex allowances derived from FY13 opex (including one year of scale and price adjustments), FY14 opex and FY13+FY14 opex combined (including scale and price adjustments to the FY13 data). The FY14 data is actual data sourced from EDBs, which is shortly to be disclosed as part of annual disclosures.

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

[5] We note that while it may be possible to reduce planned maintenance to some extent to offset higher than anticipated unplanned maintenance, this is unlikely to have a significant impact as these tasks may be undertaken by different resources, at different times and locations, under different arrangements, and delivering the scheduled maintenance plan is an important factor in maintaining underlying service quality.

**Figure 2: Base Year Opex Allowance**

| $000 (FY14) | Base Year Opex: FY13 vs FY14 (FY14 Scale & Prices) FY13 | FY14 | Average | % Change Avge – FY13 |
|---|---|---|---|---|
| Alpine Energy | 12,600 | 15,272 | 13,936 | 10.6% |
| Aurora Energy | 19,342 | 22,317 | 20,830 | 7.7% |
| Centralines | 4,324 | 4,333 | 4,328 | 0.1% |
| Eastland Network | 7,566 | 7,811 | 7,689 | 1.6% |
| EA Networks | 7,936 | 8,127 | 8,031 | 1.2% |
| Electricity Invercargill | 5,467 | 4,814 | 5,141 | -6.0% |
| Horizon Energy Distribution | 7,129 | 7,731 | 7,430 | 4.2% |
| Nelson Electricity | 2,392 | 2,232 | 2,312 | -3.3% |
| Network Tasman | 8,640 | 8,543 | 8,592 | -0.6% |
| OtagoNet Joint Venture | 6,416 | 7,679 | 7,047 | 9.8% |
| Powerco | 66,395 | 67,818 | 67,106 | 1.1% |
| The Lines Company | 9,926 | 10,693 | 10,310 | 3.9% |
| Top Energy | 13,265 | 12,554 | 12,910 | -2.7% |
| Unison Networks | 33,329 | 34,854 | 34,091 | 2.3% |
| Vector | 97,526 | 106,706 | 102,116 | 4.7% |
| Wellington Electricity Lines | 28,362 | 29,611 | 28,987 | 2.2% |
| **Total** | **324,198** | **351,095** | **337,647** | **4.1%** |

23. We submit that combined FY13 and FY14 data should be used because it ensures the data is current, and avoids the year on year variations illustrated above, and in more detail in the ENA submission.

24. We note that selecting a low opex base year generates a level of forecast opex which is inconsistent with the quality of supply targets. Thus businesses will not be provided with sufficient opex to maintain quality standards consistent with the target. Accordingly we do not support using a low base year approach, as proposed. In addition EDBs have a number of obligations they must meet via legislation, regulation, industry codes or commercial arrangements. Sufficient opex must be provided to ensure they are able to meet these obligations efficiently, safely and prudently.

25. The DPP Forecasting Paper suggests that EDBs have been incentivised to inflate their FY14 opex spend on the assumption that it was to be used to determine forecasts for the next regulatory period. We note that this statement is somewhat speculative, and there is no evidence presented to support it. Further, the trend analysis presented by the ENA shows that the FY14 opex level is a continuation of a trend of rising opex since FY10 - when expressed in constant price and constant scale terms (using the DPP methods for price and scale adjustments). As noted above, there is evidence which shows that FY13 is the outlier year, which is supported by the abnormally low outage statistics in that year.

## *Network scale adjustments*

26. We agree that if a base year approach is used, then adjustments for expected changes in network scale should be made. In this respect we note that:

- Scale projections should be derived from as up to date information as possible, and thus FY14 data should be included in the econometric modelling before the price paths are finalised
- We note that some outlier data has been removed from the model but is not clear what criteria were applied to determine the "outliers". For example Orion's FY11 data is removed but not FY12, however FY12 was the year in which the full impact of the

earthquakes was first recorded, because the most catastrophic earthquake occurred late in FY11

- Regional population growth since FY10, does not appear to have tracked well with ICP growth, as illustrated below:

**Figure 3: Population Growth and ICP Growth**

| | Population and ICPs: FY10-FY14 (average annual growth rate) | | | | |
|---|---|---|---|---|---|
| | Population | Total ICPs | | Domestic ICPs | |
| | % | % | Variance | % | Variance |
| Alpine Energy | 0.6% | 0.6% | 0.0% | 0.0% | 0.6% |
| Aurora Energy | 1.1% | 0.8% | 0.3% | 0.7% | 1.1% |
| Centralines | -0.1% | 1.3% | -1.4% | -0.3% | -0.1% |
| Eastland Network | 0.1% | 0.0% | 0.0% | 0.1% | 0.1% |
| EA Networks | 1.7% | 0.9% | 0.8% | 0.5% | 1.7% |
| Electricity Invercargill | 0.5% | 0.0% | 0.5% | 0.1% | 0.5% |
| Horizon Energy Distribution | -0.4% | 0.2% | -0.6% | 0.2% | -0.4% |
| Nelson Electricity | 1.0% | 0.4% | 0.5% | 0.5% | 1.0% |
| Network Tasman | 0.9% | 0.9% | 0.0% | 1.1% | 0.9% |
| OtagoNet Joint Venture | 0.1% | 0.0% | 0.1% | 0.1% | 0.1% |
| Powerco | 0.6% | 0.6% | 0.0% | 0.5% | 0.6% |
| The Lines Company | -0.3% | -0.9% | 0.6% | -0.8% | -0.3% |
| Top Energy | 0.1% | 0.5% | -0.4% | 0.1% | 0.1% |
| Unison Networks | 0.3% | 0.4% | -0.1% | -1.8% | 0.3% |
| Vector | 1.5% | 0.6% | 0.9% | 0.6% | 1.5% |
| Wellington Electricity Lines | 0.8% | 0.1% | 0.7% | 0.2% | 0.8% |

- We note adjustments have been made to line length data after consulting with some EDBs. It does not appear that similar adjustments have been incorporated into the data used for the productivity analysis.
- We believe that extrapolation of historical circuit km growth rates is a reasonable forecasting approach, in the absence of a forecasting proxy for circuit km. We also suggest historical extrapolation may be a better method for forecasting changes in connection growth, given the relatively poor performance of the regional population forecasts in replicating ICP growth for the current regulatory period.

# Partial productivity

27. The EDBs which support this submission are not experts in productivity measurement or productivity forecasting. We are therefore interested in the views of the experts. We note that the Commission's expert Economic Insights (EI)[6] has undertaken a statistical exercise which concludes that for NZ EDBs, opex partial productivity average annual growth has been in the range of **-0.1% to -0.8 %** over the past decade (page iv). EI explains that this reflects the fact that output growth has slowed, and opex quantities have grown strongly.

[6] Economic Insights, Electricity Distribution Industry Productivity Analysis: 1996-2013, 24 June 2014

28. The ENA has also engaged expert advice on the same matter from Pacific Economics Group (PEG)[7]. PEG concludes that the EDB opex partial factor productivity trend was between **-1.58% and -2.04%** per annum between 2001 and 2012 (page 4).

29. EI recommends that an:

> *"opex partial productivity growth rate of zero would strike the appropriate balance between recognising the apparent changed circumstances facing electricity distribution over the last decade, while anticipating a return to more positive, albeit reduced compared to the period before 2007, output growth while providing incentives for efficiency improvements"* (EI page iv)

30. PEG however recommends an opex partial factor productivity trend of **-2.04%**, because this value is derived consistent with the two output specification that the Commission uses for scale adjustments to opex (PEG page 5).

31. After considering the expert analysis and recommendations we do not support the proposal to adopt a **0%** opex partial productivity factor because:

    - both expert reports contain empirical evidence of negative opex partial productivity trends for EDBs, and no evidence which supports a nil trend
    - while EI is an expert in the statistical methods which are employed to calculate the productivity trends, we do not consider that the EI recommendation for adopting a 0% assumption is credible because this recommendation relies on assumptions which do not reflect the expertise for which EI has been engaged, and the recommendation is not supported by empirical evidence.

32. Accordingly, we support the ENA submission which submits that the Commission must provide robust evidence and reasoning for why an opex partial productivity factor which is contrary to the empirical evidence should be adopted. We consider a negative value should be used, to be derived from the data and empirical analysis undertaken by EI and PEG. In this respect we note PEG's recommendation that it is necessary to retain consistency with the scaling coefficients used elsewhere in the opex forecast. For this reason the ENA submits a **-2%** value is appropriate, and we support this proposal.

## *Input price inflation*

33. It is proposed that forecasts of all industry labour (LCI) and producers (PPI) indices are used (with a weighting of 60:40) to allow for input price inflation over the regulatory period. We have previously suggested that more industry specific cost indices should be incorporated into these forecasts if possible. This view was supported by the ENA's Forecasting Working Group, and summarised by Frontier Economics in their submission on the Process and Issues Paper.

34. We note the analysis presented by the ENA which compares the Statistics NZ LCI index, and the Electricity, Gas and Water (EGW) subsector index. The EGW index consistently exceeds the all industry index.

35. This data provides an explanation as to why the current forecasting approach may have underestimated opex growth in the current regulatory period. We would encourage the Commission to consider further the proposal by the ENA to include a margin on the LCI forecast to reflect the evidence presented by the ENA. This shows that industry wage pressure has exceeded economy wide wage pressure since mid 2012, and we expect this trend will continue for the foreseeable future.

[7] Pacific Economics Group, Productivity Trends of New Zealand Electricity Distributors, June 2014

# Capex forecasts

## Methodology

36. The DPP Forecasting Paper proposes that capex is forecast based on EDB AMP capex forecasts, subject to certain adjustments to be applied under certain circumstances. For the purpose of this discussion we have ignore adjustments for proposed spur asset acquisitions, which are addressed in our accompanying submission on the DPP Policy Paper.

37. We agree with a forecasting approach which is based on suppliers' own capex forecasts, because these forecasts are most relevant to the demands and status of each network, and thus are tailored to meeting the needs of the consumers serviced by each network. In addition we note that other potential capex forecasting methods are not readily available and none of the alternative options[8] have been tested in the context of Part 4 price-quality regulation.

38. We understand the desire to limit capex allowances where forecasts are notably above historical levels. We consider this is a pragmatic approach which is suitable for the DPP. The challenge arises in determining how the cap is applied.

39. It is proposed that:

    - March 2014 forecasts sourced from AMP disclosures form the base data, expressed in constant price terms
    - a forecast of the capital goods price index (CGPI) is applied to convert the forecasts into nominal terms
    - caps of either 120% or 110% of the historical average are applied to network capex (expressed net of capital contributions). The lower cap applies where actual capex has been significantly lower than the 2010 forecast capex which was used to set the 2012 DPP price paths
    - caps of 200% are applied to non-network capex, unless non-network capex makes up more than 5% of total capex. If this is the case, a sliding scale limit is proposed with a minimum 120% cap applied where non-network capex makes up 25% of total capex.

40. We suggest that FY14 data should be included in the analysis before the final capex forecasts are determined.

## Actual vs 2010 forecast

41. In considering the caps, outturn capex data relative to 2010 forecasts has been used. We note that new regulatory rules were implemented after 2010 which changed the way in which capex was allocated and recorded for regulatory reporting purposes. The 2010 forecasts were prepared prior to the implementation of the new rules. The changes introduced into the IMs include:

    - new rules for establishing the value of related party transactions in respect of commissioned assets
    - new cost allocation rules
    - new rules for how interest during construction is calculated

[8] A number of alternative capex forecasting options were discussed in the Process and Issues Paper.

- different ways of valuing vested assets.

42. FY13 disclosure statements include FY10-FY12 commissioned asset data prepared consistent with the IMs. A comparison of these disclosures, with the previously disclosed commissioned asset data (as per FY10, FY11 and FY12 disclosures) shows the financial impact of the new rules for each EDB. Our analysis of disclosure data shows that all EDBs were required to adjust the value of commissioned assets for FY10-FY12, in order to align them with the IMs.

43. Of particular note is the impact of the new related party transaction rules. These capped the values able to be assigned to related party capex. This resulted in lower values of commissioned assets relative to forecasts due to the change in valuation rules for some EDBs. We therefore submit that it is not appropriate to apply a 'forecasting accuracy' penalty where there are legitimate differences between the measurement of actual capex and the basis of the forecasts. The differences are a consequence of changes to the regulatory rules for recording capex.

44. We also believe that the proposed forecasting penalty, in practice, penalises EDBs in the forthcoming regulatory period, where they have made efficiency gains within the current regulatory period. Networks have made innovations which have caused them to modify their expenditure plans. Annual AMP updates illustrate these changes. Innovation has caused some networks to reduce their capex from that planned, and customer connection and asset relocation capex is highly dependent on the decisions of others. As a result a lower RAB than previously forecast will be incorporated into the next price path, and consumers will benefit from lower prices than they otherwise would have incurred. This behaviour is entirely consistent with the purpose statement and should be encouraged not penalised.

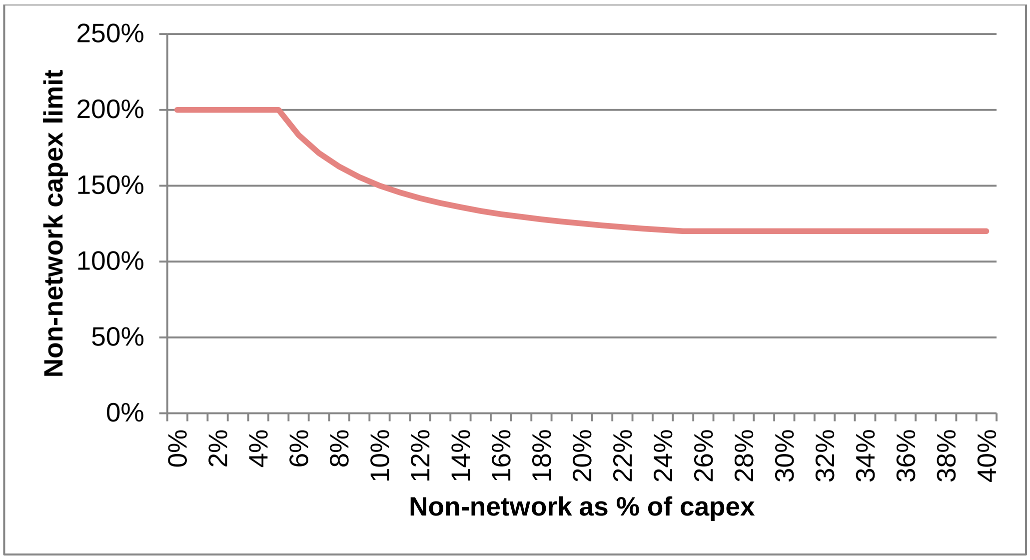
45. Accordingly we suggest that businesses for which a forecasting penalty is proposed, are given the opportunity to explain why the actual outturn was lower than the forecast, and assuming a reasonable explanation is available, the penalty should be removed or reduced. We believe this is achievable, and consistent with ensuring the proposed forecasting method is fit for purpose.

## Non network capex

46. For non network capex, a cap is to be applied if forecast capex exceeds 200% of the annual average. However where non network capex is more than 5% of total capex, a sliding scale is proposed. We do not support the 5% threshold as it penalises businesses with different structural arrangements particularly those that undertake most of their activities using in-house arrangements. It also penalises those businesses with more investment in supporting systems which support a smart grid strategy.

47. We also not that the proposed caps and scaling factors are somewhat arbitrary, and in some cases overly punative. For example the proposed sliding scale for non-network capex is non-linear. Thus once the 5% threshold is breached the proposed scale adjustments change quickly, as illustrated below:

**Figure 4: Non-network capex sliding scale**




48. We therefore submit that the 200% cap is applied to all non-network capex. We agree with the higher cap for non network capex relative to network capex, because non-network capex is more variable year on year.

## Retention factors

49. We note that the proposed capex expenditure efficiency incentive is to include a retention factor of 20%. While we will be commenting in more detail in our forthcoming submission on the expenditure efficiency schemes, we understand that the relatively low retention factor is partly influenced by the low cost forecasting method proposed. We support the intent to equalise efficiency incentives within and between regulatory periods.

50. We are concerned however that the proposed caps mean that not all EDBs are starting from a similar position, because for those where the capping is material, significant efficiencies must be made in order to reach the DPP forecast capex allowance, before the incentive comes into play.

# Real revenue growth

## Impact on price path

51. The real revenue growth assumptions are important as they attempt to predict the amount of revenue a distributor will earn from changes in billable quantities during the regulatory period, and make adjustments for that revenue (ie: reduce the price path where expected real revenue growth is positive). If actual real revenue growth differs to that forecast, distributors will either under or over recover relative to allowable revenue.

## Proposed approach

52. The proposed approach to estimating real revenue growth is the same as that adopted for the 2012 reset, and is summarised in Chapter 5 and Attachment C of the DPP Forecasting Paper.

53. Real revenue growth for residential consumers is forecast by estimating:

    - ICP growth, which is estimated from regional population forecasts
    - changes in electricity use per residential consumer, which is assumed to be nil based on Commission analysis
    - proportion of line charge revenue recovered from residential consumers, and the weighting of fixed and variable residential revenues (from EDB data)

54. .Real revenue growth for commercial/industrial consumers is forecast by estimating:

    - regional GDP growth, which is estimated from NZIER forecasts with regional allocations to EDBs, determined by energy supplied to each GXP using data from the Electricity Authority
    - elasticity of constant price commercial/industrial revenue to GDP, based on Commission analysis
    - proportion of line charge revenue recovered from commercial/industrial consumers (from EDB data).

55. Evidence compiled by the ENA suggests that this forecasting approach has not performed well in the current regulatory period. [9] In particular we note that:

    - actual ICP growth and regional population growth have diverged for total consumers and residential consumers (as illustrated in the previous section)
    - actual regional GDP growth does not align well with the forecasts which were relied upon, notably Auckland and Wellington actuals are less than forecast, and the regions are higher
    - the energy intensity assumption for residential consumers is not supported by the data from the current period, which shows an overwhelming trend of lower energy use per residential ICP
    - the real revenue growth estimates by customer group which have been estimated by the ENA show considerable divergence to those predicted at the time the 2012 DPP was reset.

[9] Refer ENA submission, Attachment A, 15 August 2014

56. With regard to the third bullet point above, we note that the ENA has presented evidence compiled by Sapare Research Associates which considers how electricity consumption per residential consumers is likely to change in the future, given the recent trend of declining energy intensity. This counters the suggestion in the DPP Forecasting Paper that there are unlikely to be further reductions in residential energy intensity because electricity price increases are starting to moderate, economic activity is picking up and electric cars are becoming viable. As noted by the Sapare, there are a number of other factors which will influence future residential energy consumption which suggest that the current trend for declining energy use will continue.

57. We therefore do not support the assumption of no change in energy intensity for residential consumers.

## *Modified approach*

58. The EDBs which support this submission are concerned that the real revenue growth forecasting approach which is proposed has not performed sufficiently well in the current regulatory period for it to be adopted for the next regulatory period. We appreciate that an alternative model is not currently available to the Commission, although we anticipate that the current round of submissions may reveal useful suggested improvements or alternatives.

59. It is our view that there are two options available in the absence of a significantly improved forecasting model:

    - abandon the use of a forecasting model, and extrapolate real revenue growth from actual EDB historical trends
    - include a volume wash-up to correct for errors in the forecasts at the end of the regulatory period.

60. These options are not mutually exclusive, and we suggest that given the difficulty in establishing measures of real revenue growth (which requires analysis of detailed data for each EDB)[10] a volume wash-up should be included in any event. We also support abandoning the current forecasting model in favour of extrapolation of historical data for each EDB. We do not believe the current model can be retained because it has performed so poorly in the current regulatory period.

---

[10] We note that the PxQ schedules which each non exempt EDB provides in its annual DPP compliance statement include appropriately detailed historical data to calculate actual real revenue growth for each EDB.

# Other forecast items

## Other regulated income

61. Forecasts of other sources of revenue are included in the price path calculations as a deduction, in order to derive the revenue allowance which is able to be recovered from line charges. Other regulated incomes are generally a small proportion of total revenues for a lines business.

62. It is proposed to use historical data for each EDB, adjusted for inflation as the basis of the forecasts. We agree with this approach. We have noted that historical values are being deflated in error which needs to be corrected.

## Disposals

63. Forecasts of disposals are also required, as these are deducted from the RAB during the forecast period. It is proposed that historical disposal data is used for each EDB, projected forward with inflation. We note that the deflation error described above has also been applied to the disposals forecasts, which requires correction. We support the use of historical disposals data for each EDB for this purpose.

64. In addition, gains/losses on disposals are projected forward and included as other regulated income. It is proposed that an industry average of 89% loss on disposal is applied for this purpose. This masks a wide variation in the gains/losses disclosed by EDBs, and we believe that, given the disposal forecasts reflect historical data for each EDB, the gain/loss history should be used also to determine the value of gains/losses on disposals. Thus the two items will be prepared from internally consistent data, and reflect the disposal policy of each EDB.

65. The historical data series used is derived from disclosure data. We note that over the past year the Commission has provided considerable clarification as to its interpretation of the asset valuation IM in respect of disposals. This clarification has caused some business to alter their methods for determining the value of disposals and gains/losses on disposal. The Commission should be mindful of this when assessing the data it is relying on to determine these foreasts.

## Weighted average cost of capital

66. The method for deriving the weighted average cost of capital which must be used for a DPP price path is set out in the DPP IMs. We understand that the value to be applied is to be determined by the end of October, and a recent consultation paper describes the proposed process. We will respond to that paper in due course.

## CPI revaluations

67. CPI is forecast in order to determine the revaluation component of the RAB roll forward. The forecast method is specified in the DPP IMs.

68. RAB revaluation forecasts expose consumers and EDBs to inflation risk. As the RAB is reset for the next regulatory period after incorporating revaluations derived from actual inflation, financial capital maintenance is unable to be maintained over the life of the assets, where actual and forecast inflation diverge. We believe that this is contrary to the rationale which was relied on when CPI revaluations were included in the RAB roll forward method when the IMs were first determined.

69. We note that this error can go either way (ie: in favour of consumers or suppliers) and note that up to the end of FY14, it was $196m in favour of the consumers of the 16 non-exempt EDBs.[11] We therefore believe, consistent with Vector's submission, that as CPI is not able to be controlled by EDBs, there should be a wash-up mechanism which adjusts for the impact of the difference between actual and forecast inflation on RAB, at the end of the DPP regulatory period. This ensures suppliers and consumers are indifferent to the revaluation component of the RAB, over the life of the assets, as they should be. A wash-up mechanism was proposed by Vector.

70. We note that in footnote 8 of the DPP Forecasting Paper, it is suggested that a similar result could be achieved by applying forecast rather than actual inflation when revaluing the RAB. We agree that this is an option that would address the inflation risks discussed above for future regulatory periods. We believe it is inconsistent however to recognise the issue and put forward a solution in the Low Cost Forecasting Paper for future periods, at the same time as rejecting a wash-up for the error in the current regulatory period. By the end of the regulatory period, 16 non-exempt EDBs will have been denied over $200m of revenue, which they are unable to recover in future regulatory periods, due to the 2012 DPP decision over-forecasting CPI.

71. We therefore submit that a wash-up is included in the forthcoming DPP reset to adjust for the difference between forecast and actual inflation on asset revaluations, as proposed by Vector. Going forward, we agree that the same outcome could be achieved by substituting forecast rather than actual CPI when deriving the opening RAB value to be used for future DPP resets.

[11] PwC, A wash-up mechanism for the DPP revaluation rate, A report prepared for Vector, April 2014, page 5