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Dear John McLaren

Draft Decision on 2015-2020 Default Price-quality Path

1. Introduction

Wellington Electricity Lines Limited (**WELL**) welcomes the opportunity to make a submission in response to the Commerce Commission's (**Commission**) consultation paper "*Proposed Default Price-Quality Paths For Electricity Distributors from 1 April 2015*" and associated paper "*Low Cost Forecasting Approaches For Default Price-Quality Paths*" published on 4 July 2014. This submission collectively refers to these two papers as the 'Draft Decision'.

WELL's submission covers the following key issues:

- Section 2 - Executive summary;
- Section 3 - Forecast constant price revenue growth;
- Section 4 - Forecast operating expenditure;
- Section 5 - Forecast capital expenditure;
- Section 6 - Quality standards and incentives;
- Section 7 - D-factor energy efficiency scheme;
- Section 8 - Treatment of pass through and recoverable costs;
- Section 9 - Compensation for catastrophic events;
- Section 10 - Time value of money.

Attachments to this submission include:

- Attachment A – Centre for International Economics, A *review of the Commerce Commission's constant price revenue model,* August 2014;
- Attachment B – Frontier Economics, *Review of Constant Price Revenue Growth model for 2015-20 Default Price-Quality Path*, August 2014;
- Attachment C – New Zealand Institute of Economic Research, *Limitations in regional GDP projections,* August 2014;
- Attachment D – Calculation of WELL's constant price revenue growth in MS Excel.

On 18 July 2014, the Commission released a series of seven additional consultation papers on specific matters relating to the 2015-20 DPP reset, including:

- A policy paper on the proposed quality targets and incentives and supporting models;
- A policy paper on the proposed compliance regime;
- The draft DPP Determination which includes details of the price path formula;
- A policy paper and draft Input Methodology (**IM**) amendments that are intended to give effect to the proposals in the policy papers relating to the Draft Decision, quality targets and incentives, and compliance regime and the draft DPP Determination;

- A policy paper and draft IM amendments relating to the proposed opex and capex incentive schemes.

WELL will make additional submissions on each of the above consultation papers on the respective due dates. As some issues are covered, to varying degrees, across multiple consultation papers, WELL expects that the Commission will take into consideration all of the matters raised in each of WELL's submissions both individually and collectively as appropriate.

2. Executive summary

WELL's submission makes the following key points:

- The constant price revenue growth (**CPRG**) model has performed very poorly over the current regulatory period and is not statistically robust. Errors in the CPRG forecasts have significant financial impacts on both consumers and Electricity Distribution Businesses (**EDBs**). The current CPRG model does not promote outcomes consistent with the purpose of Part 4 of the *Commerce Act 1986*.
- The Commission should apply the historic growth in CPRG over the period 2011 to 2014 as the forecast for the 2015-20 period. This approach is shown to be materially better as it provides unbiased and more accurate forecasts over time.
- Applying a historical average to forecast CPRG provides a simple solution which is appropriate for a low cost DPP regime. It should not be necessary for EDBs to undertake costly CPP applications to fix the errors in the current CPRG model when a simple solution is readily available.
- The Commission should also include a wash-up for the remaining errors in the CPRG model for the 2015-20 period to mitigate the significant financial impacts on both consumers and EDBs. A longer term and efficient solution is for the Commission to implement a revenue cap during the 2017 IM review process to remove the effects of forecasting error in CPRG which cannot be managed by EDBs.
- Opex forecasts should be based on the 2014 year actual opex as this reflects the current costs required given current network scale and performance and regulatory obligations. As the analysis provided shows, 2014 actual opex does not represent an unusual year, in contrast to 2013 actual opex, which is unusual. However, if the Commission does not have confidence in relying solely on the 2014 year, it should apply a longer period average from 2011 to 2014. Either option is materially better than the proposed approach to use the 2013 year only.
- Capex forecasts should not be capped at a 20 per cent increase above historic spend and should be based on the Asset Management Plan (**AMP**) forecasts. AMP capex forecasts are developed to reflect the requirements of the network to maintain service levels, security and reliability performance and meet regulatory obligations given current asset age, condition, utilisation and risk. Capex requirements are not linear, particularly replacement capex, and therefore the proposed cap above historic is inappropriate. There is no justification as to why the capped capex forecasts are better than EDB's AMPs.
- The approach to review opex forecasts, capex forecasts and quality target thresholds in isolation from each other ignores the inter-dependencies between investment decisions and outcomes for consumers. Opex, capex and reliability are interrelated such that lowering one element will require one of the remaining two elements to increase to maintain service equilibrium. The Draft Decision proposes to cap capex below the AMP forecasts, but:
    - provides no counter balancing increase in the opex allowance, to recognise that without replacement capex, there will be increased maintenance spend required for managing older assets to maintain reliability performance.
    - is inconsistent with the proposal to increase the required level of reliability. The AMP capex forecasts are based on maintaining current reliability performance. Additional expenditure is required to improve reliability above current performance. In addition, the quality incentive would further penalise EDBs that cannot meet the increased level of reliability.

- Prudent resilience expenditure, driven by legislative changes in the Building Act, is an important and justified basis for a step change in opex and capex allowances under the current DPP. Not providing for the allowance in the price path for this expenditure is inconsistent with the Governments national infrastructure policy directives.
- Quality targets must be set consistently with the normalisation process to be applied. Amending historical data to penalise EDBs for past breaches does not afford those EDBs natural justice. By definition, the reliability limits will be exceeded 17 per cent of the time and the Commission has not found those EDBs that exceeded the limit to be at fault due to negligent or deliberate behaviour. Therefore the Commission should not edit the historic data used to set the targets, with the effect of imposing financial penalties retrospectively.
- SAIDI and SAIFI should be normalised independently. SAIFI cannot be used to normalise SAIDI. Such an approach is inconsistent with the IEEE standard and assumes that SAIFI and SAIDI are closely related for each outage event. This ignores the inverse relationship between time and frequency, therefore creating an anomaly in most situations. However, WELL and many other EDBs, would have a very low chance of exceeding the proposed SAIFI boundary given the configuration of the network. WELL has never triggered the current SAIFI boundary value over the past 10 years, however it has experienced a number of major events including storms and earthquakes, which have had significant impact on customer outage duration and SAIDI outcomes.
- The proposed D-factor scheme has good intent but does not provide positive incentives for investment in energy efficiency and demand side management. Therefore, it is neither satisfactory nor sufficient to fully achieve the objectives of section 54Q of the *Commerce Act 1986*. At best the proposed scheme provides an opportunity to potentially recover some of the revenue losses associated with such initiatives.
- Pass through and recoverable costs are third party costs which an EDB should be able to recover in full. WELL agrees with the intent to ensure this happens, however the proposed ascertainable cost method does not allow EDBs to fully recover costs as one year of non-transmission pass through and recoverable costs are never recovered. The Commission should introduce a simple annual wash up to correct for mis-forecasting of all pass through and recoverable costs.
- It is important to amend the IMs to provide certainty to EDBs that opex incurred following a catastrophic event can be recovered. However it is highly inappropriate for the Commission to explicitly exclude the recovery of lost revenue associated with a catastrophic event. Such an exclusion ensures that EDBs cannot expect ex ante to recover their efficient costs. It is recommended that the Commission does not explicitly exclude the recovery of foregone revenue in the proposed IM amendment.
- The time value of the money is the WACC and should be applied in all situations irrespective of whether EDBs are recovering costs or customers are being compensated. The WACC is determined by the riskiness of an investment (a distribution network in this case) and represents the return that EDBs or customers would forego for an investment with a similar degree of risk.
- The incremental decisions in the Draft Decision, including to cap capex forecasts, introduce more stringent quality targets and financial penalties, provide no compensation for errors in CPRG forecasts or revenue losses associated with catastrophic events, have increased the risk to investors.

The above key points are explained in detail in the remainder of this submission. WELL considers that this submission and the attached reports provide better alternative options that are appropriate for a low cost DPP and provide for the long term benefit to consumers.

3. Forecast constant price revenue growth

The Draft Decision does not acknowledge or address the majority of concerns made by WELL in relation to the fundamental errors in the CPRG model, which were set out in both WELL's submission on the issues and process paper dated 30 April 2014 and WELL's letter to the Commission dated 21 February 2014.

In particular, the Commission has not undertaken any analysis to assess how its CPRG model has performed relative to outturn data before proposing to continue using the model for the Draft Decision. CPRG forecasts have a significant impact on the price path and errors in the forecasts have significant financial impacts on consumers and EDBs.

In addition, the Commission did not issue an information request to seek the required revenue, volume and customer growth data from EDBs in a timely manner to provide stakeholders the opportunity to analyse the information for the purposes of engaging in the Draft Decision consultation process.

The Commission has an obligation under section 53P(2) of the *Commerce Act 1986* to consult with stakeholders in setting the DPP price-quality path. WELL reminds the Commission that meaningful consultation requires, among other things, that:

- Sufficient information is made available to enable parties who are consulted to be adequately informed and make intelligent and useful responses;
- The decision maker approach the matter with an open mind and must be prepared to change or even start a process afresh; and
- The decision maker provide evidence that it has, fairly and evenly, considered all the information received and gathered during the consultation process.

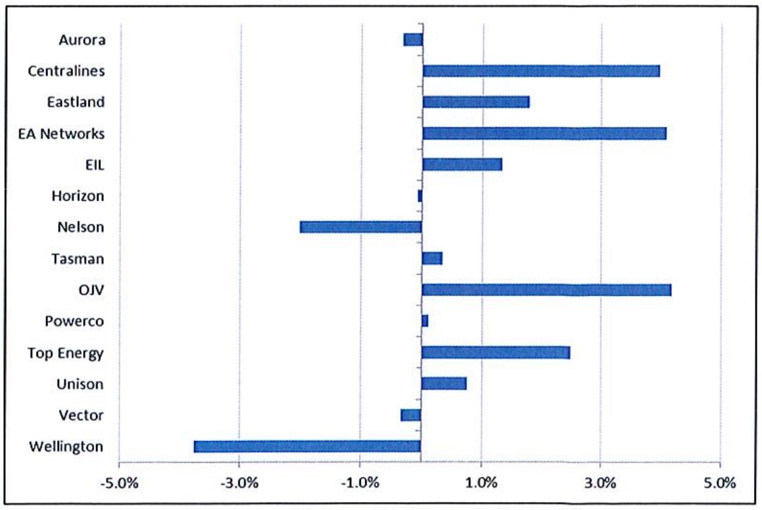
3.1. Forecasting capability of current model

WELL's previous submission and letter to the Commission explained a number of issues with the Commission's model for forecasting CPRG, including demonstrating that the model significantly over-estimated WELL's actual CPRG over the 2010 to 2014 period. This submission extends the analysis of the errors in the CPRG model to all EDBs to demonstrate that this is not a WELL specific issue and it should urgently be addressed as part of the 2015-20 DPP reset.

In absence of the Commission seeking the required data from EDBs, the ENA has therefore taken the initiative to collect this data to enable some analysis to be undertaken by PwC on the ENA's behalf. However, EDBs have not been able to access the full datasets individually to extend the analysis or provide this to consultants.

Figure 1 demonstrates that the Commission's forecasts were significantly different from actual CPRG outcomes for almost all EDBs. In most cases the CPRG forecasts were under-forecast relative to actual. As a result it is both consumers and EDBs that have borne the material financial impact of mis-forecasting CPRG.

Figure 1 - Difference between annual average constant price distribution revenue growth and 2012 DPP forecast (2010-14)[1]



Source: PwC on behalf of ENA

[1] Analysis based on growth in distribution revenue by customer group deflated for CPI and other identified price changes including the 2013 Starting Price Adjustments.

3.2. *Financial impact in current period of errors in current model*

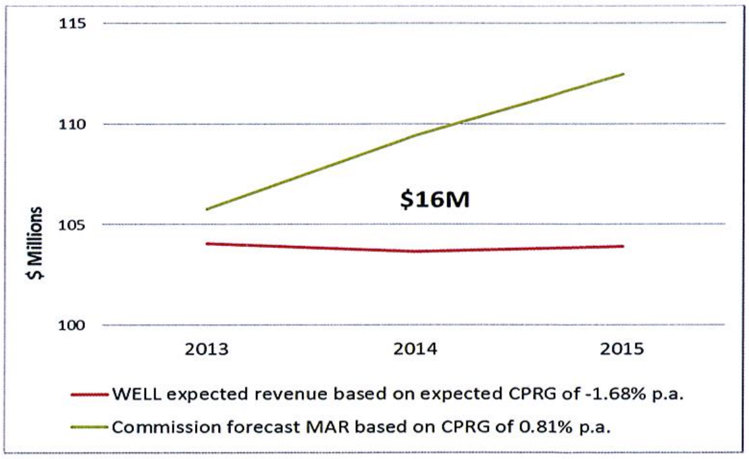
The financial impact of the difference between the Commission's forecasts and actual CPRG compounds through the regulatory period such that every 1% error in the annual growth forecast compounds through the period leading to a 4% error in total revenue over the five year regulatory period. This applies irrespective of the EDB the error relates to, the starting revenue or the direction of the error.

In any regulatory period the financial impact of errors in the CPRG forecasts occur through:

- The year 1 MAR – which is derived based on the forecast of CPRG. If the CPRG is over-forecast then the year 1 MAR is lower than it otherwise should be;
- The year 1 Allowable Revenue - which is based on the year 1 MAR divided by two years of forecast CPRG and therefore includes two years of additional error compounded;
- In years 2 to 5 - the error compounds annually as the Commission forecast revenue path and the actual revenue path increasingly diverge (as demonstrated in figure 4) which shows the revenue path with Commission assumption of CPRG and revenue path with WELL's expectation over the 2015-20 period).

As a consequence of the unrealistically high CPRG forecasts applied by the Commission in the 2012 DPP reset decision, WELL will under-recover approximately $16M (nominal) in the current regulatory period (since the 2012 DPP reset). This material under-recovery is a direct result of the difference between the Commission's forecast CPRG of 0.81% per annum compared to WELL's actual negative growth of -1.68% (annual average from 2010 to 2014) as demonstrated in figure 2.

Figure 2 – Impact on Wellington Electricity revenue of errors in constant price revenue growth forecasts – current period



Source: Wellington Electricity analysis of Commission 2012 DPP Reset

WELL's actual CPRG rate of -1.68% (annual average) is calculated by holding all tariffs constant and assessing the impact of the change in volumes from period *t-1* to period *t* associated with each tariff. The formula for this is set out below.

$$CPRG = ((\Sigma P_{t-1} * Q_t) - (\Sigma P_{t-1} * Q_{t-1})) / (\Sigma P_{t-1} * Q_{t-1})$$

The Commission's model has resulted in significant errors in the CPRG forecasts over the current regulatory period for most EDBs as demonstrated in figure 1 above. Consequently there have been large financial impacts on both consumers (when the Commission under-forecasts) and other EDBs (when the Commission over-forecasts). Applying the same CPRG model for the 2015-20 DPP can be expected to lead to even larger errors as the regulatory period runs for a full five years and errors compound annually.

There is no mechanism in the DPP for WELL to recover revenue losses resulting from error in the Commission's CPRG forecasts. The significant financial impact of these errors places substantive financial stress on the business to reduce costs, in line with reduced revenue. This clearly has significant impact on the ability of EDBs to service its customer base, necessitates short-term decision making, which is not in the long term interests of consumers.

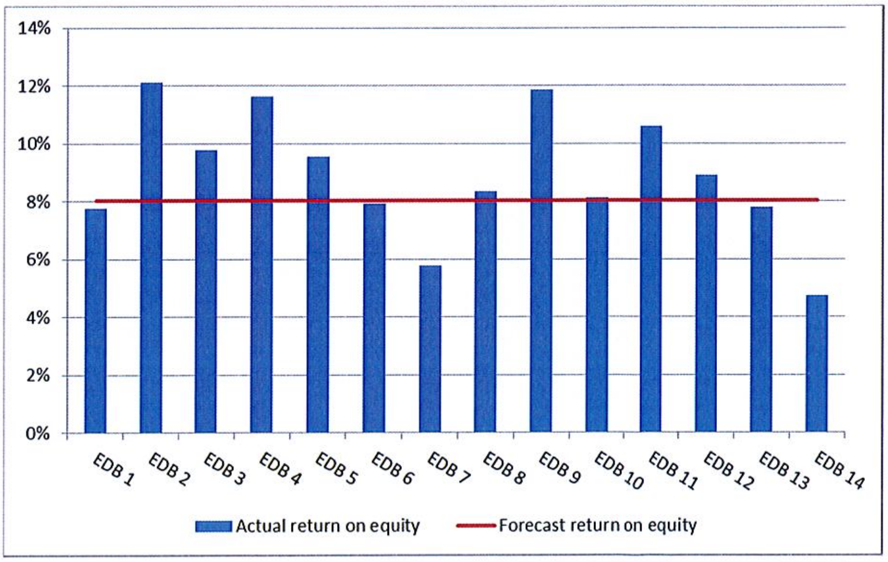
The current methodology is therefore inconsistent with the purposes of Part 4 of the Act to promote the long term interest of consumers, to promote incentives for EDBs to innovate and invest and promote incentives to provide services at a quality that reflect consumer demands.

3.3. Financial impact in next regulatory period if errors were repeated

If WELL performed to all the DPP forecasts of the Commission, except CPRG as assumed above, then its actual return on equity would be 4.7%. Figure 3 extends this analysis to all EDBs. The bars show the return on equity an EDB would earn over 2015-20 if they performed to all Commission forecasts except CPRG, which differs from the Commission's forecast by the same difference observed so far in the current regulatory period. The range of return on equity is 4.7% to 12.1%, due entirely to CPRG forecasting error. No rational investor would require a return on equity of only 8% if the range of potential return on equity due to a single uncontrollable factor was that shown in figure 3.

The volatility in expected returns created by the magnitude of expected errors in the current CPRG model demonstrates that the current model is inconsistent with the purpose of Part 4 of the Act to promote incentives for EDBs to invest and innovate for the long term benefit of consumers.

Figure 3: Hypothetical return on equity resulting only from errors in constant price revenue growth forecasts[2]



Source: Wellington Electricity analysis of impact on ROI of ENA estimate of CPRG errors

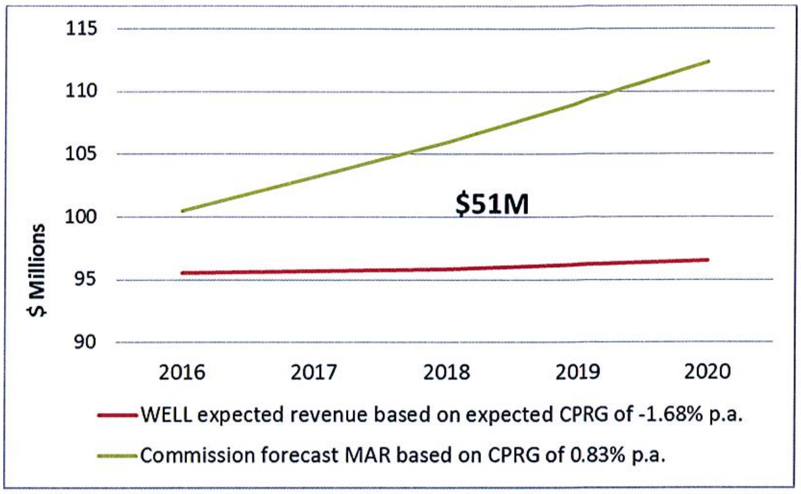
3.4. Financial impact in next regulatory period based on draft decision

As a consequence of the unrealistically high CPRG forecasts in the Draft Decision, WELL simply will not recover the Building Blocks allowable revenue calculated by the Commission. This is because WELL does not expect to even get close to the Commission's forecast CPRG which are used to set the 2015/16 MAR and the calculation for determining the 2015/16 Allowable Revenue.

[2] Maximum allowable revenue and Regulatory Asset Base data for each EDB for 2016 regulatory year sourced from Commission Model 9 - Financial model for 2015-20 DPP reset. Estimated errors in CPRG sourced from PwC analysis on behalf of ENA.

WELL estimates that the impact of the Commission's Draft Decision on WELL's 2015-2020 revenue is approximately $51M (nominal). This is based on WELL's expectation of actual CPRG of negative 1.68% per annum (consistent with historical actual CPRG) relative to the Commission forecast CPRG of positive 0.83% per annum. The financial impact is material and equivalent to approximately 10% of revenue loss, relative to the Commission's building blocks allowable revenue, over the regulatory period. This impact is demonstrated in figure 4.

Figure 4: Impact on revenue of difference between actual and forecast constant price revenue growth over five year regulatory period



Source: Wellington Electricity analysis of Commission Draft Decision

As a result of the significant divergence between the Commission's CPRG forecasts relative to outturn and the substantial financial impact resulting from these errors, WELL does not consider that the current CPRG model promotes outcomes consistent with the purpose of Part 4. Section 52P(1) of the Act states that:

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

The large revenue short-fall created by over-forecasting of CPRG means that EDBs cannot even expect to achieve the required building blocks revenue forecast by the Commission. This situation does not create incentives for EDBs to innovate or invest at the right time, or to improve efficiency or quality of service. Furthermore, when the Commission under-forecasts CPRG, EDBs may be able to recover more revenue than the building blocks revenue requirement. Therefore under the current CPRG model, the objectives of section 52P(1) will not be met.

3.5. Reasons for divergence between current model and actual revenue growth

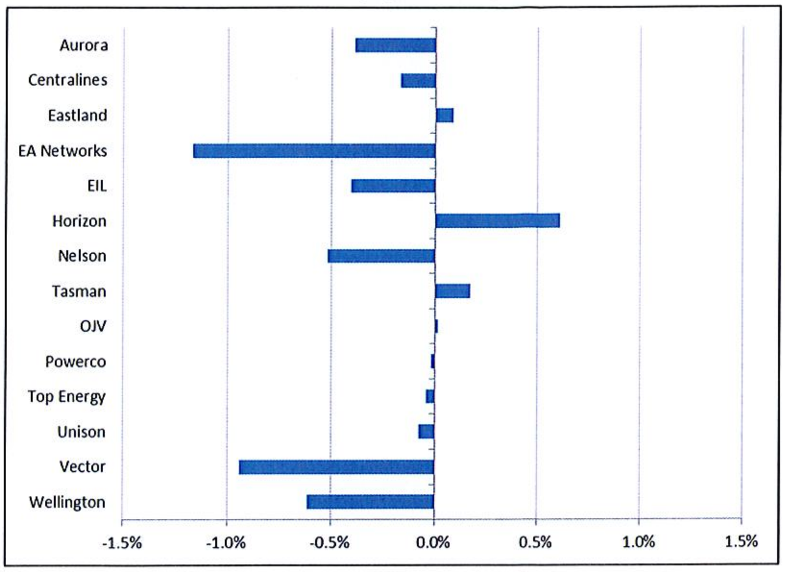
Residential sector growth

Forecasts of residential ICP growth

The CPRG model assumes that population growth matches the growth in the number of connections. This is not true for the WELL network. Over the 2010-2014 period ICPs grew at 0.16% per annum while Statistics NZ reported population growth of 0.69% per annum over the period 2010-2013 period. Figure 5 demonstrates that residential ICP growth does not match population growth for all EDBs for the period 2010 to 2014.

WELL notes that the misalignment between residential ICP growth and population growth is likely due to the increasing presence of embedded networks (e.g. apartment dwellings) and the population estimates reflecting regions in aggregate rather than EDB specific network areas. The increasing trend towards embedded networks has the effect of reducing ICP count as it consolidates to a 400V level and aggregates to a gateway meter. This also lowers the revenue received by the EDB. There have been approximately 1,600 customer ICPs aggregated to 40 embedded networks over the last five year period.

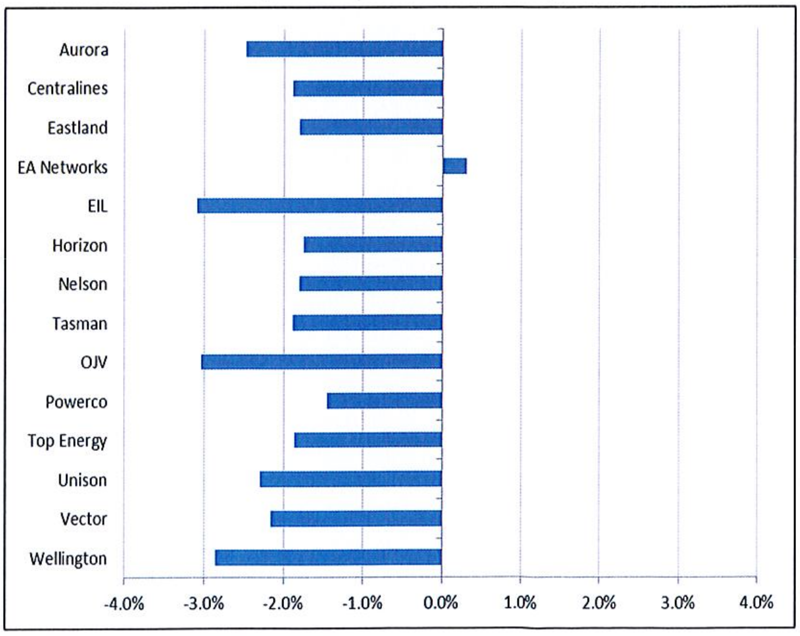
Figure 5: Average annual difference between growth of residential ICPs and population (2010-14)



Source: PwC on behalf of ENA

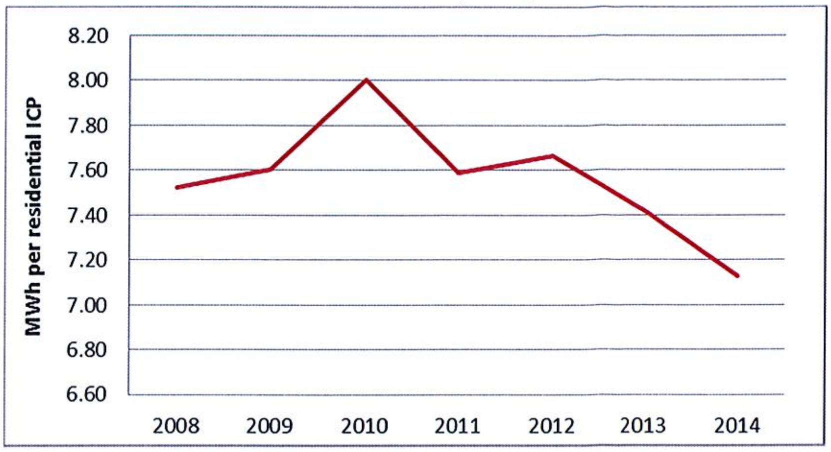
The CPRG model also assumes that energy use per user is constant across time. For WELL, residential electricity consumption declined by an annual average of -2.83% per annum over the last four years. As demonstrated in figure 6, over the period 2010 to 2014 consumption per residential user has been negative across most of the industry. The declining trend in WELL's electricity consumption per residential connection is demonstrated in figure 7. This analysis is supported by MBIE data which shows that total New Zealand residential electricity consumption is declining, as demonstrated in figure 8.

Figure 6: Difference between average annual growth rate in kWh per residential ICP (2010-14) and DPP assumption of 0%



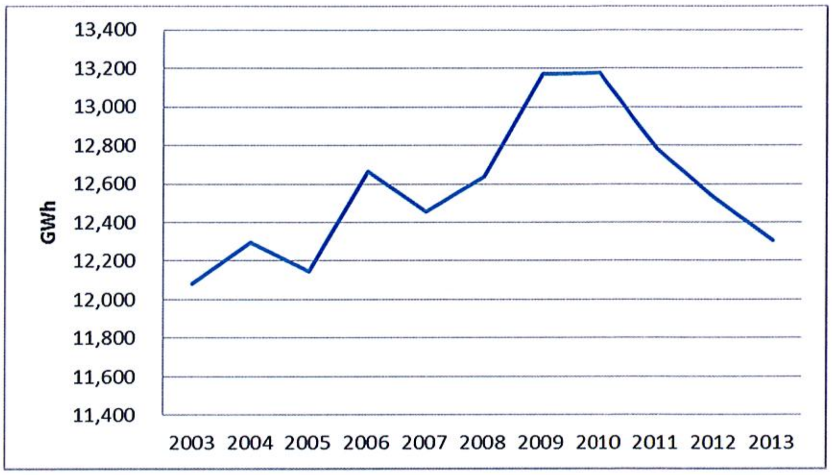
Source: PwC on behalf of ENA

Figure 7: Wellington Electricity consumption per residential connection



Source: Wellington Electricity

Figure 8: Total New Zealand Residential Electricity Consumption



Source: MBIE Electricity Data file 2014

The continuation of historical trends in declining energy use is supported by observed market behaviour, including the increasing uptake of less energy intensive appliances (e.g. lighting, electronics and refrigeration), increased apartment living in CBD areas (apartments are much less energy intensive than standalone houses) and increasing penetration of insulated housing and smart meter platforms allowing visibility of consumption periods. Some EDB regions also have a distributed gas network, so consumers have a choice in home heating sources other than electricity and warmer ambient temperatures are reducing the time residential properties are using electric heating.

These trends also reflect government initiatives such as the Warm up New Zealand Scheme which provides subsidies for insulating houses built pre-2000. The programme has been in place since 2009 and in 2013 received additional government funding to extend the scheme for a further three years. Analysis of the scheme has shown a statistically significant impact on household energy consumption as evidence by Motu.[3]

The trend in Smart Meter deployment by Retailers is having an effect of greater visibility to online account information at a half hour level by customers who are choosing to take an interest in consumption periods and appliances.

[3] Motu, '*Cost Benefit analysis of the Warm up New Zealand: Heat Smart Programme*', report prepared for the Ministry of Economic Development, October 2012.

The trends in declining electricity use are also being observed in other countries, including the United States and Australia as demonstrated by the Brattle Group.[4] In additional the Australian Energy Regulator recently stated that:[5]

> *"A significant issue in recent times has been the widespread difficulty experienced in all sectors of the NEM in accurately forecasting customer demand. Despite economic growth and renewed business activity across the nation following the global financial crisis, energy demand has continued to exhibit a downward trend. This trend is widely attributed to a range of factors including higher energy efficiency, widespread penetration of solar, higher prices and increased customer concern about climate change. This makes the future forecasting of demand a very difficult task for all in the industry" (page 67)*

The trend in declining energy use per household is therefore expected to continue through the 2015-20 DPP period as households continue to become more energy efficient.

It is unreasonable for the Commission to state in the Draft Decision that it will set a zero value unless EDBs are able to provide empirical evidence of future trends. This is a virtually impossible task. The best available information on future trends is observations in historical trends and qualitative observations and information about the likely trends over the next five years. Both of these factors support continued declines in energy volumes per residential user over the 2015-20 DPP period.

Commercial and industrial sector growth

Econometric model

The Commission has developed an econometric model relating growth in constant price revenue to growth in Gross Domestic Product (**GDP**). WELL engaged the Centre for International Economics (**CIE**) and Frontier Economics (**Frontier**) to review the robustness of the Commission's econometric analysis. These reports are included in Attachments A and B.

Both CIE and Frontier found that GDP growth is a very poor predictor of industrial and commercial sector CPRG because:

- The elasticity estimated is very sensitive to the period of data included in the analysis with substantive changes in the estimated coefficient as more years of data are included in the analysis. This demonstrates that the estimated co-efficient are not stable or robust.
- The elasticity estimated is sensitive to subsets of EDBs included in the analysis. Therefore the estimate coefficient is not controlling for important differences in EDBs.
- The estimated elasticity on GDP is very sensitive to the inclusion of other variables in the model, demonstrating the model is mis-specified and the coefficients are likely biased.
- The model is likely a spurious regression as the revenue variable is non-stationary and revenue and GDP are not co-integrated. Therefore the results are not valid from a statistical perspective. Frontier attempted to control for this issue by taking differences in the variables and this demonstrated that there is no statistical relationship between revenue and GDP.
- The model was estimated as a level relationship but applied as a growth rate, which is a problem when the data are non-stationary.

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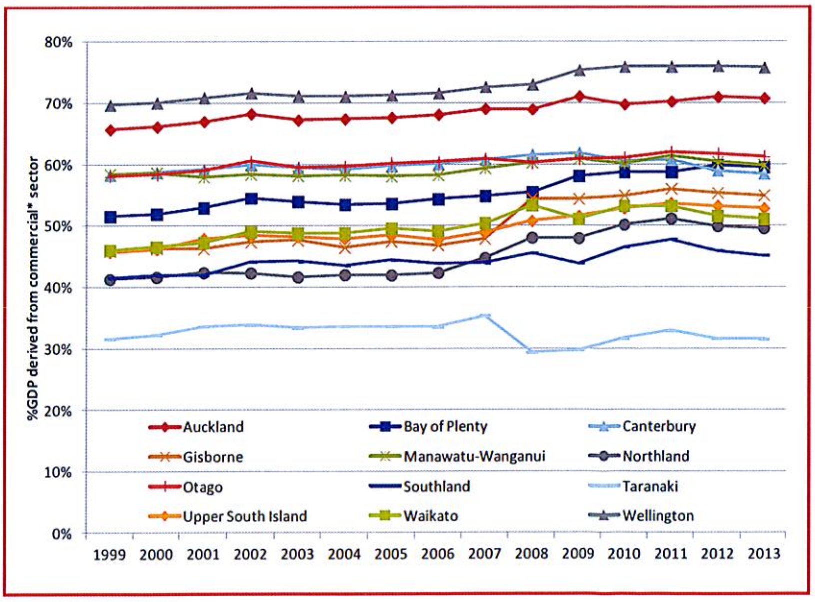
[4] The Brattle Group, Strategies for Surviving sub-one percent growth: an American perspective., 7 August 2014. http://www.accc.gov.au/system/files/Session%203%20Regulating%20in%20the%20face%20of%20declining%20demand%20%20A%20Faruqui.pdf

[5] AER, *Preliminary positions on Framework and Approach for Victorian distributors for the regulatory period commencing 1 January 2016*, May 2013. http://www.aer.gov.au/node/24436

- The relationship between GDP and revenue is very weak statistically which can be seen by:
    - A time trend provides a lower in-sample error than the relationship between GDP and revenue;
    - Including a time trend in the model results in the coefficient on GDP becoming negative, further demonstrating that the relationship between revenue and GDP is spurious,
    - A simple auto regressive model provides a better in sample fit than the relationship between GDP and revenue.
- The deflated revenue data included in the model does not reflect the variable which the Commission is attempting to predict because the revenue data:
    - Includes transmission and other recoverable and pass through costs which have not changed at the rate of CPI only;
    - Captures revenue from all customers not just commercial and industrial sector customers and many EDBs receive over 50% of revenue from residential users. Therefore the model is mis-specified and the elasticity is likely statistically biased;
    - Does not adjust revenue in the 2004-2009 period for the individual x-factors that EDBs were permitted to apply to prices; and
    - Does not adjust revenue for past breaches of the thresholds price path. This is a particular issue for the 2004 to 2008 when the thresholds regime applied and there were large and inconsistent variations in price increases above CPI-x.
- Deflated revenue is arguably a poor proxy for CPRG and energy volumes is likely a more accurate measure.
- The model makes no allowance for the impact of weather. Weather would be expected to lead to a level of mean reversion such that a very cold year would likely lead to high electricity use and there would be a reversion back to the mean in normal weather years.
- The model has no ability to capture the impact on CPRG resulting from differences in consumption intensity between the commercial and industrial sectors. This is a particular concern where the share of commercial and industrial sector activity varies considerable across EDBs as demonstrated in Figure 9.

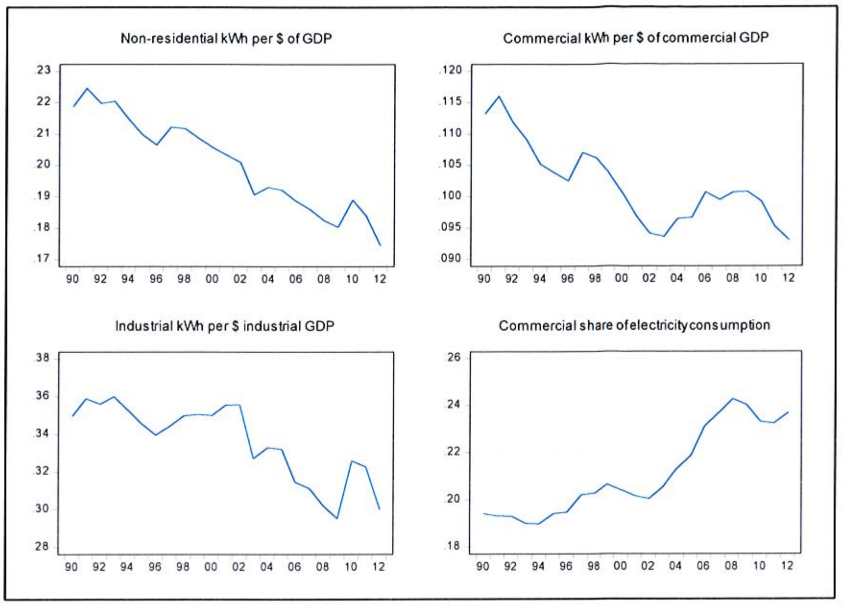
Figure 9: Share of GDP from commercial sector



Source: Frontier Economics and NZIER

As shown in figure 10, industrial customers typically demand significantly more energy than commercial customers. As a consequence there is a long-term shift towards less energy intense industries and, as shown in Figure 10, the relationship between the non-residential sector energy demand per $ of GDP is declining.

Figure 10: Energy consumption in Industrial and Commercial sectors



Source: NZIER, Statistics NZ, MBIE

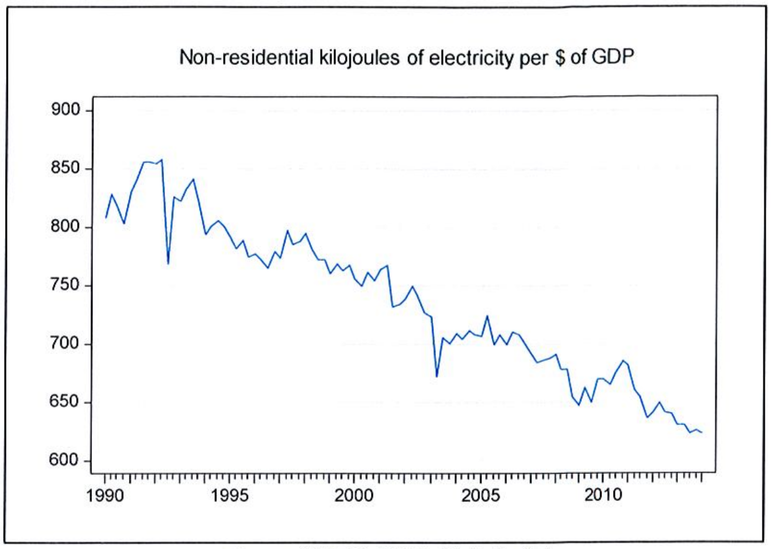
As a result of the numerous and substantive statistical concerns with the Commission's econometric model noted above, EDBs can have absolutely no confidence that the estimated coefficient on GDP is appropriate for forecasting CPRG from industrial and commercial users, or if it were applied to all groups of users.

GDP forecasts

WELL engaged NZIER to review the appropriateness of the regional GDP forecasts for the purposes in which the Commission has applied them to forecast CPRG. NZIER note that the Commission's approach to forecasting CPRG is inconsistent with the NZIER regional GDP forecasts. This is because the regional GDP forecasts take into consideration long term trends in industry shares of GDP including the increasing shares of services in total economic activity and regional variations in industry composition, however the Commission's CPRG model assume the same relationship between GDP and CPRG for all regions and that the relationship is constant over time.

NZIER notes that the CPRG model does not take into account the impact on CPRG of the declining share of GDP from the industrial and primary sectors, which are more energy intensive than the services sector, or the declining trend in energy intensity in all sectors of the economy. NZIER note that these two factors imply a non-linear relationship between economic growth and electricity demand. Furthermore NZIER note that the observed relationship between non-residential sector GDP and electricity demand is negative as demonstrated in figure 11.

Figure 11: Non-residential electricity use per $ of GDP



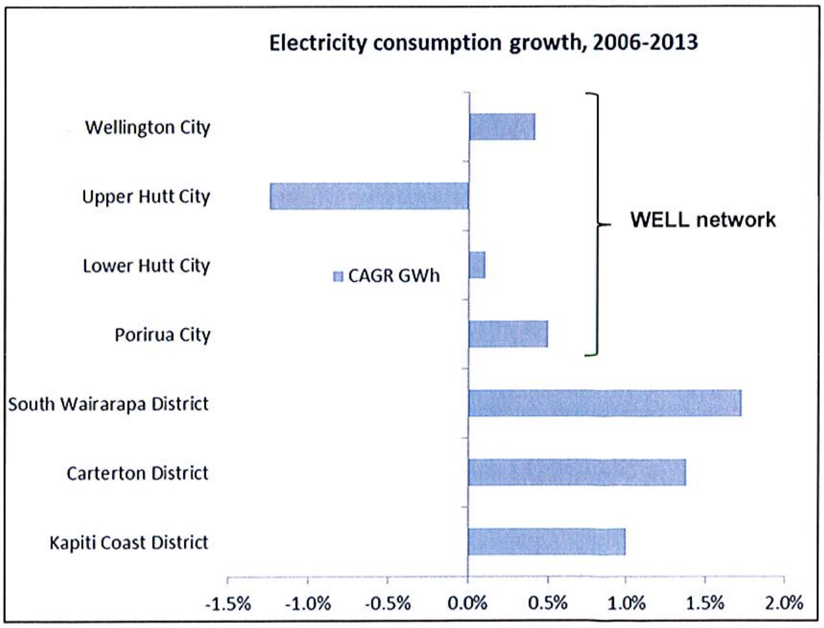
Source NZIER, MBIE, Statistic NZ

Additionally, EDB network areas do not map one to one with the regional GDP boundaries and the NZIER projections are a generalisation of economic trends are across a region, given the industry composition on the entire region. NZIER demonstrate that there is significant variation in economic activity and growth within regions.

For the Wellington region the regional GDP forecasts include the districts of Kapiti Coast, Carterton, Masterton, South Wairarapa and Tararua which are not part of the WELL network area. This distorts the GDP forecasts that are relevant to the WELL network. Figure 12 below clearly shows that the districts outside WELL's network area have had superior growth in electricity consumption than the districts within WELL's network area.

WELL understands that this type of issue also affects other EDBs where the network area does not match the GDP region and different parts of the region have varying growth prospects, for example in the Otago and Bay of Plenty regions.

Figure 12: Electricity consumption growth in Wellington region



Source: NZIER, Reconciliation Manager

3.6. *Proposed alternative model*

WELL engaged CIE to develop an alternative CPRG forecasting model which can be applied to all EDBs. CIE found that given the identified issues with the Commission's current CPRG model and that there is no robust empirical model currently available that can accurately forecast CPRG, the most appropriate option is to use historical CPRG to forecast future CPRG.

As demonstrated by CIE, using historical data to forecast future values will over time balance out overs and unders in the forecasts relative to outturn, ensuring that over time EDBs are net present value neutral. CIE demonstrate that using historic growth to forecast future growth has the same properties as an unbiased statistical model, resulting in an expected error of zero over a 20 year period and EDBs receiving +/- 2 per cent of expected revenue over a 20 year period. This is a significant improvement on the Commission's current model which is not unbiased, and does not have an expected error of zero.

Using historical data would therefore be more accurate than the Commission's current model, which has been demonstrated to be substantially inaccurate. Using historical growth would inherently take into account recent trends in energy consumption and connections growth. Using historical information to forecast future values is also consistent with the Commission's proposed approach to forecasting other key aspects of the DPP, including quality of supply targets, opex and capex.

WELL recommends that the Commission calculate the historic CPRG trends for each EDB using weighted average demand across customer groups as recommended by CIE and set out in figure 13. The historic average growth should be calculated using data over the period 2010 to 2014.

Figure 13: Recommended method for calculating constant price revenue growth

Weighted average demand growth:

$$WQ_t = \sum_{j=(r,c,i)} \frac{Q_t^j}{Q_0^j} \cdot \frac{R^j}{R} + \sum_{j=(r,c,i)} \frac{N_t^j}{N_0^j} \cdot \frac{RN^j}{R}$$

Where Q is quantity of electricity supplied, N is number of connections, R is total revenue, R^j is the revenue from volume components for customer class j and RN^j is the revenue from fixed charges for customer class j.

Using the information from its section 53ZD information request issued on 13 August 2014, the Commission should undertake this calculation by:

1. Calculating energy volume growth for each of the residential, commercial and industrial customer classes and weight the growth rates for customer group by revenue shares.
2. Calculating ICP growth for each of the residential, commercial and industrial customer classes and weight the growth rates for customer group by revenue shares.
3. Take a weighted average of 1 and 2 above by weighting ICP growth by the proportion of revenue that is fixed and weighting energy volume growth by the proportion of revenue that is variable.

While growth in deflated distribution revenue is a reasonable proxy for CPRG, it can be inaccurate due to factors such as tariff re-weighting or EDBs under or over-pricing relative to the price path. The proposed methodology above avoids any concern that deflated distribution revenue growth could capture factors other than CPRG.

WELL recommends that the Commission adopt this methodology to calculate historic CPRG and apply the historic growth rate as the forecast for the 2015-20 DPP reset. The Commission can calculate this using the data provided by EDBs in response to the section 53ZD information request issued on 13 August 2014.

The proposed approach provides a more accurate forecast, which is significantly more reflective of EDBs actual circumstances than the current model, can be applied across all EDBs and is readily implementable for the 2015-20 DPP. Failure to adopt appropriate alternatives that are proposed and clearly superior to the current model would represent a significant failing in the Commission's process.

3.7. Amendments to current model if alternative not accepted

However and whilst not recommended, if the Commission retains its current CPRG model then WELL considers that the Commission must revise its input assumptions as follows:

- Apply the recent historical growth rate in residential ICPs specific to each EDB;
- Apply a negative growth rate in consumption per residential user in its CPRG model in line with the historical data trends and expected market behaviour over the next five years. The Commission should apply either an industry wide historical growth rate or use the EDBs specific historical data to estimate the recent historical trend per EDB.
- Apply the recent historical trend in energy consumption growth for industrial and commercial users specific to each EDB. The Commission should not retain its current econometric model as it has no ability to forecast CPRG and is not statistically robust.

To facilitate this secondary, not recommended, option, the Commission can use the information collected through its section 53ZD information request issued on 13 August 2014.

3.8. Price path correction for CPRG forecasts ("wash-up")

Whilst the proposed alternative model in section 3.6 is highly likely to perform materially better than the Commission's current CPRG model (or a revised model as per section 3.7), it is still susceptible to material error. The alternative model has been proposed in the context of a low cost DPP where detailed bottom up CPRG forecasts by EDB is not appropriate. In other jurisdictions where EDBs operate under a pure price cap, data intensive bottom up methods are used to develop CPRG forecasts and therefore the risk of material error is significantly lower. A pure price cap and low cost CPRG approach are simply incompatible. Therefore the Commission must introduce a correction mechanism into the price path formula to correct for significant CPRG forecasting errors that are inherent in low cost forecasting approaches.

WELL considers that such an approach can be incorporated through the DPP determination without an amendment to the Input Methodologies. For example, a simple revenue wash-up could be introduced into the price path with a two year lag to correct for the difference between forecast CPRG and actual CPRG. WELL notes that the Commission has proposed to introduce a number of wash ups for items of far less material importance, for example the proposed capex wash-up for the difference between actual and forecast 2015 capex.

The Commission cannot continue to state that EDBs can influence electricity consumption when the issue is clearly not a matter of influencing consumption but the inherent lack of forecasting capability of the Commission's CPRG model. Notwithstanding and as previously stressed, WELL does not consider that EDBs can or should try to influence customer electricity consumption. Furthermore, even if EDBs could influence consumption, a marginal change in consumption would not be anywhere near sufficient to offset the magnitude of the error in the Commission's CPRG model.

WELL therefore strongly recommends that the Commission introduce a wash-up mechanism into the price path to correct for situations where there is significant anomaly in the CPRG forecasts.

The wash up should adjust the Allowable Revenue for the difference between the revenue that was allowed based on the forecast CPRG and the revenue that would have been allowed based on actual CPRG.

3.9. Long-term solution - Revenue cap

For future resets, the Commission should amend the IM's to replace the weighted average price cap with a revenue cap as this removes the issue of mis-forecasting CPRG altogether and is therefore more consistent with the low cost intent of the DPP. WELL has previously written to the Commission about the benefits of a revenue cap.

Moving to a revenue cap is consistent with regulators in other jurisdictions, including Australia and the United Kingdom, that with the maturing of the regulatory regime have recognised that the theoretical benefits of a weighted average price cap have not eventuated in practice and conflict with other policy objectives, including the promotion of energy efficiency opportunities. These regulators have increasingly shifted to revenue caps as the form of control even though they operate in customised price path type regimes where energy forecasts can be developed using sophisticated bottom up methods.

The Australian Energy Regulator recently made the following statements with regards to the benefits of a revenue cap:[6]

> *"A significant issue in recent times has been the widespread difficulty experienced in all sectors of the NEM in accurately forecasting customer demand. Despite economic growth and renewed business activity across the nation following the global financial crisis, energy demand has continued to exhibit a downward trend. This trend is widely attributed to a range of factors including higher energy efficiency, widespread penetration of solar, higher prices and increased customer concern about climate change. This makes the future forecasting of demand a very difficult task for all in the industry" (page 67)*
>
> *"We consider that a revenue cap provides a high likelihood of efficient cost recovery. We consider that because costs for distributors are largely fixed and unrelated to energy sales, revenue recovery should also be largely fixed and unrelated to energy sales." (page 70)*
>
> *"We consider that a WAPC does not provide a high or even reasonable likelihood of efficient cost recovery." (page 71)*
>
> *"We consider a revenue cap provides an efficient incentive to undertake demand side management. Under a revenue cap we fix distributors' revenue over the regulatory control period. Distributors can therefore increase profits by reducing costs. This creates an incentive for distributors to undertake demand side management projects that reduce total costs. That is, any demand side management project where the reduction in network expenditure is greater than the cost of implementing the demand side management. We consider this provides an efficient incentive to distributors to undertake demand side management within a regulatory control period." (pages 72-73)*

4. Forecast operating expenditure

WELL considers that the base year, trend and step approach to forecasting operating expenditure (**opex**) is appropriate for the 2015-20 DPP reset.

4.1. Base year

It is important that the base level of opex used for forecasting future opex is representative of EDBs underlying opex requirements, given current network condition and scale, current input costs, term credit spread differential and current regulatory obligations.

In the Draft Decision the Commission has applied the 2013 opex data as the base year and stated that it is very unlikely to take into consideration the 2014 actual opex data.

WELL does not support the use of 2013 opex only as the base year. The opex for the 2014 year provides the most up to date information available on costs currently required to manage each EDB's network and best reflects the current condition, scale and performance of the network and current input costs and regulatory obligations.

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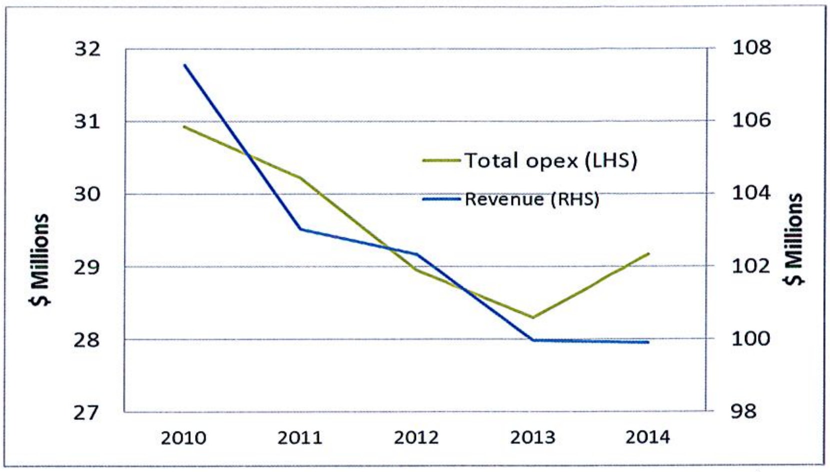
[6] AER, *Preliminary positions on Framework and Approach for Victorian distributors for the regulatory period commencing 1 January 2016*, May 2013. http://www.aer.gov.au/node/24436

Conversely, WELL's 2013 opex is not reflective of WELL's underlying opex requirements to maintain current network performance. As shown in Figure 14 WELL's revenue has been declining in real terms since 2010 and the rate of decline increased in the 2013 year due to generally mild temperatures and continually declining energy consumption. As a result, in 2013 WELL was forced to make significant temporary reductions in its non-network opex. These reductions are unsustainable and have been incorrectly termed efficiency gains by the Commission. WELL's 2014 opex is a better reflection of a normal years' expenditure.

Figure 14 demonstrates that 2013 was a particularly low opex year for WELL for the reasons noted above, 2014 opex is more in line with prior years' opex and should be used by the Commission as the base for forecasting WELL's future opex requirements.

Figure 14: Wellington Electricity Opex and Revenue

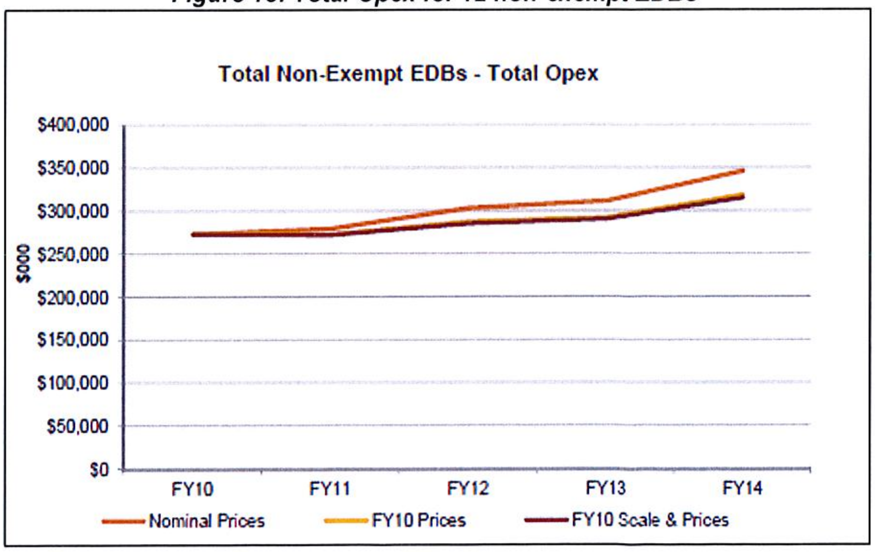


Source: Wellington Electricity Information Disclosure Reports[7]

Figure 15 demonstrates that across the industry in general 2014 was not an unusually high opex year and there was no significant step up between 2013 and 2014. Opex has generally been trending upward over the period reflecting:

- Increasing regulatory obligations, including the implementation of the new information disclosure requirements and increased costs for compliance with Public Safety Management Systems and the new WorkSafe New Zealand Act 2013; and
- Real price pressures in labour and material that exceed the general economy.

Figure 15: Total Opex for 12 non-exempt EDBs[8]



Source: PwC on behalf of Electricity Networks Association

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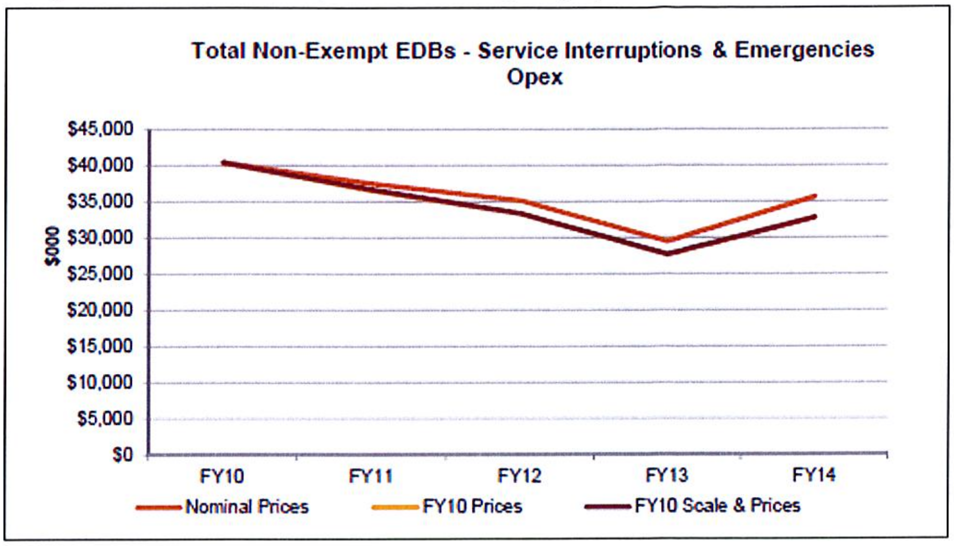
[7] Line charge revenue and operating expenditure net of pass through and recoverable costs and deflated by CPI.

[8] PwC sourced actual 2014 nominal opex data from EDBs in August 2014. Nominal opex has been converted to real $ 2010 using the Commission's opex price index of 0.6*LCI + 0.4*PPI using data from Statistics NZ.

Conversely, due to mild temperatures in New Zealand during the 2013 regulatory year network opex was unusually low across the industry, as demonstrated by figure 16. As a result it would be inappropriate for the Commission to rely solely on 2013 opex given that network opex was unusually low.

Figure 16: Service Interruptions and Emergency opex for 12 non-exempt EDBs [9]



Source: PwC on behalf of Electricity Networks Association

This analysis demonstrates that it is appropriate for the Commission to rely on 2014 as the basis for predicting future opex requirements because it best reflects the current costs required for EDB's to manage the network given current network condition, scale and performance and current input costs, term credit spread differential and regulatory obligations. There is no evidence to indicate that EDBs have deliberately stepped up 2014 opex, as suggested by the Commission. It also demonstrates that it is not appropriate for the Commission to rely solely on 2013 opex as this year is not reflective of the underlying opex that would have been required if 2013 had not been a mild year in terms of temperatures across the country.

Additionally, WELL considers it appropriate that as part of the introduction of the Commission's proposed incremental rolling incentive scheme (**IRIS**) for opex, the Commission needs to demonstrate a commitment to EDBs that it will use the penultimate year of a regulatory period as the base for forecasting the next period's opex allowance. Failure to do so would undermine the incentive properties of the proposed opex IRIS as the Commission has complete discretion to change its position ex post, particularly as there is no Input Methodology in relation to how the opex allowance is to be determined.

WELL therefore recommends that 2014 is used as the base for forecasting opex requirements for the 2015-20 DPP period.

Notwithstanding, if the Commission is still unsatisfied with using the 2014 year then it should apply an historical average of prior years' expenditure over a longer time period, for example 2011 to 2014. This results in each years' expenditure receiving only a quarter weighting. In calculating an average the Commission should adjust historical expenditure for real price growth and changes in network scale. Taking a historical average approach would not place undue weight on any one year's expenditure outcomes.

4.2. Term credit spread differential allowance (TCSDA)

Importantly, a large proportion of WELL's long term debt became due for re-issuing during the 2014 year. WELL therefore has a term credit spread differential allowance in its 2014 Information Disclosure Report which should be included in its opex forecasts for the 2015-20 period.

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[9] Ibid.

Clause 4.4.9 (3) of the Input Methodologies Determination states that for purposes of assessing EDBs profitability for the DPP reset, the Commission will treat the TCSDA disclosed by suppliers as an expense.

4.3. Input cost escalation

In the Draft Decision the Commission has applied the all industries Labour Cost Index (**LCI**) and all industries Producer Price Index to escalate the base level opex for forecast changes in input costs relating to labour and materials. These all industries price indices are developed based on the general economy and are not reflective of input cost changes specific to the electricity distribution industry. The electricity distribution sector requires more specialised labour skills which are in short supply in New Zealand.

Figure 17 below demonstrates that there is a substantive difference in the annual average labour cost growth between the electricity distribution and transmission sector and the general economy or Electricity Gas Water and Waste sector.

The electricity distribution and transmission sector specific wage growth is based on a representative survey of approximately 25 transmission and distribution networks in New Zealand undertaken by Strategic Pay remuneration consultants.

WELL recommends that the Commission apply an industry specific labour costs escalator, such as the EGWW LCI, which takes into account the skill sets that are relevant to the electricity distribution industry. This approach will provide a better estimate of expected increases in EDBs future costs than a generic labour costs escalator which includes blended skills set not reflective of the electricity distribution industry.

Figure 17: Measures of labour cost growth

Measure of labour cost growth	Average annual growth December 2009 to December 2013
All industries LCI	1.79%
EGWW LCI	2.27%
Strategic Pay – Electricity distribution and Transmission Sector	3.08%

Source: Statistics New Zealand, Strategic Pay

4.4. Step changes

WELL does not agree with the principle set out in the Commission's Draft Decision that a step change will only be considered if it is applicable to all EDBs. The low cost intent of the DPP does not have to be as restrictive as this. If the Commission allows all EDBs the same opportunity to follow the same low cost process for seeking step changes then this would still be consistent with the low cost intent of DPP regulation. WELL recommends that a low cost process would involve allowing step changes that have been quantified and independently audited or verified.

WELL is seeking a step change for resilience opex to ensure that it can meet its obligations under the *Building Act 2004*. WELL has no choice but to incur the opex for meeting its compliance obligation under the Building Code. Policy leaders have made it very clear that compliance with the Building Code is of high priority. The 2011 National Infrastructure Plan states that:

> *"The government has committed to a programme of regulatory reform to ensure that the right infrastructure is available at the right time and in the right place. Regulation affecting infrastructure needs to balance short- and long- term objectives. Future efforts should focus on streamlining infrastructure delivery and being more efficient in the way we use infrastructure. Specifically, regulation will: ... Balance short-and long-term objectives and encourage resilience in infrastructure assets to improve investor confidence."* (page 17)

Under the *Building Act 2004*, local councils are responsible for assessing all pre-1976 buildings. Following the Canterbury earthquakes and the more recent Seddon earthquakes which affected the Wellington region, local councils have increased the level of assessment activity. This reflects the increased social and business awareness of not only the need for a safe and reliable electricity supply but also for a more resilient infrastructure, better enabling power to be restored safely and quickly following a major earthquake.

WELL has recently received approximately 150 notifications from the Wellington City Council, at least one quarter of which indicate the building may be earthquake prone. Upon receiving council notification, WELL must engage a qualified engineer to assess the building and determine the work required to bring the building into compliance with the Building Code.

Given the large number of pre-1976 buildings on WELL's network (approximately 320) and their importance to ensuring a resilient power supply, WELL is embarking on a pro-active process of substation building assessment. WELL considers that a pro-active approach is necessary to manage the risk of earthquake damage resulting in significant loss of assets and electricity supply and that this is cost efficient for consumers. Early reinforcement expenditure has proven to be less costly than replacing damaged equipment post an event. This earthquake resilience expenditure will reduce restoration times for key substation assets by enabling substation buildings to remain operational following an earthquake.

The building assessment activity will be undertaken and completed during the 2015-20 DPP period. WELL forecasts that this will require additional opex of $1.4M (nominal) during the 2015-20 DPP period.[10] These costs are not reflected in WELL's historic opex and are equivalent to an approximate 1% per annum increase above historic annual opex.

WELL's opex forecasts of $1.4M for seismic strengthening assessment work are based on the current legislative requirements regarding seismic strengthening. This opex forecast would change in the future if the *Building (Earthquake-prone Buildings) Amendment Bill* currently before Select Committee is passed into law. The Bill is due to be reported back to Parliament in early September 2014. The Bill is therefore very likely to be passed into law before the 2015-20 DPP period commences.

The Bill increases the volume of buildings to be assessed. These additional costs are not included in this submission, or in WELL's 2014 AMP, as the Bill has not been passed into law. However, this Bill reinforces the need for businesses to be pro-active about assessing building earthquake strength. In addition, there is increased social and business awareness nationally of the need for a safe and reliable electricity supply and more resilient infrastructure so that power can be restored safely and quickly following a major adverse event.

4.5. Opex partial productivity

The Commission engaged Economic Insights to estimate a partial productivity adjustment. Economic Insights analysis found that opex partial productivity has been declining over the period 2004 to 2013 at the rate of between -0.1 and -0.8 percent per annum depending on the model used to estimate productivity growth. This result is supported by the analysis undertaken by Pacific Economics Group (**PEG**) for the Electricity Networks Association (**ENA**). PEG's analysis suggested opex partial productivity growth has been between -1.58% and -2.04% percent per annum. All of the empirical analysis strongly indicates that the industry has experience negative opex partial productivity.

PEG discusses that it is appropriate to apply negative productivity adjustments in circumstances where input cost growth is systematically growing more rapidly than output growth. PEG also notes that a negative productivity trend is not necessarily reflective of declining productivity in an industry, rather it may reflect the factors that have led to input costs growing at a faster rate than outputs. For the electricity distribution industry the factors likely contributing to stronger input growth relative to output growth are described below. These factors are expected to continue to overwhelm any underlying productivity improvements over the next five years.

[10] The estimated opex of $1.4M relates to the building assessments which do not subsequently lead to reinforcement work and therefore are not able to be capitalised.

- Labour costs escalating to enable retention of specialised staff. As demonstrated in Figure 17, actual labour cost growth for electricity networks has been significantly higher than measured for the general economy or the Electricity Gas Water Waste (EGWW) sector. This trend is expected to continue as the demand for labour has been relatively suppressed during the economic downturn and is now expected to rebound.
- The nature of the civil construction activities undertaken by EDBs which means that information technology does not provide the same extent of productivity enhancing benefits as for the commercial or services sectors of the economy.
- Increasing regulatory obligations which lead to increased input costs but do not result in increases in the quantity of services provided by EDBs. This is expected to continue as New Zealand continues to reform its workplace health and safety requirements.
- There has been slow to negative growth in electricity distribution outputs, in particular negative growth in energy consumption. This trend is expected to continue with the ongoing improvements in energy efficiency.

Importantly, PEG considers that the Commission's opex rate of change model should be internally consistent with regards to the variables used to measure scale escalation and partial productivity growth, as both are intending to measure growth in EDB outputs. PEG's analysis found that applying partial productivity growth rate of -2.04 percent would ensure that the Commission's model is internally consistent.

WELL supports the principle of internal consistency in the Commission models for setting the DPP and considers that there is more than sufficient empirical evidence to support applying a negative opex partial productivity growth rate for the 2015-20 DPP.

5. Forecast capital expenditure

5.1. Capex forecasts

WELL considers that the Asset Management Plans (**AMP**) produced by EDBs should continue to be relied on by the Commission for forecasting capex, including network and non-network capex. As demonstrated in the Draft Decision, WELL's actual capital expenditure over the period is very close to its 2010 AMP forecasts, within a one per cent difference.

This evidence indicates that the Commission can rely on the 2014 AMP forecasts where EDBs actual capital expenditure has closely reflected its 2010 AMP forecasts. AMPs are developed through a robust internal planning process based on detailed knowledge of asset performance and network characteristics, are subject to internal review and robust governance arrangements, and have received Director Certification of the reasonableness of expenditure forecasts.

WELL does not support the Commission's approach in the Draft Decision to cap capital expenditure at 20 per cent above historical expenditure. Such an approach fails to recognise the lumpy and cyclical nature of capital expenditure. In particular WELL requires an increase above 20 per cent on historical because:

- WELL is obligated under the Building Act to undertake resilience capex to ensure all its substation buildings are compliant with the current Building Code, and meet required levels of earthquake resilience. This proposed capex is required to meet a regulatory obligation and is not discretionary. The proposed resilience capex is a step change in capex as it is a category of expenditure which is not included in WELL's historic capex. The majority of WELL's seismic strengthening capital works programme must be undertaken during the 2015-20 DPP period. WELL has approximately 320 pre-1976 buildings to assess and has already received approximately 150 council notifications at least one quarter of which indicate that the building may be earthquake-prone. WELL's 2014 AMP capex forecasts include a total of $33 million (nominal) for resilience work, $17 million (nominal) of which is forecast for the 2015-20 DPP period. In addition to being a regulatory obligation, this earthquake resilience capex will maintain the security of supply into Wellington, reduce restoration times for vulnerable cable assets and enable substation buildings to remain operational following an earthquake. Investment in resilience capex is supported by the National Infrastructure Plan (as noted in section 4.4). Sufficient funding should therefore be provided by the Commission to enable WELL to recover its costs. It is significantly more cost effective for consumers to invest in resilience expenditure now rather than suffer substantial social and economic losses due to prolonged supply outages as a result of damage to strategic assets following a major earthquake.

- WELL has a large proportion of assets that require replacement over the 2015-20 period. This is clearly demonstrated in the asset age profile charts included in WELL's 2014 AMP[11] and the approximate 26% real increase in WELL's forecast asset replacement expenditure for the forthcoming regulatory period relative to historic expenditure during the 2011 to 2014 period. Failure to replace aging assets over the 2015-20 period would lead to a significant increase in maintenance expenditure during the 2015-20 period and very likely increase the potential for asset failures and increased supply outages during the period and in subsequent periods.
- WELL's opex forecasts included in the 2014 AMP assume the capex forecast spend will occur. If this is not the case then there is an increased need for maintenance opex. The Commission needs to be cognisant of the relationship between capex and opex when determining the respective allowances in the 2015-20 DPP reset and be mindful not to inadvertently drive inefficient approaches to asset repair and/or replacement.
- Additional system growth expenditure is required to address identified capacity constraints in key network areas including, the Wellington CBD, Mana, Whitby and the Johnsonville-Churton Park area which is arising due to increased peak period utilisation of network assets. Failure to address capacity constraints over the next five years would lead to overloading, potential for premature asset failure due to high peak period utilisation, and reduced network performance arising from large customer numbers on affected assets (average SAIDI and SAIFI per fault increasing). WELL's 2014 AMP includes an 87% real increase in system growth capex for the forthcoming regulatory period relative to historic expenditure during the 2011 to 2014 period. This is because significant augmentation expenditure has not been required in the past few years, for example the Wellington CBD has not had a new zone substation built in 25 years. This type of investment represents a large one-off investment that is needed now and expected to provide sufficient capacity for the next 10 to 20 years given forecast peak demand growth in specific network areas.[12]

The above explains that, unlike opex, capex requirements do not follow a linear trend and are instead driven by the unique characteristics of each EDB's existing assets and changes in peak loads on specific network assets. For this reason WELL maintains that the Commission should rely on EDBs AMP forecasts where EDBs have demonstrated that these forecasts are reasonably reliable.

If, however, the Commission's final decision is to apply a cap on forecasts above historical expenditure then the 2009/10 year should not be included in the calculation of the historical average. The 2009/10 year is not part of the current regulatory period and is no longer a reflection of EDBs current capex levels. For WELL the 2009/10 year was a very low capex year as it only took over management of the Wellington Network in July 2009. Because 2009/10 year was a management transition year the previous management did not develop network investment strategies for the new management and it took some time for the new management to familiarise itself with the network and develop its own network investment strategies. Consequently, WELL's capex in 2009/10 was abnormally low and this significantly reduces the historical average from which the cap is applied and therefore results in a less than 20 per cent increase in forecast capex above historic capex.

Additionally, WELL's 2014 AMP only includes the capex required to meet the current legislative requirements relating to earthquake prone buildings. This mainly affects WELL's substation buildings which were built before the 1976 building code amendment. However, if the *Building (Earthquake-prone Buildings) Amendment Bill* currently before Select Committee is passed into law, additional costs would be incurred. This is because in its current form the Bill would also require WELL to assess and strengthen all its pre-2005 buildings to at least 34% of the current Building Code. This will increase the volume of buildings to be assessed and possibly strengthened. The Bill also specifies that priority buildings would be required to be strengthened within a reduced timeframe specified by the territorial authority, which may

[11] Wellington Electricity, *10 year Asset Management Plan 1 April 2014 to 31 March 2024*, section 3.4.

[12] While aggregate energy demand is declining, demand in specific network areas is increasing.

be less than the current timeframes[13]. If this applies to electricity network assets then WELL's seismic strengthening capex currently planned for post-2020 may need to be brought forward into the 2015-20 DPP period. These additional and brought forward costs are not included in WELL's 2014 AMP because the Bill has not been passed into law.

5.2. Inter-dependencies between opex, capex and quality standards and incentives

It is important that the Commission recognise the relationships between the forecasts it sets for each component of the DPP.

Importantly, there are trade-offs between opex and capex. WELL's AMP opex forecasts are based on its forecast level of capex. If the Commission caps the capex allowance then WELL cannot undertake the same level of age-based replacement expenditure as planned and therefore additional maintenance opex is required to maintain asset performance.

Similarly, WELL's capex forecasts are based on maintaining the current level of reliability performance as that experienced over the past five years. However, the Draft Decision proposes both reducing the capex allowance and increasing the expected level of reliability performance and introduces financial penalties if the increased reliability performance is not achieved. WELL considers that this piecemeal approach to determining the capex and opex allowances and setting the reliability targets is inconsistent and fails to recognise important interdependencies. Such an approach is inconsistent with the purpose of Part 4 of the Act to promote the long term benefits of consumers by promoting incentives for EDBs to invest and innovate and provide service quality that reflects consumer demands.

Furthermore, the Commission's proposed capex incremental rolling incentive scheme has the effect of penalising EDBs that over spend the capex allowances during the regulatory period, even though EDBs have indicated the required level of expenditure to maintain service performance through the AMPs. As a result, EDBs may face financial penalties as a result of the capping method rather than as a result of inefficient capital investment.

The Commission requires EDBs to invest significant time and resource into developing AMPs which result in realistic expectation of the capex and opex required to make the necessary network investments that are required to meet regulatory obligations and maintain network performance. In undertaking this assessment EDB's must weigh up the trade-offs between opex, capex and network reliability. It is therefore not appropriate for the Commission to start forecasting each item independently without giving due consideration to these trade-offs. It is therefore appropriate that the Commission use the AMP forecasts to set the capex allowances for the 2015-20 DPP.

For the reasons outlined above, WELL considers that the proposed approach to cap capex forecasts at 20% above historic spend is inappropriate and that use of AMP forecasts is a better approach.

6. Quality standards and incentives

The Draft Decision sets out the Commission's intention to introduce a financial incentive scheme to the reliability standards which would accompany a revised pass/fail enforcement regime for failing to meet the reliability target.

Decisions regarding a quality incentive scheme, the reliability target and the normalisation process are a package and must be considered in combination. Importantly, any normalisation method that is to be applied in the new quality regime must be fully and solely applied to the historical data used to set the reliability targets. It is highly inappropriate and inconsistent for the Commission to apply one method for normalisation going forward and a different normalisation method to set the targets upon which the new normalisation will be applied.

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[13] The current Act requires strengthening within 15 years, however Wellington City Council has specified 10 years for buildings with a post disaster function.

WELL is disappointed that, in addition to introducing a financial incentive scheme, the Commission has proposed to retain and strengthen its enforcement criteria for failing to meet the reliability standards. WELL understood that the purpose of introducing a financial incentive scheme was to remove the difficulty in identifying when reliability breaches were caused by uncontrollable or unintended events or a result of intentionally poor network management. WELL is unsure what, if any, benefit a financial incentive scheme provides if the Commission is unwilling to trust the incentive scheme and relax its enforcement criteria.

6.1. Reliability targets

In particular, it is unreasonable that the Commission has set the reliability targets by normalising historical SAIDI and SAIFI data in years when the previous limits have been exceeded, such an approach:

- Assumes that the original limits were the efficient reliability levels. A limit based on a non-random five year historical period does not necessarily provide any reflection of an efficient level of reliability. For the Wellington Network the 2005-2009 period had unusually benign weather patterns and as a result the SAIDI and SAIFI values were very low. Notably the 2004 year was a considerably higher SAIDI year but this year is excluded from the calculation of the current targets. The four years from 2010 to 2014 presented much more adverse weather conditions and natural events including two earthquakes, four major storms and four days of snow. The major storm on 20 June 2013 was described by National Institute of Water and Atmospheric Research as the worst storm in 37 years and snow in the Wellington Region is exceptionally rare.
- Assumes that the current normalisation process is appropriate when clearly it is not appropriate for networks with many zero event days. The current boundary values for some networks are a very large proportion of the target value, WELL's SAIDI boundary value is currently 24 per cent of the current SAIDI limit. Consequently the normalisation process is ineffective for these EDBs leading to increased likelihood of breaching the limit.
- Does not afford natural justice to EDBs that have exceeded the quality limits. The proposed process financially penalises EDBs in the next regulatory period for exceeding the limits in the current DPP regulatory period despite the Commission not determining any fault for which it sought compensation for. This approach effectively applies retrospective penalties for events that occurred in the prior DPP period without ascertaining deliberate or negligent fault.
- Completely ignores the fact given the normal distribution of outcomes around the mean value, there is a 17% probability of any EDB exceeding the limit simply due to natural variation.
- Furthermore, the process the Commission has used to undertake the normalisation of prior years that exceeded the limit has the effect of reducing the annual values used to calculate the target to less than the current limit, thereby further penalising EDBs that exceeded the limits. This means that, all else equal, an EDB that came close to or reached the limit receives a higher value for calculating the target than an EDB that exceeded the limit, irrespective of the factors that contributed to the limit being exceeded.

WELL therefore recommends that the targets should be set based on the raw data with a normalisation method applied which is the same as the normalisation method that is to be used in the 2015-20 regulatory period. Such an approach ensures consistency between targets and the normalisation method used for assessing compliance and applying financial rewards/penalties under the quality incentive scheme. A consistent approach is also necessary to prevent a situation where EDBs are set unfairly and unrealistically low targets and are unduly punished for reliability outcomes caused by past events beyond their control.

6.2. *Normalisation method*

Trigger for normalisation

WELL does not support the method applied in the Draft Decision to normalise for SAIDI major event days using the SAIFI boundary value. This approach incorrectly assumes that SAIDI and SAIFI are closely related for every outage event. This ignores the inverse relationship between time and frequency, therefore creating an anomaly in most situations. For example, while a substation outage may produce a high SAIDI and SAIFI, a weather event which damages a number of 11kV feeders from separate substations (a more common occurrence) would incur a large SAIDI but relatively smaller SAIFI. In the last 10 years the daily SAIFI on the Wellington network has not exceeded the current SAIFI boundary value. However, over the same period the network has experienced some major SAIDI events, for example major storms, some of which have significantly exceeded the current SAIDI boundary.

As an example, if SAIFI was the normalisation trigger in the current regulatory period then WELL's 2014 raw SAIDI value of 190 minutes (more than 4 times the SAIDI limit), including 132 minutes accrued over a two day period, would have had no normalisation applied.

WELL has a low likelihood of exceeding the SAIFI boundary because the configuration of its network is such that there are too few customers supplied from each substation to reach the SAIFI boundary based on a single event. The proposed SAIFI boundary of 0.11 corresponds to an outage affecting 18,000 customers on the WELL network, however WELL's largest zone substation supplies only 11,000 customers, therefore given the configuration of WELL's 33kV network using transformer feeders, it is not possible for a single event to ever exceed the SAIFI boundary value and trigger a SAIDI normalisation, no matter how catastrophic. For example, the Wainuiomata Zone Substation supplies approximately 6,500 customers. A slip on the Wainuiomata Hill affecting both 33kV lines would lead to approximately 0.04 SAIFI, but would accrue SAIDI at a rate of approximately 2.4 SAIDI per hour until supply could be restored. The SAIDI boundary value would be breached in less than three hours, yet none of this SAIDI would be normalised if SAIFI was the trigger for SAIDI normalisation.

In addition, using SAIFI to normalise SAIDI does not achieve the Commission's assumption that the expected probability of a Major Event Day (**MED**) occurring is 2.3 time per year. WELL has only exceeded the proposed new SAIFI boundary of 0.11 twice over the past 10 years resulting in a probability of only 0.2 MEDs per year rather than 2.3. Therefore the combination of the proposed method for calculating the boundary values and the application of the SAIFI trigger does not result in achieving the Commission's objective.

The IEEE method for normalisation relies on SAIDI rather than SAIFI as the normalisation. Annex B of IEEE 1366:2012 states that:

> *'Daily SAIDI values are preferred to daily SAIFI values because SAIDI values are a better measure of the total cost of reliability events, including utility repair costs and customer losses.'*
>
> And
>
> *'Duration-related costs of outages are higher than initial costs, especially for major events, which typically have long duration outages. Thus, a duration-related index will be a better indicator of total costs than a frequency-related index like SAIFI or MAIFI. Because CAIDI is a value per customer, it does not reflect the size of outage events. Therefore, SAIDI best reflects the customer cost of unreliability, and is the index used to identify MEDs. SAIDI in minutes/day is the random variable used for MED identification.'*

The IEEE method defines a major event as:

> *'An event that exceeds reasonable design and or operational limits of the electric power system'*

This definition does not require that a large number of customers be affected for a major event to have occurred, rather a major event is defined relative to reasonable network capability. Consequently, a major event could involve a substantial impact on a smaller number of customers.

The Commission has stated that its reason for using SAIFI as the normalisation trigger for SAIDI is to mitigate its concern that EDBs would deliberately allow SAIDI to accrue to the SAIDI boundary before commencing restoration work. This type of statement demonstrates a fundamental misunderstanding of EDB's primary objectives as suppliers of electricity distribution systems to produce a safe and reliable supply of electricity to its customers. The Commission's suggestion is also impracticable as EDBs do not know at the time an outage occurs whether or not the outage will qualify for normalisation. The objective of field crew is to restore supply as quickly, and safely as possible, with a large emphasis on crew safety.

Furthermore, the Commission's proposal is contrary to the objective of an electricity distribution business to prioritise safety of crew working on live lines and in dangerous or hazardous conditions and is inconsistent with the new WorkSafe NZ legislation which aims to ensure employee safety takes precedence. This is because SAIDI normalisation will not be triggered unless there is an event affecting many parts of the network, consequently SAIDI could become extremely large during major events.

This is demonstrated by the three day storm event in 2013/14 where WELL could not commence restoration immediately due to ongoing storm conditions making it too dangerous to send in field staff. WELL was not willing to risk the safety of lines workers by sending them into hazardous conditions in-order to minimise regulatory outcomes. As a consequence, WELL incurred 132 SAIDI minutes (over three times the current limit). If SAIFI was applied as the normalisation, WELL would have received no normalisation at all for this major event The Commission's proposal to normalise SAIDI based on SAIFI therefore effectively penalise EDBs that rightly place crew safety ahead of supply restoration.

Additionally, WELL notes that the Commission has normalised the raw SAIDI data used to set the targets by applying the SAIDI boundary value. However this means that the SAIDI target is not set consistently with the proposed normalisation method which is based on the SAIFI boundary value. As a result, the statistical properties associated with the IEEE method are lost as the probability of exceeding the SAIDI target and target plus one standard deviation become significantly greater than anticipated and the probability distribution no longer reflects a normal distribution. For all the reasons explained above, WELL recommends that SAIDI and SAIFI are normalised independently.

Method for determining the boundary value

WELL supports the principle that the method for calculating the SAIDI and SAIFI boundary values should be improved to better account for the presence of a large number of zero days in the historical dataset.

While the Commission has developed a method for accounting for zero event days, the IEEE standard already contains such a method. The IEEE method is developed by independent engineering experts and therefore WELL considers that it would be more appropriate to follow this method rather than develop an alternative method which is untested.

WELL therefore recommends that the IEEE method which accounts for zero event days should be used to calculate the boundary values.

6.3. Enforcement criteria

The Commission has proposed that in addition to the financial incentive scheme, it will still investigate and potentially take enforcement action in situations where in any one year an EDB exceeds it reliability target by more than one standard deviation above the mean. This proposed enforcement criterion is much stricter than the current regime where enforcement action is only possible if an EDB exceeds one standard deviation above the mean in the current year and in one of the two immediately preceding years.

Given a normal distribution of variation around a mean value, the probability of an EDB hitting the new proposed enforcement criteria is now 17% or approximately once in the five year regulatory period. The proposed approach will therefore make it even more difficult for the Commission to identify breaches resulting from natural variation or uncontrollable, unintentional adverse events as opposed to deliberate actions taken by management to reduce network performance.

WELL does not consider it necessary for the Commission to apply such strict enforcement criteria in addition to the financial incentive scheme which will result in automatic financial penalties to EDBs that exceed the quality target. The proposed financial incentive scheme provides an automatic deterrent to EDBs and is therefore a stronger mechanism than the current situation where there is uncertainty regarding the Commission's enforcement approach.

The Commission should revise the enforcement criteria such that it will only investigate if an EDB exceeds the mean plus one standard deviation in both the current year and the immediately preceding year.

In addition, the Commission has proposed that any financial penalties it imposes under its enforcement proceedings would be additional to the financial penalties already incurred by an EDB under the incentive scheme. WELL considers that this is highly inappropriate as it is effectively double punishment for the same reliability event(s). WELL recommends that the Commission explicitly provide for financial penalties incurred under the incentive scheme to be counted toward any financial penalty incurred under subsequent enforcement action relating to the same reliability event(s).

Furthermore, as noted above any financial incentive scheme and approach to enforcement must be cognisant of the relationship between reliability and the capex and opex allowances.

Finally, WELL is very concerned that the Draft Decision proposes that any reliability outcomes above the mean would be deemed non-compliant even though enforcement action would not occur until the mean plus one standard deviation is exceeded. It is highly inappropriate for the Commission to deem an outcome with a 50 percent probability of occurring as non-compliance with the rules and amounts to very heavy handed regulation. This proposal significantly increases the risk of reputational damage to EDBs and increases the costs to EDBs of managing internal and external stakeholders. This includes explaining to media and Board Directors that a non-compliance is not actually a breach of the requirements, has no risk of enforcement action and should be expected every two years on average. WELL does not see any benefit to the regulatory regime in deeming an outcome above the mean value as non-compliant, particularly when no action is to be taken. If the Commission intends to retain this proposal then it must explain what purpose it is intended to serve and how it will balance the potential negative outcomes EDB's will encounter.

6.4. Quality incentive scheme

WELL only supports the introduction of the proposed financial incentive scheme on the basis that, for the final decision, the Commission:

- Recalculate the target values without adjusting the raw data for past years where annual actual values exceeded the DPP limit;
- Normalise the raw historical data to establish the target based on the same normalisation method that is to be applied for the 2015-20 period;
- Provide for SAIFI and SAIDI to be normalised independently;
- Change the criteria for potential enforcement action such that an investigation only occurs if an EDB exceeds the mean plus one standard deviation in the current year and one of the two immediately preceding years (as per the status quo).
- Remove the classification of outcomes that exceed the target as 'non-compliant' as this serves no purpose and provides no value to the regulatory regime.

WELL does not support introducing an incentive scheme if the targets and normalisation method are not set consistently and are deliberately set to financially penalise EDBs that have breached the quality path in the past, despite no evidence of deliberate fault on the EDB's part.

6.5. *Subsequent submission on quality targets and incentives*

WELL will provide additional comment on the quality normalisation process and proposed incentives scheme in its submission on the Commission's *'Quality targets and Incentives'* consultation paper due 29 August 2014.

7. *D-factor energy efficiency scheme*

The Draft Decision proposes introducing a D-factor mechanism for the 2015-20 DPP to compensate EDBs for revenue losses attributable to demand side management or energy efficiency initiatives.

WELL supports the principle of ensuring EDBs are compensated for revenue losses associated with demand-side management and energy efficiency initiatives. Energy efficiency is an important factor in enhancing New Zealand's overall economic efficiency and EDBs are well placed to facilitate and contribute to energy efficiency improvements. Compensation for revenue losses is necessary to offset the current disincentive for EDBs to invest in these initiatives which is created by the current weighted average price cap form of control.

WELL is not opposed to the proposed D-factor scheme, but considers that in its proposed form it is likely to have minimal benefits compared to other options (i.e. a revenue cap) because:

- The proposed scheme only provides compensation for revenue losses and therefore is only intended to make EDBs neutral, at least in relation to revenue outcomes, on whether to invest in demand-side management and energy efficiency initiatives. The proposed scheme therefore is only intended to offset the current disincentives but does not provide positive incentives for investment.
- The proposed scheme, however, does not make EDBs neutral because:
    - EDBs retain risk that the Commission does not allow full compensation. The proposed scheme requires the Commission's ex post approval of the proposed revenue recovery. The proposed ex post approval process would create uncertainty regarding whether the Commission will allow recovery of the estimated revenue losses and, whether full or only partial recovery will be approved. Particularly given that the proposed approval criteria the Commission will take into consideration are principles-based which leaves considerable judgement and discretion to the Commission in relation to whether the evidence is sufficient to achieve its interpretation of the principles. Without certainty of cost recovery EDBs are less likely to participate in energy efficiency and demand-side management activities.
    - Revenue losses are recovered at less than the time value of money. The proposed scheme would enable recovery of the revenue losses two years following the year in which the loss is incurred, however the Commission has proposed only to apply the cost of debt as the time value of money rather than the WACC. This means that EDBs forego the true time value of money if they choose to invest in energy efficiency initiatives which are expected to lead to revenue losses. As a general principle, the Commission should always apply the WACC rather than the cost of debt as the time value of money, irrespective of whether it is EDBs or consumers that are recovering. This is discussed in more detail in section 10.
- In addition, the Commission states that compensation under the D-factor would only be available until the next price reset, at which point the Commission will factor in the reduced demand volumes into its starting price adjustment. In the absence of certainty regarding how the mechanism works beyond the current regulatory period, particularly given the current CPRG model is based solely on future forecasts of population and GDP growth, further risk and uncertainty prevails for EDBs.
- The proposed scheme does not provide any compensation for the costs of investment in energy efficiency initiatives that are not related to revenue losses. Demand side management programmes can lead to additional opex costs that would not have been incurred if traditional network solutions were implemented through capex.

The different retention factors applied in the Commission's proposed opex and capex incentive schemes means that EDBs face higher penalties for over-spending the opex allowances relative to underspending the capex allowances. Therefore EDBs are not kept whole from investments in demand-side management initiatives even with a potential recovery of foregone revenue. This is also a concern in situations where the cost-benefit case to an individual EDB of an initiative is not NPV positive, but the initiative would have provided third party benefits and would therefore have provided a net social benefit.

WELL notes that the D-factor scheme previously applied in New South Wales has had limited success with few applications for revenue recovery and limited observed energy efficiency activity taking place. The Australian Energy Regulator has now indicated its intention to remove the D-factor scheme and introducing a revenue-cap as the form of control for the 2014-19 regulatory period as this is more effective means of promoting effective demand management initiatives.

Based on the above WELL considers that the proposed D-factor scheme does not fully achieve the objectives of section 54Q of the *Commerce Act 1986* as it does not promote incentives for energy efficiency and demand side management and goes only part of the way towards removing disincentives.

WELL considers that it would be significantly more consistent with the low cost intent of DPP regulation if the Commission were to replace the weighted average price cap form of control with a revenue cap. This approach would provide more certainty to EDBs of revenue recovery ex ante and would not involve the administrative burden of the proposed D-factor scheme.

Notwithstanding, if the Commission retains the proposed D-factor scheme then WELL:

- Supports a broad definition of what constitutes energy efficiency and demand-side initiatives which is not limited to regulated activities. A broad definition prevents a situation where the definition constrains the types of innovations that are considered;
- Recommends that the Commission provide for an ex ante process for seeking approval to recover revenue losses associated with the proposed initiative. This would reduce the uncertainty associated with the Commission declining recovery of revenue losses after the investment is already made.
- Recommends that the WACC is applied as the time value of money for the delayed recovery of revenue losses. This ensures that the true time value of money is recovered.
- Recommends that a positive incentive is provided by applying an incentive factor above 1 to revenue losses.

8. *Treatment of pass through and recoverable costs*

Pass through and recoverable costs are third party charges that EDBs should be able to fully recover from customers without any risk of accidentally breaching the price path or failing to fully recover the costs.

The Draft Decision proposes a hybrid mechanism for the recovery of pass through and recoverable costs. First transmission charges are to be treated independently of the DPP price path compliance test and a separate compliance test is applied. Second, all other pass through and recoverable costs must be 'ascertainable' before being passed onto customers. Third, some certain charges are subject to pre-approval.

WELL consider this two stage approach is unnecessarily complex and does not enable EDBs to fully recover theses third party costs. This is because:

- EDBs never recover one full year of non-transmission pass through and recoverable costs that are not ascertainable at the time that prices are set. This is because there is always a one year delay in recovering the non-ascertainable costs which is never corrected.
- The Commission proposes to apply the costs of debt as the time value of money and therefore EDBs cannot expect to recover the true time value of money on non-ascertainable costs.
- There is a degree of judgement regarding what is an 'ascertainable' cost.

- Different charges are to be treated differently depending on the combination of categories the costs fall into. This creates a matrix of outcomes as costs are to be categorised as each of:
    - Ascertainable or not ascertainable;
    - Transmission or non-transmission;
    - Pass through or recoverable;
    - Requiring Commission pre-approval or not.

A more simple approach is to treat all pass through and recoverable costs in the same way by introducing a simple annual correction mechanism into the price path compliance test. The simple correction mechanism would work as follows:

- EDBs forecast pass through and recoverable costs relating to period t for the purposes of setting prices in period t (as per the status quo);
- EDBs report in the annual compliance statement the difference between the actual charges and the forecasts included period t prices;
- The difference between the actual and forecast costs in period t is added to the price path formula in period t+2;
- The time value of money based on the WACC is applied.

This approach is clean and simple and therefore more consistent with the low cost intent of the DPP.

Additionally, if the Commission is concerned about the potential for there to be significant differences between actual and forecast charges, it could limit the size of the recovery of under or over-forecast of charges to 2% of annual revenue, where EDB's can reasonably be expected to forecast with accuracy. This would ensure that EDBs still have a strong incentive to forecast as accurately as possible.

It is appropriate that the Commission apply the WACC as the time value of money for both under or over-recoveries. Applying the WACC is essential because it reflects the true time value of money, as discussed in section 10. Unlike the cost of debt, applying the WACC ensures that EDBs are neutral to under or over-recovering third party costs in any given year.

9. *Compensation for catastrophic events*

The Draft Decision discusses the Commission's proposal to amend the Input Methodologies (**IM**) to provide compensation for costs incurred as a result of catastrophic events. The Draft Decision proposes that following a catastrophic event:

- EDBs should be compensated for prudent net costs incurred before the DPP is reset.

  WELL supports this principle.

- EDBs should be compensated for prudent net cost forecasts to be incurred after the DPP is reset.

  WELL supports this principle.

- EDB should only be compensated for the impact of the catastrophic event on future demand but not compensated for the impact on demand before the DPP is reset.

  WELL does not support this principle for the reasons set out below.

- The compensation be implemented a recoverable costs in the DPP price path formula;

  WELL supports this principle.

- The cost of debt be applied as the time value of money

  As discussed in section 10, WELL does not support the use of the cost of debt as the time value of money because it does not reflect the true time value of money and consequently EDBs are not able to fully recover the costs of the catastrophic event.

WELL considers that the basis for the Commission's current position that EDBs should not be compensated either ex ante or ex post for revenue losses following catastrophic risk is incorrect for the following reasons:

- The Commission has previously stated and continues, in the Draft Decision, to apply the argument that diversified investors can minimise the impact of catastrophic risk by diversifying their investments such that risks specific to one investment are offset by unexpected positive benefits from other investments. As previously explained by WELL catastrophic risk is a type 1 asymmetric risk for which there is no potential countervailing upside event of the same magnitude. Asymmetric risks therefore cannot be diversified through investment as there is no equivalent offsetting investment available. Even if an EDB invested in every single other EDB around the world, which is impracticable, there is still no guarantee that all the demand from the EDB that experienced the catastrophic risk eventuates elsewhere. Some demand losses may occur due to household composition changes leading to less consumption per person or economic activity that dissolves rather than relocating. WELL does not consider that the level of diversification of the investor of an EDB that experiences catastrophic event should have any bearing on the principle that each individual EDB should have an ex ante expectation of full cost recovery. Therefore the Commission cannot use this argument as a justification for not providing compensation for revenue losses.
- If the Commission does not enable EDBs to recover revenue losses associated with catastrophic events either ex ante or ex post then EDBs can only expect to recover less than their efficient costs as there is a real risk of significant revenue losses associated with catastrophic events. For some EDBs the ex ante probability of the risk eventuating is greater than for others. As noted by Professor Yarrow:[14]

  > *"Looking at matters ex ante, it is reasonable to anticipate that a regulator will allow for the recovery of efficiently incurred, expected costs (where by expected costs is meant the mathematical expectation or mean of probabilistic cost projections). Expected costs caused by catastrophic events are properly included in this calculation."*

EDBs must be compensated for catastrophic risk either ex post or ex ante. WELL considers that an ex post approach would be more appropriate and significantly less costly for consumers. The ex ante cost of catastrophic risk insurance is estimated by Aon[15] to be approximately 10% of the insured limit which requires a catastrophic event to occur every ten years for consumers to be neutral.

WELL strongly recommends that the Commission include in the proposed catastrophic event allowance the ability for EDBs to recover revenue losses associated with catastrophic events that are incurred before the price path is reset.

WELL will provide an additional submission on this matter in response to the Commission's policy paper and Draft IM amendments that are intended to give effect to the Commission's proposed policy on 29 August in accordance with the submission due date.

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[14] Professor Yarrow, *The Orion CPP Determination*, report prepared for the Commerce Commission, June 2013, Page 4.

[15] AON, *Orion & Risk Financing*, Letter to Commerce Commission, 24 July 2013.

10. Time value of money

The Commission has taken an opportunistic approach to its decision making in relation to whether the cost of debt or WACC should apply as the time value of money. When EDBs are required to return money to customers the Commission tends to apply the WACC but when EDBs are recovering costs from customers the Commission tends to apply only the cost of debt.

Similarly, the Draft Decision proposes different time value of money assumptions be applied depending on the costs in question, for example for the delayed recovery of pass through and recoverable costs the cost of debt is proposed while for the purposes of the opex and capex IRIS the WACC is proposed. For the purposes of calculating the proposed capex wash up the Commission applies the WACC to calculate the amount of the adjustment to the price path and then uses the cost of debt as the time value of money for the application of the adjustment to prices.

The Commission's DPP financial model consistently assumes that the WACC is the time value of money for an EDB, for instance:

- Any cash flows which occur at mid-year which are required to be escalated to the end of the year are escalated by half a year's WACC.
- The smoothing of maximum allowable revenue to recover building block costs is performed using WACC as the time value of money.

In the DPP financial model, any asset owned by the EDB earns a WACC return, including fixed assets and deferred tax assets. There is no reason why a deferred revenue asset (e.g. unrecovered pass through costs) should be treated any differently.

Economic theory also supports this approach. The WACC is the opportunity cost of capital for both EDBs and customers. The WACC is determined by the riskiness of an investment (a distribution network in this case) and represents the return that EDBs or customers would forego for an investment with a similar degree of risk.

WELL strongly recommends that the Commission consistently apply the WACC as the time value of money across all situations. The Commission's current opportunistic approach is not supported by economic theory and is inconsistent.

11. Closing

WELL appreciates the opportunity to provide a submission on the Commission's Draft Decision for the 2015-20 DPP and would welcome the opportunity to discuss with the Commission any of the matters raised in this submission.

WELL notes that it will make subsequent submissions on the following consultation papers published by the Commission on 18 July 2014:

- Policy paper on the proposed quality targets and incentives and publication of supporting models;
- Policy paper on the proposed compliance regime;
- Draft DPP Determination which includes details of the price path formula and adjustment mechanisms;
- Policy paper and draft IM amendments that are intended to give effect to the proposals in the policy papers relating to the Draft Decision, quality targets and incentives, and compliance regime and the draft DPP Determination;
- Policy paper and draft IM amendments relating to the proposed opex and capex incentive schemes.

Given that many issues are covered, to varying degrees, across a number of the Commission's consultation papers, WELL's expectation is that the Commission will consider all of WELL's submissions in relation to each issue.

Please do not hesitate to contact Megan Willcox, Senior Regulatory Economist, on MWillcox@welectricity.co.nz if you have any queries.

Yours sincerely

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